VENCorp

ELECTRICITY ANNUAL PLANNING REPORT

2004

JUNE 2004

DISCLAIMER

ELECTRICITY ANNUAL PLANNING REPORT 2004

EXECUTIVE SUMMARY

VENCorp is the monopoly provider of shared transmission network services in Victoria, and has responsibilities under various legal and regulatory instruments to plan and direct the augmentation of the shared transmission network within Victoria. As such, VENCorp is registered as the Transmission Network Service Provider for the shared transmission network in Victoria under the National Electricity Code (NEC). This Annual Planning Report examines the adequacy of the Victorian transmission network to meet the long-term requirements of Victorian electricity customers and provides the first step in VENCorp's consultations with interested parties in relation to possible future transmission network augmentation. Issues relating to supply/demand balance in Victoria are the responsibility of NEMMCO and are covered in NEMMCO's Statement of Opportunities.

Intra-Regional Energy/Demand Projections

Three scenarios of Victorian load growth are provided for the next ten years. These are based on scenarios of electricity sales developed for VENCorp by the National Institute of Economic and Industry Research (NIEIR). The medium growth scenario provides forecasts of the sales that could be expected under the most likely economic growth conditions. NIEIR also provides forecasts of Summer and Winter maximum demands, which take into account ambient temperature conditions.

Between 2004 and 2009 the medium scenario averages a projected growth in electricity consumption of 1.9% per annum, a growth in Summer maximum demand of 2.8% per annum and a growth in Winter demand of 2.1% per annum. These forecasts are slightly higher than the forecasts provided for the next five years in the 2003 Annual Planning Review, and also confirm the continued divergence between growth in Summer maximum demand and annual energy growth, predominantly due to increasing penetration of domestic and commercial air conditioning. Between 2009 and 2014 the medium scenario averages a projected growth in electricity consumption of 1.9% per annum, a growth in Summer maximum demand of 2.5% per annum and a growth in Winter demand of 2.1% per annum.

The system load growth scenarios, together with individual supply point loading information from the Distribution Companies, form the basis for the assessment of transmission adequacy over the planning horizon. Winter 2004 and Summer 2004/05 maximum demand forecasts are shown below for the 10%, 50% and 90% POE[1], also included is the forecast energy usage for 2004/05.

[1] Probability Of Exceedence is usually expressed in terms of 10, 50 or 90 percentile seasonal MDs which correspond to average daily temperatures. For instance a Summer 10% POE MD correlates to an average temperature (average of the minimum overnight and maximum daily ambient temperature), being exceeded, in the long run average, on 10% of occasions (i.e. 1 Summer in 10).

MAXIMUM DEMAND			
Probability of exceedence once or more in one Season (Summer / Winter)	10%	50%	90%
Winter average Melbourne temperature	5.0°C	6.8°C	8.0°C
Maximum Demand Winter Forecast (2004)	8,072 MW	7,864 MW	7,694 MW
Summer average Melbourne temperature	32.9°C	29.6°C	27.1°C
Maximum Demand Summer Forecast (2004/05)	9,787 MW	8,997 MW	8,482 MW
ENERGY			
Economic growth level	Base	High	Low
Economic growth rate (2004/05)	2.2%	3.4%	1.1%
Annual Energy consumption (2004/05)	50,402 GWh	50,987 GWh	49,879 GWh

The energy forecast for 2004/05 remains largely unchanged from the 2003 APR. The 10% summer MD has increased by approximately 57MW or 0.06% from the previous year. The 10% winter MD has increased by approximately 100MW.

Intra-Regional Network Adequacy

The intra-regional network adequacy chapter provides a description of the existing shared network and its ability to meet the actual and forecast 2003/04 Summer peak demand conditions. The chapter also includes a review of the shared network conditions such as peak demands, high spot prices, and significant system incidents that have occurred during Summer 2003/04. An overview of the active and reactive supply demand balance at times of peak demand is also included to identify and highlight the importance of the Victorian forecast reserve level and Summer aggregate generation capacity for 2003/04, and the current maximum supportable demand in Victoria. A summary of fault levels with the margin available is included for the Victorian terminal stations. It is a VENCorp responsibility to ensure fault levels are always maintained within plant capability in the transmission network.

Intra-Regional Proposed Network Developments Within 5 Years

VENCorp undertakes the responsibility for removal of transmission network constraints in accordance with its Licence obligations, the National Electricity Code and the Victorian Electricity System Code. Additionally the feasibility of transmission projects are assessed using the Regulatory Test as specified by the ACCC.

VENCorp considers the major, economic benefits associated with transmission investment are:

- a reduction in the amount of expected unserved energy;
- a reduction in the use of ‘out of merit order’ generation;
- a reduction in real and reactive transmission losses; and
- deferral of reactive plant.

The unserved energy resulting from network constraints has been assessed using a Value of Customer Reliability (VCR) that represents an economic value assigned to the end use of electricity of $29,600/MWh. Application of the VCR allows expected unserved energy to be economically quantified, thereby justifying investment decisions.

A probabilistic approach is applied in the assessment of cost and benefits of transmission augmentation. It considers the likelihood and coincidence of the contingency event and the onerous loading and ambient conditions. VENCorp's detailed "Electricity Transmission Network Planning Criteria" is available at www.vencorp.com.au. Importantly, the application of an expected unserved energy implies that under some conditions it is actually economic to have load at risk following a credible contingency.

The design principles used by VENCorp for planning the transmission network are as follows:

- Following a single contingency, the system must remain in a satisfactory state (i.e. no performance or plant limit breached).
- Following the forced outage of a single contingency, it must be possible to re-adjust (secure) the system within 30 minutes so that it is capable of tolerating a further forced outage and remain in a satisfactory state (i.e. no performance or plant limit breached).
- Sufficient periods are available to allow maintenance of critical shared network elements without exposing the network to excessive risk in the event of a further unscheduled outage of a network element.
- Load shedding and re-dispatch of generation are considered as legitimate options to network augmentation.

For each constraint investigated one of the following three options apply:

- For large network augmentations a detailed public consultation will be undertaken for each of the projects in accordance with the Clause 5.6.6 of the National Electricity Code, defined for projects that have a capital cost greater than $10 million dollars.
- Small network augmentations have a capital cost less than $10 millions dollars and greater than $1 million dollars. This APR forms the basis for consultation process in accordance with Clause 5.6.6A of the National Electricity Code. Interested parties are invited to make submissions regarding the proposed augmentations and any non-network options they consider as an alternative. The closing date for submissions is Friday 30th July 2004.
- Some constraints have no economic network solution at this point in time.

The following table details the potential constraints identified:

Constraint Group	Section	Constraint	Augmentation Type	Date	Estimated Cost ($K)
South East Metropolitan Radial Network	6.6	Loading of Rowville to Springvale and Heatherton 220 kV Lines	Small Network Augmentation	Dec 2005	2,000
	6.7	Loading of Rowville to Malvern 220 kV Radial Lines	Emerging constraint		To be Determined
	6.8	Security of Double Circuit 220 kV Lines to South East Metropolitan Area	No economic solution identified (security Issue)		To be determined
South East Metropolitan Meshed Network	6.9	Loading of 500/220 kV and 330/220 kV Metropolitan Tie Transformers & associated 220 kV links	Small Network Augmentation	Dec 2005	6,000
			Large Network Augmentation	Dec 2006	45,000
Western Metropolitan	6.10	Loading of Geelong to Keilor 220 kV Lines and Keilor 500/220 kV Transformers	Minor Network Augmentation	Dec 2004	400
			Large Network Augmentation	Dec 2006	26,000
	6.11	Loading of Keilor to West Melbourne 220 kV Lines	Minor Network Augmentation	Dec 2004	400
	6.12	Loading of Fisherman's Bend to West Melbourne 220 kV Circuits	Emerging constraint		To be determined
Hazelwood Transformers	6.13	Loading of Hazelwood 500/220 kV Tie Transformers	Large Network Augmentation	Dec 2008	25,000
State Grid (High Export)	6.14	Loading of Moorabool to Ballarat 220 kV Lines	Minor Network Augmentation	Nov 2005	400
	6.15	Loading of Ballarat to Bendigo 220 kV Line	Emerging constraint		To be determined
State Grid (High Import)	6.16	Loading of Shepparton to Bendigo 220 kV Line	Emerging constraint		To be determined
	6.17	Loading of Murray to Dederang 330 kV Lines	Emerging constraint		To be determined
	6.18	Loading of Dederang to South Morang 330 kV Lines	Emerging constraint		To be determined
	6.19	Loading of 330/220 kV Dederang Tie Transformers	Minor Network Augmentation	Dec 2004	100
	6.20	Loading of Eildon to Thomastown 220 kV Line	Emerging constraint		To be determined
Reactive Support	6.21	Reactive Support for Maximum Demand Conditions	Emerging constraint		To be determined

Intra-Regional Possible Network Developments Within 10 Years

This chapter provides a ten-year outlook to indicate possible constraints that may occur in the period up to 2013/14, together with transmission options and associated costs, to remove the constraints, assuming the full forecast Victorian demand is to be supported.

The network has been modelled with a demand of 12,350 MW in 2013/14. Assuming 300 MW export to South Australia, 1,900 MW import from NSW, 600 MW import from Tasmania and 265 MW Victorian local reserve[2] requirement, approximately 2,050 MW of new generation capacity will need to be added by 2013/14. As the location and size of generation will impact on the transmission needs, a range of supply scenarios, which load up different parts of the network, have been examined.

	Increased LV Gen	Increased Import from NSW/Snowy	Metro Generation/DSM	Total Cost $M
Scenario 1	1,450 MW	0 MW	600 MW	465
Scenario 2	1,270 MW	180 MW	600 MW	470
Scenario 3	670 MW	180 MW	1,200 MW	306
Scenario 4	850 MW	600 MW	600 MW	344
Scenario 5	1,150 MW	600 MW	300 MW	344
Scenario 6	150 MW	1,600 MW	300 MW	520

Inquiries

VENCorp is pleased to provide any interested party with more detailed information on specific planning issues at any time. Interested parties should contact:

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[2] Victoria and South Australia combined regional reserve requirement is 530 MW

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ABBREVIATIONS

The following abbreviations are used through out this report:

ACCC	Australian Competition and Consumer Commission
APR	Annual Planning Report
BoM	Bureau of Meteorology
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
EHV	Extra High Voltage
GSP	Gross State Product
GWh	Giga Watt Hours
km	Kilometers
kV	Kilovolts
LOR2	Lack of Reserve Level 2
LRA	Long Run Average
M	Million
MD	Maximum Demand
MVA	Megavolt Amps
MVAr	Megavolt Amps reactive
MW	Mega Watts
MWh	Mega Watt hours
NEC	National Electricity Code
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NIEIR	National Institute of Economic and Industry Research
POE	Probability of Exceedence
SOO	Statement of Opportunities
TNSP	Transmission Network Service Provider
TXU	Texas Utilities
UE	United Energy
VCR	Value of Customer Reliability

ELECTRICITY ANNUAL PLANNING REPORT

2004

1. INTRODUCTION

VENCorp is the Transmission Network Service Provider for the shared transmission network in Victoria under the National Electricity Code (NEC) and as such has entered into an access undertaking with the ACCC regarding provision of access to the transmission network.

VENCorp's functions in relation to electricity are:

- to plan and direct the augmentation of the shared transmission network[3] to provide an economic level of transmission system capability consistent with market reliability requirements and expectations, and to advise and liaise with NEMMCO on network constraints, including interconnection transfer limits;
- to procure 'bulk' transmission network services from asset owners consistent with the above;
- to provide shared transmission network services to network users for a price consistent with the National Electricity Code and ACCC requirements;
- to monitor and report on the technical compliance of connected parties to the shared transmission network in terms of quality of supply and control systems, and provide power system data and models to NEMMCO;
- to participate in market development activities in the areas that affect VENCorp's functions;
- to assist in managing an electricity emergency by liaising between the government and NEMMCO, communicating with the Victorian industry and community both before and during an emergency and entering into agreements with distributors and retailers regarding load shedding arrangements; and
- to provide information and support to the Victorian Government.

[3] The term 'shared network' is defined in more detail at the VENCorp website (www.vencorp.com.au), and in VENCorp's electricity transmission licence (www.esc.gov.au).

The NEC requires VENCorp, the TNSP for the shared network in Victoria, to undertake an annual planning review and produce an Annual Planning Report. This report must set out:

(1) The forecast loads submitted by a Distribution Network Service Provider;

(2) Planning proposals for future connection points[4];

(3) A forecast of constraints and inability to meet the network performance requirements; and

(4) Detailed analysis of all proposed augmentations to the network. These augmentations may be either small or large network augmentations.

The National Electricity Code requires NEMMCO to publish a Statement of Opportunities on 31 July each year, which examines the supply/demand balance within each region of the national market and the transmission capability, which connects regions. VENCorp provides the load forecasts, network adequacy and network development as inputs to the NEMMCO document.

The scope of this VENCorp Electricity Annual Planning Report (APR) is therefore confined to assessing the adequacy of the Victorian shared transmission network to meet the Victorian load growth over the next 10 years.

In addressing this issue, this report considers:

- the most recent information on forecast Victorian electricity demands;
- the most recent information on transmission plant performance;
- possible scenarios for growth in the demand of Victorian electricity consumers; and
- the impacts of committed projects for additional generation or augmentation of a transmission network or a distribution network.

1.1 Purpose of the Report

The NEMMCO Statement of Opportunities provides the primary document for reviewing the supply/demand balance in each state and across the National Electricity Market. The VENCorp Annual Planning Report provides a review of the adequacy of the Victorian shared transmission network to meet load growth over the next 10 years. Both documents provide information to industry participants and potential participants on opportunities to invest in infrastructure or to connect loads or generation.

[4] The adequacy and reliability of the sub transmission and distribution networks, which are owned, operated, maintained and planned by the five distribution companies have not been considered in this document. These issues are subject to oversight by the Essential Services Commission (ESC). Distribution Companies are also responsible for the planning of the transmission connection assets from which they take supply and publish a connection asset planning document which is available on their specific websites. This document provides information on the transformation capability (compared to historic and forecast loads) for each terminal station supplying the Distribution Companies. This information can be used to assess the level of energy at risk at the various terminal stations in the event of a transformer failure.

This year the Ministerial Council on Energy has also progressed reforms relating to transmission planning and has requested that NEMMCO produce an Annual National Transmission Statement (ANTS) and to standardise the jurisdictional APRs with the ANTS. This year's Annual Planning Report reflects some of these changes.

The Annual Planning Report does not define a specific future development plan for the shared network. It is intended to be the first stage of a consultation process aimed at providing an economically optimum level of transmission system capacity.

VENCorp is pleased to provide any interested party with more detailed information on specific planning issues at any time. Interested parties should contact:

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1.2 Standardisation of the Report

To assist in the delivery of information, VENCorp along with the other jurisdictions across the National Electricity Market (NEM) have adopted a common approach to the layout of all review documents. This standardisation will allow readers of any APR to find the same relevant information across the same chapters. This standardisation of the review will be as follows:

Chapter 2 - of the review presents a summary of relevant committed developments that will impact on the major national transmission flow path.

Chapter 3 - of the review present intra-regional energy/demand projections of future Victorian load which take into account:

- the variability of load with temperature; and
- different economic scenarios.

This chapter also reconciles the recent performance of the load forecasts and provides commentary on the important characteristics of Victorian electricity demand that influence the amount of energy at risk for a given transmission system capability.

Additionally this chapter provides detail on the Victorian DNSP load forecast and appendix A provides copies of the complete forecasts.

Chapter 4 - reviews the Intra-Regional network adequacy to meet demand and lists current and committed network developments.

Chapter 5 - provides information on intra-regional committed network augmentations.

Chapter 6 - provides information on intra-regional proposed network developments within 5 Years. Potential transmission constraints over the next five years are assessed and transmission augmentation options available to maintain the reliability of the network in the most economic manner are then considered.

Chapter 7 - provides intra-regional possible network developments within 10 Years. This chapter takes a more scenario based approach and is provided as a guide for what is likely to occur outside the detailed 5 year planning timeframe.

1.3 Feedback on the Report

In line with a continuous improvement focus VENCorp is happy to receive any comments about the format and content of its Electricity Annual Planning Report (APR) document. Any interested parties wishing to make comment are encouraged to do so by contacting:

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2. SUMMARY OF RELEVANT MAJOR NATIONAL TRANSMISSION FLOW PATH DEVELOPMENTS

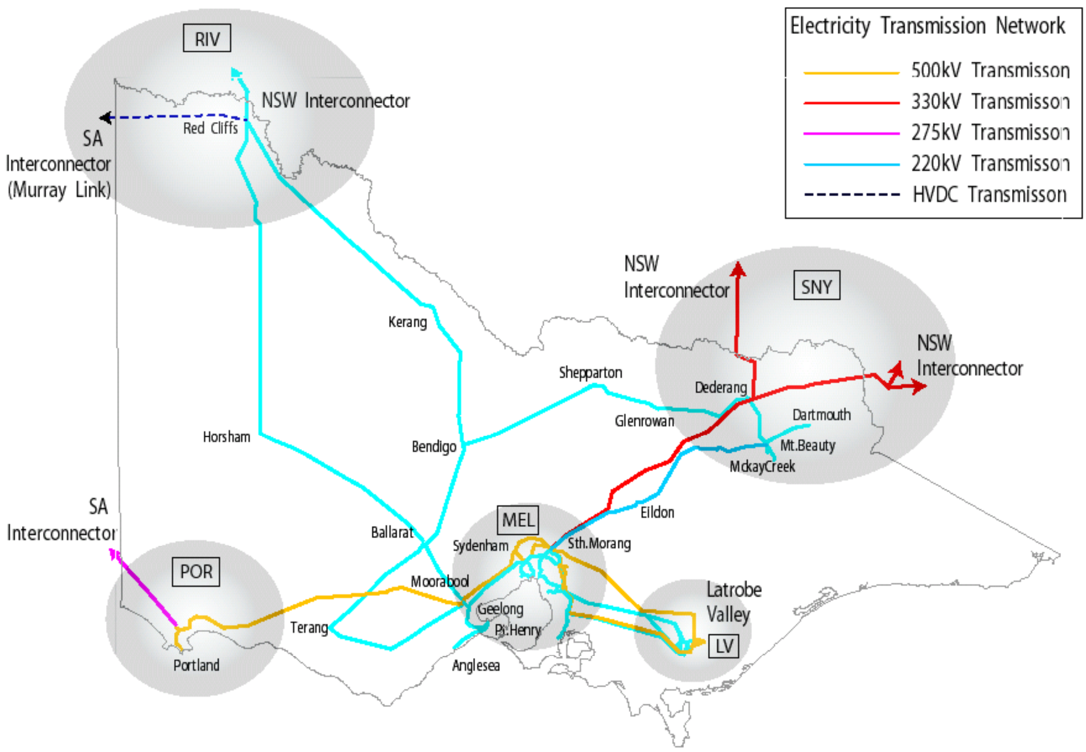
2.1 Introduction

To assist in the delivery of information, VENCorp along with the other jurisdictions across the National Electricity Market (NEM) have adopted a common approach to the layout of all Annual Planning Reports. This standardisation will allow readers of any APR to find the same relevant information across the same chapters.

This chapter of the APR provides a summary of relevant major national transmission flow path developments, which are committed projects. The definition of a major national flow path development is as follows:

"Major national transmission flow path" means those elements of the transmission networks used to transport significant amounts of electricity between generation centres and major load centres.

The shaded areas in the diagram below detail the centres between which the major national flow paths in Victoria can be deduced:



- LV – Latrobe Valley
- POR – Portland
- MEL – Melbourne, Geelong
- SNY – Snowy, Wagga & Northeast Victoria
- RIV – Southeast New South Wales, South Australian Riverland & North West Victoria

The committed projects, which will have an impact on major flow paths in the next 12 months are as follows:

- Latrobe Valley to Melbourne - Fourth 500 kV line [LV – MEL]
- Murraylink Regulation Project [RIV]
- Basslink [LV]

2.2 Latrobe Valley (LV) to Melbourne (MEL) – Fourth 500 kV line

In 2002/03, VENCorp undertook a public consultation process on its assessment of the optimum capacity for the Latrobe Valley to Melbourne electricity transmission network. This was in accordance with the ACCC Regulatory Test and from this process it was identified that the one of the Latrobe Valley to Melbourne transmission lines should be converted from operation at 220 kV to operation at 500 kV and that a 500/220 kV 1,000 MVA transformer should be installed at the Cranbourne Terminal Station for service by December 2004.

This project reduces the risk of load shedding as a result of 500 kV line outages, reduces transmission losses and will further improve the reliability and security of supply to the eastern metropolitan area, and compliment the distribution businesses' development of 220/66 kV transformation at Cranbourne.

Works include conversion of the Hazelwood to Rowville No.3 line to operation at 500 kV, development of a 500 kV switchyard and installation of a 1000 MVA, 500/220 kV transformer at Cranbourne Terminal Station, reconfiguration and circuit breaker replacement in the Latrobe Valley network and re-instatement of the Hazelwood to Jeeralang No.2 220 kV line.

Following a tender process commenced in April 2003, VENCorp has contracted with SPI PowerNet for provision of contestable network services comprising a 500 kV switchyard and a 500/220 kV 1,000 MVA transformer at Cranbourne by December 2004. For provision of non-contestable works, contracts were made with the two incumbent network owners, SPI PowerNet and Rowville Transmission Facility Pty Ltd.

The project is in progress to meet the target service date by December 2004.

2.3 Murraylink Regulation Project (RIV)

Murraylink is an electricity transmission asset operated by the Murraylink Transmission Company (MTC). It provides a connection between Red Cliffs Terminal Station in Victoria and Monash substation in South Australia and has a rated capacity of 220 MW. The connection was established as a privately funded asset funded as a Market Network Service Provider (MNSP).

In October 2003, the ACCC approved Murraylink's application for conversion to a prescribed service and set a maximum allowable revenue. As part of its decision, the ACCC approved augmentations to the Victorian shared transmission network which will allow for 220 MW transfer capacity across Murraylink from Victoria to South Australia during peak periods.

The works involve seven new capacitor banks, modifications to five existing capacitor banks and schemes for very fast run-back of Murraylink for transmission outages.

The works are expected to have a capital cost of around $15 M capital and the project is being considered as a "new large network asset" for the purposes of this application. The ACCC has consulted on this matter and is satisfied that the augmentation works satisfy the regulatory test.

The project is expected to commence in the second half of 2004 with a service date of mid 2005.

2.4 Basslink

Basslink has been proposed as a monopolar DC link with connection points at Loy Yang 500 kV bus in Victoria's Latrobe Valley and George Town 220 kV bus near Tasmania's north coast. The technology of the converter stations utilises solid-state thyristor switched converter bridges.

Its design capacity is 480 MW continuous import from Tasmania and up to 600 MW short term, and 500 MW export to Tasmania.

Preliminary assessment has been made of the effect of Basslink on Victorian export limits based on transient stability and indicative import limits have been calculated based on voltage control and thermal considerations. The assessment shows only minor impact (<80 MW) on the export capability to Snowy and South Australia with concurrent 500 MW to Tasmania. The import capability from Snowy may reduce by up to 110 MW for the full 600 MW import from Tasmania condition. For further information on Basslink see the NEMMCO website (www.nemmco.com.au/future/interconnectors/basslink) for the Interconnector Options Working Group (IOWG) technical assessment.

Basslink is a Market Network Service Provider and is planned for service in November 2005.

3. INTRA-REGIONAL ENERGY/DEMAND PROJECTIONS

3.1 Introduction

This chapter presents the load forecasts for Victoria, both Summer and Winter peak demands and annual energy for the next 10-year period. Previous forecasts and actual loads are compared and the characteristics of the Victorian demand are also discussed.

Load forecasts are a key element in assessing future transmission adequacy. The load forecasts presented here are also provided to NEMMCO under Clause 5.6.4 of the National Electricity Code for inclusion in the Statement of Opportunities.

VENCorp commissioned the National Institute of Economic and Industry Research (NIEIR) to produce macroeconomic forecasts for Victoria and, from these forecasts develop the electricity load forecasts presented here.

3.1.1 Forecasts for 2004/05 and Percentile at a Glance

Forecast Victorian electricity energy use for the year ending 30 June 2005 and peak half hour average demands in Summer 2004/05 and Winter 2004 forecasts, measured at the terminals of generators dispatched by NEMMCO (including Anglesea Power Station) are shown.

Forecast Energy, Medium Growth Scenario, year ending 30 June 2005 – 50,402 GWh

Probability of exceedence in one Summer	10%	50%	90%
Melbourne CBD average daily temperature	32.9°C	29.6°C	27.1°C
Maximum Forecast Demand	9,787 MW	8,997 MW	8,482 MW

Table 3.1 - Maximum Demand Forecast, Medium Growth Scenario, Summer 2004/05

Probability of exceedence in one Winter	10%	50%	90%
Melbourne CBD average daily temperature	5.0°C	6.8°C	8.0°C
Maximum Forecast Demand	8,072 MW	7,864 MW	7,696 MW

Table 3.2 - Maximum Demand Forecast, Medium Growth Scenario, Winter 2004

Summer 2004/05 forecast MD has increased 57 MW (0.6%) compared to last year's forecast, to 9,787 MW. The change is dominated by increased air conditioning and consistent with last Summer's high long run average temperatures - 20.8 ^{o}C (27th percentile).

3.2 Forecasts (2004/05 –2013/14)

3.2.1 Economic Forecasts

NIEIR based its forecasts of Victorian electricity consumption on its three Victorian economic outlook scenarios, corresponding to medium (or base), high and low economic growth. Three sets of energy and maximum demand forecasts are presented, one for each scenario.

For each scenario, NIEIR uses its econometric model to assess expected Victorian macroeconomic activity as a component of the world and Australian economies. Forecasts of Victorian industry output by sector, capital stocks, dwelling formation numbers and population are obtained, forecasting in turn the Victorian Gross State Product (GSP).

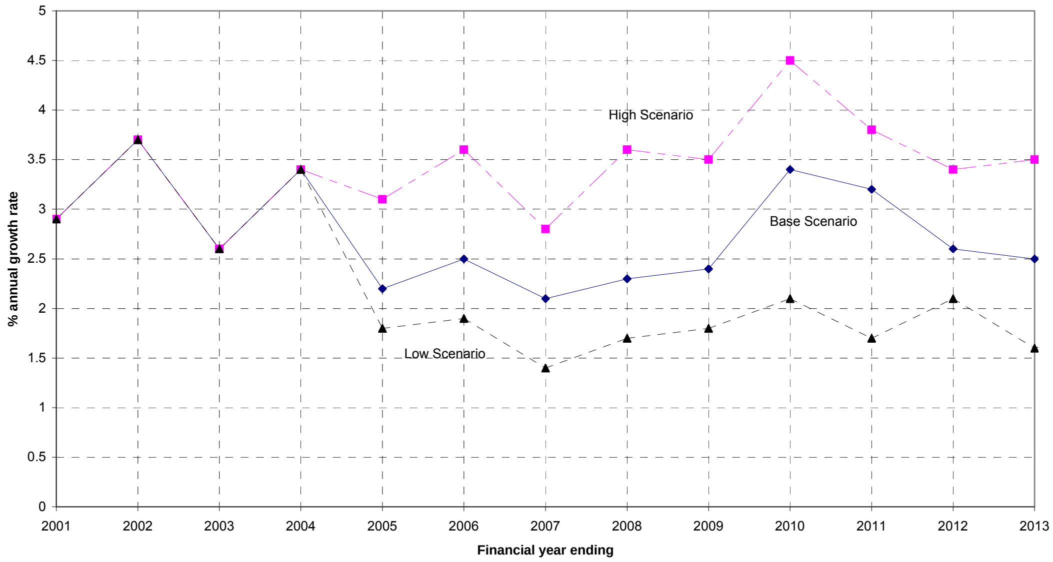


Figure 3.1 - Victorian GSP Growth Rates

Figure 3.1 above shows the outlook for Victorian GSP growth over the period to 2012/13 for the base, high and low growth scenarios. On average Victorian GSP growth averages 2.7% under the base scenario between 2002/03 and 2013/14, 3.6% under the high scenario and 1.9% under the low scenario.

Victorian GSP growth moderated in 2002/03 following very strong growth over the previous five years. Victorian GSP growth was 2.6% in 2002/03 following growth of 3.7% in 2001/02. Recovery from the drought, stronger business investment and consumption expenditure led to stronger Victorian GSP growth of 3.4% in 2003/04. Falls in private dwelling investment and slower growth in Victorian private consumption expenditure reduce Victoria's GSP growth rate over 2004-05 and 2005-06. Victorian GSP growth in 2004/05 and 2005/06 is 2.2 and 2.5% respectively. Victorian GSP growth over the period 2002/03 to 2007/08 is forecast to average 2.5%. Weaker economic growth over the next three to four years in Victoria, compared to the national economy, is consistent with previous experience (following periods of high economic growth).

3.2.2 Energy Forecasts

Figure 3.2 shows the actual and forecast Victorian electricity energy use levels for the three economic scenarios. Annual growth rate (medium scenario) for 2004/05 is forecast to be 2.2% and subsequently range from 1.5% to 2.3% over the remaining ten years to 2013/14. These growth forecasts are based on the economic forecast provided to VENCorp in April 2004.

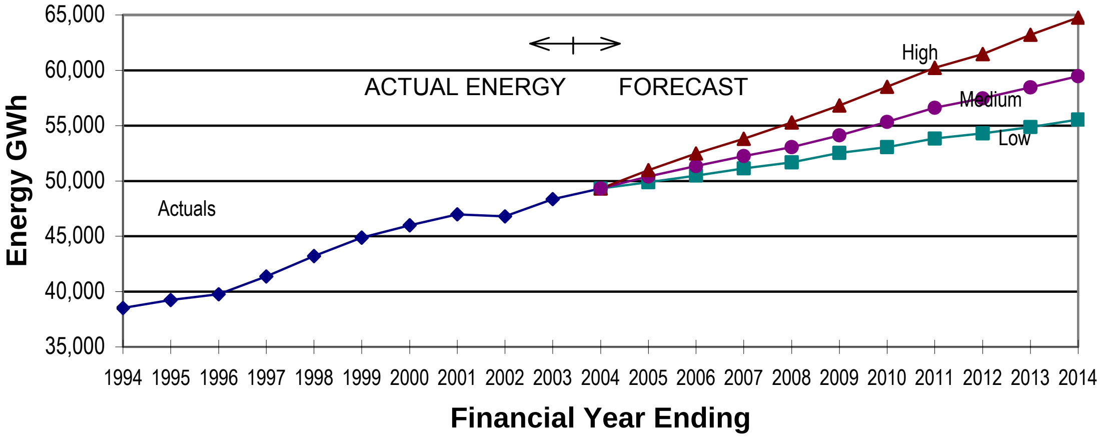


Figure 3.2 - Victorian System Annual Requirement: Three Scenarios

The energy forecasts are at terminals of generators dispatched by NEMMCO (including Anglesea Power Station). Table 3.3 details these energy forecasts and shows the growth rates from year to year.

Financial Year	ACTUAL	
	GWh	% rise
1993/94	38,506	0.2%
1994/95	39,246	1.9%
1995/96	39,744	1.3%
1996/97	41,370	4.1%
1997/98	43,215	4.5%
1998/99	44,861	3.8%
1999/00	45,993	2.5%
2000/01	46,972	2.1%
2001/02	46,791	-0.4%
2002/03	48,361	3.4%

Financial Year	MEDIUM		HIGH		LOW	
	GWh	% rise	GWh	% rise	GWh	% rise
2003/04	49,315	2.0%	49,315	2.0%	49,315	2.0%
2004/05	50,402	2.2%	50,987	3.4%	49,879	1.1%
2005/06	51,326	1.8%	52,491	2.9%	50,476	1.2%
2006/07	52,256	1.8%	53,807	2.5%	51,133	1.3%
2007/08	53,065	1.5%	55,285	2.7%	51,682	1.1%
2008/09	54,129	2.0%	56,809	2.8%	52,521	1.6%
2009/10	55,327	2.2%	58,508	3.0%	53,040	1.0%
2010/11	56,616	2.3%	60,221	2.9%	53,835	1.5%
2011/12	57,478	1.5%	61,466	2.1%	54,290	0.8%
2012/13	58,464	1.7%	63,196	2.8%	54,863	1.1%
2013/14	59,479	1.7%	64,777	2.8%	55,863	1.1%

Table 3.3 - Energy Forecasts at Generator Terminals (including Anglesea Power Station)

3.2.3 Maximum Winter Demand Forecasts to 2014

The Winter Table 3.4 shows nine sets of maximum Winter demand forecasts corresponding to average daily temperatures having 10%, 50% and 90% POE (Probability of Exceedence) under each of medium, high and low economic scenarios. Figure 3.3 shows only the peak demand forecasts for the medium economic scenario.

WINTER Calendar year	Actual (MW)								
1993	5,885								
1994	5,890								
1995	6,018								
1996	6,059								
1997	6,404								
1998	6,662								
1999	6,682								
2000	7,091								
2001	7,054								
2002	7,281								
2003	7,491								
Calendar year	10% Probability of Exceedence			50% Probability of Exceedence			90% Probability of Exceedence		
	Medium	High	Low	Medium	High	Low	Medium	High	Low
2004	8,072	8,197	7,941	7,864	7,986	7,737	7,696	7,814	7,572
2005	8,247	8,464	8,057	8,027	8,238	7,843	7,844	8,047	7,665
2006	8,412	8,706	8,183	8,182	8,467	7,960	7,985	8,261	7,771
2007	8,568	8,971	8,296	8,327	8,717	8,065	8,117	8,493	7,864
2008	8,757	9,246	8,458	8,504	8,977	8,216	8,278	8,735	8,002
2009	8,961	9,534	8,570	8,695	9,248	8,318	8,452	8,985	8,090
2010	9,180	9,827	8,716	8,902	9,525	8,454	8,644	9,243	8,215
2011	9,339	10,065	8,812	9,051	9,750	8,543	8,780	9,450	8,293
2012	9,536	10,376	8,937	9,236	10,044	8,659	8,950	9,725	8,398
2013	9,717	10,660	9,078	9,404	10,311	8,790	9,103	9,971	8,517
2014	9,963	11,035	9,269	9,636	10,666	8,971	9,317	10,302	8,683

10th	50th	90th
5.0 °C	6.8 °C	8.0 °C

Winter MD Melbourne CBD temperature percentiles

Table 3.4 - Winter Maximum Demand Forecasts

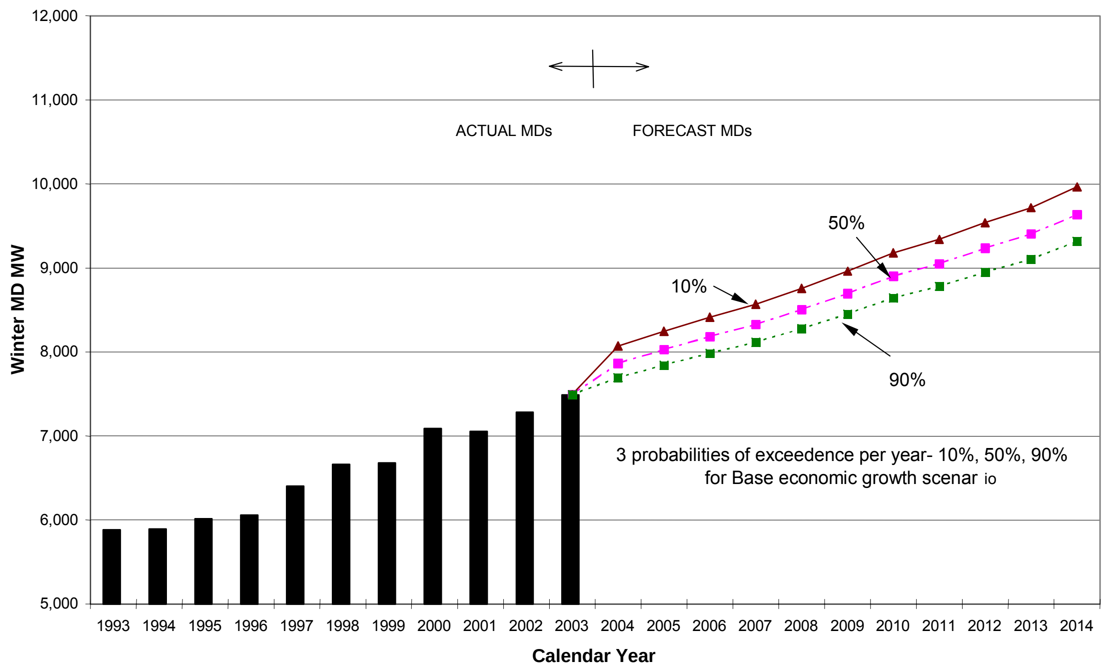


Figure 3.3 - Winter MDs: Three Growth Scenarios

3.2.4 Maximum Summer Demand Forecasts to 2014

The nine sets of forecasts are shown in Table 3.5 are for (Melbourne CBD) 50^{th} percentile "long run average Summer temperatures", evaluated over 1954/55-2003/04 Summers. Corresponding sets of nine Summer maximum demand forecasts, not presented in detail, have also been prepared for 10^{th} and 90^{th} percentile long run average Summer temperatures. These two additional sets of forecasts provide an upper and lower sensitivity to air-conditioning utilisation for extended periods of hot or mild Summer conditions. The upper forecasts indicate an increase of 85 MW for the Summer with 10^{th} percentile long run average Summer conditions and the lower forecast indicates a decrease of 40 MW for a Summer with 90^{th} percentile long run average conditions.

SUMMER	Actual (MW)	Equiv. 10%
1993/94	6,134	6,739
1994/95	6,509	6,802
1995/96	5,922	6,909
1996/97	7,115	7,314
1997/98	7,213	7,556
1998/99	7,576	7,994
1999/00	7,815	8,335
2000/01	8,179	8,600
2001/02	7,621	8,469
2002/03	8,203	8,696
2003/04	8,574	9,107

10^{th}	50^{th}	90^{th}
32.9 °C	29.6 °C	27.1 °C

Summer MD Melbourne CBD temperature percentiles

SUMMER	10% Probability of Exceedence			50% Probability of Exceedence			90% Probability of Exceedence		
	Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	9,787	9,853	9,728	8,997	9,056	8,943	8,482	8,535	8,431
2005/06	10,103	10,254	9,973	9,274	9,414	9,154	8,734	8,867	8,621
2006/07	10,373	10,598	10,202	9,509	9,720	9,353	8,947	9,147	8,800
2007/08	10,621	10,955	10,391	9,725	10,038	9,512	9,140	9,439	8,939
2008/09	10,913	11,337	10,646	9,981	10,379	9,736	9,373	9,754	9,142
2009/10	11,231	11,748	10,838	10,262	10,747	9,895	9,630	10,094	9,280
2010/11	11,543	12,146	11,067	10,542	11,106	10,097	9,889	10,427	9,464
2011/12	11,796	12,480	11,241	10,764	11,400	10,245	10,090	10,696	9,596
2012/13	12,065	12,888	11,434	10,999	11,767	10,411	10,304	11,037	9,743
2013/14	12,348	13,297	11,668	11,246	12,132	10,615	10,528	11,372	9,929

Table 3.5 – Summer Maximum Demand Forecasts

Forecast Summer 10^{th} percentile MDs shown in Table 3.5 grow annually by an average 2.8% from 2004/05 to 2008/09, moderating slightly to 2.5% from 2008/09 to 2009/14 for the medium economic scenario. The average growth rates are about 0.8% pa higher for the High economic scenario and about 0.6% pa lower for the Low economic scenario. Corresponding average growth rates for Summer 50^{th} and 90^{th} percentile MDs shown in Table 3.5 are similar, being up to 0.2% pa lower.

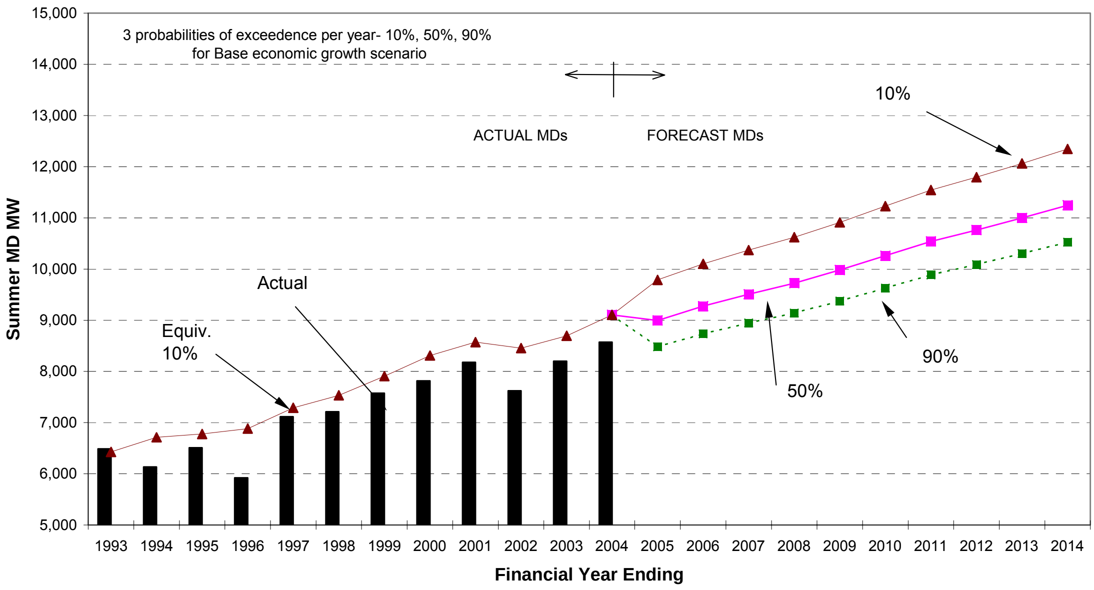


Figure 3.4 - Summer Maximum Demand: Three Growth Scenarios

3.2.5 Comparison with Code Participants Provided Connection Point Forecasts

VENCorp provides another perspective on Victorian peak demand load forecasts in Summer and Winter by combining forecasts by distribution network service providers of peak demand at their (terminal station) points of connection to the transmission network. VENCorp does this by assessing the diversities between the system peaks, and the peak loads which are drawn by distributors from each connection point on various days at various times. VENCorp adjusts these forecasts for transmission losses and demand not supplied through the transmission and distribution networks, such as power station internal usage, to place them on the same basis as the peak demand forecasts NIEIR provides.

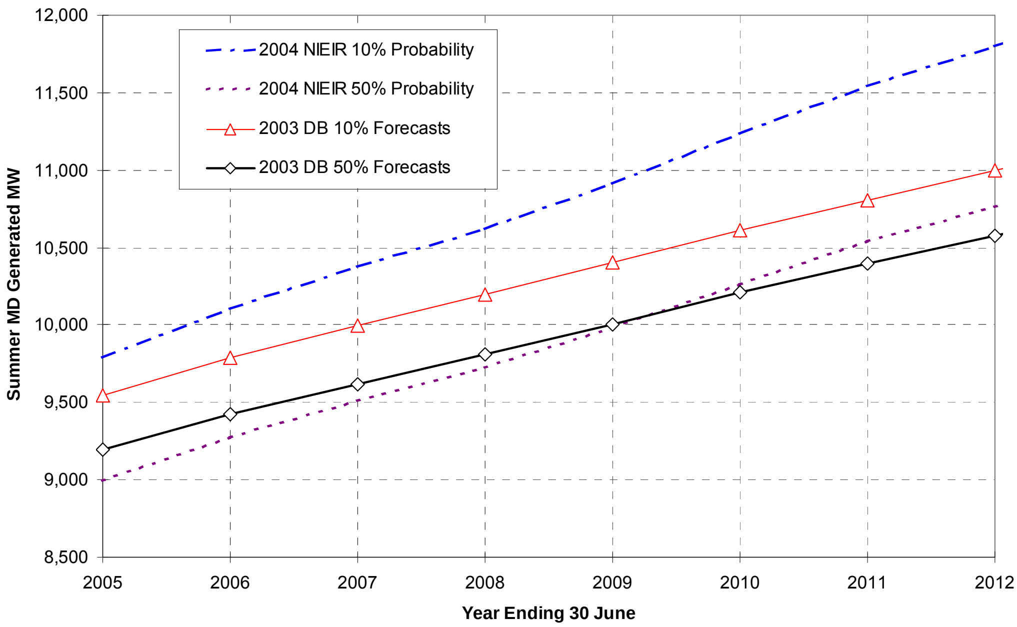


Figure 3.5 - Comparison of NIEIR and System Participants Peak Summer Load Forecasts

Figure 3.5 shows the peak demands that are expected to occur with medium economic growth, and ambient temperature conditions occurring on average one Summer in two (i.e. 50% probability), and one Summer in ten (i.e. 10% probability), comparing the latest (September 2003) terminal station demand forecasts (presented in Appendix A1) and the latest NIEIR (May 2004) forecasts.

The 50% POE Summer demands forecast by System Participants are similar to the NIEIR forecasts throughout the forecast period, varying steadily from 200 MW above NIEIR forecasts initially to 250 MW below them in 2012/13. The 10% POE Summer demands forecast by System Participants are also similar to NIEIR values for the first five forecast periods, being approximately 240 MW lower in 2004/05, after which this deficit increases steadily to 500 MW over the following four years.

The highest year-to-year growth rate of NIEIR's 10% POE Summer demand forecasts is 3.2% and lowest is 2.2% averaging 2.7% pa. The highest year-to-year growth rate of NIEIR's 50% POE Summer demand forecasts is 3.1% and lowest is 2.1% averaging 2.5% pa. System Participant annual growth rates generally fall throughout the period from 2.6% to 1.7%, averaging 2.0% pa.

Figure 3.6 shows the corresponding, 10 and 50 percentile Victorian peak Winter demand forecasts.

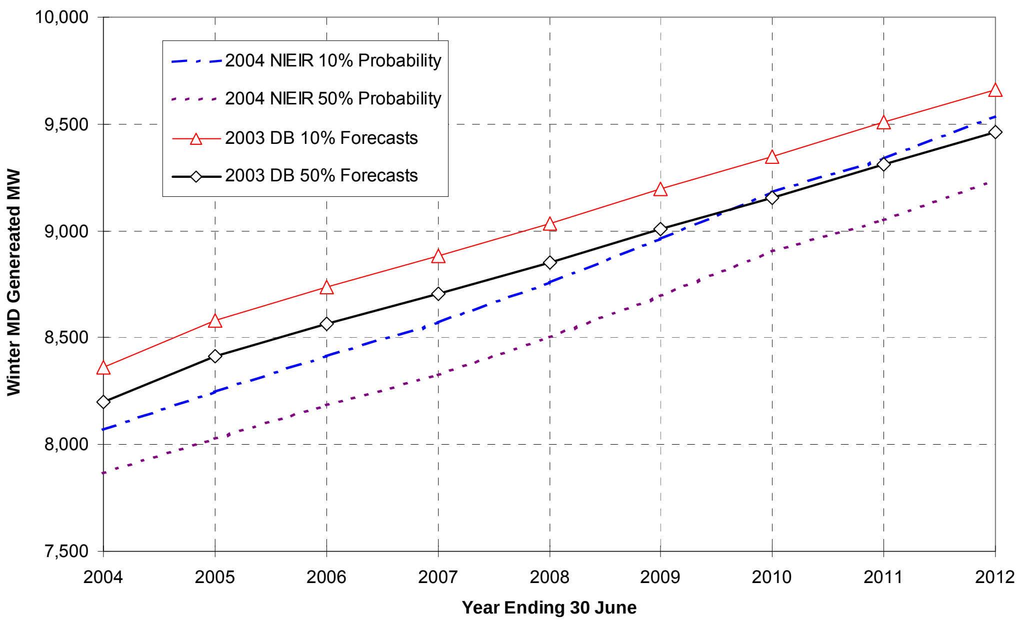


Figure 3.6 - Comparison of NIEIR and System Participants Peak Winter Load Forecasts

System Participants' Winter peak demand forecasts highest growth rate is 2.6% and the lowest growth rate is 1.6% averaging 1.8% pa over the period. This growth is similar to, but slightly less than, their Summer forecasts' growth pattern. NIEIR's 10% and 50% POE Winter forecasts highest growth rate is 2.2% and lowest is 1.7% averaging 2.0% over the period.

3.3 Observed 2003/04 Energy & Peak Demands

This section details the highest daily energy and peak demand levels occurring in Winter 2003 and Summer 2003/04, including the highest weekend demand.

3.3.1 Energy 2003/04

(a) Total Annual Energy

Figure 3.8 shows energy use is higher for most months in 2003/04 than for the same month in 2002/03. December and January energy consumptions are of particular interest, being above forecast, in December, continuing a trend from 2002/03, and below forecast in January. These deviations are most likely due to the monthly average temperatures, which differed from the Long Run Average (LRA), December being 2.7°C hotter then the LRA and conversely January being 1.2°C cooler than the LRA.

Total energy for the 2003/04 year is estimated to be 49,315 GWh[5].

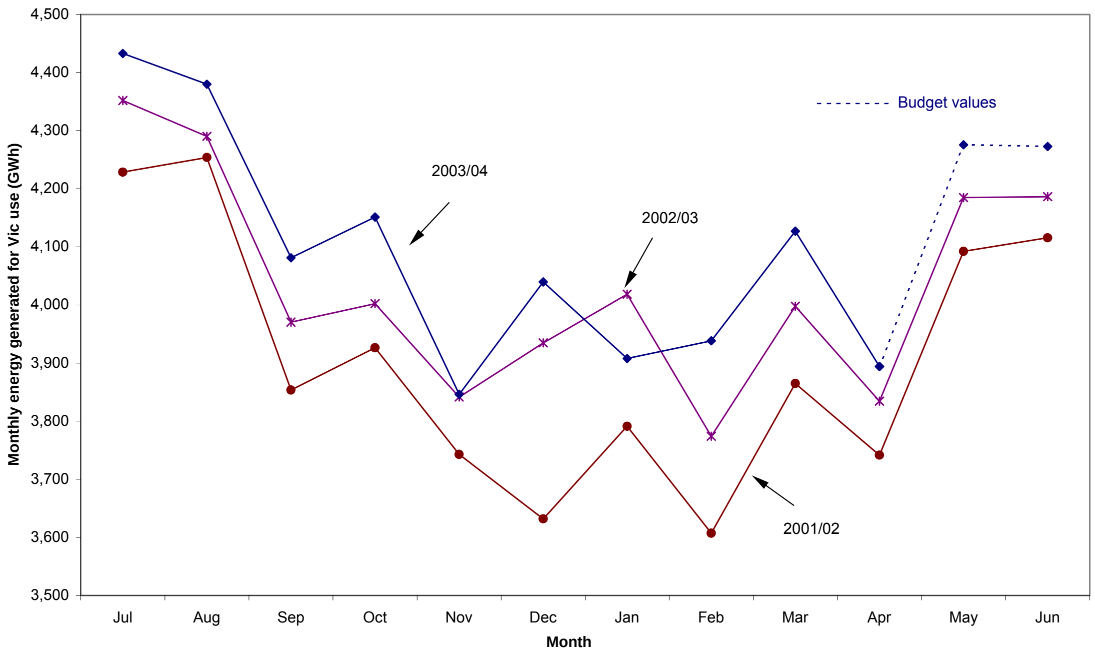


Figure 3.8 - Monthly Energy Generated / Imported for Victorian Use, 2001/02 – 2003/04

(b) Highest Energy Consumption Days for Summer and Winter

Maximum daily energy consumption was 164.5 GWh on Thursday 17 December 2003, exceeding by approximately 4 GWh the previous record observed the day prior. The previous Summer daily energy record was 156 GWh, which occurred on 24 February 2003.

Maximum Winter daily energy consumption was 154.8 GWh on Wednesday 30 July 2003, exceeding by approximately 3 GWh the 152 GWh previous record.

[5] 2003/04 Energy consumption is an estimate as the months of May & June are forecast figures.

Season	Date	Day	Daily Energy (GWh)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)
Summer	17-Dec 03	Wed	164.5	21.8	38.3	30.05
Winter	30-Jul 03	Wed	154.8	6.0	11.2	8.60

Table 3.6 - Highest Daily Energy Consumptions Summer & Winter 2003/04

3.3.2 Maximum Winter Demand Days 2003

Winter 2003 electricity MD occurred on Wednesday 30 July 2003, when the Melbourne CBD temperature ranged from 6.0°C to 11.2°C, averaging 8.6°C. The demand peaked at 7,491 MW, which was a new Victorian Winter record.

Table 3.7 below shows the top 10 Winter demand days for 2003, noting that all days were warmer than the 90% POE CBD minimum daily average temperature.

Date	Day	Potential Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp
30-Jul 03	Wed	7,491	6.0	11.2	8.60	>90%
29-Jul 03	Tue	7,432[6]	6.6	11.9	9.25	>90%
23-Jun 03	Mon	7,363[7]	5.0	12.6	8.80	>90%
24-Jul 03	Thu	7,323	6.8	13.2	10.00	>90%
28-Jul 03	Mon	7,305	8.1	13.9	11.00	>90%
31-Jul 03	Thu	7,298	7.1	14.3	10.70	>90%
23-Jul 03	Wed	7,295	8.2	11.6	9.90	>90%
24-Jun 03	Tue	7,225	4.7	13.9	9.30	>90%

Table 3.7 - Higher Daily Demand Days, Winter 2003

3.3.3 Summer Demand 2003/04

The overall electricity MD in 2003/04 occurred on Thursday 17 December 2003, when the Melbourne CBD temperature ranged from 21.8°C to 38.3°C, giving an average temperature of 30.05°C (34.6% POE). The demand peaked at 8,574 MW, which was a new Victorian record.

Table 3.8 below shows all days of Summer 2003/04 where the Melbourne CBD average temperature was greater than 27.1°C or a 90% POE.

[6] Actual MD observed on Tue 29 Jul 2003 was 7,394 MW.

[7] Actual MD observed on Mon 23 Jun 2003 was 7,284 MW.

Date	Day	Potential Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp
17-Dec 03	Wed	8,574.1	21.8	38.3	30.05	34.6
16-Dec 03	Tue	8,395.0[8]	18.6	36.2	27.40	86.3
09-Dec 03	Tue	8,113.0	19.4	37	28.20	78.4
14-Feb 04	Sat	7,389.6	16.1	40.4	28.25	77
30-Dec 03	Tue	7,330.1	23.7	40.3	32.00	14
20-Jan 04	Tue	7,269.6	18.7	36.5	27.60	84.8
10-Dec 03	Wed	7,150.5	26.4	30.5	28.45	71.4
15-Feb 04	Sun	6,812.1	24.1	31.2	27.65	84.7
08-Feb 04	Sun	6,363.1	17.2	39.7	28.45	71.4
15-Nov 03	Sat	6,326.0	19.6	39.1	29.35	50.5

Table 3.8 - Higher Daily Demand Days, Summer 2003/04

Figure 3.9 below shows the daily demand and temperature for Summer 2003/04, and the LRA daily temperature. Interesting to note is the number of days during December when the temperature was above the LRA giving rise to a number of higher demand days in that month. Conversely the figure also shows the number of days in January where the temperature was lower than the LRA providing a relatively low demand month.

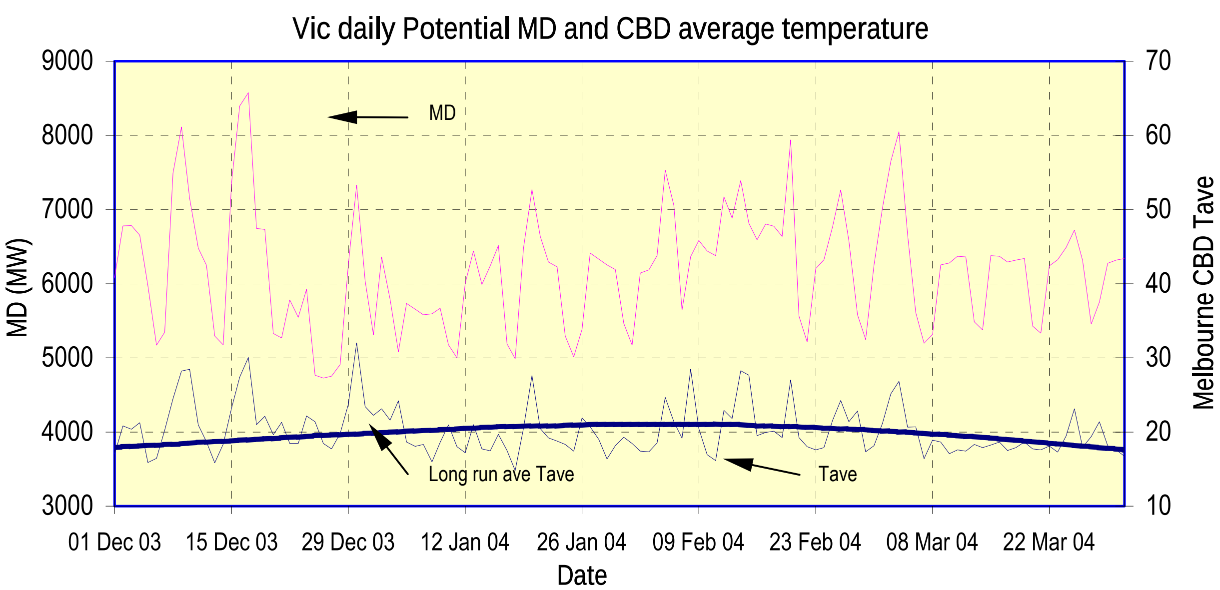


Figure 3.9 - Demand and Temperature, Summer 2003/04

[8] Actual MD observed on Tue 16 Dec 2003 was 8,302 MW.

3.3.4 Weekend Demand Summer & Winter

Demand continues to be lower on weekends than business days with similar temperatures, with the highest weekend demand being approximately 1,200 MW lower than the highest weekday demand. The maximum weekend demand of 7,390 MW, occurring on Saturday 14 February, was approximately 50 MW lower than the previous Summer weekend record.

Date	Day	Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp
14-Feb 04	Sat	7,389.6	16.1	40.4	28.25	77
15-Dec 03	Sun	6,812.1	24.1	31.2	27.65	84.7
15-Nov 03	Sat	6,326.0	19.6	39.1	29.35	50.5
14-Jun 03	Sat	6,399	8.8	12.8	10.80	>90%

Table 3.9 – Higher Weekend Demand Days 2003/04

3.3.5 Load Characteristics

This section looks at the characteristics of the Summer and Winter maximum demand weeks, also comparing them to the previous year's Summer and Winter maximum demand weeks.

(a) Daily Variation in Demand

The following figures display the load variation for the 2003/04 Summer, and 2003 Winter weeks containing each season's maximum demand day. These weeks are as follows:

- Summer 2003/04, 14-20 December with MD occurring on Wednesday 17.
- Winter 2003, 27 July to 2 August with MD on Wednesday, 30 July.

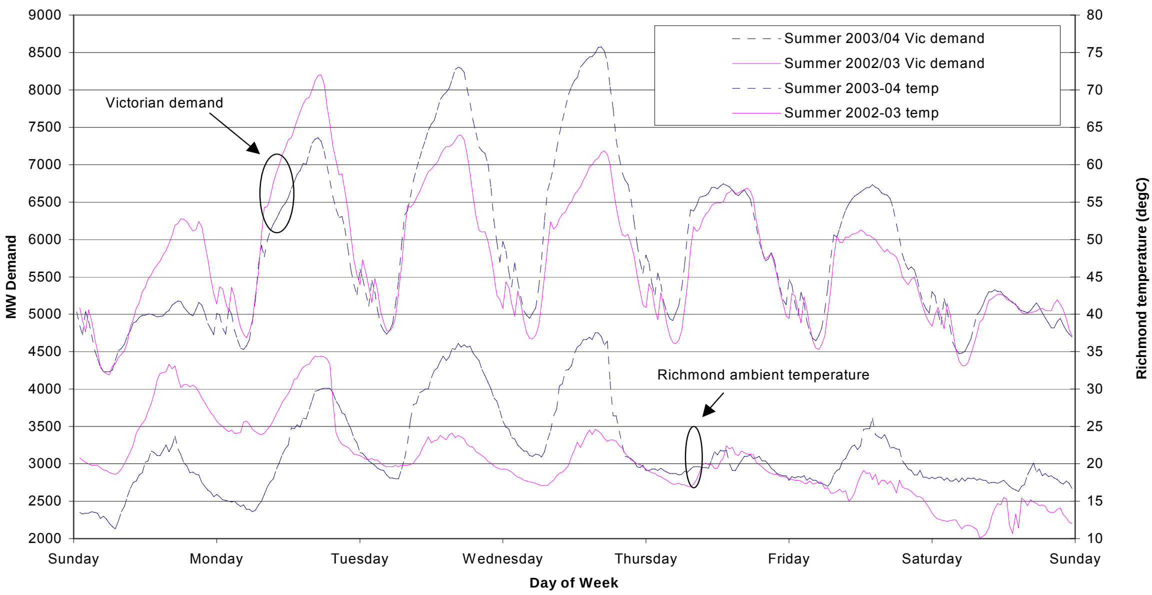


Figure 3.10 - Summers 2003/04 and 2002/03 Maximum Demand Weeks

The main features of the Summer 2003/04 Maximum Demand week are as follows:

- The 2003/04 demand and temperature traces clearly show the build effect of temperatures increasing over a number of days. In this case Melbourne CBD daily peak temperature rose from 25 °C on the Sunday to 32 °C on Monday, 36 °C on Tuesday and ultimately 38.3 °C on Wednesday. Daily average temperatures rose over this period from 18.4 °C to 30.1 °C due to increasing overnight minimum temperatures (11.6 °C rising to 21.8 °C).

- This sustained rise differed from the previous Summer where the temperature rose over a two-day period with the first day being a Sunday, with lower commercial premises cooling input.

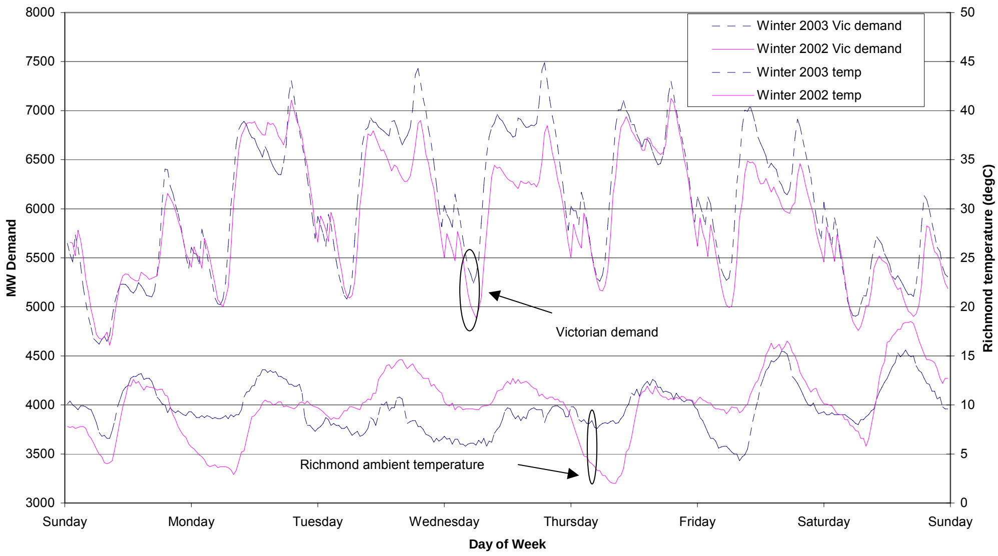


Figure 3.11 - Winters 2003 and 2002 Maximum Demand Weeks

The main features of the Winter 2003 Maximum Demand week are as follows:

- The lower response to temperature variation in Winter - about 100 MW/°C, compared with about 180 MW/°C in Summer.

- There are two major daily peaks in Winter weekdays, morning and evening (with evening being the larger on cold days) compared with one peak in the afternoon on hot Summer days.

- The Winter and Summer daily demand traces for 9.00pm in the evening to 10.00am of the following morning tend to be very similar in shape. Evening and overnight demand levels are similar on extreme Summer and Winter days, but up to about 500 MW lower for milder Summer days than milder Winter days. On hot Summer days, the load trace does not have the characteristic mid-morning drop in demand usually obvious in the Winter trace. Rather, the demand continues to rise through the morning and the afternoon, reaching a peak in the later afternoon. The early evening peak, which is obvious in the Winter trace (and usually produces the daily maximum demand), is barely perceptible in the Summer trace.

(b) Seasonal Variation in Energy & Demand

As can be seen in Figure 3.12 daily energy consumption in Victoria continues to be greatest during the Winter months, usually exceeding 138 GWh. Peak daily consumption and MDs occur in Summer. This has become more pronounced over recent years, due primarily to the increasing installation and use of residential air-conditioners, including fitting of units both to existing and new residences. However, aggregate energy consumption is typically lowest during the Summer months with daily usage usually below 135 GWh. The temperature sensitivity of daily energy on coldest and hottest days is also demonstrated.

The variation in Victorian daily MD because of seasonal change and holidays is displayed in Figure 3.13 which shows daily maximum demands for the 2002/03 financial year.

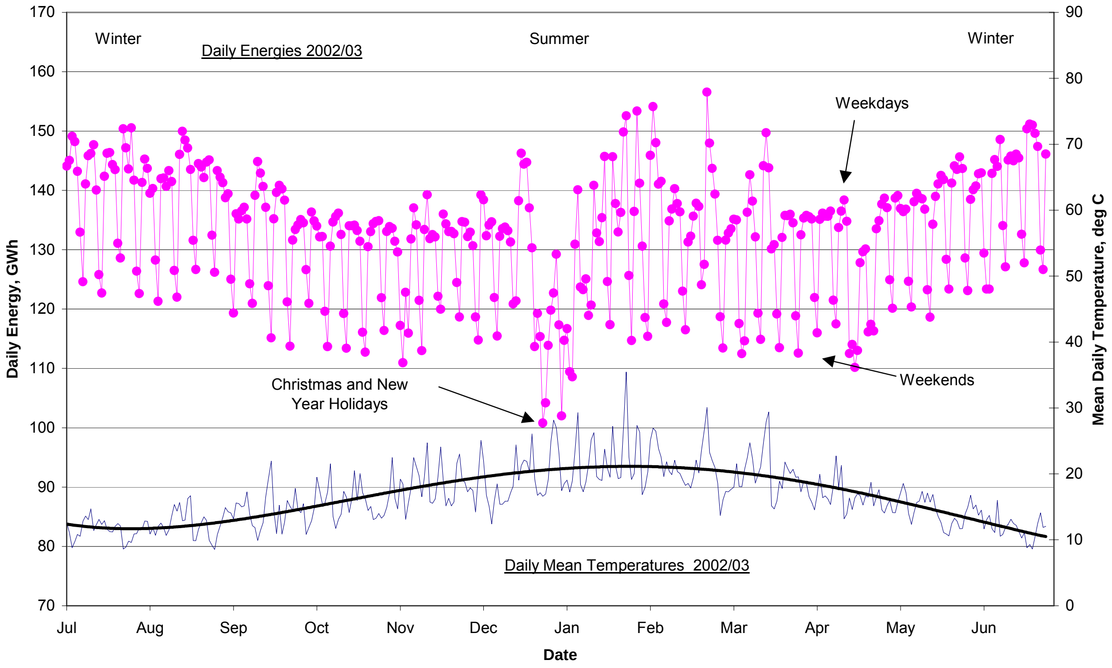


Figure 3.12 – 2002/03 Daily Energy and Mean Daily Temperatures

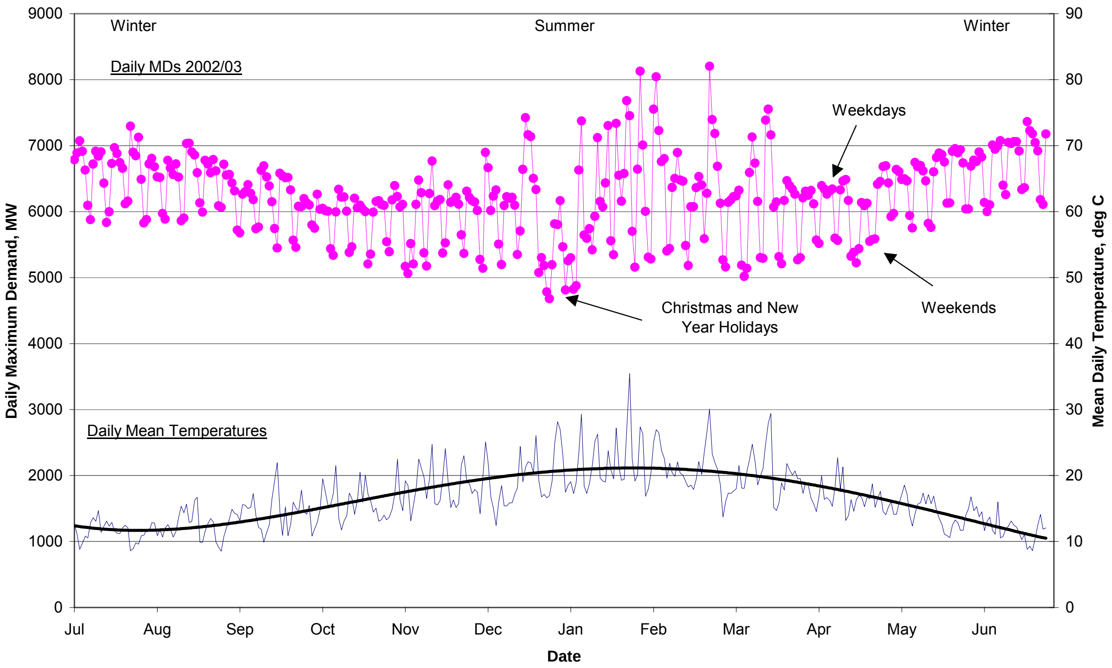


Figure 3.13 - 2002/03 Daily Maximum Demand and Mean Daily Temperatures

Figure 3.13 also shows more generally the temperature daily MD sensitivities already described for the Summer and Winter MD weeks.

(c) Load Duration Curve

Annual load duration curves displaying the percentage of time that the load is above a certain MW level are shown in Figures 3.14 and 3.15.

The following points are noted:

- The top 15% of maximum loads on the system occur for 1% of the time or about 88 hours per year.
- Excluding the 5% highest and 5% lowest demand levels, about 90% of the loads for the year fall within a comparatively narrow range of 4,500 to 6,500 MW.

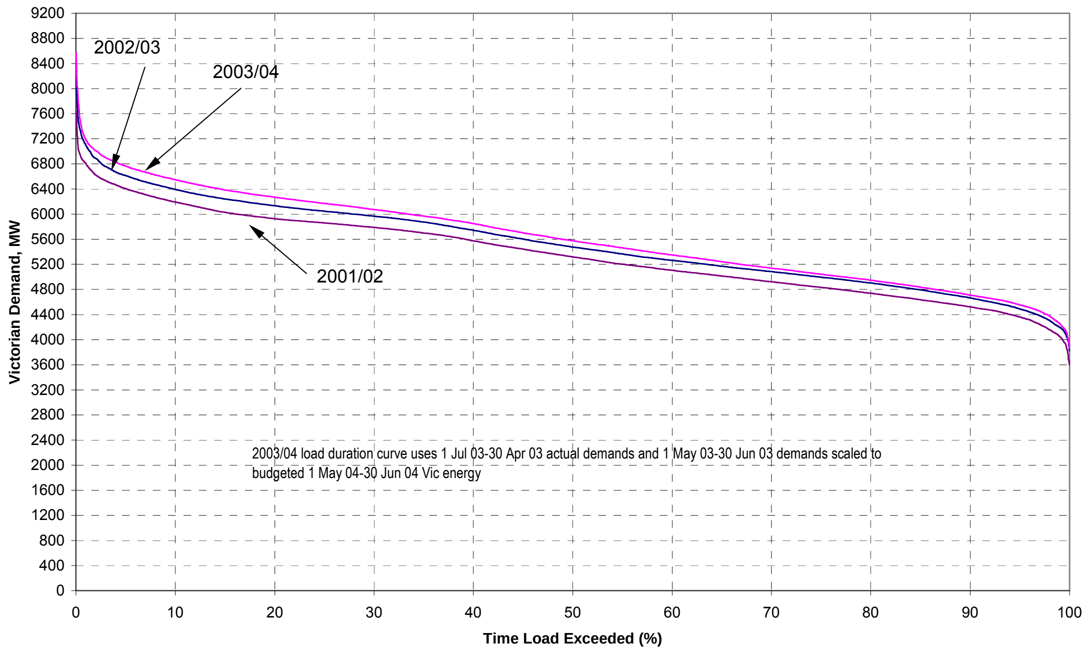


Figure 3.14 - 2001/02 - 2003/04[9] YTD Annual Load Duration Curve

[9] 2002/03 load duration curve uses 1 Jul 02 - 30 Apr 03 actual demands and 1 May 02 - 30 Jun 02 demands scaled by 1.035, being the ratio of 1 Jul 02 – 30 Apr 03 Vic energy to 1 Jul 01 – 30 Apr 02 Vic energy.

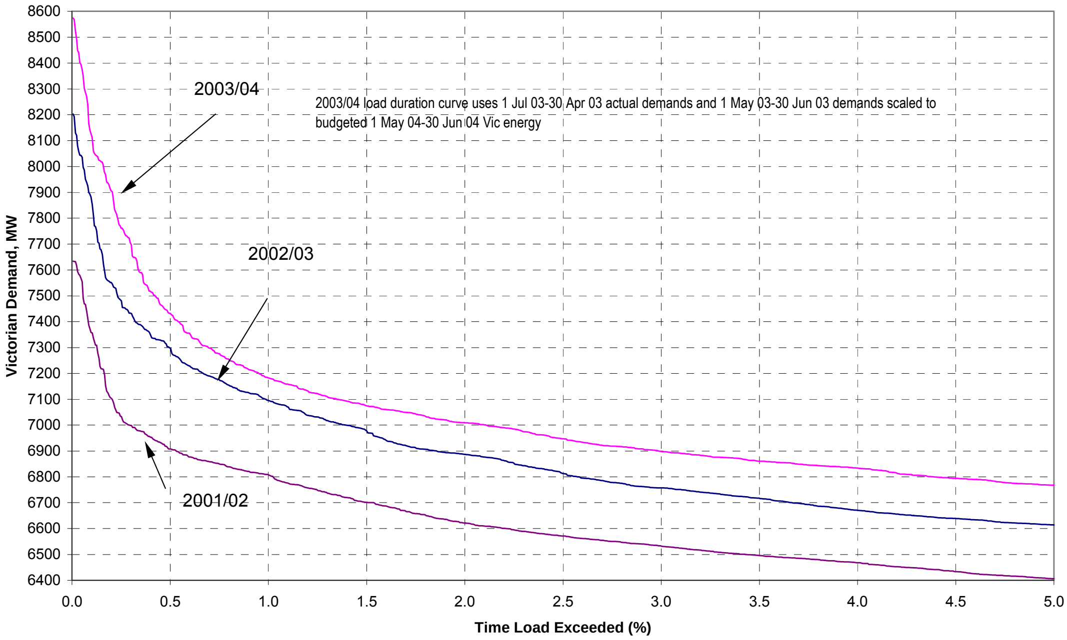


Figure 3.15 - 2001/02-2003/04 Expanded Annual Load Duration Curve

(d) Summer & Winter Load Factors

The Victorian Summer demand is characterised by a peakiness with the top 15% of maximum loads on the system occurring for 1% of the time or about 88 hours per year. This increase in peak demand is largely being driven by the increasing installation of domestic air conditioning.

In transmission network planning, the forecast maximum demand is a dominant factor in assessing future transmission augmentation. (Likewise, in the analysis of capacity reserve requirements, the forecast maximum demand is used to calculate the additional capacity requirements to maintain reserve levels).

The continuing high growth in Summer maximum demand forecast, about half due to increased cooling as shown in Figure 3.16, would result in the continued divergence between the Summer peak demand and energy growth levels. For example, the forecast average annual growth in the medium economic growth scenario Summer 10% maximum demand over the period 2004/05-2008/09 is 2.8%. In contrast, the forecast average annual growths over this period are 1.8% for energy consumption and 2.1% for Winter maximum demand for the same scenario.

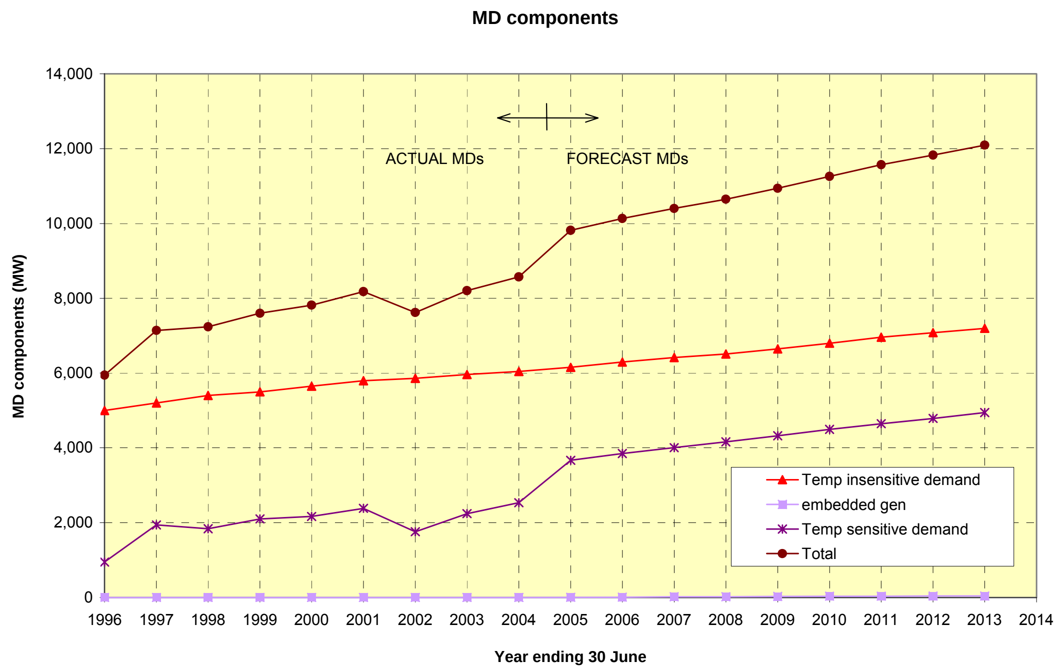


Figure 3.16 - Temperature Sensitive and Insensitive Components of Summer 10% POE MD Forecast

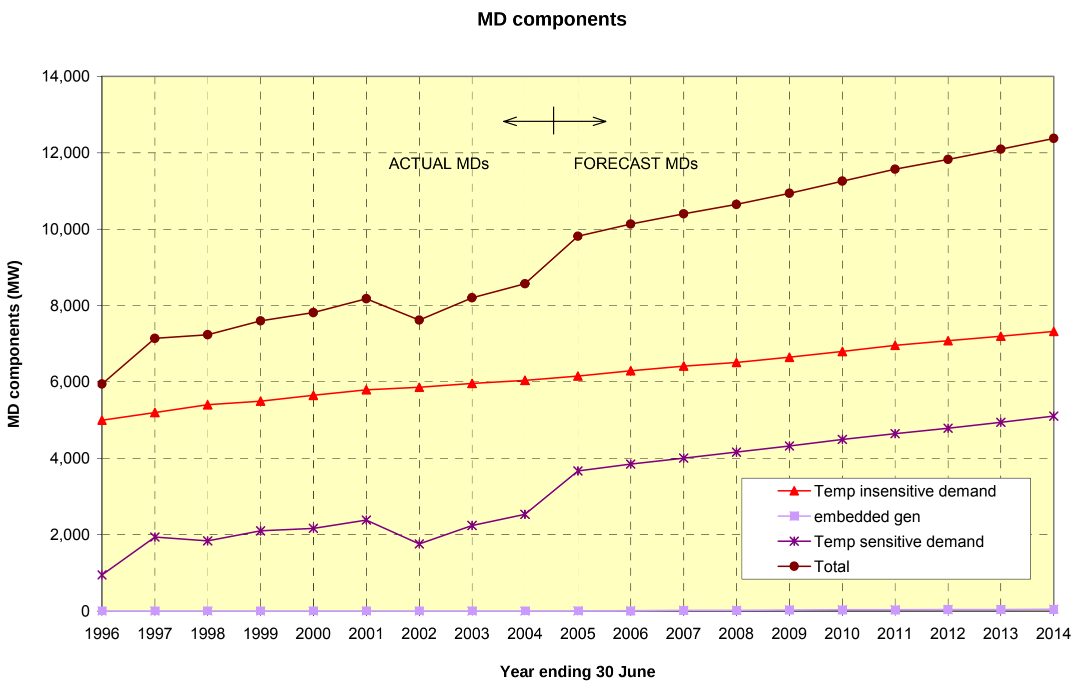


Figure 3.17 - Winter and Summer Load Factors

The longer term divergence in Summer peak demand growth and energy growth can be demonstrated by considering the system load factor since 1993[10].

Figure 3.17 shows the variation in the Summer and Winter load factors from 1993 up to the present. The forecast seasonal load factors are also presented, corresponding to the medium growth scenario, 10%, 50% and 90% Summer and Winter maximum demand forecasts. Deviation from the trend can be noted for the actual load factors to 2002, particularly for the cool Summer in 1995/96 and 2001/02 and the mild Winters in 1999-2001.

The decrease in the forecast Summer load factor (from 0.64 in 2003/04 to 0.60 in 2012/2013 for the 50% peak demand and from 0.60 to 0.55 over the same period for the 10% peak demand), clearly demonstrates the continuing divergence in the growth rates of Summer maximum demand from the annual energy consumption and highlights the expected increasing peakiness in demand. The Winter load factor is forecast to remain steady (90% POE) or reduce slightly (10% POE) over the coming 10 years, showing that the growth in energy is forecast to be similar to, or marginally below, the growth in Winter maximum demand.

(e) Building Shell and Human Activity Impact on Summer MD

In recent years there has been an increased level of unexplained daily Summer MD variations with Melbourne CBD daily average temperatures. VENCorp has previously investigated other expanded models, which have incorporated:

- weighted averages of temperatures at different locations;
- weighted averages of Melbourne CBD daily maximum and minimum temperatures on successive days; and
- wind and solar radiation.

Whilst the investigations did identify a small improvement with these additional variables, the overall forecasting improvement was not material.

The growing unexplained MD variability may be largely due to the greatly increased proportion of the MD comprising residential air conditioning. A further investigation has been commissioned aiming at modelling more fundamentally the MD residential air conditioning component by identifying causal relationships between its variations and the combined impacts of such factors as:

- Thermal performances of the range of residences;
- Behaviour/activity of people living in air conditioned residences; and
- Weather.

This investigation may improve both understanding of past MD variations and future MD forecasts, with building regulation changes encouraging increased residential energy efficiency. It is envisaged that any findings of this investigation will be made public in July/August 2004.

10 The (Summer) system load factor is the ratio of the annual energy demand at generator terminals in MWh to the maximum demand in MW multiplied by 8,760 hours. A Winter load factor can be similarly defined by using the Winter maximum demand.

3.4 2003 APR Forecast Performance Against Actuals

3.4.1 Economic (GSP)

Figure 3.18 details the differences between the 2003 and 2004 medium economic scenarios provided by NIEIR.

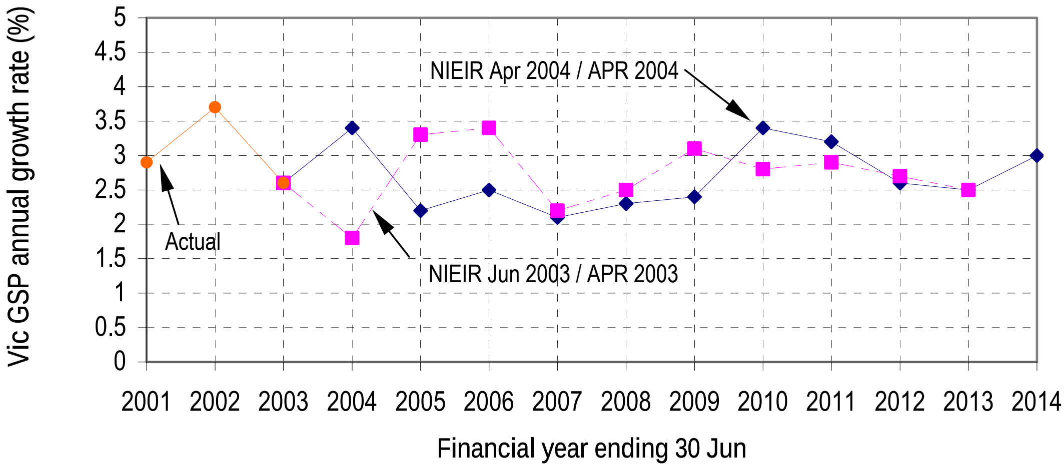


Figure 3.18 – Victorian GSP Medium Growth: Comparison of Forecasts

Table 3.10 below, shows the base (medium), high and low scenario Victorian economic growth forecasts NIEIR provided in April 2004 on which the load forecast in this Annual Planning Report are based. The latest Victorian economic growth forecasts issued by Access Economics and the Victorian Government are also included, for comparison.

Year	Actuals		Forecasts			
	2002/03	2003/04	2004/05	2005/06	2006/07	Issued
NIEIR Medium Growth	2.6%	3.4%	2.2%	2.5%	2.1%	Apr 2004
NIEIR High Growth	2.6%	3.4%	3.1%	3.6%	2.8%	Apr 2004
NIEIR Low Growth	2.6%	3.4%	1.8%	1.9%	1.4%	Apr 2004
ACCESS Economics[11]	2.7%	2.8%	2.9%	1.9%	2.9%	Apr 2004
Victorian Budget Update[12]	2.6%	3.25%	3.5%	3.5%	3.5%	Dec 2003

Table 3.10 - Economic Growth Actuals 2001/02 to 2002/03 and Forecasts, 2003/04 to 2005/06

[11] Data obtained from "Access Economics Budget Monitor – March 2004".

[12] Data obtained from Victorian Treasury April 2003.

From the NIEIR perspective the Victorian GSP growth moderated in 2002-03 following very strong growth over the previous five years. Victorian GSP growth was 2.6% in 2002-03 following growth of 3.7% in 2001-02.

The recovery from the drought, stronger business investment and consumption expenditure led to stronger Victorian GSP growth of 3.4% in 2003-04. Falls in private dwelling investment and slower growth in Victorian private consumption expenditure reduce Victoria's GSP growth rate over 2004-05 and 2005-06. Victorian GSP growth in 2004-05 and 2005-06 is 2.2 and 2.5% respectively.

Victorian GSP growth over the period 2002-03 to 2007-08 is forecast to average 2.5%. Weaker economic growth over the next three to four years in Victoria, compared to the national economy, is consistent with previous experience (following periods of high economic growth), although it is possible a major external shock could produce a sharp contraction in Victorian economic growth.

3.4.2 Energy (2003/04 Financial Year)

The actual growth in energy during 2002/03 rose by 3.4% against a predicted increase of 2.3% medium growth forecast in the Electricity Annual Planning Review 2003. The driving factor for this higher than forecast energy was the GSP being 3.4% as opposed to the 1.8% forecast. A secondary reason for this increase in energy against the predicted rise is due to use of actual, rather than typical Anglesea Power Station generation.

For the following year (2003/04), the forecast growth rates in the Electricity Annual Planning Review 2003 were 2.3%, 2.3 % and 3.1% respectively for the medium, low and high growth scenarios. A comparison of the energy consumption for the 2003/04 financial year, using actual energy to end-April 2004 and May/June 2004 energies forecast in 2003 with the 2002/03 energy shows an increase in energy consumption of 2.0% with no weather correction used. This differs slightly from the previous APR where a increase of 2.3% was reported for the medium scenario. To date, it appears that the significantly higher than forecast economic growth and warmer December and February in 2003/04 contributed to the increased energy consumption.

The most recent full year forecasts (presented here) are for growth rates in 2004/05 are 2.2%, 1.1% and 3.4% for the medium, low and high growth scenarios, respectively compared to the corresponding 1.5%, 0.9% and 1.9% 2004/05 forecast growths presented in the 2003 APR.

3.4.3 Winter Maximum Demand (2003)

Forecast performance for Winter 2003 is shown in Table 3.11. The eight top demand days show the variance, after linear interpolation between the NIEIR forecast and actual ranging from –6% to -11.0%. It must be pointed out that none of these days reached a 90% POE temperature, therefore no assessment of the NIEIR forecast accuracy is provided.

Date	Day	Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp	NIEIR Forecast (MW)	Forecast Variance (MW)
30-Jul 03	Wed	7,491	6.0	11.2	8.60	>90%	7,033	-458
29-Jul 03	Tue	7,432	6.6	11.9	9.25	>90%	6,574	-558
24-Jul 03	Thu	7,323	6.8	13.2	10.00	>90%	6,691	-632
28-Jul 03	Mon	7,305	8.1	13.9	11.00	>90%	6,447	-858
31-Jul 03	Thu	7,298	7.1	14.3	10.70	>90%	6,250	-777
23-Jul 03	Wed	7,363	8.2	11.6	9.90	>90%	6,716	-579
23-Jun 03	Mon	7,284	5.0	12.6	8.80	>90%	6,984	-379
24-Jun 03	Tue	7,225	4.7	13.9	9.30	>90%	6,862	-363

Table 3.11 - Higher Daily Demand Days, Winter 2002

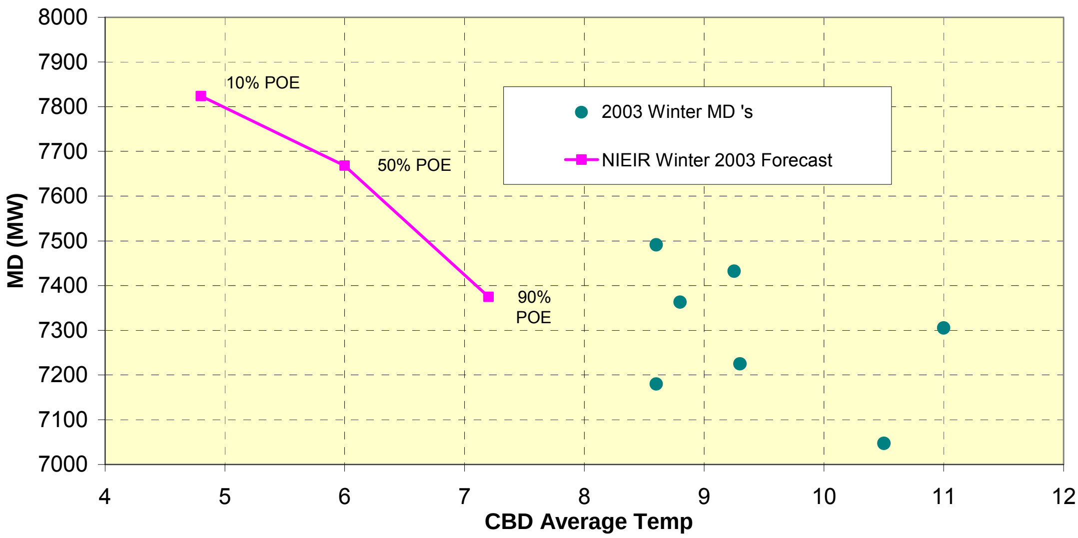


Figure 3.19 - Higher Daily Demand Days, Winter 2003

3.4.4 Summer Maximum Demand (2003/04)

The overall electricity Maximum Demand (MD) occurred on Thursday 17 December 2003, when the Melbourne CBD temperature ranged from 21.8-38.3 °C, giving an average temperature of 31.05 °C. The demand peaked at 8,574 MW, which was a new Victorian record. The average temperature of 31.05 °C equated to a 34.6% (POE). The NIEIR forecast for this POE was 8,884 MW, providing an error of 310 MW or 3.4%.

The overall performance of the NIEIR MD forecast ranged from 9 to 435 MW higher than actual MD on the three hottest business days this Summer when Melbourne CBD temperatures averaged 27.1°C or more. This excludes two other hot days when cool changes occurred very early in the day. The 3 days, which can be used to assess the accuracy of, actual versus forecast resulted in an average error of -2.8% or 250 MW.

Of note this year was the large number of hot Summer days that occurred during periods when it would not be expected to achieve a record Victorian MD. These being non-business days, weekends or during the Christmas/January holiday period. MDs are much lower on these days, which are therefore excluded from weather percentile evaluations (for purposes of MD assessment).

Date	Day	Max Demand (MW)	Daily Min Temp (°C)	Daily Max Temp (°C)	Daily Average Temp (°C)	% POE Temp	NIEIR Forecast (MW)[13]	Forecast Variance (MW)
17-Dec	Wed	8,574.1	21.8	38.3	30.05	34.6	8,884	309.9
16-Dec	Tue	8,395.0	18.6	36.2	27.40	86.3	8,404	9.1
09-Dec	Tue	8,113.0	19.4	37	28.20	78.4	8,546	432.7
14-Feb	Sat	7,389.6	16.1	40.4	28.25	77	NA	NA
30-Dec	Tue	7,330.1	23.7	40.3	32.00	14	NA	NA
20-Jan	Tue	7,269.6	18.7	36.5	27.60	84.8	NA	NA
10-Dec	Wed	7,150.5	26.4	30.5	28.45	71.4	NA	NA
15-Dec	Sun	6,812.1	24.1	31.2	27.65	84.7	NA	NA
08-Feb	Sun	6,363.1	17.2	39.7	28.45	71.4	NA	NA
15-Nov	Sat	6,326.0	19.6	39.1	29.35	50.5	NA	NA

Table 3.12 - Performance of NIEIR Maximum Demand Forecast, Summer 2003/2004

[13] VENCorp calculates the "NIEIR Forecast" and associated error by linearly interpolating the NIEIR forecasts.

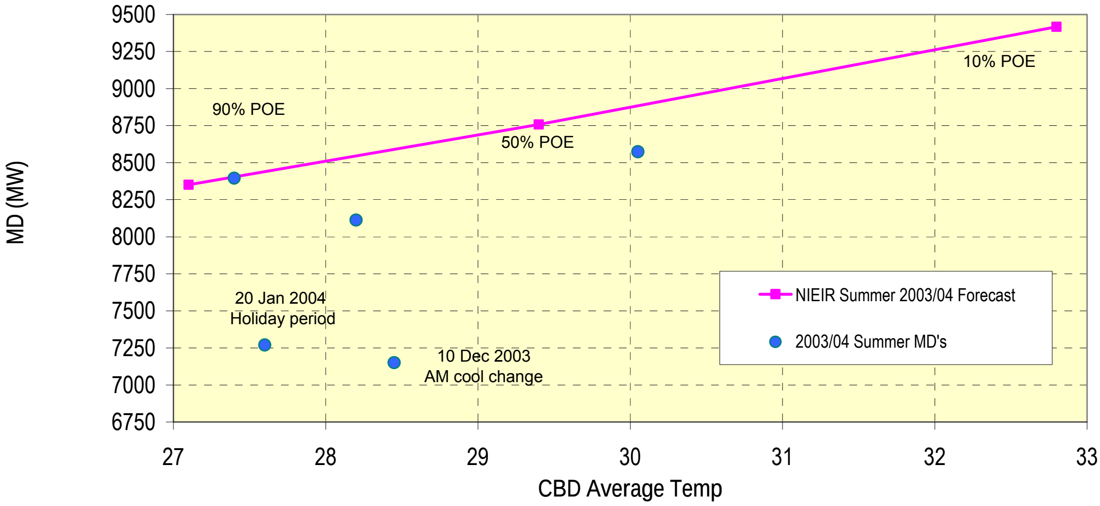


Figure 3.20 - Higher Daily Demand Days, Summer 2003/04

3.5 Basis & Methodology Underlying Load Forecasts

3.5.1 Forecasting Energy Use

NIEIR's econometric model is directly linked to its energy forecasting model, determining annual demands for each type of energy comprising factor inputs to the economy, including household usage. The energy forecasts also use actual annual electricity sales/use by each customer class, aluminium smelting, power station and mine own use and network losses.

NIEIR uses the forecasts of Victorian electricity sales and peak demand for aluminium smelting that VicPower Trading provides to VENCorp.

Actual and forecast levels of electricity generation supplying load directly (i.e. not through the Victorian transmission or distribution system) or embedded in the distribution network are modelled so that energy supply and demand levels correspond.

3.5.2 Cogeneration, Independent Power Production and other Impacts

Based on its own assessments and information from others, NIEIR determines forecasts of electricity energy and peak demands met by generation not transmitted through the Victorian transmission and distribution system. NIEIR also assesses and includes effects of other relevant impacts, such as conservation and technological advances (e.g. Greenhouse gas abatement measures, appliance efficiency improvement, and fuel cell research) that can impact on future energy demand. Continuation of existing policies and activities leading to natural improvements in conservation and end-use efficiency improvements was assumed in relation to demand management and cogeneration levels.

Table 3.13 and Figure 3.21 show observed and forecast capacity and energy output levels of unscheduled cogeneration and Independent Power Producers' (IPPs') generation (other than cogeneration) embedded within Victorian distribution networks. The emerging wind embedded generation capacity, forecast to grow strongly over the next six years in line with overseas experience and Government initiatives, is also identified.

These generation outputs (including for own use) are recognised in NIEIR's econometric analysis as a factor input of Victorian GSP additional to electricity energy and peak demands that are supplied from scheduled generators. Table 3.13 shows that over the forecast period 2004/05 to 20113/14, aggregated unscheduled cogeneration and IPP contributions to load levels increase from 483 MW to 725 MW capacity and 2,194 GWh to 2,980 GWh output, of which 1,094 GWh to 1,633 GWh is bought back and 1,100 GWh to 1,347 GWh used by the producer.

Levels of cogeneration and IPP are driven by gas and electricity prices and the following policy initiatives:

- National Greenhouse Strategy (1998) promoting cogeneration through workshops and studies, providing shared funding for renewable energy technologies under the $21 M Renewable Energies Equity Fund (REEF), providing loans and grants for renewable energy projects with strong commercial potential under the $30 M Renewable Energy Commercialisation Program (RECP) and providing $10.5 M aggregate seed funding for a few leading edge renewable energy projects. Mandated Renewable Energy Targets (MRET) under The Renewable Energy (Electricity) Act 2000 and associated acts will require wholesale purchasers of electricity in Australia to contribute proportionately towards the generation of an additional 9,500 GWh of renewable energy per year by 2010, to be maintained to 2020; and

- Goods and Services Tax/A New Tax System (GST/ANTS) (1999) providing up to $264 M over four years for remote area power supplies to replace diesel generation, $31 M in photovoltaic system rebates (up to 50%/$5,500 per household), and an additional $26 M for RECP and $400 M over four years to 2003/04 for projects that most cost effectively reduce greenhouse gas emissions - the Greenhouse Gas Abatement program (GGAP).

	Capacity (MW)				Actual / Forecast Output (GWh)				
Year	Cogen	IPP		Total	Cogen	IPP	Total	Buyback	Own Use
		Wind	Other						
2001/02	240	39	117	396	1,248	411	1,659	739	920
2002/03	257	91	121	469	1,495	684	2,179	1,079	1,100
2003/04	257	91	123	471	1,495	684	2,179	1,079	1,100
2004/05	257	91	135	483	1,495	700	2,194	1,094	1,100
2005/06	265	91	141	497	1,529	715	2,245	1,137	1,108
2006/07	287	111	147	545	1,588	784	2,372	1,232	1,141
2007/08	293	111	153	557	1,602	799	2,401	1,251	1,150
2008/09	308	131	159	598	1,680	868	2,548	1,350	1,199
2009/10	318	131	165	614	1,733	884	2,616	1,381	1,236
2010/11	318	131	165	614	1,733	884	2,616	1,381	1,236
2011/12	333	161	171	665	1,812	978	2,790	1,482	1,308
2012/13	333	161	171	665	1,812	978	2,790	1,482	1,308
2013/14	347	201	177	725	1,881	1,099	2,980	1,633	1,347

Table 3.13 – NIEIR Forecast of Victorian Embedded Unscheduled Generation Capacity and Output 2000-2013

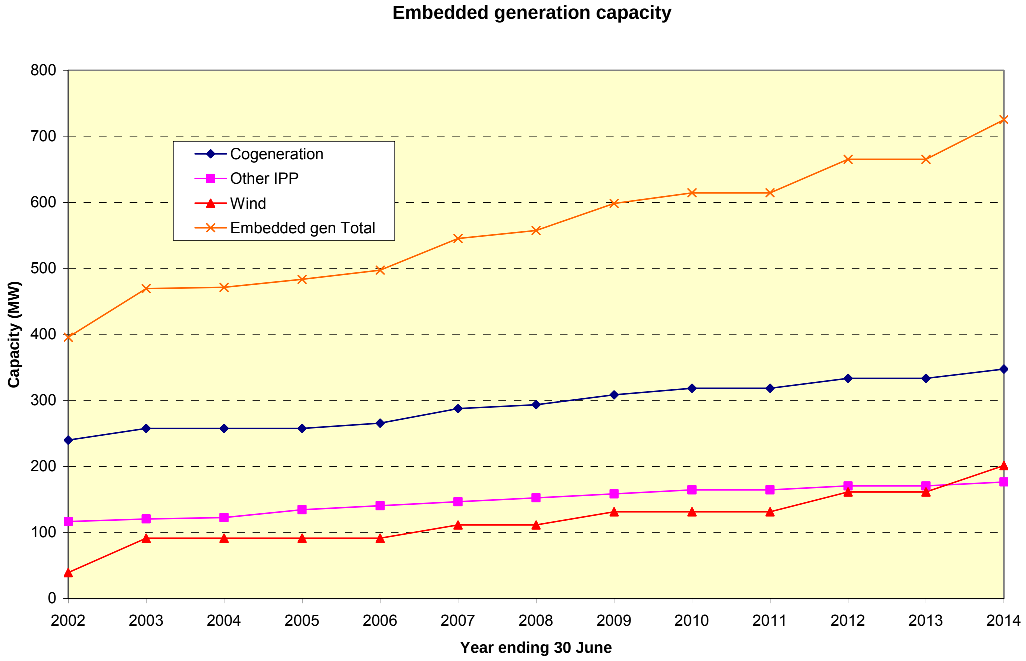


Figure 3.21 - Victorian Embedded Unscheduled Generation Capacity 2003-2014

Forecasts of Summer MDs (Maximum Demands) for Victoria are developed by NIEIR using an approach, which takes account of:

(i) non-temperature sensitive load;

(ii) temperature sensitive load;

(iii) major industrial load; and

(iv) embedded generation (IPP).

Non-temperature sensitive load refers to non-temperature sensitive residential, commercial and industrial load. It may include some space cooling, however, these units are normally operating, even at relatively mild temperatures.

For the Summer MD, temperature sensitive load consists of mainly of space cooling appliances such as refrigerative and evaporative and other ventilation equipment such as fans.

Major industrial load refers, in Victoria's case, to aluminium smelting.

Embedded generation in terms of MW of capacity (discounted by the rate of utilisation) is directly deducted from the Summer MD forecasts. The following rates of capacity utilisation at system maximum demand were assumed in the forecasts.

Embedded cogeneration	20 per cent
Biomass and biogas	60 per cent
Wind	7 per cent
Mini hydro	30 per cent
Other non-renewable IPP	50 per cent

There is considerable uncertainty regarding the availability of embedded generation at times of system maximum demands.

The key uncertainty in terms of the forecasts is the availability of wind generation. As noted above, only 7% of new installed wind generation capacity is deducted from the MD forecast[14].

3.5.3 Definition of Victorian Demand

The energy and maximum demand forecasts in this document are of Victorian demand as measured at all scheduled power station generator terminals. [15] This is the same definition of demand as used by NEMMCO for their "at terminals" figure.

3.5.4 Forecasting Peak Winter Demand

Peak Winter electricity non-smelter demands are subdivided into a temperature sensitive component due to air conditioning reverse cycle operation (forecast from the air conditioning methodology described above), a relatively less temperature sensitive component comprising other temperature sensitive load and temperature insensitive non-smelter load.

Growth in peak Winter non-smelter load, excluding the air conditioning reverse cycle component, is forecast by projecting forward regressions of the ratio of this peak load, for 10, 50 and 90 percentile daily average temperature conditions, to non-smelter energy. Table 3.4 shows Winter 10, 50 and 90 percentile average daily ambient temperatures and corresponding peak demand forecasts for Winter 2004.

3.5.5 Forecasting Peak Summer Demand

Peak Summer electricity demands for purposes other than aluminium smelting are subdivided into components sensitive and insensitive to ambient temperature.

Growth in peak Summer load that is sensitive to ambient temperature is dominated by increased sales and use of refrigerative air conditioning. NIEIR forecasts sales in refrigerative air conditioning units by a model using levels of residential and commercial building activity, real income, unit replacement and average ambient temperature over Summer. Air conditioning unit sales are forecast for each economic scenario, and for cases of each Summer being 10, 50 or 90 percentile[16] average temperature (i.e. nine sets of forecasts).

Forecast growth in temperature-sensitive peak Summer load on a Summer day of 10, 50 or 90 percentile average daily temperature is determined from these air conditioning unit sales forecasts, and from historical temperature-sensitive peak Summer electricity demand increases, with historical electrical demand of aggregate air conditioner sales, over the last decade. This results in 27 sets of peak Summer demand forecasts, however forecasts are presented here only for 50 percentile average temperature Summers, found to correspond approximately to the previous Victorian basis of Summer forecasts, and taking a middle path with regard to long run weather impacts on air conditioner sales.

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[14] Consistant with the NEMMCO 'SOO'

[15] A list of the scheduled generation and scheduled loads in the National Electricity Market is available from the NEMMCO website www.nemmco.com.au/operating/participation/participation.htm

[16] A given percentile season occurs if a more extreme level of the relevant parameter (average Summer temperature in this case) occurs in the long run average than that percentage of occasions. For example a Summer of 10 percentile average temperature is a Summer with average temperature exceeded, in the long run average, on 10% of occasions (i.e. 1 Summer in 10).

Growth in peak Summer non-smelter load insensitive to ambient temperature is forecast by projecting forward regressions of the ratio of this peak load to non-smelter energy. Table 3.5 shows Summer 10, 50 and 90 percentile average daily ambient temperatures and corresponding peak demand forecasts for Summer 2004/05.

4. INTRA-REGIONAL NETWORK ADEQUACY

4.1 Introduction

This chapter describes the existing transmission network and its ability to meet the actual and forecast 2003/04 Summer peak demand conditions. It includes:

- a review of the shared network conditions during Summer 2003/04;
- an overview of the active and reactive supply demand balance at times of peak demand; and
- a summary of fault levels and the available margin at Victorian terminal stations.

It aims to assist existing or potential network users in understanding transmission network constraints, in assessing future transmission augmentation requirements and in identifying locations with spare capacity for load growth or generation, or locations where demand management could defer the cost of network augmentation.

4.2 Existing Transmission Network

The Victorian transmission network consists of various transmission lines and transformers that link power stations to the distribution system. The transmission operates at voltages of 500 kV, 330 kV, 275 kV, and 220 kV. The 500 kV transmission primarily transports bulk electricity from generators in the Latrobe Valley in Victoria's east to the major load centre of Melbourne, and then onto the major smelter load and interconnection with South Australia in the west. Strongly meshed 220 kV transmission services the metropolitan area and major regional cities of Victoria, while the 330 kV transmission interconnects with the Snowy region and New South Wales. 275 kV transmission provides for the interconnection with South Australia as per Figure 4.1.

The electricity transmitted through the extra high voltage transmission is converted to lower voltages at terminal stations where it then supports the distribution system. There are a total of 37 terminal stations in Victoria. The total circuit distance covered by transmission lines is approximately 6,000 kilometres.

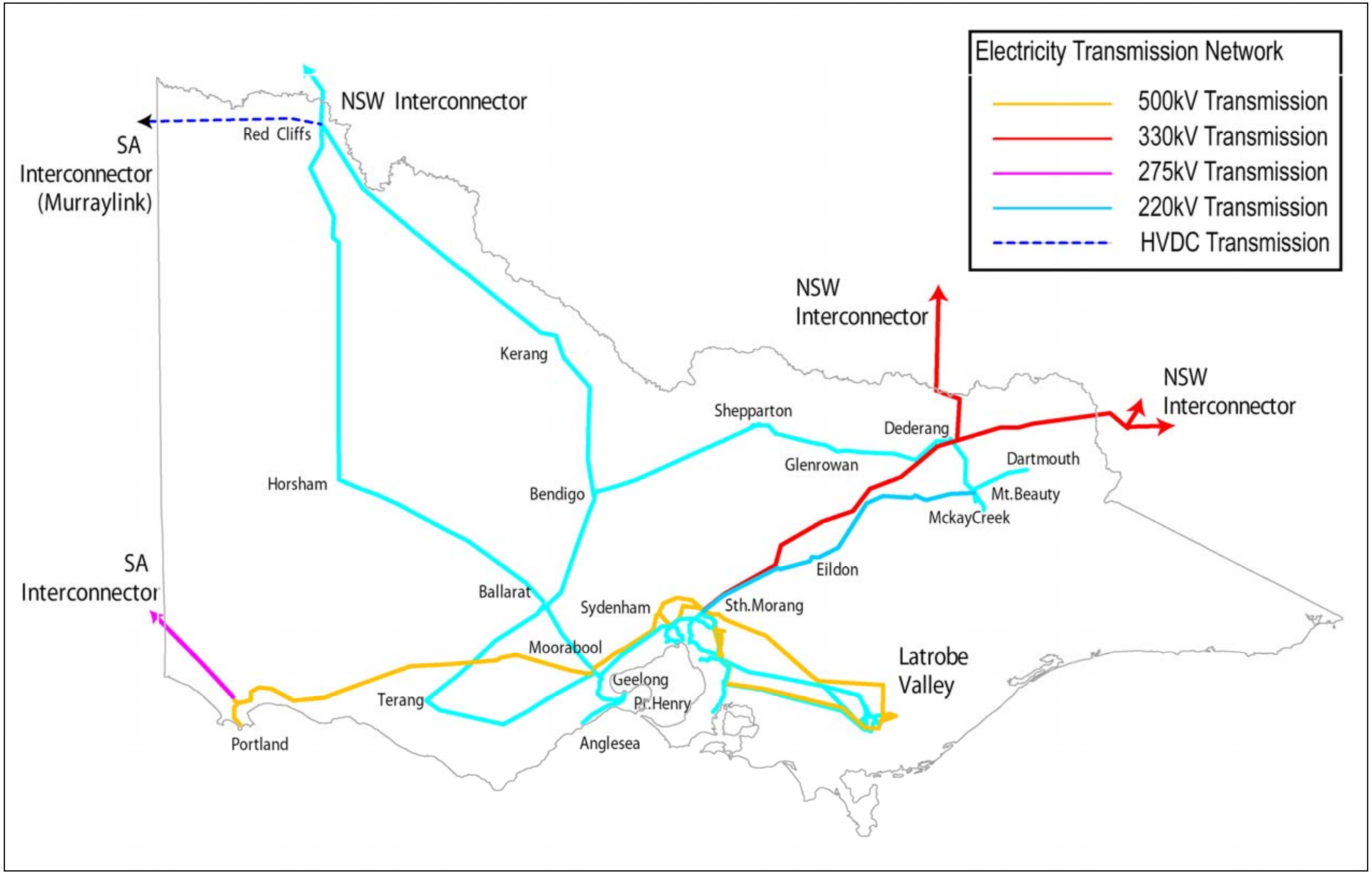

Figure 4.1 - Victorian Transmission Network

4.3 Summer 2003/04 Conditions

As discussed in chapter 3, the peak electricity demand experienced in Victoria in Summer 2003/04 was 8,574 MW and this occurred on Wednesday 17 December 2003. The temperature conditions on this day were consistent with a POE level of 34.6%. The maximum ambient temperature reached was relatively high at 38.3°C and the average Melbourne temperature was 30.05°C.

The Victorian shared transmission network has been economically designed to meet a demand of 9,590 MW, therefore the shared transmission network was operated at well within its design capability during the year with the actual peak demand being 1,000 MW below the maximum supportable demand.

The intra / inter-regional transfer levels and Victorian prices during Summer 2003/04 were only minimally impacted by planned network outages associated with augmentation projects and forced network outages. There were no significant system incidents or bushfires that occurred which caused price volatility during Summer 2003/04.

4.4 System Active and Reactive Power Supply Demand Balance

As shown in Table 4.1, the Victorian forecast reserve level (with a nominal 250 MW transfer level to South Australia) at peak demand conditions with all generation available is 587 MW, which is in excess of the regional LOR2[17] trigger level of 530 MW.

	VIC
Forecast Demand (10% Medium)	9,417
Expected Demand Side Participation	179
Reserve Trigger Level	530
Supply Needed to Meet Reserve	9,768
Local Generation	8,175
Import Capability From Snowy/NSW	1,900
Nominal Transfer to SA	250
Total Region Supply	9,825
Reserve Level	587
Reserve Surplus	57

Table 4.1 - Summer 2003/04 Supply Demand Balance for Victoria

[17] Lack of reserve level 2 (LOR2) - when NEMMCO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding

This supply demand balance is on the basis of the following generation capacity:

Generation	Summer MW Capacity 03/04
Anglesea	155
Bairnsdale	70
Energy Brix Complex	144
Hazelwood	1,600
Hume (VIC)	58
Jeeralang A	208
Jeeralang B	225
Loy Yang A	2,030
Loy Yang B	1,005
Newport	475
Somerton GT	123
Southern Hydro	382
Valley Power	280
Yallourn W	1,420
Total	8,175

Table 4.2 - Summer Aggregate Generation Capacity for Victoria (Source: 2003 SOO)

The forecast demand level of 9,417 MW is representative of conditions where:

- The transmission losses are approximately 410 MW (4.3%)
- The Used in Station load is approximately 500 MW (5.3%)
- Major Industrial load is approximately 1,100 MW (11.7%)
- State Regional load is approximately 1,510 MW (16.0%)[18]
- Western metropolitan area load is approximately 1,630 MW (17.3)[19]
- Eastern metropolitan area load is approximately 3,950 MW (41.9%)[20]
- Latrobe Valley area load is approximately 320 MW (3.4%)[21]

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[18] Defined as load supplied out of Geelong, Terang, Ballarat, Bendigo, Shepparton, Glenrowan, Mt Beauty, Wodonga, Kerang, Red Cliffs and Horsham Terminal Stations.

[19] Defined as load supplied out of Keilor, West Melbourne, Fisherman's Bend, Brooklyn and Altona Terminal Stations.

[20] Defined as load supplied out of Thomastown, Brunswick, Richmond, Malvern, Templestowe, Ringwood, Springvale, Heatherton, East Rowville, and Tyabb Terminal Stations.

[21] Defined as load supplied out of Yallourn and Morwell.

The maximum supportable demand in Victoria has been, and may continue to be, constrained by a voltage control limitation. At any time, the system must be operated to maintain an acceptable voltage profile and reactive reserve margin before and after a critical contingency. The pre-defined level of maximum supportable demand is based on an economic analysis as per VENCorp's application of the Regulatory Test and therefore dictated by VENCorp's Value of Customer Reliability and the cost of various network or non-network solutions. On a day-to-day basis, the actual system demand will be limited to below the maximum supportable demand to ensure acceptable post contingency voltages and reserve margins. For Summer 2003/04, the maximum supportable demand under the favourable conditions was 9,590 MW.

The reactive balance for the Summer 2003/04 system with the forecast maximum demand of 9,417 MW is given in Tables 4.3 and 4.4. Table 4.3 shows the system normal condition with all generator and transmission elements in service with 1,900 MW import from NSW/Snowy and 500 MW export to South Australia via Heywood Terminal Station and an additional 105 MW export to South Australia via Murraylink. Table 4.4 shows the system following a contingent outage of the Newport Power Station 500 MW unit. For this arrangement it was assumed that frequency control was being carried out utilising Snowy/NSW generators. As a result of the generator outage, import from NSW/Snowy increases up to 2,400 MW causing an increase in transmission active and reactive power losses. In addition, loss of the generator reduces the amount of reactive supply. The increased net reactive supply is met by the remaining generators, synchronous condensers, static var compensators and series capacitors.

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,240	3,698	Loads
SVC's and Synchronous Condensers	-4	207	Line Reactors
Line Charging	2,689	5,869	Line Losses
Shunt Capacitors	5,000	308	Inter- regional Transfer
Series Capacitors	157		
Total	10,082	10,082	Total

Table 4.3 - System Normal Reactive Power Supply and Demand Balance – 9,417 MW Demand

Reactive Supply (MVAr)		Reactive Demand (MVAr)	
Generation	2,332	3,698	Loads
SVC's and Synchronous Condensers	433	205	Line Reactors
Line Charging	2,664	6,626	Line Losses
Shunt Capacitors	4,965	146	Inter- regional Transfer
Series Capacitors	281		
Total	10,675	10,675	Total

Table 4.4 - Post Contingency Reactive Power Supply and Demand Balance – 9,417 MW Demand

4.5 Shared Network Loading

This section provides a review of the shared network loadings that were experienced for Summer 2003/04 and an indication of the network loadings that would have occurred if the forecast Summer load was achieved. This information is presented in Table 4.6 where loadings of shared transmission network lines and transformers, as a proportion of ratings are shown for the following three conditions:

- Actual 2003/04 8,574 MW MD;
- Forecast 2003/04 10% POE 9,417 MW MD; and
- Forecast 2003/04 9,417 MW MD with the single contingency outage producing the highest loading for each network element.

Table 4.5 below summarises the system loading conditions under these actual MD and 10% POE forecast MD conditions.

Demands (30 min average MW)	Actual MD	10% POE forecast MD
Victorian Demand	8,574	9,417
Victorian Generation	7,095	8,022
NSW/Snowy to Victoria transfer	1,344	1,895
Victoria to SA transfer	- 135	500

Table 4.5 - Actual and 10% POE Forecast 2003/04 MD System Loading Conditions

Allowing for hot Summer conditions likely to produce a 10% POE MD, continuous ratings used are for 40 ^{o}C ambient temperature conditions. Line ratings are based on the standard 0.6 m/s wind speed except in the case of Rowville to Springvale circuits, where wind monitoring is installed and ratings based on 1.2 m/s wind speed are typically applicable on hot days. Transformer continuous ratings are also used.

The contingency loadings presented are within short term transformer and line ratings, although these are not shown. A range of post-contingent actions to reschedule generation, reconfigure the network, and/or shed load, using automatic controls or remote manual intervention are available to ensure that after a critical contingency the transmission system remains in a satisfactory state. In particular this ensures that transmission operates at all times within ratings. In some cases action is needed within minutes of a critical contingency occurring under maximum demand conditions to retain operation within ratings. Within 30 minutes additional action may be needed to return the transmission system to a secure state, allowing the transmission system to remain in a satisfactory state should a further outage occur.

Note the items that are marked * show higher flows for the actual conditions then for the forecast demand. This is due to the different generation and import / export patterns.

Network Actual and Forecast 2003/04 MD Loadings - system normal and critical single outages	< 90%			90% - 100%			> 100%		
Transmission Link	Actual	10% MD	Critical outage	Actual	10% MD	Critical outage	Actual	10% MD	Critical outage
220 kV lines (East Metro Meshed)									
Brunswick-Richmond	42	78							135
Brunswick-Thomastown	29	36	55						
East Rowville-Rowville	51	58							116
East Rowville-Tyabb	15	21	43						
Keilor-Thomastown	21	21	47						
Rowville-Richmond *	43	37	82						
Rowville-Ringwood	39	44	67						
Rowville-Templestowe *	31	19	45						
Rowville-Thomastown (4-5 parallel circuits)	17	11	68						
Ringwood-Thomastown *	42	40							110
Templestowe-Thomastown	17	36							101
220 kV lines (East Metro Radial)									
Heatherton-Springvale	45	48				96			
Rowville-Malvern	35	39	79						
Rowville-Springvale	67	74							149
Tyabb-JLA (BHP)	9	15	16						
220 kV lines (Latrobe Valley to Melbourne)									
Hazelwood PS-Jeeralang	27	36	88						
Hazelwood PS-Morwell *	14	10	28						
Hazelwood PS-Rowville	60	62				94			
Hazelwood PS-Yallourn	69	76				96			
Hazelwood TS-Hazelwood PS *	50	38	81						
Rowville-Yallourn (4 parallel circuits)	83	89							105
220 kV lines (Regional)									
Ballarat-Bendigo *	22	7	84						
Ballarat-Horsham	22	22	43						
Ballarat-Moorabool *	39	35				90			
Ballarat-Terang	10	18	47						
Bendigo-Kerang	21	25	53						
Bendigo-Shepparton	58	72				93			
Dederang-Glenrowan	42	50	85						
Dederang-Mount Beauty	5	10	80						
Dederang-Shepparton	51	61	85						
Eildon-Mount Beauty *	56	52	75						
Eildon-Thomastown	39	81							101
Geelong-Keilor	25	39							124
Geelong-Moorabool *	23	21							40
Geelong-Point Henry/Anglesea	43	49				99			

Network Actual and Forecast 2003/04 MD Loadings - system normal and critical single outages	< 90%			90% - 100%			> 100%		
Transmission Link	Actual	10% MD	Critical outage	Actual	10% MD	Critical outage	Actual	10% MD	Critical outage
Glenrowan-Shepparton	31	37	71						
Horsham-Red Cliffs *	10	7	23						
Kerang-Red Cliffs	13	13	46						
Moorabool-Terang	34	37	65						
220 kV lines (West Melbourne Loop)									
Altona-Brooklyn	1	17	26						
Altona-Keilor *	21	14	26						
Brooklyn-Fishermen's Bend	5	9	38						
Brooklyn-Keilor *	22	13	32						
Brooklyn-Newport	27	38	63						
Fishermen's Bend-Newport *	33	26	61						
Fishermen's Bend-West Melbourne *	24	20	52						
Keilor-West Melbourne	25	39	71						
330 / 275 kV Lines									
Dederang-Murray	58	78							133
Dederang-South Morang	45	70							120
Dederang-Wodonga	12	13	34						
Heywood-SESS (SA)	12	52							100
Jindera-Wodonga	5	20	41						
500 kV Lines									
APD-Heywood	13	13	31						
Hazelwood TS-Loy Yang PS	27	29	44						
Hazelwood TS-Rowville	37	39	53						
Hazelwood TS-South Morang	39	42	65						
Moorabool-Heywood/APD	12	20	43						
Moorabool-Sydenham	19	29	54						
Keilor-Sydenham	11	11	45						
South Morang-Keilor	38	45	59						
South Morang-Rowville	13	18	36						
South Morang-Sydenham	24	30	51						
Main Tie transformers									
Dederang 330/220 kV	52	56							123
Heywood 500/275 kV	13	39							147
Keilor 500/220 kV	63	71				96			
Moorabool 500/220 kV *	67	65	77						
South Morang 330/220 kV	68	74							122
South Morang 500/330 kV *	17	12	44						
Rowville 500/220 kV	81	81							105
Hazelwood 500/220 kV	66	71							110

Table 4.6 - Network Actual and Forecast 2003/04 MD Loadings

4.6 Connection Asset Loading

The responsibility for planning of distribution related connection assets resides with the Distribution Businesses. The Distribution Businesses jointly publish an annual report on the performance and capability of the connection assets entitled 'Transmission Connection Planning Report'. This report is available via the Distribution Businesses' respective websites. VENCorp provides the following summary of connection asset loading over the Summer 2003/04 period for information purposes.

Table 4.7 shown below represents the 2003/04 Summer actual and forecast connection point loading as a percentage of (N-1) rating.

2003/04 Summer (Actual and Forecast) Connection Asset Loadings as % of firm rating		< 80%		80% - 90%		90% - 100%		> 100%	
Station	Voltage	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
Altona\Brooklyn*	66							✓	✓
Ballarat*	66				✓	✓			
Bendigo	66			✓	✓				
Bendigo	22	✓	✓						
Brooklyn*	22					✓	✓		
Brunswick*	22			✓			✓		
East Rowville (inc FTS) *	66							✓	✓
Fisherman's Bend	66	✓	✓						
Glenrowan*	66		✓	✓					
Geelong*	66					✓			✓
Horsham*	66					✓	✓		
Heatherton*	66							✓	✓
Kerang	66							✓	✓
Kerang	22	✓	✓						
Keilor	66					✓			✓
Mount Beauty (ex CLPS) *	66	✓	✓						
Malvern	66							✓	✓
Malvern*	22			✓	✓				
Morwell (incl LY) *	66							✓	✓
Red Cliffs*	66							✓	✓
Red Cliffs*	22							✓	✓
Richmond*	66							✓	✓
Richmond	22	✓	✓						
Ringwood*	66							✓	✓
Ringwood*	22							✓	✓
Shepparton	66	✓	✓						
Springvale*	66							✓	✓
Tyabb*	66							✓	✓
Terang*	66							✓	✓
Templestowe*	66					✓	✓		
Thomastown 1&2 Group*	66							✓	✓
Thomastown 3&4 Group*	66							✓	✓
West Melbourne*	66	✓			✓				
West Melbourne*	22	✓					✓		

Station	Voltage	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
Wodonga*	22			✓	✓				
Wodonga (ex HPS) *	66	✓	✓						
Yallourn	11	✓	✓						

Table 4.7 – Loading Levels of Connection Assets[22]

4.7 Fault Level Control

VENCorp has the responsibility to ensure that fault levels are always maintained within plant capability in the transmission network. At 275 kV, 330 kV and 500 kV voltage levels the fault levels are well below the switchgear ratings and it is unlikely that any of these stations would impose a constraint on development within the foreseeable future. However, at 220 kV and below (66 kV and 22 kV station buses) there are a number of stations close to the rated fault capability of the plant. Table 4.8 summarises the headroom available at these voltage levels at stations in the Victorian network based on Summer 2003/04.

Summer 2003/04 Maximum Prospective Short Circuit Current at the Busbar above 80% of the Circuit Breaker Interrupting Capability			
Terminal Station Switchyard	< 80%	80% - 90%	> 90%
220 kV			
Ballarat			✓
Brooklyn			✓
Brunswick	✓		
East Rowville			✓
Fisherman's Bend	✓		
Geelong	✓		
Hazelwood			✓
Heatherton	✓		
Keilor			✓
Malvern	✓		
Mount Beauty			✓
Redcliffs	✓		
Richmond		✓	
Ringwood	✓		
Rowville			✓
Springvale	✓		
Thomastown			✓
West Melbourne			✓

[22] * Indicates that either embedded generation or load transfer capability is available. These will both reduce the potential overload, and may remove the requirement for load shedding following the critical contingency.

Summer 2003/04 Maximum Prospective Short Circuit Current at the Busbar above 80% of the Circuit Breaker Interrupting Capability			
Terminal Station Switchyard	< 80%	80% - 90%	> 90%
66 kV			
Ballarat	✓		
Brooklyn			✓
East Rowville			✓
Fisherman's Bend			✓
Geelong			✓
Heatherton		✓	
Keilor			✓
Malvern			✓
Morwell		✓	
Mount Beauty	✓		
Redcliffs	✓		
Richmond	✓		
Ringwood		✓	
Springvale		✓	
Thomastown			✓
West Melbourne			✓
22 kV			
Brooklyn			✓
Brunswick			✓
Malvern	✓		
Redcliffs		✓	
Richmond			✓
Ringwood		✓	
West Melbourne			✓

Table 4.8 - Overview of Fault Levels at Victorian Terminal Stations

Maximum prospective short circuit currents are determined with all generation in service and all generators and for the most onerous feasible operating conditions.

For Summer 2003/04 there were no locations within the Victorian transmission network where the fault duty of plant on the interrupting capability of a circuit breaker was inadequate.

The high number of locations where the maximum short circuit current is greater than 90% of the switchyards minimum interrupting capability is an indication of the historical development of the transmission network in Victoria and the way new generation has been integrated into the system.

The fault levels are continuing to rise as the result of increased load and the generation and network augmentations needed to support this growth. In particular, new generation connected close to the critical stations will have a significant impact on fault levels.

VENCorp has managed increasing fault levels by operational arrangements (i.e. splitting buses and automatic control schemes) and circuit breaker replacement. This has been an effective and economic means to manage fault levels and has contained fault levels at critical locations within plant ratings for many years. However the application and increasing complexity of operational arrangements, and the inherent reduction in plant redundancy that typically results, means this approach may no longer always provide the most economic solution. The lack of margins between fault levels and ratings means that this matter is becoming a driving factor for augmentation rather than just a consequence of augmentation as it has generally been in the past.

The other alternatives for managing fault levels include control devices (such as series reactors in lines and buses and neutral reactors in transformer tertiaries) or replacing plant to allow fault levels to be increased to higher levels.

Much of the older 220 kV and 66 kV switchgear is scheduled for replacement by SPI PowerNet over the next 10 years as part of its asset replacement strategy. The standard design level for replacement 220 kV switchgear provides for 40 kA in the metropolitan stations (compared to around 26 kA for the older existing plant) and the co-ordination of this replacement with increased fault level requirements provides an opportunity to optimise the process and minimise the additional costs. A consequence of higher 220 kV levels is higher fault levels on the terminal station low voltage buses and in the distribution system. A case by case assessment is needed to determine if this is an issue and how it should be addressed.

VENCorp has established a joint working group with SPI PowerNet and representatives of the Distribution network businesses to review this matter and determine a strategy for fault level management into the future. Work to date indicates that new local generation will be the biggest issue for fault levels and to a large extent these need to be assessed on a case by case basis. However, further work is programmed to investigate the extent of the flow through impact and costs for the distribution system so that an agreed and cost effective approach can be identified and integrated with the asset replacement program.

5. INTRA-REGIONAL COMMITTED NETWORK AUGMENTATIONS

5.1 Introduction

This chapter of the APR provides a summary of recently completed or committed intra-regional network augmentation projects. These projects will normally have appeared in previous APR documents as planned augmentations. The projects detailed in this chapter are as follows:

Projects

1. Cranbourne 220/66 kV Development;
2. Ringwood fast load-shedding scheme;
3. Network Services to reinforce supply to Geelong;
4. Terminal Station Connection (220/66/22 kV) Transformer Expansion;
5. Keilor to West Melbourne 220 kV Line;
6. Rowville A1 Transformer 220 kV Circuit Breaker; and
7. Terminal Station Refurbishments.

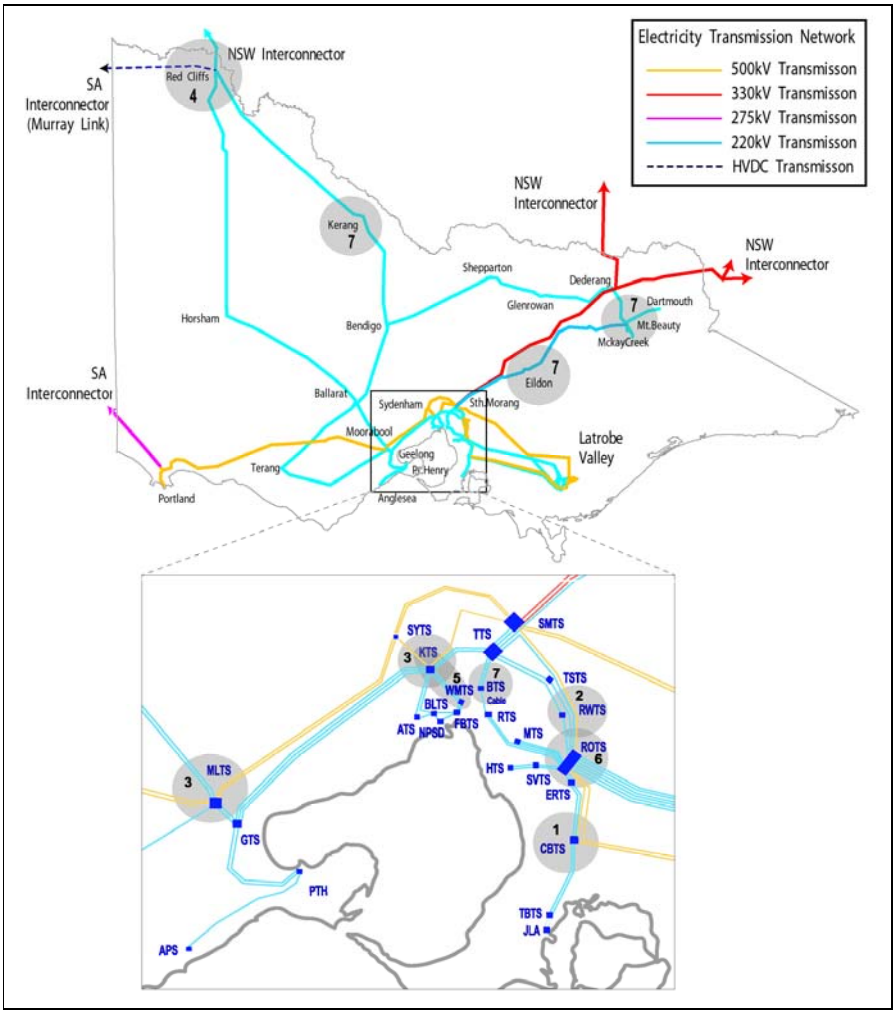

Figure 5.1 – Intra-Regional Committed Network Augmentations

5.2 Cranbourne 220/66 kV Development

In December 2001, the distribution companies United Energy (now Alinta) and TXU Networks made a connection application to VENCorp in accordance with the National Electricity Code for the establishment of a new transmission connection point at Cranbourne. This related to the need to reinforce the security of supply to the Mornington Peninsula, Berwick, Pakenham, and Cranbourne areas and was identified as part of the distribution businesses connection asset planning role.

Cranbourne Terminal Station is due to enter service as the newest Victorian terminal station in June 2004. The land had been set-aside for this purpose for some time to take advantage of the existing transmission assets. The works involve cutting in and switching of the East Rowville to Tyabb 220 kV lines and installation of two new 150 MVA 220/66 kV transformers.

This development not only supports the significant load growth in the surrounding area, but also allows heavily loaded terminal stations in the south-east of Melbourne to be offloaded, providing considerable benefits to the eastern metropolitan transmission connection and distribution system.

5.3 Ringwood

Ringwood Terminal Station is located in the eastern suburbs of Melbourne. Ringwood is supplied by two 220 kV lines, one from Thomastown, and one from Rowville. The two 220 kV lines supplying Ringwood are of differing design, with the Ringwood to Thomastown 220 kV line having a significantly lower rating than the Rowville to Ringwood 220 kV line.

Customer load is supplied from Ringwood at both 66 kV and 22 kV. The forecast peak load supplied from Ringwood for Summer 2004/05 is approximately 520 MW, growing at about 2.3% per year.

Following outage of the Rowville to Ringwood 220 kV line, the Ringwood to Thomastown 220 kV line supplies the entire Ringwood load. At times of high load at Ringwood and high ambient temperatures the loading on the Ringwood to Thomastown 220 kV line may exceed the continuous rating of the line. High ambient temperature is a significant factor as the rating of the Ringwood to Thomastown 220 kV line reduces with increasing temperature.

The likelihood of this situation occurring is low, and it is not economically justified to augment the 220 kV supply to Ringwood to completely remove the exposure to this contingency. If the contingency does occur at a critical time, system operators will manually shed load ex Ringwood to reduce the loading on the Ringwood to Thomastown 220 kV line. Dynamic short time rating facilities on the Ringwood to Thomastown 220 kV line are available to ensure that the amount of shedding is minimised while the line conductors do not exceed their design temperature, and critical line clearances are maintained.

Studies undertaken by VENCorp and outlined in our 2003 APR suggest that an automatic load shedding scheme is the preferred option to alleviate this transmission constraint as load grows and the time for manual action becomes inadequate.

The proposed load shedding scheme will continuously model the loading of the critical Ringwood to Thomastown 220 kV line against a dynamically calculated rating. When it detects that the line rating has been exceeded due to loss of the Rowville to Ringwood 220 kV line it will automatically shed load at Ringwood in order to bring the loading on the critical Ringwood to Thomastown 220 kV back within its continuous rating.

The relevant distributors supplied from Ringwood have been consulted on their preferred arrangements for load shedding, and they have also provided other input into the design of the load-shedding scheme.

The scheme is planned for service by 1st December 2004.

5.4 Network Services to Reinforce Supply to Geelong

In VENCorp's Electricity Annual Planning Review 2003, it was identified that transmission network augmentations are justified to reduce the risk to load from outage of the Moorabool 500/220 kV transformer bank. The most economic set of augmentations are installation of a spare single-phase 500/220 kV transformer at Moorabool combined with a fast load-shedding scheme to remove second contingency overloads on Keilor 500/220 kV transformers consistent with VENCorp's Electricity Transmission Planning Criteria[23].

In accordance with clause 5.6.6A of National Electricity Code (NEC), the information provided in the Electricity Annual Planning Review 2003 formed the basis for consultation on the preferred network solution to reduce the risk of load shedding from an outage of the Moorabool transformer. VENCorp received submissions from interested parties and had discussions with connected parties and DBs. Following consideration of submissions, a reassessment of economics was carried out and it was found that the net market benefits of the fast load shedding scheme and spare phase transformer at Moorabool remains higher than the net market benefits of alternative solutions. VENCorp's response to the consultation process was published[24] in September 2003.

Provision of a fast load shedding scheme and a spare phase transformer are non-contestable services and will be provided by SPI PowerNet.

The fast load shedding scheme is designed with high reliability and security for service by 1 December 2004. As an interim arrangement a coarse load shedding scheme was made available for service for the Summer 2004 peak period. The procurement of the spare phase is in progress to meet the service date of May 2005.

5.5 Terminal Station Connection (220/66/22 kV) Transformer Expansion

Powercor Australia and SPI PowerNet are in the process of installing a third 220/66/22 kV 140 MVA transformer at Redcliffs by March 2005 and a third 220/66/22 kV 35 MVA transformer at Kerang by October 2004.

Powercor Australia and SPI PowerNet will be commissioning a second 220/66/11 kV, 150 MVA transformer at Altona during 2004.

5.6 Keilor to West Melbourne Line

The overall conductor temperature of the Keilor to West Melbourne 220 kV circuits was upgraded from 65°C to 82°C operation by resagging the bottom phases between towers 37 and 38 in December 2003. No other primary or secondary modifications at Keilor or West Melbourne Terminal Stations were carried out. This allowed the overhead line rating to be increased by about 20%.

[23] VENCorp Electricity Transmission Planning Criteria available at www.vencorp.com.au

[24] VENCorp Response – Small Network Asset Augmentations available at www.vencorp.com.au

5.7 Rowville 500/220 kV Transformer 220 kV Circuit Breaker

The Rowville 500/220 kV transformer is connected to the Rowville 220 kV switchyard by a breaker and a half switching arrangement. With load grow the circuit breaker connecting to No.4 220 kV bus was identified as a constraint on the output of the transformer under peak loading conditions and high temperatures. The only feasible option was to replace the critical circuit breaker and its connections with a higher rated circuit breaker. The circuit breaker has now been replaced and the connections will be replaced during Spring 2004 when the risk associated with the necessary transformer outage will be minimised.

5.8 Terminal Station Refurbishments

SPI PowerNet is progressing the refurbishment of terminal station assets at the following locations:

- Kerang Terminal Station switchyard refurbishment service date August 2004
- Mount Beauty Terminal Station 66 kV switchyard refurbishment service date September 2004
- Eildon Power Station 220 kV switchyard refurbishment service date March 2005
- Brunswick Terminal Station switchyard refurbishment to be completed during 2004/05

SPI PowerNet is also planning refurbishment works at a number of other stations and is in the process of discussing the requirements with VENCorp and the connected parties to enable any opportunities for optimising the arrangements to be incorporated in the refurbishment works.

6. INTRA-REGIONAL PROPOSED NETWORK DEVELOPMENTS WITHIN 5 YEARS

6.1 Introduction

This section discusses the options for removal of network constraints within Victoria and presents the information required under the NEC for proposed augmentations.

As a Transmission Network Service Provider in Victoria, VENCorp is responsible for planning the Victorian shared electricity transmission network on behalf of its users. VENCorp does so in an independent manner and on a not for profit basis.

VENCorp undertakes this responsibility in accordance with its Licence obligations, the National Electricity Code and the Victorian Electricity System Code and it assesses the feasibility of transmission projects using the Regulatory Test as specified by the ACCC. In practice, this reflects in VENCorp applying the economic principle that any shared transmission investment will only be justified once its identified and quantified benefits exceed the costs of implementing the project i.e. the project must have a positive net market benefit.

VENCorp considers the benefits associated with transmission investment are:

- a reduction in the amount of expected unserved energy;
- a reduction in the total fuel cost of generation in the NEM;
- a reduction in transmission losses;
- deferral of capital plant costs; and
- a reduction in ancillary service costs.

In its planning role, VENCorp does not adopt a planning standard or criteria based on N-1 redundancy. In Victoria, a value of customer reliability (VCR) has been adopted that represents an economic value assigned to the end use of electricity. Application of the VCR allows expected unserved energy to be economically quantified, thereby providing a basis for justifying investment decisions. Importantly, the application of a net market benefit approach implies that under some conditions it is actually economic to shed load following a credible contingency.

A probabilistic approach is applied in the assessment of expected unserved energy. It considers the likelihood and coincidence of the contingency event and the onerous loading and ambient conditions.

VENCorp's detailed "Electricity Transmission Network Planning Criteria" is available at www.vencorp.com.au.

The design principles used by VENCorp for planning the transmission network are consistent with NEMMCO's obligations in operating the network and are as follows:

- Following a single contingency, the system must remain in a satisfactory state (i.e. no performance or plant limit breached).

- Following the forced outage of a single element, it must be possible to re-adjust (secure) the system within 30 minutes so that it is capable of tolerating a further forced outage and remain in a satisfactory state (i.e. no performance or plant limit breached).

- Following an outage at least 15 minutes must be available for manual action[25]. If less than 15 minutes is available then, it is necessary to take pre-contingent action to provide the 15 minutes or have in place an automatic control scheme.

- Sufficient periods are available to allow maintenance of critical shared network elements without exposing the network to excessive risk in the event of a further unscheduled outage of a network element.

- Load shedding and re-dispatch of generation are considered as legitimate options to network augmentation.

The unserved energy resulting from network constraints has been assessed using a Value of Customer Reliability (VCR) of $29,600/MWh.

For some sections of the Victorian electricity network, particularly in the Victorian State Grid[26], securing the system following outage of a single element such that the system remains in a satisfactory state following a second contingency has not been included in the economic analysis. The System Overload Control Scheme (SOCS) will need to be modified to manage circuit overloads following the second contingency.

SOCS is a transmission line overload monitoring and automatic load shedding scheme, that monitors the line loading at either end of the circuit and if required sheds an appropriate amount of load to restore the circuit loading to below its continuous rating.

Using this scheme to manage overloads following second contingencies has not been analysed in the past, and we recognise that SOCS is a central processor based scheme of lower reliability and security than protection. As such the acceptability of using SOCS in this way, will be investigated with asset owners.

6.2 Consultation

For large network augmentations detailed public consultation will be undertaken for each of the projects in accordance with the Clause 5.6.6 of the NEC.

For small network assets, this APR forms the basis for consultation in accordance with Clause 5.6.6A of the NEC. Interested parties are invited to make submissions regarding the proposed augmentations and any non-network options they consider as an alternative. The closing date for submissions is Monday 2nd August 2004.

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[25] In the Electricity Annual Planning Review 2003, a minimum of 10 minutes for manual action was applied. The 15 minutes for manual action is in line with NEMMCO's revised operating procedure dated 16/12/2003.

[26] Regional Victoria (from Hamilton to Mildura to Glenrowan) excluding Gippsland and further east, is supplied from the 220 kV 'State Grid'.

Submissions should be addressed to:

Executive Manager, Energy Infrastructure (Mr John Howarth)
PO Box 413 World Trade Centre Vic 8005
Phone: 03 8664 6565
Fax: 03 8664 6511
Email: john.howarth@vencorp.vic.gov.au
Website: http://www.vencorp.com.au/

Following consideration of any submissions in accordance with Code consultation procedures, VENCorp will publish its conclusions and recommended course of action. VENCorp will then proceed with the approval processes required to implement these proposed new small network assets in the required timeframes.

6.3 Market Modelling Basis

To implement its probabilistic planning criteria, VENCorp simulates the National Electricity Market in order to determine the use of the shared network in such an environment. A Monte-Carlo based modelling of flows on the shared network is extrapolated from the NEM dispatch data. These forecast flow conditions are then compared with the capability of critical plant, allowing the exposure to unserved energy to be quantified over the analysis time frame.

The assumptions and specifications of VENCorp's NEM modelling for the 2004 Annual Planning Review include:

- Scenarios / Demand Traces – Only committed changes to the NEM interconnector capabilities and generation were considered for VENCorp's intra-regional transmission planning. Appropriate historical demand traces were scaled for all current NEM regions over the analysis period with 10, 50, and 90 percentile peak demand scenarios being considered based on a medium economic (energy) growth outlook.
- Demand / Energy Forecasts – NEMMCO's 2003 Statement of Opportunity and VENCorp's 2003 APR were used as the source of regional energy and demand forecasts.
- Generation – The Summer and Winter capacities of all dispatched NEM generators were modelled from NEMMCO's 2003 Statement of Opportunity. Forced outage rates and mean repair times were based on publicly available material from Regulatory Test assessments such as SNI and SNOVIC. Planned outage programs were based on historical market behaviour and MT PASA forecasts.
- Generation Bidding – Short Run Marginal Costs based on publicly available material from Regulatory Test assessments such as SNI and SNOVIC have been applied.
- Inter-regional marginal loss factor equations and intra-regional loss factors were based on NEMMCO's 2003/04 loss factor publication.
- Hydro Generation – Forced Outage Rates were not modelled for hydro units. Energy targets for Snowy and Southern Hydro Generation were enforced, as per NEMMCO's 2003 Statement of Opportunity.
- New Entry Criteria – New Generators were entered into the market based on the principle of 'Reliability Driven Generation' to ensure that all regions maintained adequate reserve margins.

6.4 Identified Network Constraints

Due to the increasingly complex and interdependent nature of many solutions to the constraints identified in the Victorian shared network, VENCorp has undertaken to evaluate the constraints in groups.

Table 6.1 details the potential constraints that have been identified, additionally showing the type of augmentation and estimated costs:

Constraint Group	Section	Constraint	Augmentation Type	Date	Estimated Cost ($K)
South East Metropolitan Radial Network	6.6	Loading of Rowville to Springvale and Heatherton 220 kV Lines	Small Network Augmentation	Dec 2005	2,000
	6.7	Loading of Rowville to Malvern 220 kV Radial Lines	Emerging constraint		To be determined
	6.8	Security of Double Circuit 220 kV Lines to South East Metropolitan Area	No economic solution identified (security Issue)		To be determined
South East Metropolitan Meshed Network	6.9	Loading of 500/220 kV and 330/220 kV Metropolitan Tie Transformers & associated 220 kV links	Small Network Augmentation	Dec 2005	6,000
			Large Network Augmentation	Dec 2006	45,000
Western Metropolitan.	6.10	Loading of Geelong to Keilor 220 kV Lines and Keilor 500/220 kV Transformers	Minor Network Augmentation	Dec 2004	400
			Large Network Augmentation	Dec 2006	26,000
	6.11	Loading of Keilor to West Melbourne 220 kV Lines	Minor Network Augmentation	Dec 2004	400
	6.12	Loading of Fisherman's Bend to West Melbourne 220 kV Circuits	Emerging constraint		To be determined
Hazelwood Transformers	6.13	Loading of Hazelwood 500/220 kV Tie Transformers	Large Network Augmentation	Dec 2008	25,000
State Grid (High Export)	6.14	Loading of Moorabool to Ballarat 220 kV Lines	Minor Network Augmentation	Nov 2005	400
	6.15	Loading of Ballarat to Bendigo 220 kV Line	Emerging constraint		To be determined
State Grid (High Import)	6.16	Loading of Shepparton to Bendigo 220 kV Line	Emerging constraint		To be determined
	6.17	Loading of Murray to Dederang 330 kV Lines	Emerging constraint		To be determined
	6.18	Loading of Dederang to South Morang 330 kV Lines	Emerging constraint		To be determined
	6.19	Loading of 330/220 kV Dederang Tie Transformers	Minor Network Augmentation	Dec 2004	100
	6.20	Loading of Eildon to Thomastown 220 kV Line	Emerging constraint		To be determined
Reactive Support	6.21	Reactive Support for Maximum Demand Conditions	Emerging constraint		To be determined

Table 6.1 - Identified Constraints and Augmentation Type

6.4.1 Constraint Evaluation Process

Each constraint identified steps through the following process:

- Reasons for the constraint, including sensitivities, critical events, critically loaded plant and capabilities;
- impacts of constraint, deterministic, then probabilistic over three years 2004/05–2006/07–2008/09;
- identification of network solutions and costs, additionally any non-network solutions;
- impact of solutions on other constraints;
- identification of all benefits of solutions;
- economic analysis to provide range of NPV's for each option; and
- identification of preferred option, timing, rankings, large, small or minor augmentation.

6.4.2 Distribution Business Planning Impacts on the Shared Transmission Network Planning

VENCorp performs network planning based on the load forecasts provided by the System Participants who have a supply point(s) of connection to the shared transmission network. In doing so VENCorp insures that network augmentation plans to support the development at the connected stations and new connections planned by distribution businesses have been addressed in the planning of the shared transmission network. Additionally, the impacts of the distribution business augmentation plans on the shared network planning have been individually addressed in each of the constraints.

The general impact of distribution load growth is addressed through modelling of growth at the connection stations. The following table addresses a number of instances where the distribution businesses have foreshadowed plans which may have a specific impact on the shared network.

The table shows the planned connection modification presented in the distribution businesses 2003 TCPR (Transmission Connection Planning Report) and VENCorp's consideration of this augmentation in respect of the shared network.

Terminal Station	Preferred Network Solution	VENCorp Consideration
East Geelong	Establish new 220/66 kV terminal station to off-load Geelong Terminal Station some time around 2010.	The requirement to support supply into the Geelong area from Moorabool and Keilor will not be changed by this development. However, the relocation of load from Geelong to East Geelong will increase the loading on the Geelong to Point Henry 220 kV lines. There is spare capacity in these lines to support additional load. VENCorp will review the requirements with Powercor and advise affected parties
Malvern 66 kV and 22 kV	Redevelopment of Malvern Terminal Station and possible transfer of load from adjacent terminal stations.	The existing 220 kV circuits from Rowville are adequate to meet supply to Malvern. If the load at Malvern goes beyond 270 MVA the circuits could become a constraint at times of high demand. There is capability to uprate these circuits when economically justifiable.
Richmond 66 kV	Establish new terminal station by approximately 2010/11	This would significantly reduce the loading on the Richmond to Brunswick circuit and the Rowville to Richmond circuits and reduce the risk of the constraints on these circuits.
Thomastown 66 kV	Establish new terminal station by approximately 2010/11 at either Sydenham or South Morang	VENCorp has not specifically provided for this development in its plans as the impacts differ considerably depending on the arrangement. At present this load is represented at Thomastown. If the development were to be connected at the 500 kV at Sydenham then this would have the benefit of slightly off-loading the 220 kV network and existing 500/220 kV transformation. If it is at 220 kV from Sydenham then new 220 kV circuits and possibly a new 220 kV bus at South Morang will be required. If it is 220 kV at South Morang than a 220 kV bus will need to be established at South Morang.

Table 6.2 - Distribution Business Planning Impacts

6.5 South East Metropolitan Radial Network

6.5.1 Introduction

The characteristics of the flows in the south east metropolitan radial network will change as a consequence of the Latrobe Valley to Melbourne upgrade project and the development of the Cranbourne Terminal Station in 2004.

A number of constraints within this network are interdependent and potential solutions to resolve some constraints will have an influence (both positively and negatively) on other constraints.

Table 6.3 summarises and ranks (in a deterministic manner) the constraints under evaluation in this section:

Ranking	Constraint	Nominal 40degC Rating	Contingency	CRI[27] 04/05	CRI 06/07	CRI 08/09	CGI[28]	CII[29] 04/05
1	Rowville to Springvale Circuit	575 MVA	Rowville to Springvale parallel circuit	1.35	1.43	1.53	1.14	2.01
2	Rowville to Malvern Circuit	234 MVA	Rowville to Malvern parallel circuit	0.86	0.93	1.02	1.19	2.04
	Security of double circuit supplies to south-eastern metro	Note[30]						

Table 6.3 – Ranking of Constraints in South East Metropolitan Radial Network

Note, Table 6.3 is based on deterministic studies under peak demand conditions and should only be used to give some perspective and reference to the various constraints. It should not necessarily be used to indicate the relative value of each constraint. This is done via the full probabilistic and economic analysis presented in the following sections, whereby operational considerations and VENCorp's full planning criteria are applied.

This section considers the impact of the various network augmentation options under consideration by determining their impacts on all relevant constraints. It then aims to co-ordinate the benefits of each option so that those options that minimise the overall energy at risk and minimise the overall capital expenditure are preferred as they would maximise the net market benefit.

[27] CRI, Contingency Ranking Index is defined as the ratio of the post-contingent loading to the 40˚C rating in the given year.

[28] CGI, Contingency Growth Index is defined as the ratio of the post-contingent loading in 2008/09 to the post-contingent loading in 2004/05.

[29] CII, Contingency Impact Index is defined as the post-contingent loading to the pre-contingent loading in the given year.

[30] This section discusses security of the network to supply load at specific locations and is not related to a constraint or plant being overloaded.

6.6 Loading of Rowville to Springvale and Heatherton 220 kV Lines

6.6.1 Introduction

(a) Location of Constraint

Springvale Terminal Station and Heatherton Terminal Station are supplied radially from Rowville Terminal Station via the Rowville to Springvale and Springvale to Heatherton double circuit 220 kV lines, as shown in Figures 6.1 and 6.2.

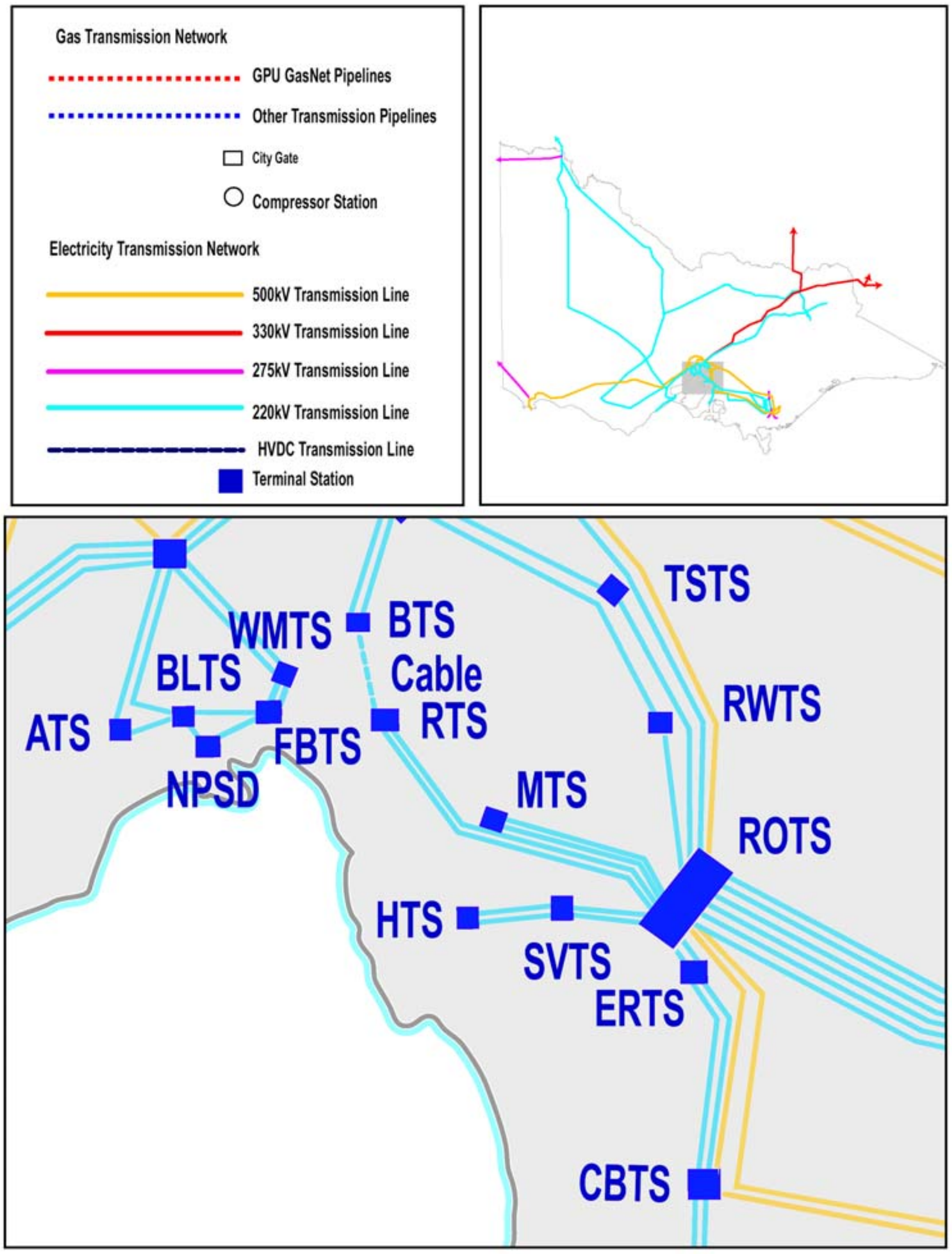


Figure 6.1 - Geographical Representation of Rowville to Springvale and Heatherton 220 kV Lines

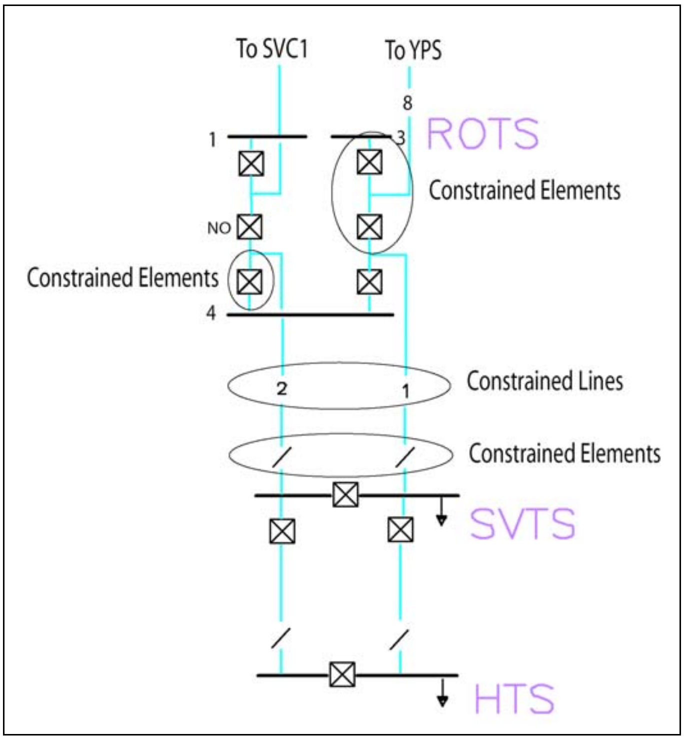


Figure 6.2 - Electrical Representation of Supply to Springvale and Heatherton Areas

Abbreviation: HTS – Heatherton Terminal Station
ROTS – Rowville Terminal Station
SVTS – Springvale Terminal Station
YPS – Yallourn Power Station
SVC – Static VAr Compensator
NO – Normally Open Circuit Breaker

(b) Reason for Constraint

The loading on the Rowville to Springvale circuits is forecast to increase as a result of load growth in the Springvale and Heatherton areas. Table 6.4 summarises the 10% and 50% POE demand forecasts at Springvale and Heatherton up to Summer 2008/09.

The centre circuit breaker of the Rowville to Springvale No.2 circuit at Rowville is open for system normal operation in order to split the Rowville 220 kV buses into two groups for fault level control. An auto close scheme is available on this normally open circuit breaker. The scheme will automatically operate to close the normally open circuit breaker following outage of the Rowville No.4 bus if loading of circuit breaker of section Rowville No.3 bus/Rowville to Yallourn Power Station No.8 line exceeds the set point.

Following service of the 500/220 kV transformer at Cranbourne in Summer 2004/05, if the normally open circuit breaker closed it would increase the prospective fault levels above the rupture capability of the station. Hence the auto close scheme will be disabled. This could result in potential overloading of the circuit breakers and isolators of Rowville No.3 bus/Rowville to Yallourn Power Station No.8 section following an outage of the Rowville No.4 bus.

Year	POE %	Springvale Demand (MW)	Heatherton Demand (MW)	Total Demand (MW)
2004/05	10	444	315	759
	50	428	303	731
2005/06	10	458	327	785
	50	441	314	755
2006/07	10	472	335	807
	50	453	322	775
2007/08	10	485	344	829
	50	466	330	795
2008/09	10	500	354	854
	50	480	339	819

Table 6.4 – Maximum Demand Forecast at Springvale and Heatherton

(c) Conditions of Constraint

Each of the Rowville to Springvale circuits carries 50% of the total combined load at Springvale and Heatherton under normal conditions. If an outage of one of the two parallel circuits were to occur on a high temperature day at a time of high demand, the remaining circuit could be loaded above it's continuous rating.

Factors affecting the transfer capability between Rowville and Springvale are the thermal capacity of:

- The Rowville to Springvale overhead circuits. A wind monitoring scheme is in service for these lines and at wind speeds above the design level, higher ratings of the circuits can be obtained;
- The 220 kV line isolators and terminations at Springvale of both circuits;
- Isolator and termination at Rowville of No.2 circuit; and
- Isolators and circuit breaker at Rowville between Rowville No.3 220 kV bus and Yallourn No.8 220 kV line.

Each of the Rowville to Springvale circuits has a nominal continuous rating of 648 MVA at 35^{O}C. Table 6.5 summarises the thermal ratings of the constraint elements on the Rowville to Springvale line.

Outage	Critical Circuit	Constrained Transmission Element	Rating at 35°C (Amps)
Circuit 1 or 2	Circuit 1 or 2	Transmission Circuit (wind speed - 0.6 m/s)	1,700
		Transmission Circuit (wind speed - 1.2 m/s)	2,000
		Transmission Circuit (wind speed - 1.8 m/s)	2,271
Circuit 1 or 2	Circuit 1or 2	Isolators at Springvale	2,100 (2,200[31])
		Circuit terminations at Springvale	2,150
Circuit 1 or 2	Circuit 1 or 2	Circuit termination at Rowville	2,260
Circuit 1	Circuit 2	Bus side isolator at Rowville	2,150
		Circuit terminations at Rowville - isolator to circuit breaker, circuit breaker to isolator and isolator to Circuit junction connections	2,260
Rowville No.4 Bus Outage	Circuit 1	Rowville No.3 220 kV bus to Yallourn Power Station No.8 220 kV Circuit section: Isolators Circuit breaker	 1,300 1,350
		Yallourn Power Station No.8 220 kV Circuit to Springvale No.1 220 kV Circuit section: Circuit breaker Circuit terminations Protection limit	 2,300 2,260 1,800

Table 6.4 – Thermal Ratings of Constrained Elements

The Rowville to Springvale 220 kV double circuit line is 7.4 km in length. There have been 7 unplanned outages of either of these circuits since 1985, with an average duration of 4.39 hours for each outage. This gives an outage rate of 0.38 events per year for both circuits, compared to a benchmark figure of approximately 0.22 events per year, with average duration of no more than 10 hours per event. The benchmark probability of one of the two circuits being unavailable in a given hour is: 0.02534%. The historical outage rate of these lines is approximately 25% below this benchmark rate. The probability of Rowville No.4 bus outage is very low.

(d) Impacts of Constraint

From Summer 2005/06 the rating of termination equipment may result in pre-contingent constraints.

Post-contingent load at risk is mainly due to the transmission line Post-contigent load at risk is mainly due to the transmission line capability. The amount of post-contingent load shedding depends critically on the wind speed. The minimum amount would be determined by the Springvale isolator limit, which does not change with wind speed, and the maximum amount would be for atypical conditions when low wind speeds occur coincident with high ambient temperatures and load.

At present, this potential constraint is being addressed by:

[31] Short term rating

- The wind in the vicinity of the lines is monitored and a dynamic rating is assigned to the Rowville to Springvale 220 kV circuits based on actual wind speed. Typically, periods of high ambient temperature are associated with wind speeds of at least 1.2 m/sec, increasing the current carrying capacity by 14% and reducing the risk of loading exceeding rating following an outage on one circuit.

- An automatic control scheme continuously calculates the conductor temperature of the critical circuits so that loading beyond the continuous rating can be applied for short durations without exceeding the maximum conductor temperature. After a contingency, this scheme can automatically shed load at Springvale to ensure that the circuits do not exceed their design temperature.

(e) Impact on Constraint of Distribution Business Planning

Distribution plans published in the 2003 Transmission Connection Planning Report ("TCPR") ultimately cater for Springvale and Heatherton Terminal Station aggregate peak Summer demands of 1,440 MVA under emergency conditions at other station/s, and between 1,080 MVA and 1,440 MVA under normal network conditions.

The Rowville to Springvale line can be uprated to enable this 1,440 MVA peak emergency Summer demand to be carried under normal 220 kV network conditions (i.e. with both circuits in service), and extreme weather conditions (42 ^{o}C ambient temperature and light winds). However, with one circuit out of service at an ambient temperature of 42^{o}C the remaining (uprated) circuit could only supply:

- 62% of peak emergency demand; and

- 62-76% of the peak Summer demand under normal terminal station conditions;

- with light wind conditions, or:

- 74% of peak emergency demand; and

- 74-98% of the peak Summer demand under normal terminal station conditions

under higher wind conditions, reached 40% of the time on very hot days.

Transmission augmentation to supply these proposed Springvale and Heatherton Terminal Station load increases reliably may require installation of a third 220 kV circuit. It is probable that this could only be achieved by using a 220 kV underground cable. However, the high cost associated with a cable may result in abnormally high energy levels being placed at risk before the cable is economically justified. Similarly the additional loading of this easement exacerbates the double circuit radial security issue considered in Section 6.8.

Joint distribution/transmission planning studies are sought to review overall costs and reliability of alternative options, including connecting some of this load to another transmission easement. This matter is raised now in response to published connection asset planning for 2012 to draw attention promptly to the abnormal cost/reliability transmission supply features presented above, recognising that nearer term distribution planning may also be affected.

(f) Impact on Constraint of Asset Replacement Program

As part of SPI PowerNet's switchyard refurbishment program, the constrained elements, which were identified in Table 6.5, are planned to be replaced in 2009/10. VENCorp may request this plant to be replaced with plant of higher capability.

6.6.2 Do Nothing – Value of Expected Energy at Risk

Table 6.6 shows the pre-contingent energy at risk due to limitations on the isolators/line terminations at Rowville and Springvale. The pre-contingent load needs to be shed prior to the event to prevent overload beyond continuous rating (short term rating in the case of Springvale isolators) immediately following a contingency.

Table 6.7 shows the post-contingent energy at risk due to transmission line rating. Generally wind speed on high ambient temperature days is higher than 0.6 m/s and a typical wind speed of 1.2m/s is assumed in the assessment of transmission line rating.

Year	Unit	2004/05	2005/06	2006/07	2007/08	2008/09
Average annual hours of constraint	Hours	0	4.33	6.0	8.67	10.67
Maximum single constraint	MW	0	93	115	137	162
Energy at risk	MWh	0	146.7	246.3	371.7	568.0
Expected unserved energy	MWh	0	146.7	246.3	371.7	568.0
Value of expected unserved energy	$K	0	4,341	7,291	11,001	16,813

Table 6.6 - Pre-contingent Energy at Risk

Year	Unit	2004/05	2005/06	2006/07	2007/08	2008/09
Average annual hours of constraint	Hours	5	8	9	11	14
Maximum single constraint (pre-contingent demand at risk not included)	MW	145	171	193	215	240
Energy at risk (pre-contingent demand at risk not included)	MWh	253	371	525	680	918
Expected unserved energy	MWh	0.065	0.094	0.133	0.172	0.233
Value of expected unserved energy	$K	1.9	2.8	4.0	5.2	6.9

Table 6.7 - Post-contingent Energy at Risk

6.6.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

Possible network solutions to remove the constraint on 220 kV supply to Springvale and Heatherton are:

Option 1, Stage 1: Replacement of two 220 kV isolators and terminations at Springvale on both the Rowville to Springvale lines;

Replacement of the bus-side isolator and terminations at Rowville of Rowville to Springvale No.2 line;

Replacement of two 220 kV isolators and one circuit breaker at Rowville of Rowville No.3 bus/Rowville to Yallourn Power Station No.8 line section;

Increase protection limit of Rowville to Yallourn Power Station No.8 line/Rowville to Springvale No.1 line section; and

Replacement of a circuit breaker and line terminations at Rowville of Rowville to Yallourn Power Station No.8 line / Rowville to Springvale No.1 line section (required from Summer 2007/08).

Indicative cost for option 1 is approximately $2 M.

Option 1, Stage 2: Uprating the Rowville to Springvale lines from 68°C to 82°C operation. This involves modification of at least 7 transmission towers. An indicative cost for this option is approximately $0.5 M.

Option 2: New 220 kV underground cable connection between Malvern and Heatherton Terminal Stations which are connected to Rowville Terminal Station. Indicative cost of approximately $36 M.

(b) Non-Network Options Considered

Load transfer or demand management at Springvale or Heatherton, sufficient to keep demand below the continuous rating of termination equipment. This would avoid or defer the need for replacement of the termination equipment. To avoid load shedding after an event, sufficient load transfer or demand management would be needed to keep the lines within their continuous rating.

6.6.4 Economic Evaluation

Option 1, stage 1 will remove the pre-contingent load shedding. Once option 1, stage 1 is implemented, load at risk only occurs following an outage of either circuit.

Option 1, stage 2 will remove the potential post-contingent load at risk.

Option 2 can avoid pre and post-contingent load at risk. Option 2 has the additional benefit of securing the double circuit supplies to the South East metropolitan area.

Table 6.8 provides reduction in unserved energy in options 1 (stages 1 and 2) and 2 includes the benefits associated with securing supply to the South East metropolitan area.

Option	Present Value 30 Year Life		Annualised Value All $K					Residual Value For Remaining 25 Years 2009/10
			2004/05	2005/06	2006/07	2007/08	2008/09	
Do Nothing	- 151,253		- 2	- 4,344	- 7,295	- 11,007	- 16,820	- 122,199
Option 1 (Stage 1)	151,186	Benefit	-	4,341	7,291	11,001	16,813	122,148
	- 2,030	Equiv Annual Cost	- 180	- 180	- 180	- 180	- 180	- 1,310
	149,156	Net Benefit	- 180	4,161	7,111	10,821	16,633	120,838
Option 1 (Stage 2)	68	Benefit	2	3	4	5	7	52
	- 2,538	Equiv Annual Cost	- 225	- 225	- 225	- 225	- 225	- 1,638
	- 2,470	Net Benefit	- 223	- 223	- 221	- 220	- 218	- 1,586
Option 2	162,252[32]	Benefit	979	5,321	8,272	11,984	17,797	129,297
	- 36,540	Equiv Annual Cost	- 3,246	- 3,246	- 3,246	- 3,246	- 3,246	- 23,581
	125,712	Net Benefit	- 2,267	2,075	5,026	8,738	14,551	105,716

Table 6.8 - Reduction in Unserved Energy due to Network Augmentations

A net market benefit assessment is carried out for a 30-year period for each of the network options using a discount rate of 8% to calculate the NPV. The benefit in each option for year 6 onwards is assumed to be the year 5 value.

6.6.5 Ranking of Options

Table 6.9 summarises the NPV of each option compared to the do nothing case. Option 1, stage 1 maximises the net benefit.

Options	NPV	Ranking
Option 1, Stage 1 Upgrading of isolators and terminations at Springvale and Rowville	149,156	1
Option 2 Installation of a new 220 kV cable between Malvern and Heatherton Terminal Stations	125,712	2
Option 1, Stage 2 Upgrading of Rowville to Springvale transmission line rating (following implementation of option 1, stage 1)	Not applicable, as value is negative	-

Table 6.9 – Ranking of Options

[32] The benefit from the cable includes the "security" benerfits identified in 6.8.2

6.6.6 Timing of Network Solution

Option 1, stage 1 maximises the net benefit. Timing for option 1, stage 1 is Summer 2005/06.

6.6.7 Conclusions

Figure 6.3 depicts the benefit of upgrading the constrained elements as outlined in option 1, stage 1.

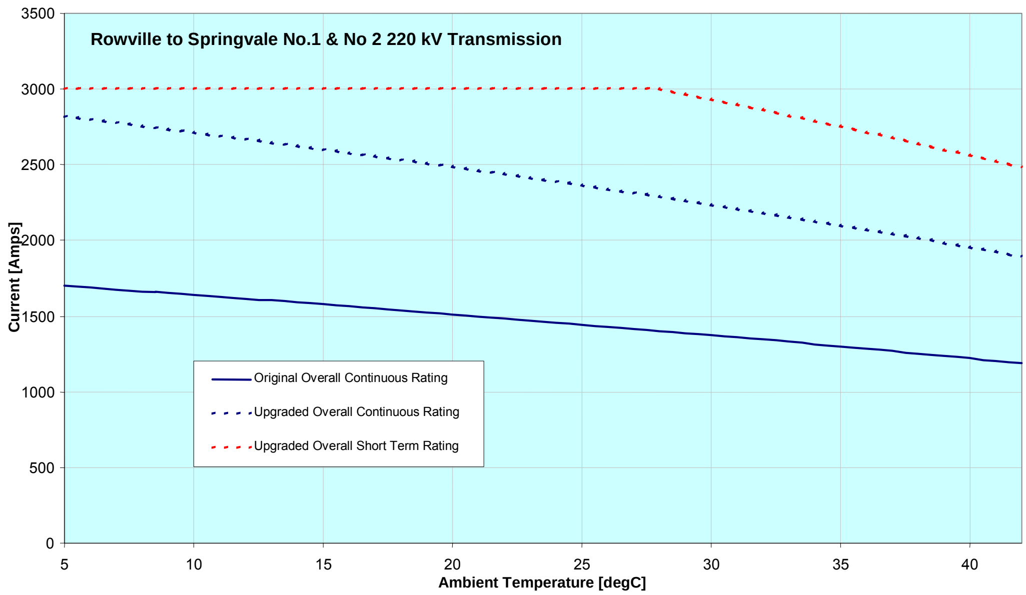


Figure 6.3 – Benefit of Option 1, Stage 1 Upgrade

Option 1, stage 1 is economically justified based on probabilistic assessment. The augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

Option 1, stage 1 will avoid pre-contingency load at risk and will not avoid potential post-contingency load at risk, which can be avoided by uprating the Rowville to Springvale transmission line. However, the uprating of the transmission line is not economically justified at least until 2008/09.

(c) Material Inter-network Impact of Constraint

VENCorp does not expect the preferred solution will have a material inter-network impact. As such, no augmentation technical report has been sought from the Inter-regional Planning Committee, nor has consent to proceed from other transmission network.

(d) Reliability or Market Augmentation

This augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

6.6.8 Recommendation

Option 1, stage 1 is recommended with an indicative cost of approximately $2 M and timing of December 2005. Project identifier code (S04-01).

6.7 Loading of Rowville to Malvern 220 kV Radial Lines

6.7.1 Introduction

(a) Location of Constraint

Malvern Terminal Station is supplied at 220 kV by a radial double circuit line from Rowville Terminal Station. The supply arrangement is shown in Figures 6.4 and 6.5 below.

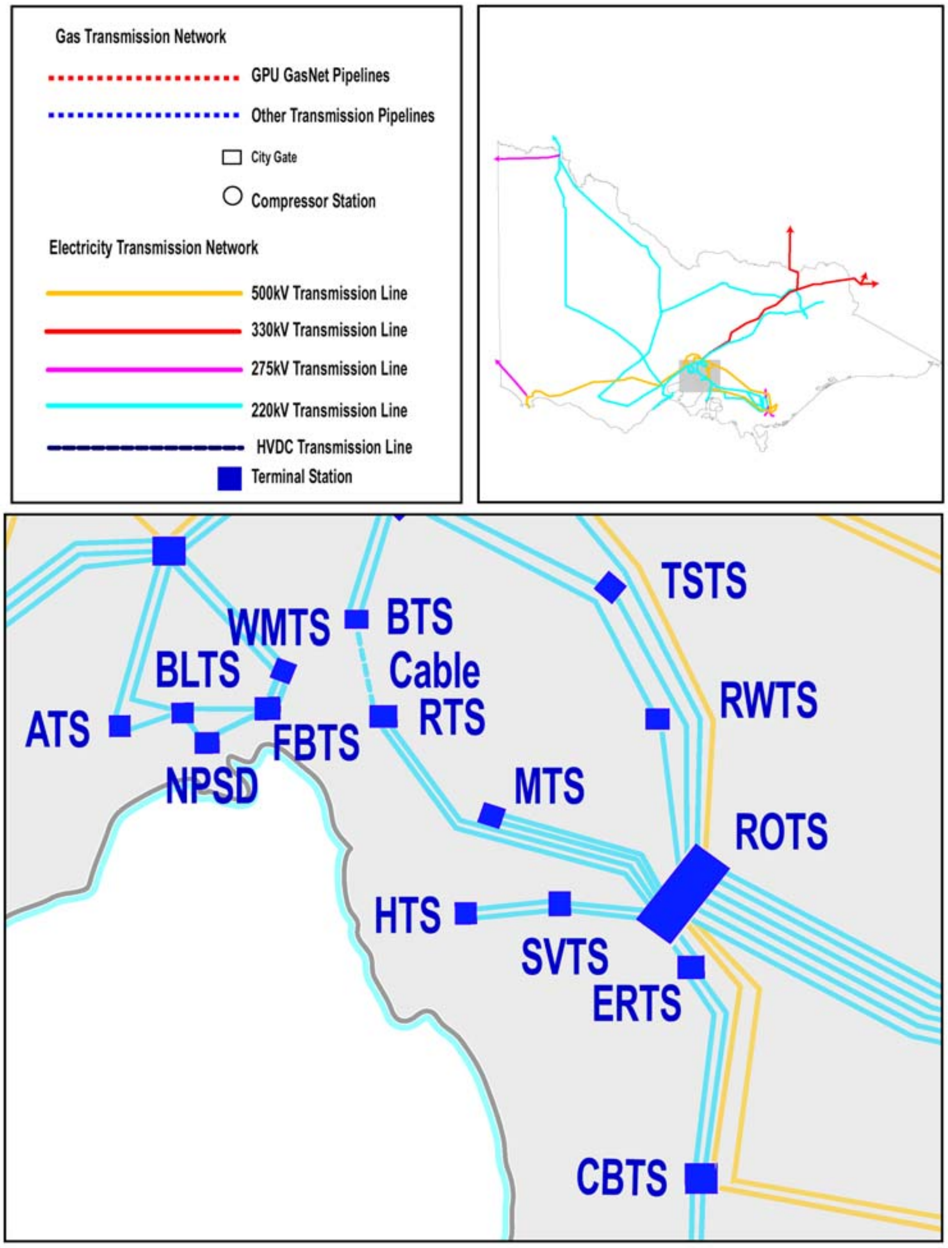


Figure 6.4 - Geographical Representation of Rowville to Malvern 220 kV Radial Lines

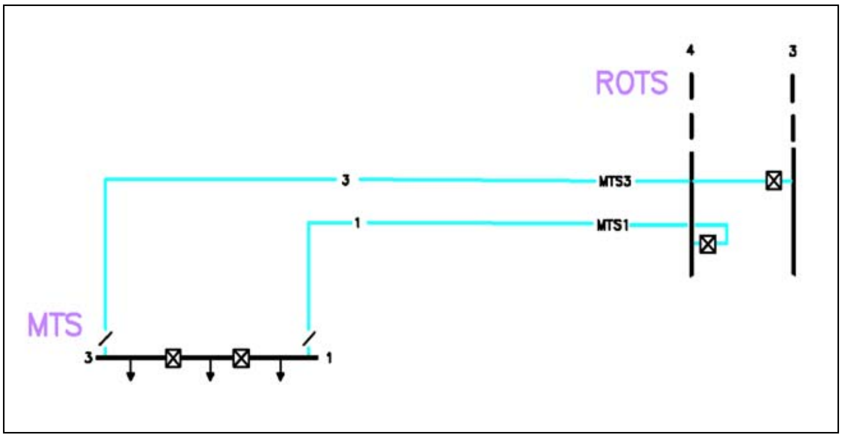


Figure 6.5 - Electrical Representation of Rowville to Malvern Radial Circuits

Abbreviation: MTS – Malvern Terminal Station
ROTS – Rowville Terminal Station

(b) Reason for Constraint

Load growth at Malvern Terminal Station has led to this constraint arising. In addition to load growth distributors are proposing to permanently transfer load from surrounding stations, including approximately 100 MW of load from Richmond to Malvern Terminal Station by approximately 2008.

Table 6.10 provides 10% POE load forecast at Malvern Terminal Station with and without the transfer of load from Richmond.

Year	Maximum Total Demand at Malvern (MW)	Incremental Load Transfer (MW)
2004/05	184	0
2005/06	190	0
2006/07	195	0
2007/08	201	0
2008/09	208	100

Table 6.10 – 10% Probability of Exceedence Load Forecasts for Malvern Terminal Station

(c) Conditions of Constraint

Each of the Rowville to Malvern 220 kV circuits carries 50% of the total load of Malvern under normal conditions. Following outage of a Rowville to Malvern circuit, the remaining parallel circuit carries the total load of Malvern. Each circuit has a nominal continuous rating of 720 Amps at 35^{o}C and 608 Amps at 42^{o}C.

Based on the 10% POE load forecast, the Summer 2008/09 potential loading of a Rowville to Malvern circuit can exceed its continuous rating following outage of the parallel circuit at times of peak demand and high ambient conditions.

(d) Impacts of Constraint

There is no constraint until November 2008. In Summer 2008/09 approximately 3 MW of load is at risk following outage of the parallel circuit. Sufficient time is available for manual load transfer or shedding following an outage of the parallel circuit. There is a low probability that the circuit outage would occur coincident with high demand and temperature conditions.

With the planned 100 MW of load transfer to Malvern around 2008, the post-contingent loading increases to approximately 961 Amps. This will result in 103 MW load at risk following an outage of a parallel circuit and about 5 minutes will be available to remove this load at risk.

(e) Impact on Constraint of Distribution Business Planning

Distribution Businesses plan to increase the capacity of Malvern and transfer about 100 MW of load from Richmond in 2008. The amount of load and its rate of growth will determine the timing for a future augmentation.

(f) Impact on Constraint of Asset Replacement Program

SPI PowerNet has planned to re-furbish the Malvern 220/66/22 kV Terminal Station in 2005. If economic the opportunity will be taken to specify the terminations at Malvern Terminal Station associated with Rowville to Malvern lines to match the ultimate rating of the lines.

(g) Network Solution

In an event of 100 MW of load being transferred from Richmond to Malvern in 2008 network options to minimise or remove the network constraint are:

- Post-contingency load shedding; available time to remove the excess load is about 5 minutes, hence a fast load shedding scheme is required. Approximate cost $150,000;

- Installation of wind monitoring scheme to take advantage of higher wind speeds experienced during hot Summer days to provide higher circuit ratings and a fast load shedding scheme to cover situations where there is inadequate wind speed at an approximate cost of $150 K;

- Uprate the Rowville to Malvern lines from 65^{o}C to 82^{o}C operation, providing approximately 30% increase in capability, from 720 Amps at 35^{o}C to approximately 936 Amps 35^{o}C. This will require about 9 replacement towers and minor terminations work at Rowville with a budget cost of approximately $3 M; and

- To completely remove the energy at risk approximately a further 4 replacement towers and re-conductoring of sections are required at an additional cost of approximately $3.5 M.

6.7.2 Economic Evaluation

If 100 MW load is transferred in 2008/09, the expected unserved energy for that year is about 0.65 MWh and the value of this expected unserved energy is $19,240. Based on this benefit, a fast load shedding scheme would maximise the net benefit until line rating is uprated. A wind monitoring scheme would not be justified.

6.7.3 Conclusions

The identification of this constraint is in its preliminary stages and in the short to medium time frame there is no constrained energy. VENCorp will continue to monitor load growth at Malvern and work with the relevant Distribution Businesses to identify the most economic network augmentation and when it will be required.

6.7.4 Recommendation

There is no constraint until 2008/09 and therefore no augmentation has been identified as yet to remove this constraint. Depending on the transfer of load to Malvern a fast load shedding scheme will be justifiable around 2008/09.

6.8 Security of Double Circuit 220 kV Lines to South East Metropolitan Area

6.8.1 Introduction

(a) Location Of Constraint

The Springvale, Heatherton, Tyabb and Malvern Terminal Stations, and the BlueScope Steel facility at Western Port (JLA) each rely on radial double circuit 220 kV line supply, as shown in Figure 6.6.

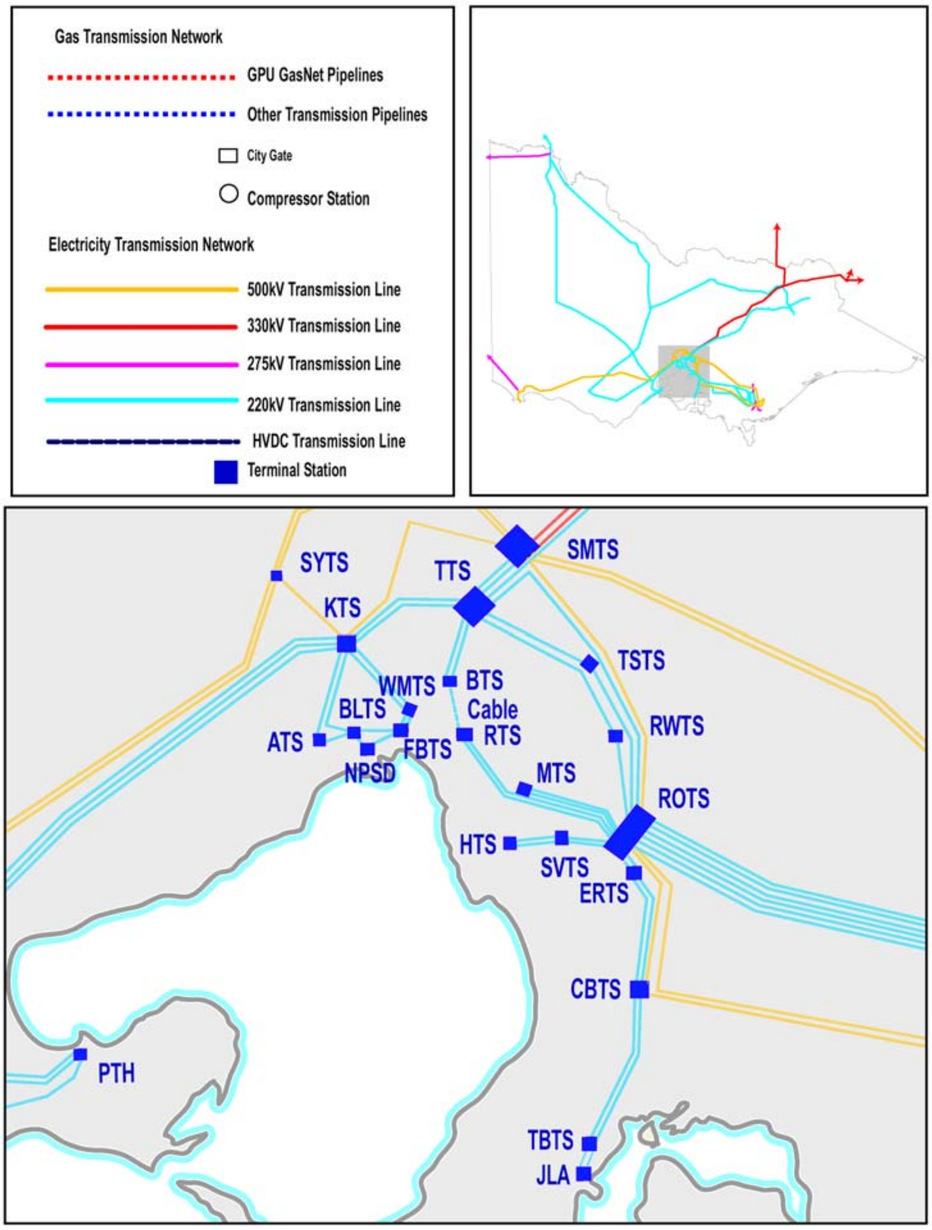


Figure 6.6 - Geographical Representation of Supply to the Southeast Metropolitan Area

Abbreviation:
SVTS – Springvale Terminal Station
HTS – Heatherton Terminal Station
TBTS – Tyabb Terminal Station
MTS – Malvern Terminal Station
CBTS – Cranbourne Terminal Station
JLA – Bluescope Steel at Western Port

(b) Reasons for Constraint

Failure of one or more double circuit towers leading to an extended outage of both circuits on a tower line is possible, although a very low probability event. Such an event could lead to an extended supply outage.

(c) Impacts of Constraint

Table 6.11 identifies the peak loading on each of the double circuit lines with loads under Summer 10% POE conditions, including the effect of Summer distribution transfers.

Double Circuit Line	Length (km)	Peak load at risk for double circuit line outage in Summer 2004/05 (MW)	
		Prior to transfers	After transfers
Rowville to Springvale	7	759	539
Springvale to Heatherton	8	315	195
Cranbourne to Tyabb	23	294	174
Tyabb to JLA	2	65	65
Rowville to Malvern	15	189	129

Table 6.11 - Load at Risk for Double Circuit 220 kV Line Outages

To minimise the consequences and recover supply after a double circuit failure the following emergency plans have been put in place by Alinta, Texas Utilities Networks, SPI PowerNet and VENCorp:

- emergency by-pass measures, utilising temporary structures and mobile cranes, developed in conjunction with SPI PowerNet, allow for restoration of full supply within 12 hours in over half of the possible tower failure cases;

- emergency measures developed in conjunction with SPI PowerNet to restore full supply to Malvern within 6 hours for a Rowville to Malvern double circuit outage;

- emergency measures developed by Alinta and TXU will progressively restore supply to some major blocks of load using transfer capacity available in their networks. Restoration time varies from 2 minutes (for remote control switching) up to about 6 hours (where some line construction work is needed); and

- Cranbourne 220/66 kV Terminal Station, jointly planned by TXU, Alinta and VENCorp, is being constructed by SPI PowerNet for mid 2004 service, with additional subtransmission capability to transfer load away from East Rowville, Heatherton and Cranbourne provided by Alinta and TXU.

6.8.2 Economic Evaluation

Table 6.12 shows transmission and distribution options and their estimated capital costs and compares these with indicative benefits associated with the augmentation.

Option	Description	Summer Rating (MVA)		Annualised Value ($K)	Benefit ($K)	NPV of Net Benefit ($K)
		Continuous	2 hour			
1	Malvern to Heatherton 8 km 220 kV underground cable	400	650	36,000	11,000	-25,000
2	Heatherton to Cranbourne 26 km 220 kV overhead line (if feasible)	800	800	15,500	13,000	-2,500
3	Heatherton to Cranbourne 26 km 220 kV underground cable	400	650	98,000	13,000	-85,000
4	Extra distribution transfers	120	120	3,000-5,000	3,000-5,000	0

Table 6.12 - Network Security Improvement Options with Indicative Benefits and Costs

6.8.3 Ranking of Options

Table 6.13 summarises the NPV of net benefits of each option. Option 1 maximises the net benefit.

Options	NPV of Net Benefits	Ranking
Option 1 Malvern to Heatherton 8 km 220 kV underground cable	-25,000	3
Option 2 Heatherton to Cranbourne 26 km 220 kV overhead line (if feasible)	-2,500	2
Option 3 Heatherton to Cranbourne 26 km 220 kV underground cable	-85,000	4
Option 4 Extra distribution transfers	0	1

Table 6.13 – Ranking of Options

6.8.4 Conclusions

VENCorp will continue to monitor risks, loading levels and augmentation costs on an annual basis and liaise with the relevant distributors on this matter.

6.8.5 Recommendation

There is no economic augmentation to remove this constraint.

6.9 South East Metropolitan Meshed Network

6.9.1 Introduction

In December 2004, the Latrobe Valley to Melbourne 4th 500 kV line project will be completed.

This project involves conversion of an existing line, the Hazelwood Power Station to Rowville Terminal Station No.3 Line, from operation at 220 kV to its design capability of operation at 500 kV. It also involves the development of a new 500 kV switchyard at Cranbourne and the installation of a 1,000 MVA 500/220 kV transformer at this site.

The project increases the transfer capability from the Latrobe Valley to Melbourne by around 1,770 MW to a nominal firm level of 5,200 MW while also reducing transmission losses considerably.

However, as a result of this project and the increasing load growth in Melbourne's south east areas, the characteristics of the power flows in the eastern metropolitan meshed network are changing and a number of constraints are emerging. Many of these constraints are interdependent and potential solutions to resolve some constraints will often influence others.

Table 6.14 summarises the constraints, which are under evaluation in this section.

Constraint	Nominal 40ºC Rating [MVA]	Contingency	CRI[33] 0405
Cranbourne A1 Transformer	1,000	Rowville A1	1.03
Thomastown to Ringwood Line	470	Rowville A1	1.12
Thomastown to Templestowe Line	470	Rowville A1	1.00
Yallourn to Rowville No.6 & 7 & 8 Line	270	Rowville A1	1.03
Rowville A1 Transformer	1,000	Cranbourne A1	1.08
Richmond to Brunswick Cable	450	Cranbourne A1	1.25
Yallourn to Rowville No.5 Line	270	Cranbourne A1	1.02

Table 6.14 – Constraints in the South East Metropolitan Meshed Network

Note, Table 6.14 is based on deterministic studies under peak demand conditions and should only be used to give some perspective and reference to the various constraints. It should not necessarily be used to indicate the relative value of each constraint. This is done via the full probabilistic and economic analysis presented in the following sections, whereby operational considerations and VENCorp's full planning criteria are applied.

This section briefly considers various network augmentation options under VENCorp's consideration with the intent of providing some insight into what is emerging as a likely large network augmentation in Metropolitan Melbourne over the next three to five years.

[33] CRI, Contingency Ranking Index is defined as the ratio of the post contingent loading to the 40˚C rating in the given year.

(a) Location of Constraint

The various constraints occur on the meshed 220 kV transmission lines and 500/220 kV transformers to the east of Thomastown Terminal Station, as shown in the geographical map of Figure 6.7 and the electrical single line diagram of Figure 6.8. The two 500/220 kV transformers at Rowville and Cranbourne, referred to as the A1 units, are critical in the secure supply of power to this area.

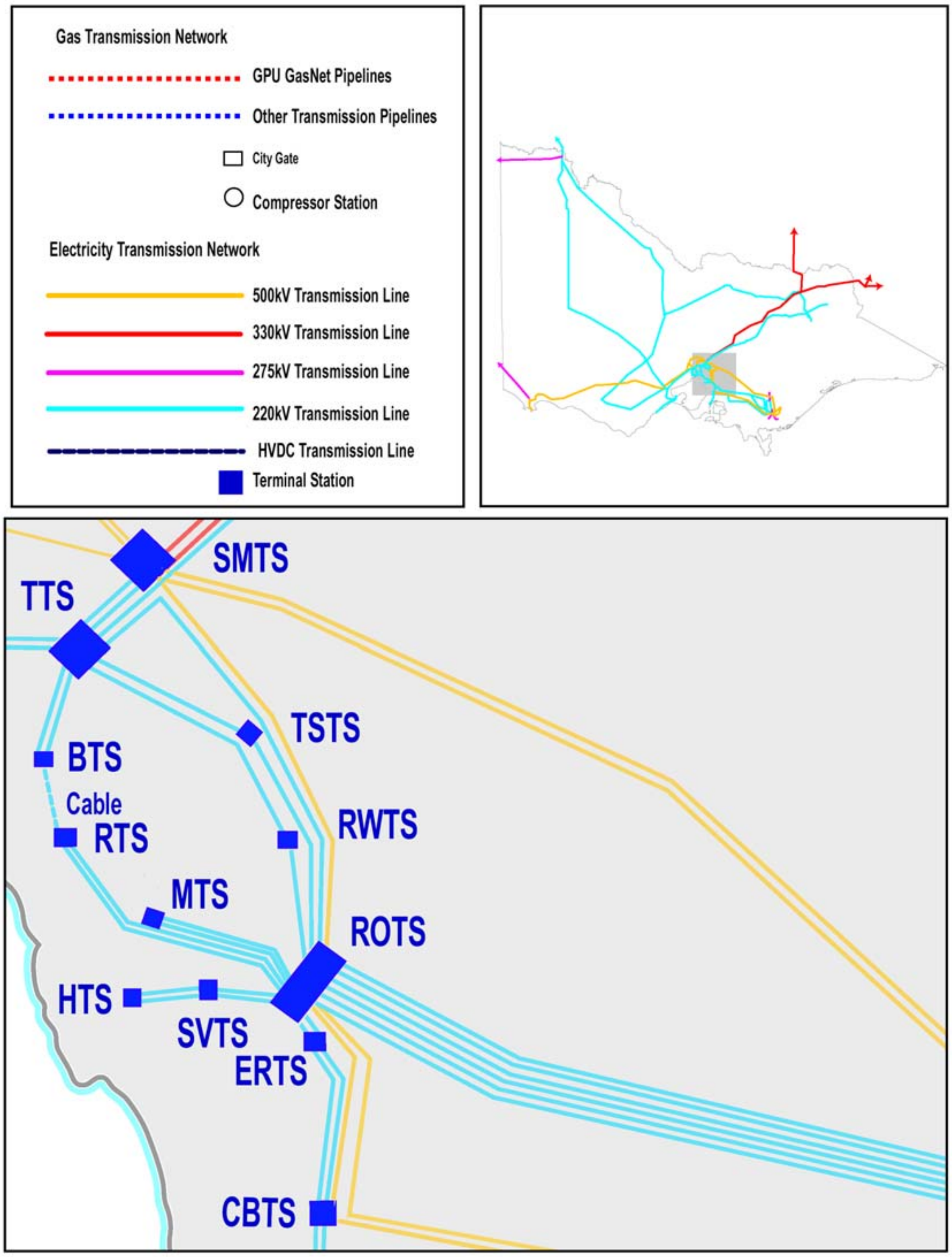
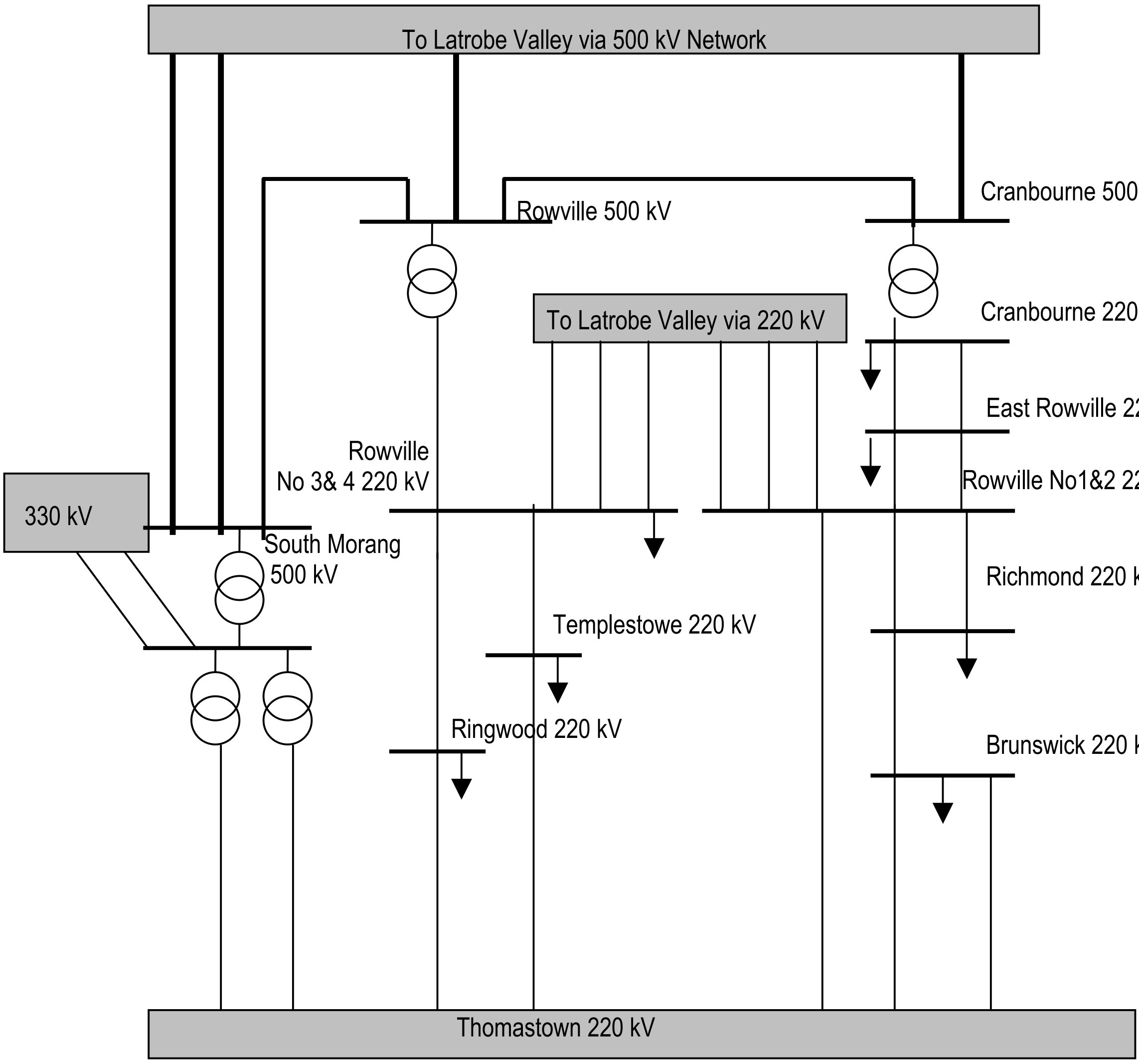


Figure 6.7 - Geographical Representation of the Constraint



Abbreviations: ROTS – Rowville Terminal Station
CBTS – Cranbourne Terminal Station
ERTS - East Rowville Terminal Station
RWTS – Ringwood Terminal Station
TTS – Thomastown Terminal station
MTS – Malvern Terminal Station
HTS – Heatherton Terminal Station
BTS – Brunswick Terminal Station

Figure 6.8 - Electrical Representation of Constraint

(b) Reason for Constraint

The constraints are primarily associated with the bulk transfer of electricity from the more efficient transmission voltage of 500 kV to the eastern metropolitan load centres in Melbourne supplied at 220 kV from Rowville and Cranbourne. The loading on the transformers at these two sites is directly related to the strong load growth in the eastern metropolitan region and, to a lesser extent, on power flowing through this network to the more western terminal stations such as Thomastown and Keilor.

Loading on the lines in the eastern metropolitan network is also influenced by various bus splitting arrangements required to maintain fault levels within acceptable levels. Such bus splits are required at Rowville and Thomastown and they have the consequence of reducing the reliability and redundancy of supply to the resultant bus groups.

Generation at Newport, Somerton and to some extent the level of transfer between Victoria and NSW also influence the loading levels of lines in the east metro meshed network.

The forecast 10% Probability of Exceedence (POE) peak load from the Rowville 220 kV No.3-4[34] bus group and No.1-2[35] bus group for Summer 2004/05 is around 1,766 MW and 1,617 MW, respectively. These are forecast to grow on average at 2.8% and 3.1% per year as shown in Table 6.15.

	Rowville 220 kV Bus 3&4 Group Demand (MW)		Rowville 220 kV Bus 1&2 Group Demand (MW)	
	10% POE	50% POE	10% POE	50% POE
2004/05	1,766	1,687	1,617	1,533
2005/06	1,822	1,740	1,675	1,586
2006/07	1,871	1,786	1,724	1,632
2007/08	1,918	1,830	1,771	1,679
2008/09	1,970	1,878	1,824	1,728

Table 6.15 – Maximum Summer Demand Forecast supplied out of Rowville

(c) Conditions of Constraint

The various constraints may occur as a result of the plant outages described in Table 6.16.

Critical Outage	Forced Outage Rates
Rowville A1 500/220 kV transformer	0.02 * 14 * 24 / 8,760 = 0.0767%
Cranbourne A1 500/220 kV transformer	0.02 * 14 * 24 / 8,760 = 0.0767%

Table 6.16 – Forced Outage Rates For Critical Plant in the South East Metro Area

The transformer forced outage rates account for the physical layout of the transformers and the presence of a spare single-phase transformer held by SPI PowerNet, which is compatible with both Rowville A1 and Cranbourne A1. The rates are based on the probability of failure statistic of 1 major failure per transformer tank every 150 years and a mean time to repair of 2 weeks.

34 Defined as load supplied from Springvale, Heatherton, Malvern, Ringwood and Templestowe.

35 Defined by load supplied from Richmond, Brunswick, East Rowville, Cranbourne and Tyabb.

The various constraints occur as a result of the thermal limitations of critical plant as described in the table below.

Critical Plant	Continuous Rating [MVA]		15 minute Short Term Rating [MVA][36]	
	5degC	35degC	5degC	35degC
Cranbourne A1 Transformer	1,000	1,000	1,500 for 30 mins	1,500 for 30 mins
Thomastown to Ringwood Line	819	530	996	639
Thomastown to Templestowe Line	819	530	915	639
Yallourn to Rowville No.6 & 7 & 8 Line	477	307	549	348
Rowville A1 Transformer	1,000	1,000	1,500 for 30 mins	1,500 for 30 mins
Richmond to Brunswick Line	450	450	650	650
Yallourn to Rowville No.5 Line	477	307	549	348

Table 6.17 – Critical Plant Capability

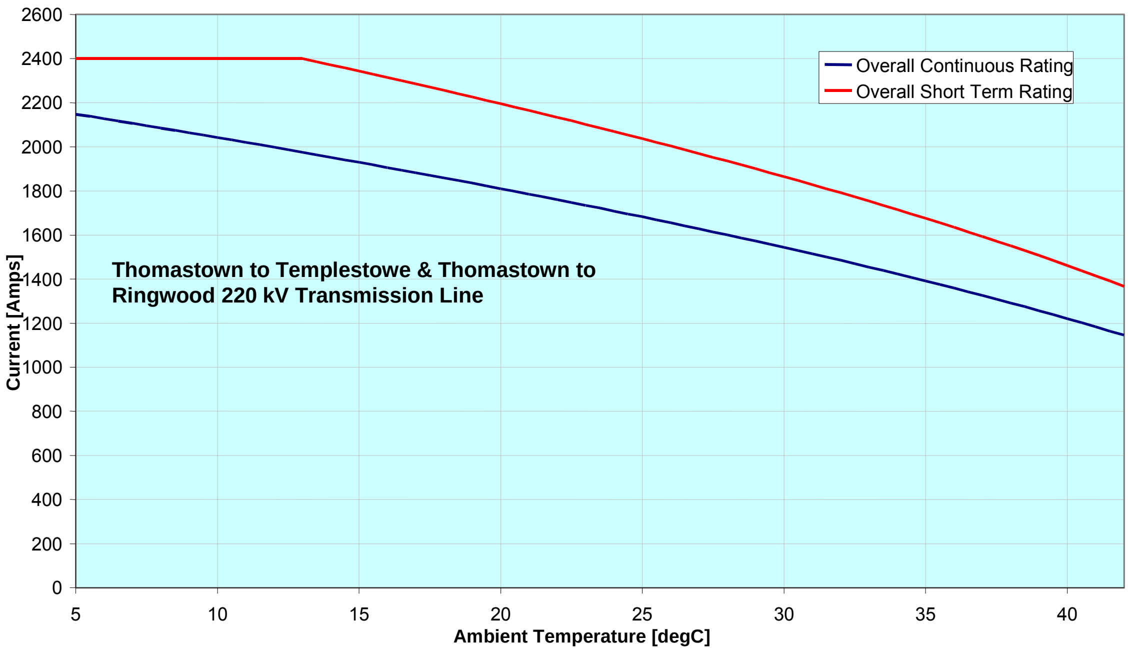


Figure 6.9 – Sample of Critical Plant Temperature Ratings

[36] For transmission lines, this rating is a function of the pre-contingent loading level so figures presented are only representative typical short term capability.

(d) Impacts of Constraint

Provided all transmission plant is in service, the east metropolitan transmission network is capable of satisfactorily and securely supplying the forecast demand out to Summer 2007/08. Beyond this timeframe, the loading on each of the Cranbourne and Rowville 500/220 kV transformers can exceed their continuous capability during a few hours of each year when demand is at its highest.

Under these conditions, there will be limited opportunity to reschedule generation out of merit order to reduce power flows on these transformers due to the tight supply demand balance and load shedding is likely to be the only solution to ensure loading levels are maintained at a satisfactory level.

Loading on the Rowville transformer is best alleviated by reducing load at Springvale, Heatherton or Malvern. A1 MW load reduction at either of these locations reduces flow on the Rowville transformer by 0.5 MW.

Loading on the Cranbourne transformer is best alleviated by reducing load at East Rowville where a 1 MW load reduction at this location reduces flow on the Cranbourne transformer by 0.32 MW.

The majority of east metropolitan 220 kV lines have short time dynamic rating capability, which allows each of them to be loaded beyond their continuous ratings for short periods of time because of the thermal inertia of the conductor. The application of these short-term ratings enables the secure transfer capacity of the network to be increased considerably.

However, under high demand conditions and subsequent to any of the outage conditions described in this chapter, manual operator intervention will be required to return the system to a satisfactory state within the available short-term time frames. Load shedding will be required to return plant to within its continuous rating. It is assumed that the security of transmission lines will be maintained under outage conditions by relying on the System Overload Control Scheme to automatically shed load after any second contingencies.

Connection of Yallourn Energy's Unit 1 generator to the 500 kV network increases the flows on the Rowville and Cranbourne transformers and therefore increases the impacts of these constraints.

After the completion of the 4th Latrobe Valley to Melbourne 500 kV Line project in December 2004, the Templestowe to Thomastown line should be switched to the Thomastown No.3 220 kV bus. This operational switching arrangement balances flows on the east metropolitan transmission lines so that they can be better utilised under both system normal and outage conditions.

6.9.2 Do Nothing – Value of Expected Energy at Risk

The following Table summarises the evaluation of the weighted Expected Value of Energy at Risk caused by the system normal constraint imposed by loading of the Rowville A1 transformer.

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	-	-	-	4	12
Maximum Single Constraint, MW	-	-	-	30	65
Average Constraint, MW	-	-	-	19	26
Energy at Risk, MWh	-	-	-	76	306
Load Shedding, MWh	-	-	-	152	612
Value of Unserved Energy, $K	-	-	-	4,500	18,120
Expected Value of Energy at Risk, $K	-	-	-	4,500	18,120

Table 6.18 - Loading on Rowville A1 500/220 kV Transformer Under System Normal Conditions

The following Table summarises the evaluation of the weighted Expected Value of Energy at Risk caused by the system normal constraint imposed by loading of the Cranbourne A1 transformer.

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	-	-	-	5	14
Maximum Single Constraint, MW	-	-	-	40	90
Average Constraint, MW	-	-	-	25	44
Energy at Risk, MWh	-	-	-	124	615
Load Shedding, MWh	-	-	-	388	1922
Value of Unserved Energy, $K	-	-	-	11,470	56,890
Expected Value of Energy at Risk, $K	-	-	-	11,470	56,890

Table 6.19 - Loading on Cranbourne A1 500/220 kV Transformer Under System Normal Conditions

Tables 6.18 and 6.19 show that under system normal conditions small overloads of the transformers may be expected within the next five year period and that these small volumes of energy at risk are valued very highly.

The following Table summarises the evaluation of the Expected Value of Energy at Risk caused by loading on the Cranbourne A1 transformer after an outage of the Rowville A1 transformer as defined by the need to return the system to a satisfactory state (i.e. in order to return loading on the critically loaded plant to within its continuous rating).

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	3	10	20	43	81
Maximum Single Constraint, Amps	227	519	540	610	762
Average Constraint, Amps	68	230	182	155	171
Energy at Risk, Amph	371	2,153	3,699	6,693	13,928
Load Shedding, MWh	349	2,025	3,480	6,297	13,102
Value of Unserved Energy, $K	10,323	59,953	103,009	186,383	387,823
Expected Value of Energy at Risk, $K	8	46	79	143	298

Table 6.20 - Loading on Cranbourne Transformer after outage of Rowville (satisfactory)

The following Table summarises the evaluation of the Expected Value of Energy at Risk caused by loading on the Cranbourne A1 transformer after an outage of the Rowville A1 transformer as defined by the need to return the system to a secure state (i.e. in order to return loading on the critically loaded plant to below its continuous rating to allow for a subsequent contingency).

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	106	356	473	633	809
Maximum Single Constraint, Amps	1,837	1,837	1,837	1,837	1,837
Average Constraint, Amps	391	354	410	432	499
Energy at Risk, Amph	42,818	126,112	193,897	273,341	404,336
Load Shedding, MWh	40,280	118,637	182,406	257,141	380,372
Value of Unserved Energy, $K	1,192,286	3,511,668	5,399,203	7,611,383	11,259,013
Expected Value of Energy at Risk, $K	915	2,694	4,142	5,839	8,637

Table 6.21 - Loading on Cranbourne Transformer after outage of Rowville (secure)

The scenario detailed in the table above considers loading on the Yallourn to Rowville No.5 line, the Hazelwood to Rowville No.1&2 lines, the Richmond to Brunswick cable and the South Morang 330/220 kV transformers in expectation of loss of the Cranbourne transformer.

The following Table summarises the evaluation of the Expected Value of Energy at Risk caused by loading on the Rowville A1 transformer after an outage of the Cranbourne A1 transformer as defined by the need to return the system to a satisfactory state (i.e. in order to return loading on the critically loaded plant to within its continuous rating).

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	9	14	32	67	112
Maximum Single Constraint, Amps	337	639	661	774	845
Average Constraint, Amps	91	260	201	188	216
Energy at Risk, Amph	950	3,444	6,408	12,633	24,250
Load Shedding, MWh	893	3,239	6,029	11,885	22,813
Value of Unserved Energy, $K	26,446	95,889	178,448	351,784	675,255
Expected Value of Energy at Risk, $K	20	74	137	270	518

Table 6.22 - Loading on Rowville Transformer after Outage of Cranbourne (satisfactory)

The following Table summarises the evaluation of the Expected Value of Energy at Risk caused by loading on the Rowville A1 transformer after an outage of the Cranbourne A1 transformer as defined by the need to return the system to a secure state (i.e. in order to return loading on the critically loaded plant to below its continuous rating to allow for a subsequent contingency).

	2004/05	2005/06	2006/07	2007/08	2008/09
Hours of Constraint	197	492	640	845	1,072
Maximum Single Constraint, Amps	1,837	1,837	1,837	1,837	1,837
Average Constraint, Amps	366	381	436	427	492
Energy at Risk, Amph	71,306	187,594	279,361	361,267	528,069
Load Shedding, MWh	67,080	176,476	262,805	339,856	496,772
Value of Unserved Energy, $K	1,985,568	5,223,687	7,779,014	10,059,729	14,704,447
Expected Value of Energy at Risk, $K	1,523	4,007	5,967	7,717	11,280

Table 6.23 - Loading on Rowville Transformer after outage of Cranbourne (secure)

The scenario detailed in the table above considers loading on the Yallourn to Rowville No.6/7/8 lines, the Thomastown to Ringwood line and the Thomastown to Templestowe line in expectation of loss of the Rowville transformer.

The following table and graph summarises and aggregates the Expected Value of Energy at Risk associated with loading of the Rowville and Cranbourne transformers.

	2004/05	2005/06	2006/07	2007/08	2008/09
System Normal, Satisfy Flow on Rowville A1 ($K)	-	-	-	4,500	18,120
System Normal, Satisfy Flow on Cranbourne A1 ($K)	-	-	-	11,470	56,890
Rowville Outage, Satisfy Flow on Cranbourne A1 ($K)	8	46	79	143	298
Rowville Outage, Secure Flow on Cranbourne A1 ($K)	915	2,694	4,142	5,839	8,637
Cranbourne Outage, Satisfy Flow on Rowville A1 ($K)	20	74	137	270	518
Cranbourne Outage, Secure Flow on Rowville A1 ($K)	1,523	4,007	5,967	7,717	11,280
Total ($K)	2,466	6,821	10,325	29,939	95,743

Table 6.24 – Aggregated Expected Value of Energy At Risk for Rowville & Cranbourne Transformer Loadings

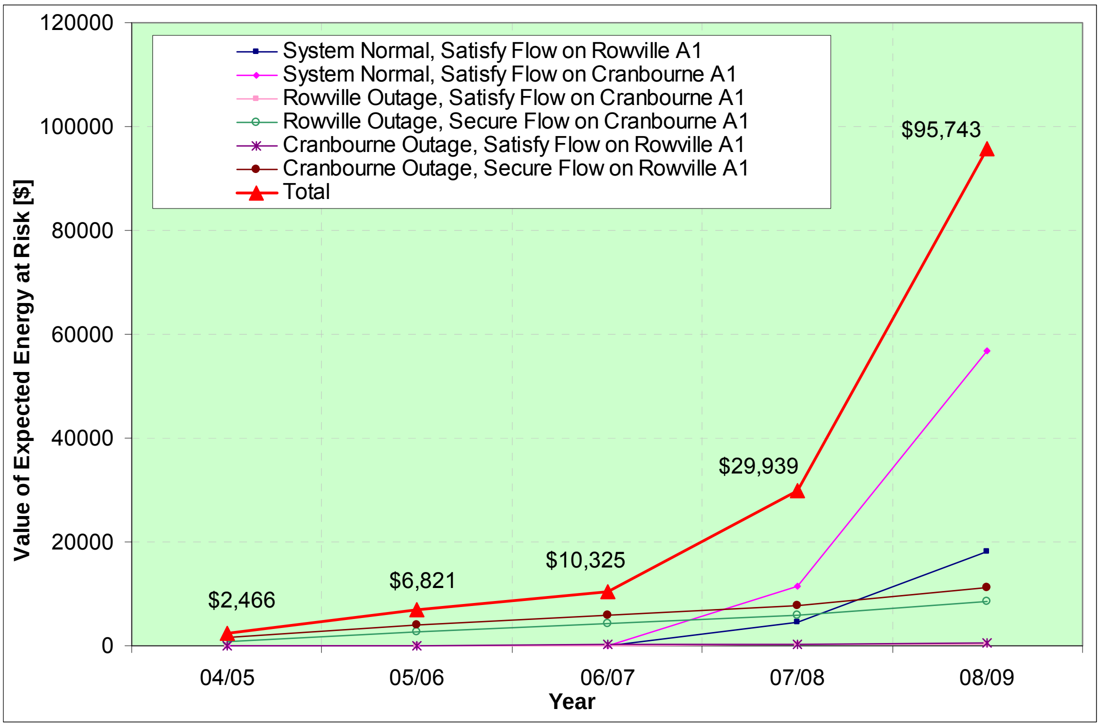


Figure 6.10 – Aggregated Expected Value of Energy At Risk [$K] for Rowville & Cranbourne Transformer Loadings

The following table summarises and aggregates the Expected Value of Energy at Risk associated with loading of the critical transmission lines in the eastern metropolitan area.

	2004/05	2005/06	2006/07	2007/08	2008/09
Rowville Outage, Satisfy Flow on Thomastown to Ringwood ($K)	0	1	3	3	3
Rowville Outage, Satisfy Flow on Thomastown to Templestowe ($K)	0	1	2	2	3
Rowville Outage, Satisfy Flow on Yallourn to Rowville No.6&7&8 ($K)	6	8	9	11	12
Cranbourne Outage, Satisfy Flow on Yallourn to Rowville No.5 ($K)	2	3	3	4	4
Cranbourne Outage, Satisfy Flow on Richmond to Brunswick No.5 ($K)	9	20	34	31	39
Total ($K)	17	33	51	51	61

Table 6.25 – Expected Value of Energy at Risk

Loading of critical transmission lines does not have to be reduced to secure for the next event as System Overload Control Scheme (SOCS) is designed to shed load automatically after any subsequent outages.

6.9.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

1. Minor upgrade works on the Thomastown to Ringwood and Thomastown to Templestowe lines combined with fault level mitigation works to allow the Rowville 220 kV buses to be closed after an outage of either the Rowville or Cranbourne transformers. These works will reduce the amount of load shedding required to secure the network from subsequent outages, but will not reduce the system normal overloads that are emerging in 2007/08. Estimated capital cost $6 M, subject to feasibility and detailed assessment.

2. Install new 500/220 kV transformation and associated switching in the metropolitan area to offload the Cranbourne and Rowville transformers. Tentative locations for the new transformer would be Cranbourne, Rowville, Templestowe, Ringwood or South Morang. Considerable works to mitigate higher fault levels would be required, possibly involving replacement of circuit breakers with units of higher duty, installation of modern fault limiting plant or line reactors, or opening of additional ties between terminal stations (This aspect may be co-ordinated with Option 1 in a staged development). From preliminary studies, Rowville appears to be the preferred location for an additional 500/220 kV transformer now that Cranbourne has been developed. This is based on the proximity to the high growth load centres, combined with the existing infrastructure at both the 500 kV and 220 kV levels. Estimated capital cost $45 M, subject to feasibility and detailed assessment.

3. Minor network augmentation to utilise spare capacity on the 220 kV transmission network from the Latrobe Valley to Melbourne when it is available (i.e. operation in parallel modes). This will compound the potential constraint these lines impose under high ambient temperature conditions and be more opportunistic rather than a guaranteed increase in transfer capability. Wind monitoring on the six Yallourn to Hazelwood to Rowville 220 kV lines may be required, as well as some form of fault level mitigation to increase operational flexibility. This option would also need to be considerate of the impacts on transmission losses. Estimated capital cost $5 M, subject to feasibility and detailed assessment.

4. Strategically, VENCorp can further investigate the utilisation of the 220 kV transmission network from the Latrobe Valley to Melbourne. Re-constructing these lines with modern equivalents to increase their capacity and reduce their resistance may allow system normal operation in parallel modes which may serve the dual purpose of alleviating the loading on the Hazelwood transformers and providing further support to the growing eastern metropolitan Melbourne terminal stations at the 220 kV level. This option is likely to be a staged development, which would be subject to costing, feasibility and detailed assessment. A feasibility estimate for three modern double circuit 220 kV transmission lines of around 100 km each would be $100M ±25%.

(b) Other Options Considered

5. Negotiate with Yallourn Energy for unit 1 to remain connected to the 220 kV transmission network. This option would not eliminate any of these constraints but it will reduce the impacts of the constraints.

6.9.4 Economic Evaluation

A comprehensive economic evaluation of the various constraints in the east metropolitan meshed network and the options identified to reduce their impact has not been undertaken as part of this Annual Planning Report.

The technical feasibility, costs and evaluation of all the benefits of each of the options requires further assessment. VENCorp will undertake this assessment as a matter of priority (given the long lead time of plant associated with the identified network options) over the following months and prepare a public consultation paper outlining its technical and economic evaluation, considering various market development scenarios.

Further, VENCorp will continue to monitor the operation of the east metropolitan meshed network, especially after completion of the 4th 500 kV line upgrade project to be finalised in December 2004. This operational experience may provide insight into the preferred solution.

For information purposes, the annualised costs of the network options that have been identified below in Table 6.26.

Network Option	Approximate Annualised Cost[37] [$K]
1	535
2	4,000
3	444
4	8,880

Table 6.26 - Feasibility based Cost Estimates for Identified Network Options

Based on these annualised costs and a preliminary investigation into the benefits of each option, VENCorp considers that a staged development is the likely outcome to address the highly accelerating value associated with the east metropolitan network constraints.

[37] Based on a term of 30 years and an interest rate of 8%

Option 1, which reduces the need to shed load after an outage of either the Rowville or Cranbourne transformers, will supplement work currently being progressed by VENCorp prior to Summer 2004 to increase the transfer capacity on the Thomastown to Ringwood and Rowville to Richmond lines.

VENCorp considers that benefits associated with Option 1 may justify its implementation by December 2005. However, this augmentation alone does not address the longer term issues associated with system normal overloading of the Rowville and Cranbourne transformers emerging in Summer 2006/07. Therefore, VENCorp expects Option 1 will then be followed by development of Option 2 before December 2006.

6.9.5 Conclusions / Recommendations

Subject to detailed analysis and consultation, VENCorp considers Option 1 (a Small Network Augmentation) involving minor line upgrades and fault level mitigation may be justified by December 2005.

Option 1 may then be followed by Option 2 (a Large Network Augmentation) involving installation of a new 500/220 kV transformer in east metropolitan Melbourne, in December 2006 at an approximate cost of $45 M. Project identifier code (S04–02) and (L0-03).

6.10 Loading of Keilor to Geelong 220 kV lines and Keilor 500 to 220 kV Transformers

6.10.1 *Introduction*

(a) Location of Constraint

The constraint is located on the Keilor to Geelong 220 kV lines in southwest Victoria and the Keilor 500/220 kV transformers in the western metropolitan area. Geographical and electrical representations of the constraint are given in Figures 6.11 and 6.12.

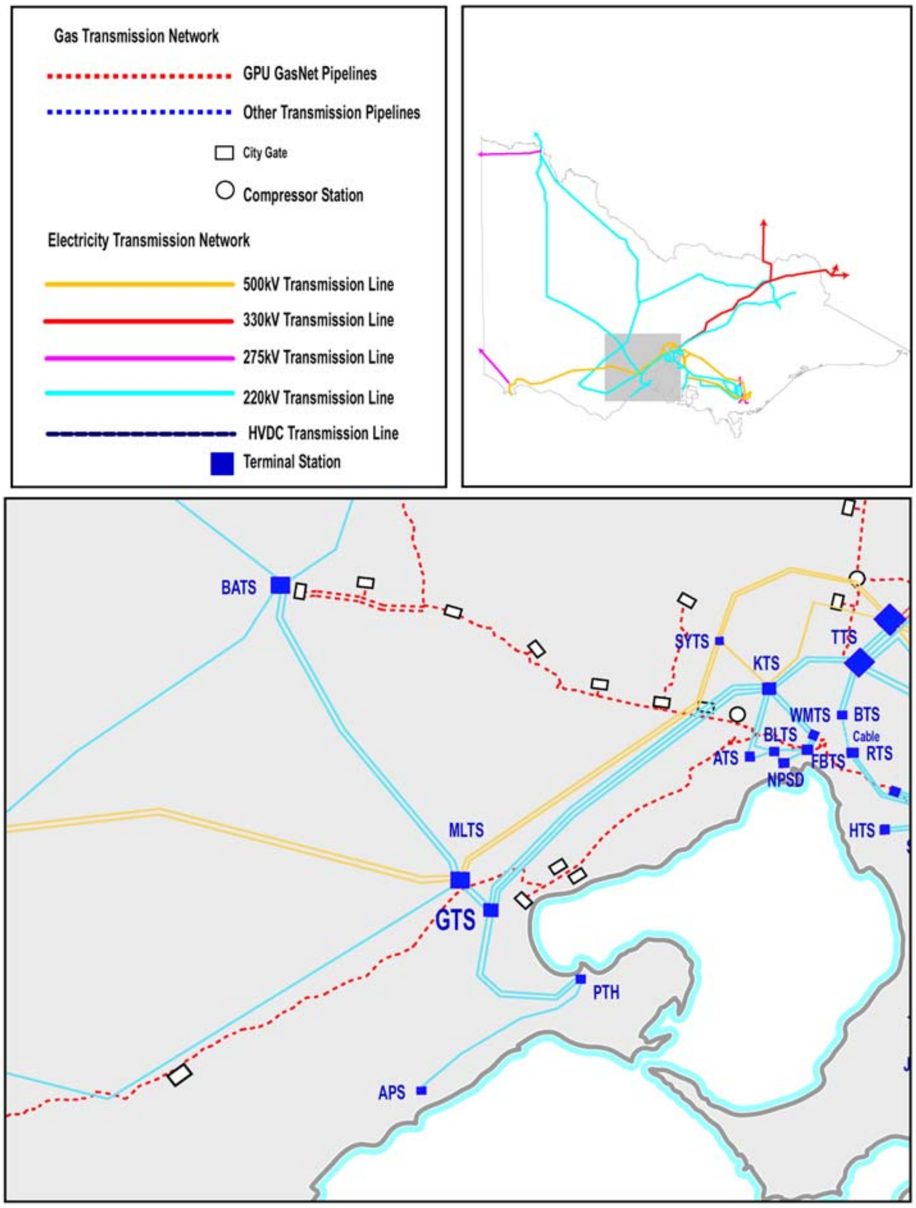
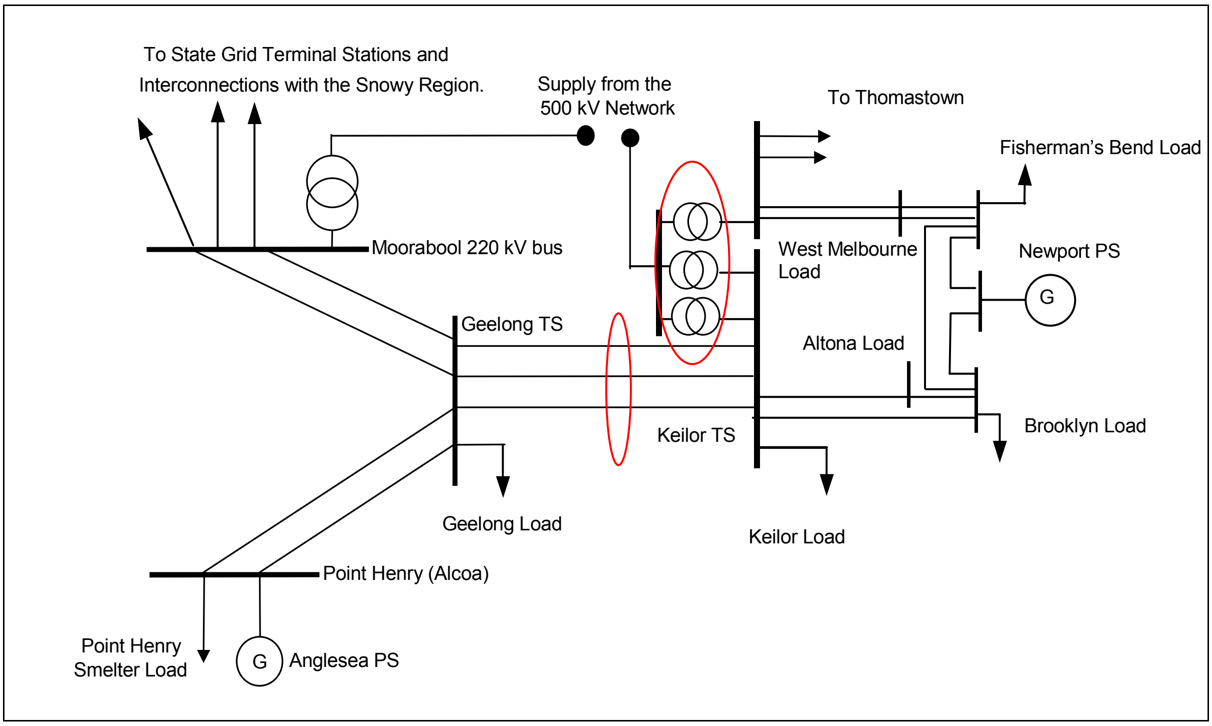


Figure 6.11- Geographic Representation of the Supply to the Geelong Area



Abbreviations:

ATS	– Altona Terminal Station
BLTS	– Brooklyn Terminal Station
FBTS	– Fisherman's Bend Terminal Station
GTS	– Geelong Terminal Station
NPSD	– Newport Power Station
KTS	– Keilor Terminal Station
MLTS	– Moorabool Terminal Station
WMTS	– West Melbourne Terminal Station

Figure 6.12 - Supply to Geelong/Western Metro Areas

(b) Reasons for Constraint

Under system normal conditions, the Moorabool 220 kV bus is supplied from the 500/220 kV 1,000 MVA transformer at Moorabool. Outage of this transformer increases loading on the Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformers.

As discussed in the 2003 APR and detailed in section 5.4 of this APR, augmentations have been put in place which reduce the energy at risk due to this constraint. However, some load remains at risk and with continued load growth in the western metropolitan area of Melbourne, Geelong and the south west part of the state, further augmentations are considered to support the supply to these areas.

(c) Conditions of Constraint

Outage of the Moorabool transformer prior to installing the spare phase, the Keilor to Geelong 220 kV lines and the Keilor 500/220 kV transformers are events which cause constraints. The thermal rating of elements which are constrained are provided in Table 6.27.

Plant	Thermal rating – continuous	Thermal rating – short term
Keilor 500/220 kV transformer (each)	750 MVA	810 MVA – 2 hours
Keilor to Geelong 220 kV line (each)	710 Amps @ 35°C ambient 623 Amps @ 40°C ambient	Depends on ambient temperature, wind speed and pre-contingency loading
Keilor to Geelong 220 kV line terminations	1,010 A @ 35°C ambient	Depends on ambient temperature and same as continuous ratings

Table 6.27 - Thermal Ratings of Constrained Plants

Keilor to Geelong 220 kV Lines

Following outage of the Moorabool transformer and during the period before the spare phase is placed into service, the three Keilor to Geelong 220 kV lines support load to Geelong, Point Henry and southwest Victorian load. The loading on the three Keilor to Geelong 220 kV lines is dependent on:

- The number of Keilor to Geelong 220 kV lines in service;
- Anglesea generation levels, which causes an increase in line loading as it is reduced ;
- Geelong area and State Grid loads, which causes an increase in line loading as they are increased;
- Ambient temperature, which lowers the line ratings as it increases;
- Southern Hydro generation, which causes an increase in line loading as it is reduced;
- Victoria and NSW transfer, which causes an increase in line loading as import decreases; and
- Murraylink transfer between Victoria and South Australia, which causes an increase as Murraylink export increases. The impact of Murraylink on post-contingent flow is removed by an automatic runback scheme. If the Moorabool transformer is tripped while Murraylink is exporting to South Australia, then the scheme would rapidly reduce Murraylink transfer to zero.

The most sensitive of these is the number of Keilor Geelong 220 kV lines in service, the ambient temperature, the output of the Anglesea Power Station and the local area load.

Keilor 500/220 kV Transformers

The three 500/220 kV transformers at Keilor feed to the load in the Western Metropolitan area, and Geelong/State Grid and Point Henry smelter loads via Keilor to Geelong lines. Outage of a Moorabool transformer will increase the loading on the Keilor transformers. The loading on the three Keilor 500/220 kV transformers for this condition will also depend on:

- Newport generation levels, which causes an increase in transformer loading as it is reduced;
- Anglesea generation levels, which causes an increase in transformer loading as it is reduced;
- Western metropolitan area, Geelong area and State Grid loads, which causes an increase in transformer loading as they are increased;
- Southern Hydro generation, which causes an increase in transformer loading as it is reduced;
- the interchange between Victoria and NSW, which causes an increase in transformer loading as import decreases; and
- Murraylink transfer between Victoria and South Australia, which causes an increase as Murraylink export increases. The impact of Murraylink on post-contingent flow is removed by an automatic runback scheme. If the Moorabool transformer is tripped while Murraylink is exporting to South Australia, then the scheme would rapidly reduce Murraylink transfer to zero.

The most critical of these is the output levels of Newport generator and Anglesea Power station and the Geelong, Point Henry and western metropolitan area loads.

Probability of Plant Outage

Table 6.28 provides the probability of plant outages, which are used for the assessment of the expected unserved energy at risk. The spare transformer at Moorabool, due for service by May 2005 limits the duration of the most likely long-term forced outages to about 2 weeks.

Plant	Probability of outage
Moorabool transformer (A spare single phase unit is to be available at Moorabool by May 2005)	Short term outage - 0.03% (based on historical data) Long-term outage 1 in 50 years with a duration of 2 weeks (i.e. 1 in 150 years with a duration of 14 days per single phase unit)
Each Keilor 500/220 kV transformer (A spare single phase unit is available at Keilor)	Short term outage - 0.055% (based on historical data) Long-term outage 1 in 50 years with a duration of 14 days (i.e. 1 in 150 years with a duration of 14 days per single phase unit)
Each Keilor to Geelong line	0.165% (based on historical data)

Table 6.28 – Probability of Plant Outages

(d) Impacts of Constraint

Keilor to Geelong 220 kV Lines

Following the outage of the Moorabool transformer the Keilor to Geelong line loading increases considerably resulting in:

- On high temperature days with high demand the available time to take action following an outage of the Moorabool transformer could be less than 15 minutes. Under such condition, automatic load shedding in Geelong/Point Henry area to remove the constraint;

- If time available to take action is more than 15 minutes, then reschedule generation - increase Southern hydro generation, Snowy to Victoria import and Murraylink import from SA; and

- If load shedding is required and if time available is more than 15 minutes then coordinate load shedding at distribution/customer level.

Keilor 500/220kV Transformers

Following outage of the Moorabool transformer, the transformers remain within their short term rating for Summer 2004/05. Beyond this time, the transformer short term rating can be exceeded for this event.

Presently impacts of the constraint are managed as follows:

- If time available to take action is more than 15 minutes, then reschedule generation - increase Southern hydro generation, Snowy to Victoria import and Murraylink import from SA.

- If load shedding is required and if time available is more than 15 minutes then coordinate load shedding at distribution/customer level.

- Therefore from 2005/06 onwards, implement pre-contigent load shedding for situations where the continuous rating will be exceeded is less than 15 minutes.

- Arm the Keilor overload control scheme (high reliable and high secure control scheme is to be available for service by December 2004). The scheme will remove overload on Keilor transformers immediately following a second contingency by shedding load at western metro area, but will not be used for the first contingency.

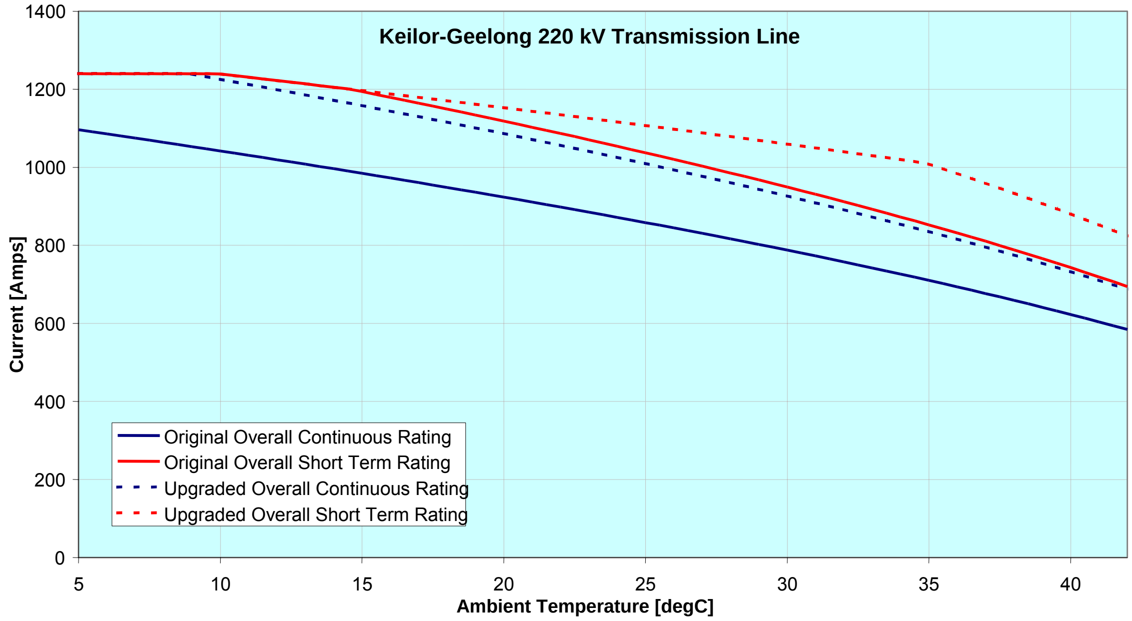


Figure 6.13 – Thermal Ratings of Constrained Plant

(e) Impact on Constraint of Distribution Business Planning

There are no distribution plans to move load that will reduce the effect of these constraints.

(f) Impacts on Constraint of Asset Replacement Program

There are no asset replacement works that affect these constraints.

6.10.2 Do Nothing – Value of Expected Energy at Risk

Market modelling studies have been undertaken to quantify exposure to Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformer constraints.

Table 6.29 provides rescheduled generation and unserved energy due to both constraints as a result of an outage of Moorabool transformer. Generation rescheduling is valued at short run marginal costs and unserved energy is valued at $29,600. Expected unserved energy and expected generation rescheduling energy is estimated based on probabilities listed in Table 6.28.

		2004/05	2005/06	2006/07	2007/08	2008/09
Unserved Energy	MWh	17,246	19,933	22,620	25,523	28,427
Rescheduled Generation	MWh	610,526	725,270	814,013	954,750	1,070,000
Value Of Unserved Energy	$K	510,000	590,000	670,000	755,000	840,000
Value of Rescheduled Generation	$K	5,500	6,100	6,600	7,100	7,600
Value of Expected Energy at Risk	$K	570	8,530	16,500	30,900	45,300

Table 6.29 - Expected Energy at risk for Do Nothing Scenario

6.10.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions are options to reduce the expected unserved energy:

- Wind monitoring scheme on Keilor to Geelong 220 kV lines;
- Use the existing Keilor fast load shedding scheme to shed load for the first contingency; and
- 2nd 500/220 kV 1,000 MVA transformer at Moorabool Terminal Station.

Wind Monitoring Scheme on Keilor to Geelong 220 kV Lines

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Historical data on actual wind speed indicates that values much higher than 0.6m/s occur at times of high temperature and by installation of wind monitoring stations the amount of load at risk can be considerably reduced. The expected cost for the wind monitoring and upgrade of line terminations to match the higher ratings is $400 K. However, the wind-monitoring scheme will not reduce the load on Keilor transformers.

Keilor Fast Load Shedding Scheme

Keilor fast load shedding scheme is to be in service for December 2004. The scheme was justified to remove the overload on the Keilor transformers following a low probability second contingency. From Summer 2005/06 onwards, the Keilor transformers could potentially exceed their short-term rating immediately following the Moorabool transformer outage. The Keilor fast load shedding scheme could be used to implement load shedding after the first contingency. However, with this option, it would be necessary to arm the Keilor fast load shedding scheme at high demand periods with all plant in service. This avoids pre-contingent load shedding but increases the risk of inadvertent operation. The acceptability of the longer term use of this option needs further consultation with market participants and the asset owner.

2nd Moorabool 500/220 kV Transformer

A second 1,000 MVA 500/220 kV transformer at Moorabool would avoid constraint on Keilor- to Geelong lines and Keilor 500/220 kV transformers. With two Moorabool transformers, there would be no energy at risk following outage of a Moorabool transformer. This additional new transformer would also provide significant improvement in voltage levels in the Geelong area under critical outage conditions and reduce the future requirement for additional reactive support in this area. The indicative cost for the second transformer is around $26 M.

(b) Non-Network Options

The following non-network solutions can partially or fully remove the network constraints:

- Demand side management in both the Geelong and Keilor areas, and
- New generation in the Geelong/Moorabool and Western metropolitan areas.

At the time of publication of this APR, no committed non-network solutions have been identified. However, there are number of proposals for new generation in Keilor and southern state grid areas. If these generations are available during the network critical period, the amount of overloading on the constraint elements can be reduced. The amount of reduction depends on location and amount of generation available to remove the constraint.

6.10.4 Economic Evaluation

A net market benefit assessment is carried out for a 30-year period for each of the network options using a discount rate of 8% to calculate the NPV, and with a value of unserved energy of $29,600/MWh are summarised in Table 6.30.

Option	Present Value 30 Year Life		Annualised Value All $K					Residual Value For Remaining 25 Years 2009/10
			2004/05	2005/06	2006/07	2007/08	2008/09	
Do Nothing	-403,590		-570	-8,530	-16,500	-30,900	-45,300	-329,108
Option 1[38] (Wind monitoring)	5,934	Benefit	430	460	490	520	550	3,996
	-406	Equiv Annual Cost	-36	-36	-36	-36	-36	-262
	5,528	Net Benefit	394	424	454	484	514	3,734
Option 2 (2nd Moorabool transformer)	395,749	Benefit	0	00	16,500	30,900	45,300	329,108
	-22,210	Equiv Annual Cost	0	0	-2,344	-2,344	-2,344	-17,030
	373,539	Net Benefit	0	0	14,156	28,556	42,956	312,077

[38] Assumes wind speed of 1.2 m/s at critical times

Option 3 (Wind Monitoring followed by 2nd Moorabool transformer)	396,541	Benefit	430	460	16,500	30,900	45,300	329,108
	-22,616	Equiv Annual Cost	-36	-36	-2,380	-2,380	-2,380	-17,292
	373,926	Net Benefit	394	424	14,120	28,250	42,920	311,815

Table 6.30 - Net Benefits of Network Augmentation Options

(c) Ranking of Options

Table 6.31 shows the NPV and ranking of the proposed network options.

Network Solutions	NPV [$K]	Ranking
Wind Monitoring (2004/05) followed by 2nd Transformer	373,926	1
2nd Transformer (2006/0)	373,539	2
Wind Monitoring (2004/05)	5,528	3

Table 6.31 - Summary of Net Present Value of Network Solutions

(d) Timing of Options

The installation of a second transformer cannot practically be achieved before 2006/07. The option to install wind monitoring in 2004/05 followed by the transformer in 2006/07 marginally maximises the NPV compared to the transformer alone. However, if generation is committed in the Keilor Geelong area, it may allow deferment of the transformer. This would increase the benefits of installing the wind monitoring scheme first.

6.10.5 Conclusions

A wind monitoring scheme should be implemented for the Keilor to Geelong lines for Summer 2004/05. Planning for the second transformer by December 2006 should commence and be reviewed if there is new generation in Keilor or the southern state grid area.

The transformer would be a large network augmentation.

(e) Reliability or Market Augmentation

VENCorp has identified a preferred network solution in accordance with the regulatory test.

The augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

(f) Material inter-network impact of constraint

VENCorp does not expect the preferred solution will have a material inter-network impact. As such, no augmentation technical report has been sought from the Inter-Regional Planning Committee, nor any consent to proceed is required from other transmission network service providers.

6.10.6 Recommendation

The preferred network option is wind-monitoring scheme at an estimated cost of $400 K for Summer 2004/05. Continue to monitor the Keilor transformer constraint with proposed generation developments. Project identifier codes (M04-04) and (L04-05).

6.11 Loading on Keilor to West Melbourne 220 kV Circuits

6.11.1 Introduction

(a) Location of Constraint

The network between Keilor and West Melbourne comprises two circuits on a single 220 kV tower line. This line forms part of the 220 kV loop emanating from Keilor Terminal Station and supplying terminal stations at Altona, Brooklyn, Fisherman's Bend and West Melbourne. The stations in this loop provide power to Powercor, AGL and CitiPower networks as well as a number of HV customers supplying power to the commercial, industrial and domestic customers in the western metropolitan and the western Central Business District.

The loop also provides a connection for the Newport Power Station. When operating Newport generation will cause a reduction in power flows into the loop from Keilor.

The location of these lines and stations is shown in Figure 6.14 and the electrical connections are shown in Figure 6.15.

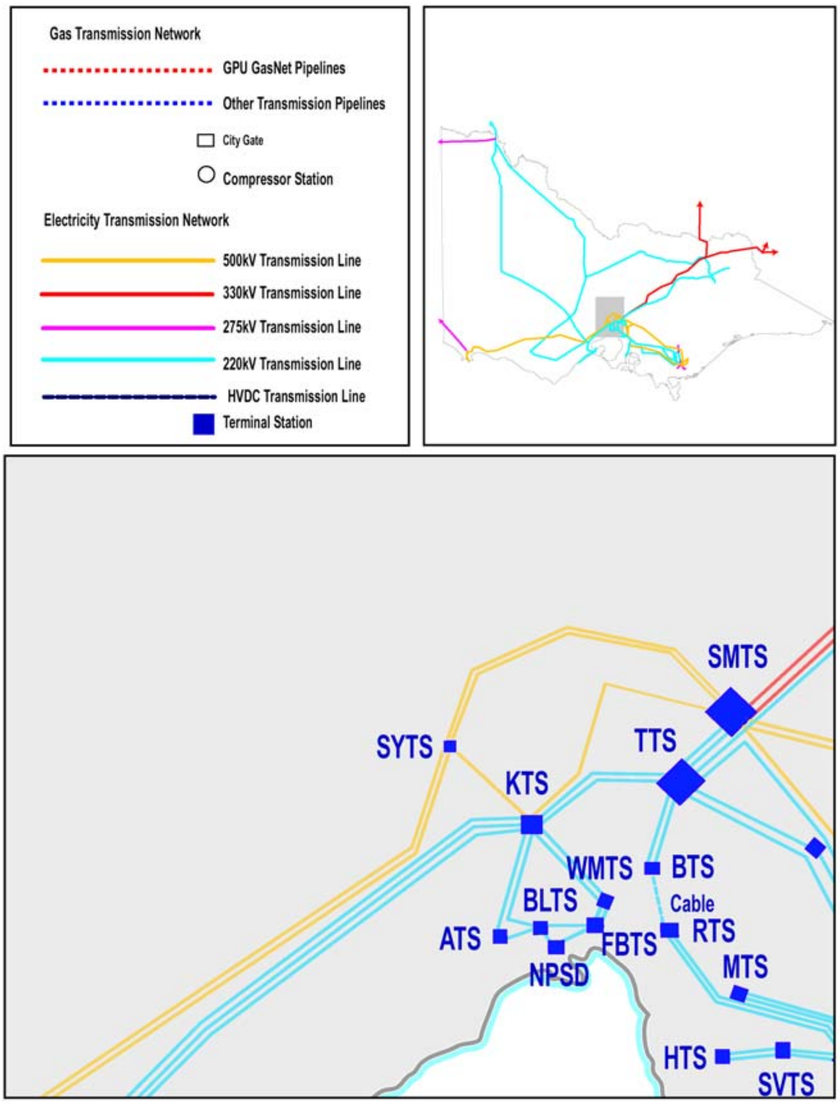
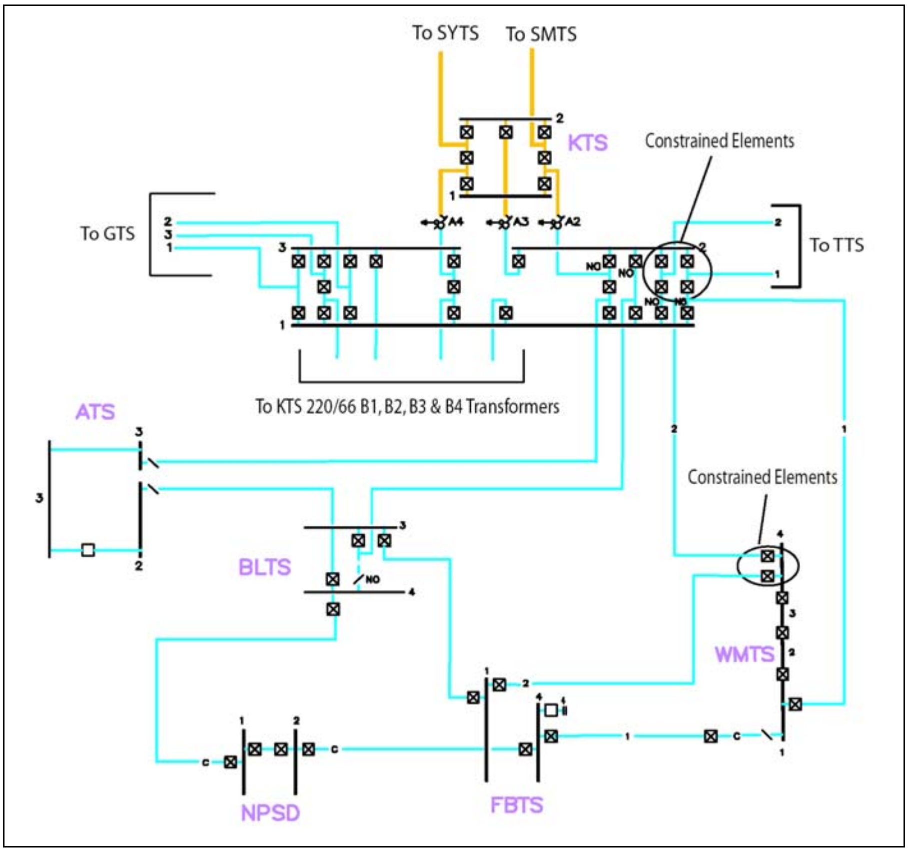


Figure 6.14 - Geographic Representation of Western Metropolitan Area



Abbreviations:
- ATS – Altona Terminal Station
- BLTS – Brooklyn Terminal Station
- FBTS – Fisherman's Bend Terminal Station
- GTS – Geelong Terminal Station
- NPSD – Newport Power Station
- SMTS – South Morang Terminal Station
- SYTS – Sydenham Terminal Station
- TTS – Thomastown Terminal Station
- WMTS – West Melbourne Terminal Station

Figure 6.15 - West Metropolitan Switching Configuration

(b) Reason for Constraint

The constraint on the Keilor to West Melbourne 220 kV circuits has arisen due to gradual load growth at the stations in the 220 kV loop supplied by these circuits.

(c) Conditions of Constraint

The constraint may occur as the result of an outage of one of the parallel Keilor to West Melbourne circuits, which will cause the remaining circuit to carry an increased load. The flow on the Keilor to West Melbourne circuits is also increased for the condition where there is a 500/220 kV transformer out of service at Keilor or Moorabool, which causes more power to be drawn into the loop via the connection to Thomastown.

The probabilities of these outages is shown in Table 6.32.

Critical Outage	Forced Outage Rate
Keilor to West Melbourne 220 kV circuit	0.154% (based on historical data)
Keilor 500/220 kV transformer	Short term outage - 0.055% (based on historical data) Long-term outage - 1 in 50 years with duration of 14 days (assuming service can be returned by using the spare single phase unit)
Moorabool 500/220 kV transformer	Short term outage - 0.03% (based on historical data) Long-term outage - 1 in 50 years with a duration of 14 days (assuming supply can be returned using the spare single phase unit which will be available from 2005)
Newport Power Station generation	1.7%

Table 6.32 – Probability of Plant Outage

The constraint is due to the thermal limitations on the 220 kV overhead circuits and the terminating equipment at Keilor and West Melbourne and will only occur if the outage condition happens at a time of high ambient temperature coincident with a high demand condition.

The rating of the limiting plant is shown in Table 6.33.

Critical Plant	Continuous Rating	15 Minute Short Time Rating
	40 deg C	40 deg C
Keilor to West Melbourne overhead circuit	1,950 A	2,330 A
220 kV connections at West Melbourne Terminal Station	2,035 A	2,035 A
220 kV connections at Keilor Terminal Station	2,140 A	2,140 A
220 kV circuit breakers at Keilor Terminal Station	2,020 A	2,020 A

Table 6.33 - Thermal Ratings of Constrained Plants

As the overhead circuits are loaded well below their continuous rating prior to the outage event, the line will take some time to reach its maximum operating temperature after the event. This thermal time constant means the line loading can move above its continuous rating for some time and the limitation immediately after the outage event will be the circuit breakers and the 220 kV connections which cannot sustain load above the continuous rating.

Once the first event has occurred and the action has been taken to bring plant within rating, the network must be prepared to be able to cope with the next worst event without overloading the remaining plant. Up to 30 minutes is allowed for this action and during this time existing operational arrangements to reconfigure the network would be implemented, avoiding the need for load shedding for this condition.

The overall limitations taking account of the short time rating capability and the terminal plant is shown in Figure 6.16.

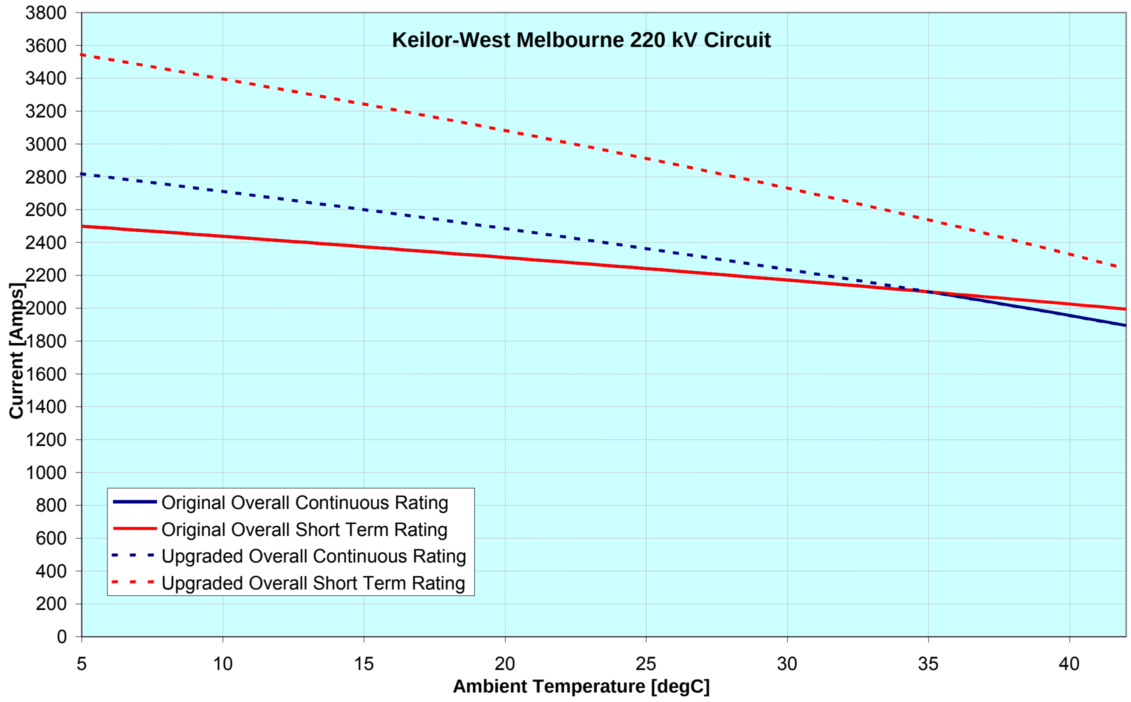


Figure 6.16 - Thermal Ratings of Constrained Plant

(d) Impacts of Constraint

The impact of the constraint depends on the amount of load, the ambient temperatures and the level of generation at Newport. In the most extreme case the post event loading could be slightly beyond the rating of the 220 kV circuit breaker and connections from 2004/05 Summer. If this condition were to occur some action would be needed to reduce the flow either prior to the outage or immediately after the outage. Market modelling indicates that this is a most unlikely condition during 2004/05 and flow would remain within the plant ratings immediately after the event. The likelihood of requiring immediate action for the first event remains low but rises gradually over the next 5 years.

However, it is likely that arrangements will be needed to reduce flows from the short time rating back to the continuous circuit rating within 15 minutes after the event and to prepare the system to cope with another network outage within 30 minutes after the event to meet the system security requirements. The next worst event is an outage of a 500/220 kV transformer at Keilor or Moorabool, or outage of the Newport generation and these have been included in the assessment of impact of the constraint

(e) Impacts on Constraint of Distribution Business Planning

The constraint will become more significant as loop load grows. There are no firm plans by the Distributors to reduce load in the 220 kV loop over the ten year period.

(f) Impact on Constraint of Asset Replacement Program

The constraining circuit breakers at Keilor are earmarked for replacement by 2008/09 as part of SPI PowerNet's asset replacement strategy. This replacement plan has been taken into account in determining the costs for the option of circuit breaker replacement discussed below.

6.11.2 Do Nothing – Value Of Expected Energy At Risk

Market modelling has been used to assess the expected unserved energy based on constraints on the Keilor to West Melbourne 220 kV line over a range of demand and generation levels in each year with a parallel Keilor to West Melbourne line outage.

The value of Expected Energy at Risk takes account of the probability of the critical outages occurring at times of the unfavourable loading and temperature conditions. The energy at risk shown in Table 6.34 is a worst-case assessment as no allowance has been made for rescheduling Newport generation to remove or reduce the constraint. Table 6.35 shows that rescheduling generation will reduce but not completely remove the energy at risk.

		2004/05	2005/06	2006/07	2007/08	2008/09
Average Annual Hours of Constraint	Hours	153	230	310	320	330
Maximum Single Constraint	MW	185	230	275	335	400
Energy At Risk	MWh	511	1,194	1,877	2,028	2,179
Unserved Energy	MWh	1,022	2,378	3,800	4,060	4,400
Rescheduled Generation	MWh	0	0	0	0	0
Value Of Unserved Energy	$K	31,070	72,357	133,644	122,342	131,039
Value of Rescheduled Generation	$K	0	0	0	0	0
Value of Expected Energy at Risk	$K	47	111	174	187	200

Table 6.34 - Energy at Risk for Do Nothing Option Without Rescheduling Generation

		2004/05	2005/06	2006/07	2007/08	2008/09
Average Annual Hours of Constraint	Hours	153	230	310	320	330
Maximum Single Constraint	MW	185	230	275	335	400
Energy At Risk	MWh	511	1,194	1,877	2,028	2,179
Unserved Energy	MWh	108	569	1,029	1,648	2,266
Rescheduled Generation	MWh	914	1,820	2,725	2,410	2,092
Value Of Unserved Energy	$K	3,200	16,800	30,500	49,000	67,000
Value of Rescheduled Generation	$K	40	70	110	100	90
Value of Expected Energy at Risk	$K	5	26	47	75	100

Table 6.35 - Do Nothing Option with Rescheduling Generation at Short Run Marginal Cost

6.11.3 Options For Removal Of Network Constraints

(g) Network Options

The following are possible network options to remove or reduce the constraint:

Uprate Keilor to West Melbourne Line Terminating Plant

Replace four 220 kV circuit breakers at Keilor and uprate the connections at Keilor and West Melbourne to remove the constraint due to the line terminating equipment. As SPI PowerNet has scheduled the circuit breakers for replacement by 2008/09 as part of its asset replacement strategy, earlier replacement would involve advancement costs only.

Automatic Network Control Scheme

The scheme would involve a fast acting automatic reconfiguration of the network to reduce flow on the remaining Keilor to West Melbourne circuit. Further evaluation is required to determine the practicality and complexity of this scheme.

Automatic Fast Load Shedding Scheme

A fast acting scheme would shed load at West Melbourne and Fisherman's Bend. It would monitor loading and temperature conditions on the Keilor to West Melbourne circuits and operate to reduce load rapidly following an outage.

(h) Cost of Network Options

Network Options	Estimated Cost ($K)
1. Uprate Keilor to West Melbourne line terminating plant	$900[39]
2. Automatic Network Control Scheme	$400
3. Automatic Fast Load Shedding Scheme	$400

Table 6.36 - Costs of Network Options

(i) Non Network Options

The following non-network solutions can partially or fully remove the network constraints:

- Demand side management in both the West Melbourne and Fisherman's Bend areas; and
- New generation in the 220 kV loop from Keilor.

At the time of publication of this APR, a number of inquiries have been received regarding new generation developments in the 220 kV loop but no projects are yet committed. The network augmentation option will be reviewed if a non-network option arises.

[39] The cost for this work includes the advancement of 220 kV circuit breaker replacements at Keilor which are currently planned for 2008/09.

6.11.4 Economic Evaluation

The Network Control Scheme and the Circuit Breaker and termination upgrade options both remove all the energy at risk.

Table 6.37 summarises the energy at risk for fast automatic load shedding scheme.

		2004/05	2005/06	2006/07	2007/08	2008/09
Average Annual Hours of Constraint	Hours	153	230	310	320	330
Maximum Single Constraint	MW	185	230	275	335	400
Energy At Risk	MWh	511	1,194	1,877	2,028	2,179
Unserved Energy	MWh	1.32	3.1	4.9	5.28	5.72
Rescheduled Generation	MWh	0	0	0	0	0
Value Of Unserved Energy	$K	90	490	900	1,450	1,980
Value of Rescheduled Generation	$K	0	0	0	0	0
Value of Expected Energy at Risk	$K	0.02	0. 06	0.11	0.19	0.26

Table 6.37 - Automatic Fast Load Shedding Scheme

(j) Summary of Net Benefits and Present Values Going Forward

Option	Present Value 30 Year Life		Annualised Value All $K					Residual Value For Remaining 25 Years 2009/10
			2004/05	2005/06	2006/07	2007/08	2008/09	
Do Nothing	-2,003		-47	-111	-174	-187	-200	-1,453
Option 1 (Keilor Circuit Breaker, line terminations upgrade)	2,003	Benefit	47	111	174	187	200	1,453
	-913	Equiv Annual Cost	-81	-81	-81	-81	-81	-590
	1,090	Net Benefit	-34	30	93	106	119	863
Option 2 (Automatic Network Control scheme)	2,003	Benefit	47	111	174	187	200	1,453
	-406	Equiv Annual Cost	-36	-36	-36	-36	-36	-262
	1,597	Net Benefit	11	75	138	151	164	1,191
Option 3 (Fast Automatic load shedding scheme)	2,003	Benefit	47	111	174	187	200	1,453
	-406	Equiv Annual Cost	-36	-36	-36	-36	-36	-262
	1,597	Net Benefit	11	75	138	151	164	1,191

Table 6.38 – Net Benefits of Network Augmentation Options

(k) Timing of Options

Table 6.39 shows the economically justified timing of the three network options based on the years in which a positive benefit is obtained.

Network Options	Timing
Keilor Circuit Breaker, line terminations upgrade	2005/06
Automatic Network Control scheme	2004/05
Fast Automatic load shedding scheme	2004/05

Table 6.39 - Timing of Network Options

(l) Ranking of Options

The ranking of the network solutions is provided in Table 6.40

Option	NPV [$K]	Ranking
Keilor Circuit Breaker, line terminations upgrade	1,090	2
Automatic Network Control scheme	1,597	1
Fast Automatic load shedding scheme	1,597	1

Table 6.40 - Ranking of Network Options

The Network Control Scheme and the Fast Load Shedding Scheme are similar in cost and provide a similar benefit. The preferred arrangement will be determined from more detailed assessment of the feasibility and costs.

6.11.5 Conclusions

VENCorp has identified two preferred network solutions, which maximise the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. Detailed costing will need to be obtained prior to selecting the preferred option. This augmentation is not a reliability augmentation.

VENCorp does not expect the preferred solution will have a material inter-network impact. As such, no augmentation technical report has been sought from the Inter-Regional Planning Committee, nor any consent to proceed is required from other transmission network service providers.

6.11.6 Recommendation

The preferred network option is an automatic network overload control scheme to either rapidly reconfigure the network or a fast load shedding. The preferred scheme is to be determined following further investigation of the feasibility and complexity of the reconfiguration option. The estimated cost is $400 K and the scheme is to be implemented before December 2004.

Before implementing the impact of any committed generation, the Keilor loop will be assessed. Project identifier code (M04-06).

6.12 Loading on Fisherman’s Bend to West Melbourne 220 kV Circuits

6.12.1 Introduction

(a) Location of Constraint

The network between Fisherman’s Bend and West Melbourne comprises two circuits on a single 220 kV tower line. This line forms part of the 220 kV loop emanating from Keilor Terminal Station and supplying terminal stations at Altona, Brooklyn, Fisherman’s Bend and West Melbourne. The stations in this loop provide power to Powercor, AGL and CitiPower networks as well as a number of HV customers supplying power to the commercial, industrial and domestic customers in the western metropolitan and the western Central Business District.

The loop also provides a connection for the Newport Power Station. When in operation Newport generation will cause a reduction in power flows into the loop from Keilor and reduce the normal power flow from West Melbourne to Fisherman’s Bend.

The location of these lines and stations is shown in Figure 6.17 and the electrical connections are shown in Figure 6.18.

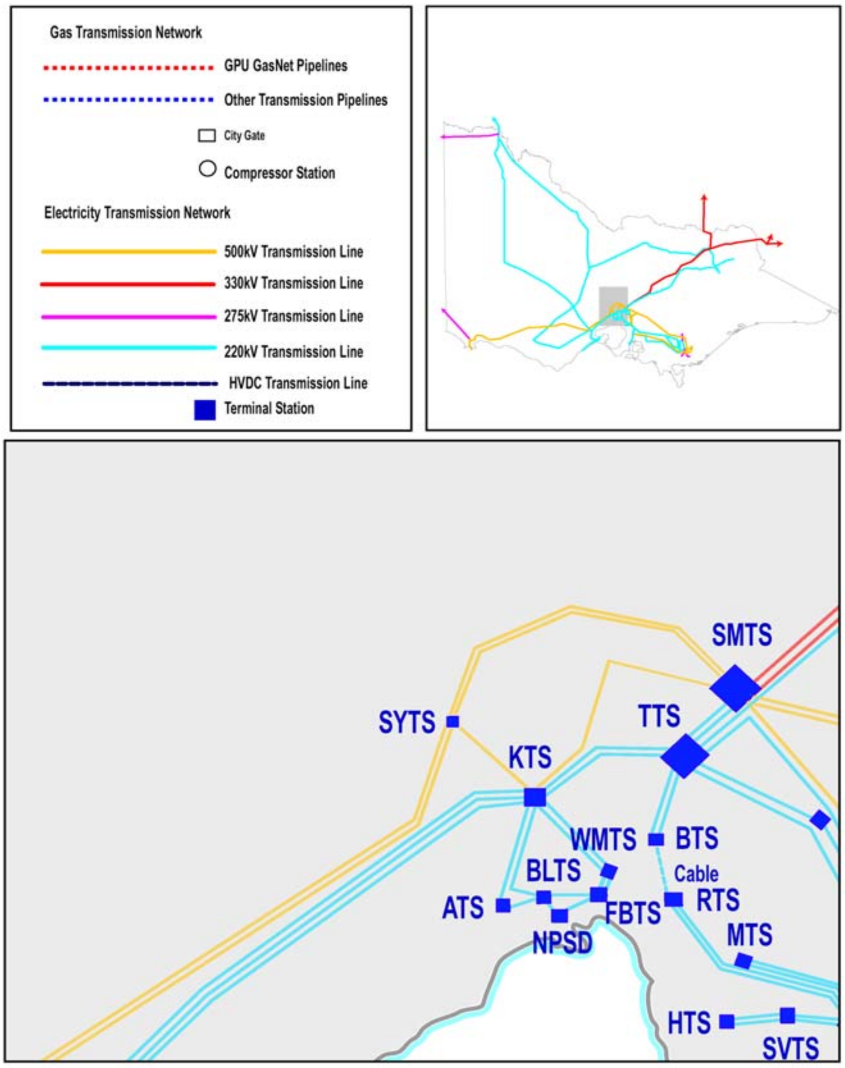


Figure 6.17 - Geographical Representation of Western Metropolitan Area

Abbreviations:
ATS – Altona Terminal Station
BLTS – Brooklyn Terminal Station
FBTS – Fisherman's Bend Terminal Station
GTS – Geelong Terminal Station
NPSD – Newport Power Station
SMTS – South Morang Terminal Station
SYTS – Sydenham Terminal Station
TTS – Thomastown Terminal Station
WMTS – West Melbourne Terminal Station

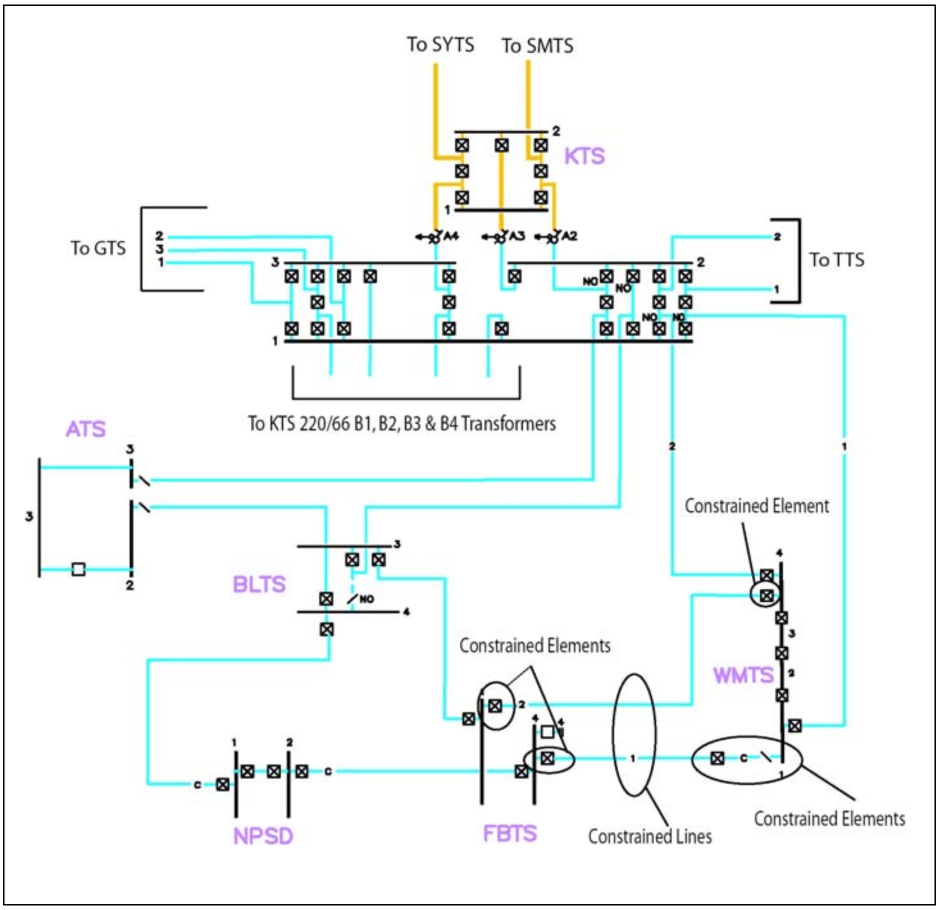


Figure 6.18 – Electrical Representation

(b) Reason for Constraint

The constraint on the Fisherman's Bend to West Melbourne 220 kV circuits has arisen due to gradual load growth at the stations in the 220 kV loop supplied by these circuits.

(c) Conditions of Constraint

The constraint may occur as the result of an outage of one of the parallel Fisherman's Bend to West Melbourne circuits, which will cause the remaining circuit to carry an increased load. The flow on the Fisherman's Bend to West Melbourne circuits is also increased for the condition where there is a 500/220 kV transformer out of service at Keilor or Moorabool, which causes more power to be drawn into the loop via the connection to Thomastown.

The probabilities of these outages is shown in Table 6.41.

Critical Outage	Forced Outage Rate
Fisherman's Bend to West Melbourne 220 kV circuit	0.032% (based on historical data)
Keilor 500/220 kV transformer (A spare single phase unit is available at Keilor to permit restoration within 14 days)	Short term outage - 0.055% (based on historical data) Long-term outage - 1 in 50 years with duration of 14 days.
Moorabool 500/220 kV transformer (A spare single phase unit will be available at Moorabool from 2005 to permit restoration within 14 days)	Short term outage - 0.03% (based on historical data) Long-term outage 1 in 50 years with a duration of 14 days
Newport Power Station generation	1.7%

Table 6.41 – Probability of Plant Outage

The constraint is due to the thermal limitations on the 220 kV overhead circuits and the terminating equipment at Fisherman's Bend and West Melbourne and will only occur if the outage condition happens at a time of high ambient temperature coincident with a high demand condition.

The rating of the limiting plant is shown in Table 6.42.

Critical Plant	Continuous Rating	15 Minute Short Time Rating
	40deg C	40 deg C
Fisherman's Bend – West Melbourne overhead circuit	1,017 A	1,200 A
220 kV connections at West Melbourne Terminal Station	1,070 A	1,070 A
220 kV connections at Fisherman's Bend Terminal Station	1,070 A	1,070 A

Table 6.42 -Thermal Ratings of Constrained Plant

As the overhead circuits are loaded well below their continuous rating prior to the outage event, the line will take some time to reach its maximum operating temperature after the event. This thermal time constant means the line loading can move above its continuous rating for some time and the limitation immediately after the outage event will be the 220 kV connections.

Once the first event has occurred and the action has been taken to bring plant within rating, the network must be prepared to be able to cope with the next worst event without overloading the remaining plant. Up to 30 minutes is allowed for this action and during this time operational arrangements to reconfigure the network would be implemented, avoiding the need for load shedding for this condition.

The overall limitations taking account of the short time rating capability and the terminal plant is shown in Figure 6.19.

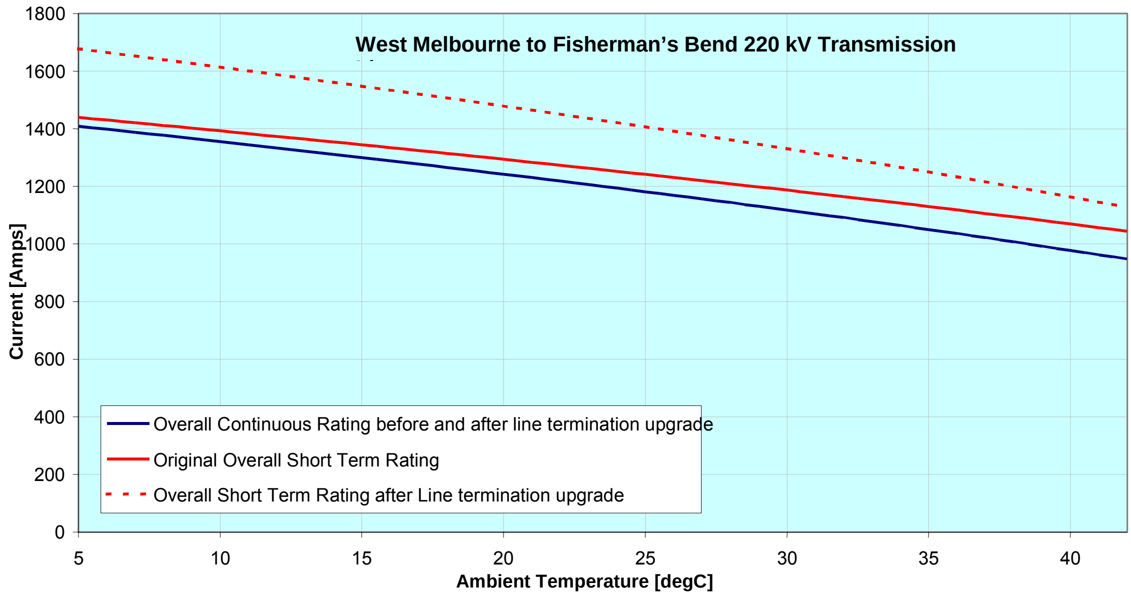


Figure 6.19 - Thermal Ratings of Constrained Plant

(d) Impacts of Constraint

The impact of the constraint depends on the amount of load, the ambient temperatures and the level of generation at Newport. In the most extreme case the post event loading could be slightly beyond the rating of the connections from 2008/09 Summer. If this condition were to occur some action would be needed to reduce the flow either prior to the outage or immediately after the outage. Market modelling shows that this is a most unlikely condition within the period and flow would remain within the plant ratings immediately after the event.

Load at Risk with Prior Outage of Newport				
Year 10 PoE	Constraint	Secure operating state with Newport Outage	Satisfactory operating state following Fisherman's Bend to West Melbourne line outage	Secure operating state following Fisherman's Bend to West Melbourne line outage
2004/05	Fisherman's Bend to West Melbourne Lines/terminations	None	360 MW	0 MW (additional)
2006/07	Fisherman's Bend to West Melbourne Lines/terminations	None	430 MW	0 MW (additional)
2008/09	Fisherman's Bend to West Melbourne Lines/terminations	110 MW	490 MW (additional)	0 MW (additional)

Table 6.43 - Load at Risk with Prior Outage of Newport Generation

(e) Impacts on Constraint of Distribution Business Planning

The constraint will become more significant as loop grows. There are no firm plans to reduce load in the 220 kV loop.

(f) Impact on Constraint of Asset Replacement Program

The circuit breakers at West Melbourne are earmarked for replacement by 2010/11 as part of SPI PowerNet's asset replacement strategy. This replacement does not impact on the constraint.

6.12.2 Options and Costs for Removal of Constraint

(g) Network Options

The following are possible network options to remove or reduce the constraint:

Uprate Fisherman's Bend to West Melbourne Line Terminating Equipment

Uprate the circuit connections at Fisherman's Bend and West Melbourne to remove the constraints due to the line terminating equipment.

Automatic Network Control Scheme

A scheme to re-configure the network to reduce flow on the remaining Fisherman's Bend 220 kV circuit after outage of the first Fisherman's Bend to West Melbourne circuit. Details of this are still being investigated.

Automatic Fast Load Shedding Scheme

A fast acting load scheme would shed load at West Melbourne and Fisherman's Bend. It would monitor loading and temperature conditions on the Fisherman's Bend to West Melbourne circuits and operate to reduce rapidly following an outage.

6.12.3 Cost of Network Options

The estimated capital cost of each of the network solutions is shown in Table 6.44:

Network Options	Estimated cost ($K)
Fast Automatic Network Control scheme	$400
Fast Automatic load shedding scheme	$400
Line termination upgrade costs	$200

Table 6.44 - Costs of Network Options

6.12.4 Non Network Options

The following non-network options can partially or fully remove the network constraints:

- Demand side management in both the West Melbourne and Fisherman's bend areas; and
- New generation in the 220 kV loop from Keilor.

At the time of publication of this APR, a number of inquiries have been received regarding new generation developments in the 220 kV loop but no projects are yet committed.

6.12.5 Economic Evaluation

A detailed economic evaluation has not been carried out because only a small amount of energy is at risk in 2008/09 and no network augmentation is required before this time.

6.12.6 Recommendation

No augmentation is proposed however the constraint is to be reviewed annually and reassessed if new generation is connected into this 220 kV loop ex Keilor.

6.13 Loading of Hazelwood 500/220 kV Tie Transformers

6.13.1 Introduction

(a) Location of Constraint

This constraint occurs at Hazelwood Terminal Station, which is in the Latrobe Valley as shown in Figures 6.20 and 6.21. The configuration shown is that which will be realised after the completion of the 4th Latrobe Valley to Melbourne 500 kV Line project in December 2004. The impact of this constraint is not expected to alter considerably as a consequence of this project.

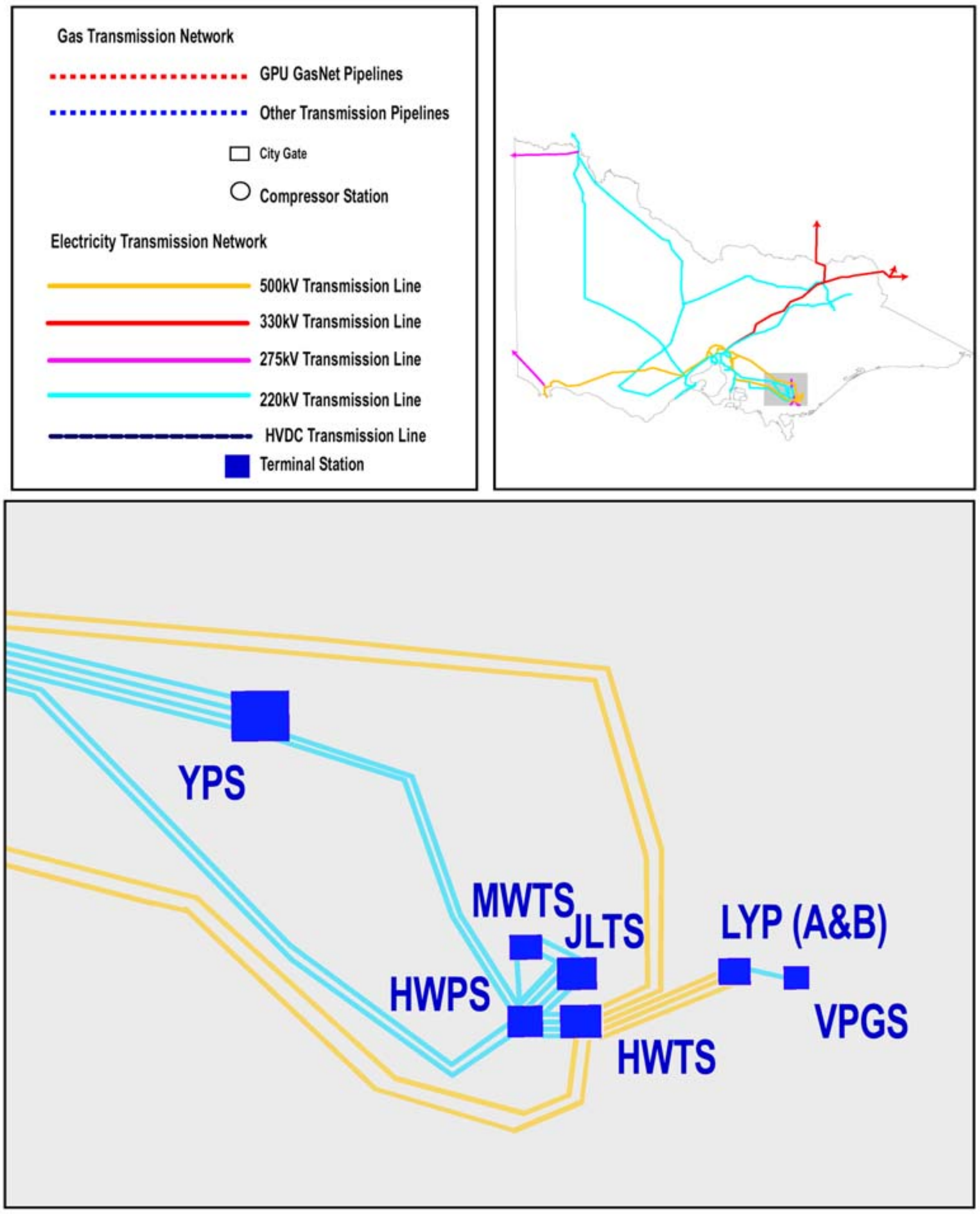
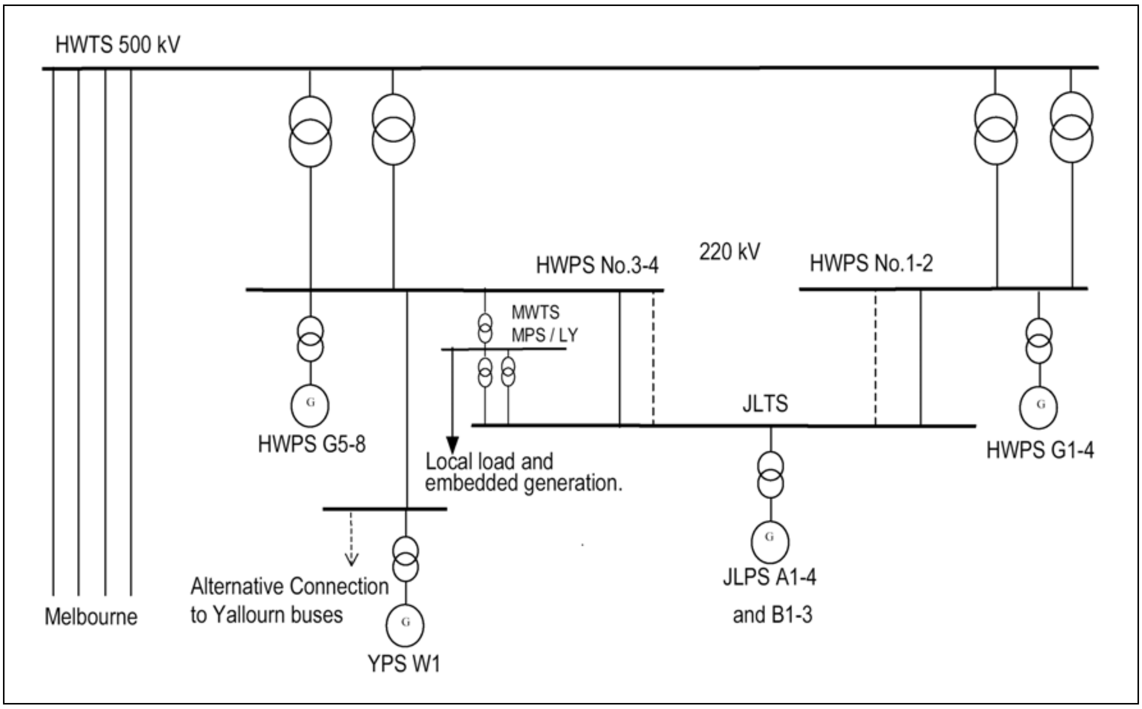


Figure 6.20 - Geographical Representation of Constraint



Abbreviation: HWTS – Hazelwood Terminal Station
HWPS – Hazelwood Power Station
JLTS – Jeeralang Terminal Station
JLPS – Jeeralang Power Station
YPS – Yallourn Power Station
MWTS – Morwell Terminal Station
MPS – Morwell Power Station
LY – Loy Yang substation
VPGS – Valley Power Gas Station

Figure 6.21 - Electrical Representation of Constraint

(b) Reason for Constraint

This constraint is primarily associated with the transfer of power from generation connected at the 220 kV voltage level or below in the Latrobe Valley into the 500 kV network. The nominal capacity of generation effected by this constraint is identified in Table 6.45.

Plant	Nominal Aggregate Capacity [MW]
Hazelwood Power Station	1,600 MW
Jeeralang Power Station A	200 MW
Jeeralang Power Station B	240 MW
Morwell Power Station	140 MW
Yallourn Power Station (Unit 1 only)	350 MW
Bairnsdale Power Station	80 MW
	2,260 MW

Table 6.45 – Generation Effected by the Hazelwood Transformer Constraint

Yallourn Energy's Unit 1 generator has a flexible connection arrangement to the shared network, allowing it to be switched between the normally isolated 220 kV and 500 kV transmission systems. Yallourn Energy has invested in and developed this flexible connection arrangement with the objective of maximising their strategic position in the National Electricity Market with respect to the treatment of transmission losses. Under system normal conditions, it will be connected via the Yallourn to Hazelwood No.2 220 kV Line to the Hazelwood No.3-4 bus group and provide an additional contribution to loading on the critical transformers connecting to the 500 kV network. However, if the constraint is forecast to occur for a considerable duration or low reserve levels are expected within Victoria, the output of Yallourn Unit 1 can be transferred to the 220 kV network via its alternative network connection.

(c) Conditions of Constraint

This constraint occurs during system normal operation in order to secure the network against any of the following plant outages:

Critical Outage	Failure Type	Forced Outage Rate
Any of the four Hazelwood A1 to A4 220/500 kV transformers	1 x transformer short term	0.02563 * 7 * 24 / 8,760 = 0.04915%
	1 x transformer long term	0.01206 * 279 * 24 / 8,760 = 0.92185%
	2 x transformers short term	0.00504 *1* 24 / 8,760 = 0.00138%
	2 x transformers medium term	0.00092 * 14 * 24 / 8,760 = 0.00353%
	2 x transformers long term	0.00023 * 279 *24 / 8,760 = 0.01758%

Table 6.46 – Probability of Plant Outages

These forced outage rates account for the physical layout of the four transformers at Hazelwood and the presence of a spare single phase unit held by SPI PowerNet, which is compatible with transformers A2, A3 and A4 (which are all comprised of three single phase banks). They are also based on specific advice from SPI PowerNet on the forced outage rates for these transformers which referenced the results of an Australian / New Zealand Transformer Reliability Study by Cigre in 1996 which indicated a basic major transformer failure rate of 1 every 250 years per transformer tank.

Under planned transformer outage conditions or extended forced outages, operational arrangements are implemented to convert the network into a parallel mode. This has the effect of minimising the dependence on the Hazelwood transformers by utilising spare capacity in the 220 kV lines to Melbourne. However, this is not a suitable arrangement during system normal conditions as transmission losses are increased nor is it a suitable arrangement at times of high ambient temperature because the capacity of 220 kV lines under such conditions is inadequate. This assessment does not attempt to cover the prior outage scenarios.

Any new generation connecting to the shared network under open access arrangements at a point that utilises the four Hazelwood transformers (i.e. at 220 kV at Hazelwood or Jeeralang or even embedded at 66 kV at Morwell or its distribution network) would compete directly with the existing generation for dispatch into the National Electricity Market.

This constraint occurs as a result of the thermal limitations of the four Hazelwood Terminal Station 220/500 kV transformers, which have the following characteristics:

Critical Plant	Continuous Rating [MVA]	Short Term Rating [MVA]
Hazelwood A1	600	750 for 1 hour
Hazelwood A2	600	638 for 1 hour*
Hazelwood A3	600	638 for 1 hour*
Hazelwood A4	600	638 for 1 hour*

Table 6.47 – Plant Rating

* Note, the short term ratings for the A2, A3 and A4 units are tentative 1 hour ratings that have recently been identified by the asset owner SPI PowerNet as potential no cost upgrades. These ratings are still under review and their application is conditional upon VENCorp and SPI PowerNet agreeing upon and accepting any changes in risk associated with application of the new ratings.

The impact of applying the tentative short term ratings is quantified in this analysis.

(d) Impacts of Constraint

As a consequence of this constraint, the generation connected at or below the 220 kV voltage level in the Latrobe Valley may be constrained off during system normal conditions to ensure system security is maintained. Should this constraint arise when there is a supply demand imbalance, the indirect consequence may be additional load shedding. On this basis, Yallourn Energy's Unit 1 generator is switched to its alternative network connection when low reserve conditions are forecast.

Constraint equations have been developed and are integrated within the National Electricity Market Dispatch Engine to model this constraint.

Equations 4.1 and 4.2 below, are presented to relate the acceptable levels of generation feeding the four transformers to local load and they can be used to indicate when the HWTS transformer constraint may become binding.

- Existing Hazelwood transformer continuous ratings of 600 MVA

HWPS G1-8 + JLPS A1-4 + JLPS B1-3 + MPS G1-5 + BDPS 1-2 + YWPS G1[40]

≤ 1,829 + MWTS Point of Connection 66 kV Demand

Equation (4.1)

The generation terms on the left hand side of this equation are expressed as "at generator terminals", and the Morwell Terminal Station Point of Connection 66 kV Demand [MW] is defined as that forecast at that terminal station and excludes scheduled embedded generation (i.e. if Bairnsdale Power Station or units 1, 2 and 3 at Morwell Power Station are running, their dispatch has been added back in to the demand).

The tentative provision of 638 MVA short term (one hour) ratings for the Hazelwood A2, A3 and A4 transformers will have the following impact on the Hazelwood Transformer Constraint Equation:

[40] If it is switched to its preferred 500 kV network connection.

- Short time Hazelwood transformer rating of 638 MVA

HWPS G1-8 + JLPS A1-4 + JLPS B1-3 + MPS G1-5 + BDPS 1-2 + YWPS G1
≤
1,935 + MWTS POC 66 kV Demand

Equation (4.2)

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

6.13.2 Do Nothing – Value of Expected Energy at Risk

In order to quantify the value of this constraint, preliminary market modeling studies have been carried out which exclude generation forced outage rates. Inclusion of the forced outage rates is likely to increase the impact and value of the constraint. Sensitivity studies will be carried out for various levels of generation forced outages as part of a more detailed assessment of this constraint.

Given the specified market modelling conditions, it was identified that the Hazelwood transformer constraint does not introduce a supply demand imbalance or result in any consequential load shedding. The impact of this constraint is rescheduling of generation out of merit order, which has been costed at an incremental fuel premium depending on which generation was dispatched as a consequence of the intra-regional constraint. The following Tables 6.48 to 6.49 present the Value of the Expected Energy at Risk for various scenarios.

		2004/05 Weighted	2005/06 Weighted	2006/07 Weighted	2007/08 Weighted	2008/09 Weighted
Hours of Constraint	Hrs	12	10	23	87	61
Maximum Single Constraint	MW	323	265	350	445	452
Average Constraint	MW	232	265	245	218	250
Energy at Risk	MWh	3,020	1,602	6,121	18,975	24,997
Average Cost of Constraint	$/MWh	17.40	6.61	13.04	13.00	15.95
Value of Expected Energy at Risk	$K	60	24	88	242	354

Table 6.48 – Evaluation of Existing Equation 4.1 with Yallourn W1 Unconditionally on the 220 kV Network

		04/05 Weighted	05/06 Weighted	06/07 Weighted	07/08 Weighted	08/09 Weighted
Hours of Constraint	hrs	12	10	18	66	54
Maximum Single Constraint	MW	361	45	244	339	331
Average Constraint	MW	179	20	165	148	165
Energy at Risk	MWh	2,511	615	2,805	9,781	14,313
Average Cost of Constraint	$/MWh	17.54	2.08	8.86	11.29	11.81
Value of Expected Energy at Risk	$K	42	3	18	77	179

Table 6.49 – Evaluation of Provisional Equation 4.2 with Yallourn Y1 Unconditionally on the 220 kV Network

The reduction in Energy at Risk in year 2005/06 can be attributed to the introduction of Basslink and its influence (reduction) on the dispatch of generation behind the Hazelwood constraint.

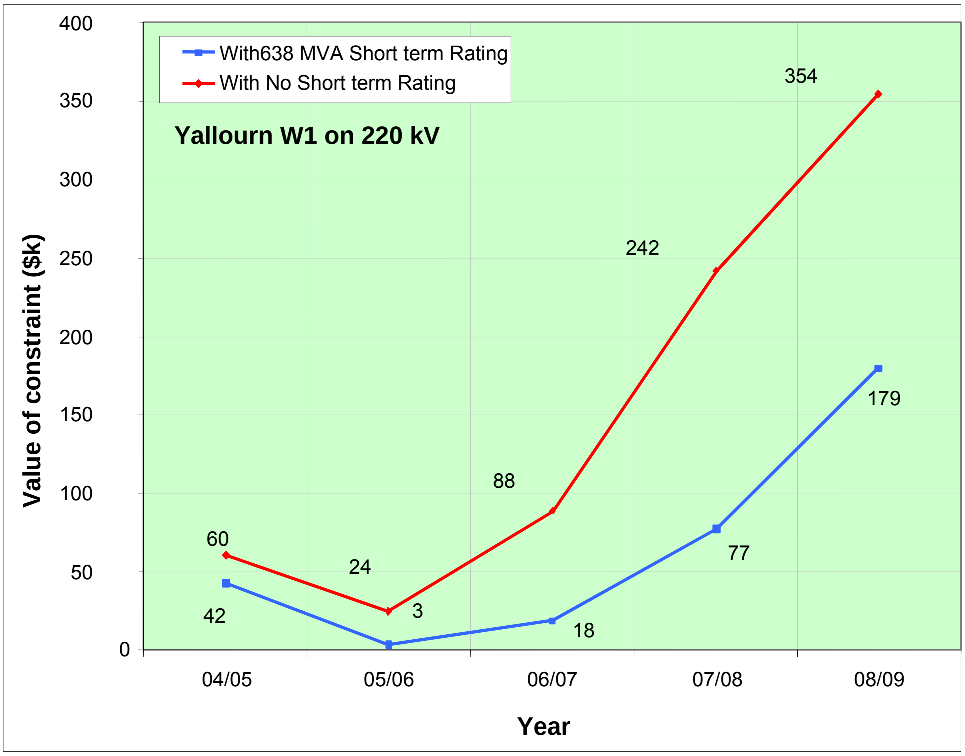


Figure 6.22 – Graph of the Annual Value of Expected Energy at Risk [$K] with Yallourn Unit 1 Unconditionally on the 220 kV Network

Figure 6.22 shows the considerable benefit of introducing the short term ratings identified by SPI PowerNet into the existing National Electricity Market Dispatch Engine constraint equation.

This assessment (with Yallourn Unit 1 unconditionally on the 220 kV network) gives an indication of the lower bound of the constraint in each year. The following Tables 6.50 and 6.51 present what could be described as an upper bound of the constraint with Yallourn Unit 1 unconditionally on the 500 kV network. In practice, the arrangements under which Yallourn can switch their generator between the two networks will result in the Value of the Expected Energy at Risk lying somewhere between the lower and upper bounds.

		2004/05 Weighted	2005/06 Weighted	2006/07 Weighted	2007/08 Weighted	2008/09 Weighted
Hours of Constraint	hrs	3,122	5,232	4,416	5,859	4,653
Maximum Single Constraint	MW	842	630	715	820	827
Average Constraint	MW	133	149	159	164	174
Energy at Risk	MWh	663,512	1,022,357	892,978	955,913	1,048,795
Average Cost of Constraint	$/MWh	1.94	1.73	1.96	3.33	4.41
Value of Expected Energy at Risk	$K	1,779	2,061	2,262	6,819	9,552

Table 6.50 – Evaluation of Existing Equation 4.1 withYallourn W1 Unconditionally on the 500 kV Network

		2004/05 Weighted	2005/06 Weighted	2006/07 Weighted	2007/08 Weighted	2008/09 Weighted
Hours of Constraint	hrs	1,705	3,338	2,872	4,117	3,271
Maximum Single Constraint	MW	736	524	609	714	708
Average Constraint	MW	82	84	84	92	95
Energy at Risk	MWh	231,392	360,064	317,700	375,766	407,063
Average Cost of Constraint	$/MWh	1.66	1.26	1.72	4.74	5.12
Value of Expected Energy at Risk	$K	587	546	865	2,571	5,621

Table 6.51 - Evaluation of provisional Equation 4.2 with Yallourn W1 Unconditionally on the 220kV Network

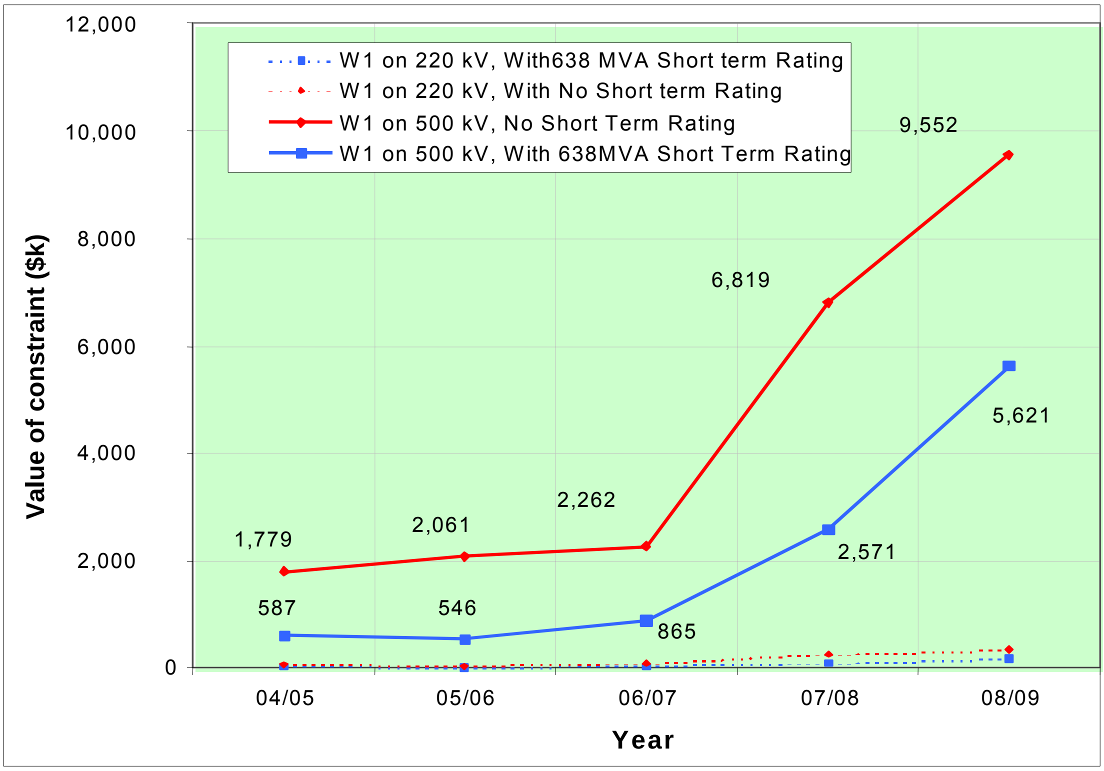


Figure 6.23 - Graph of the Annual Value of Expected Energy at Risk [$K] with Yallourn Unit 1 Unconditionally on the 500 kV Network.

The impact of having Yallourn Unit 1 unconditionally connected to the 500 kV network is considerable. This assessment shows that the constraint is likely to bind for a large portion of the year.

6.13.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

1. Install new 220/500 kV transformation and associated switching at Hazelwood Terminal Station, plus fault level mitigation. Estimated capital cost $30 M, subject to feasibility and detailed assessment.

2. Network augmentation to utilise spare capacity on the 220 kV transmission network from the Latrobe Valley to Melbourne. This will compound the potential constraint these lines impose under high ambient temperature conditions. Wind monitoring on the six Yallourn to Hazelwood to Rowville 220 kV lines may be required as well as some form of fault level mitigation to increase operational flexibility. This option would also need to be considerate of the impacts on transmission losses. Estimated capital cost $5 M, subject to feasibility and detailed assessment.

3. Strategically, VENCorp can further investigate the utilisation of the 220kV transmission network from the Latrobe Valley to Melbourne. Re-constructing these lines with modern equivalents to increase their capacity and reduce their resistance may allow system normal operation in parallel modes which may serve the dual purpose of alleviating the loading on

the Hazelwood transformers and providing further support to the growing eastern metropolitan Melbourne terminal stations at the 220 kV level. This option is likely to be a staged development, which would be subject to costing, feasibility and detailed assessment. A feasibility estimate for modern 3 x double circuit 220 kV transmission lines of around 100 km each would be $100 M ±25%.

(b) Other Options Considered

4. Obtain protection time frame short term (<5 seconds) ratings and implement a control scheme to trip excess generation post contingency. This would require one or more generator/s to agree to be tripped in the event of a transformer failure if the loading on the remaining three units exceeded their capability. Subject to valuation, feasibility and detailed assessment.

5. Negotiate with Yallourn Energy for unit 1 to remain connected to the 220 kV transmission network. This option would not eliminate this constraint.

6.13.4 Economic Evaluation

A comprehensive economic evaluation has not been undertaken for this constraint. Such an evaluation would need to address matters such as the impacts on transmission losses and all other benefits that may be realised with each proposed solution, and it would need to involve consultation with each of the effected parties.

However, when considering the annualised costs of the network options that have been identified, as shown in Table 6.52, below, and comparing them with the graphs of the Annual Value of Expected Energy at Risk for this constraint, we can observe that even after the provisional short term ratings have been adopted for the Hazelwood transformers and assuming W1 remains unconditionally connected to the 500 kV network, there will be scope for VENCorp to augment the transmission network to alleviate the Hazelwood transformer constraint within the next few years.

Network Option	Approximate Annualised Cost[41] [$K]
1	2,665
2	445
3	8,880

Table 6.52 – Annualised Cost of Options

Based on these annualised costs, VENCorp's preliminary studies indicate that Option1, which would eliminate this system normal constraint, may be justified by December 2008 if Yallourn Energy's Unit 1 were to remain unconditionally connected to the 500 kV network.

[41] Based on a term of 30 years and an interest rate of 8%

6.13.5 Conclusions

VENCorp will finalise the application of the 638 MVA short term ratings for the critically loaded transformers and implement the revised constraint equations shortly.

VENCorp will continue to monitor this constraint, especially after the completion of the Latrobe Valley to Melbourne 4th 500 kV line in December 2004, where operation experience with the new network configuration may provide some insight into alternative network options. VENCorp will progress the most economical and suitable solution as co-ordinated with all of the effected parties.

If no alternative network options are identified or non-network solutions realised, VENCorp would progress the detailed analysis and consultation for development of Option 1, a Large Network Augmentation involving new transformation at Hazelwood Terminal Station prior to December 2008 at an estimated cost of $30 M.

(c) Material Inter-Network Impact of Constraint

None of the proposed solutions would have a material inter-regional impact.

(d) Reliability or Market Augmentation

All network and non-network options are considered from the perspective of providing net market benefits.

6.13.6 Recommendation

The recommendation is to continue to monitor this constraint and to take co-ordinated action with each of the effected parties to resolve its forecast impacts.

Should the conditions effecting this emerging constraint remain as they are and Yallourn Energy's Unit 1 remain unconditionally connected to the 500 kV network, VENCorp could justify a Large Network Augmentation involving new transformation at Hazelwood Terminal Station prior to December 2008 at an estimated cost of $30 M. Project identifier code (L04-07)

6.14 Loading of Moorabool to Ballarat 220 kV Lines

6.14.1 Introduction

(a) Location of Constraint

The constraint is located between Moorabool (MLTS) and Ballarat (BATS) terminal stations in southwest Victoria. Geographical and electrical representations of the constraint are given in Figures 6.24 and 6.25 respectively.

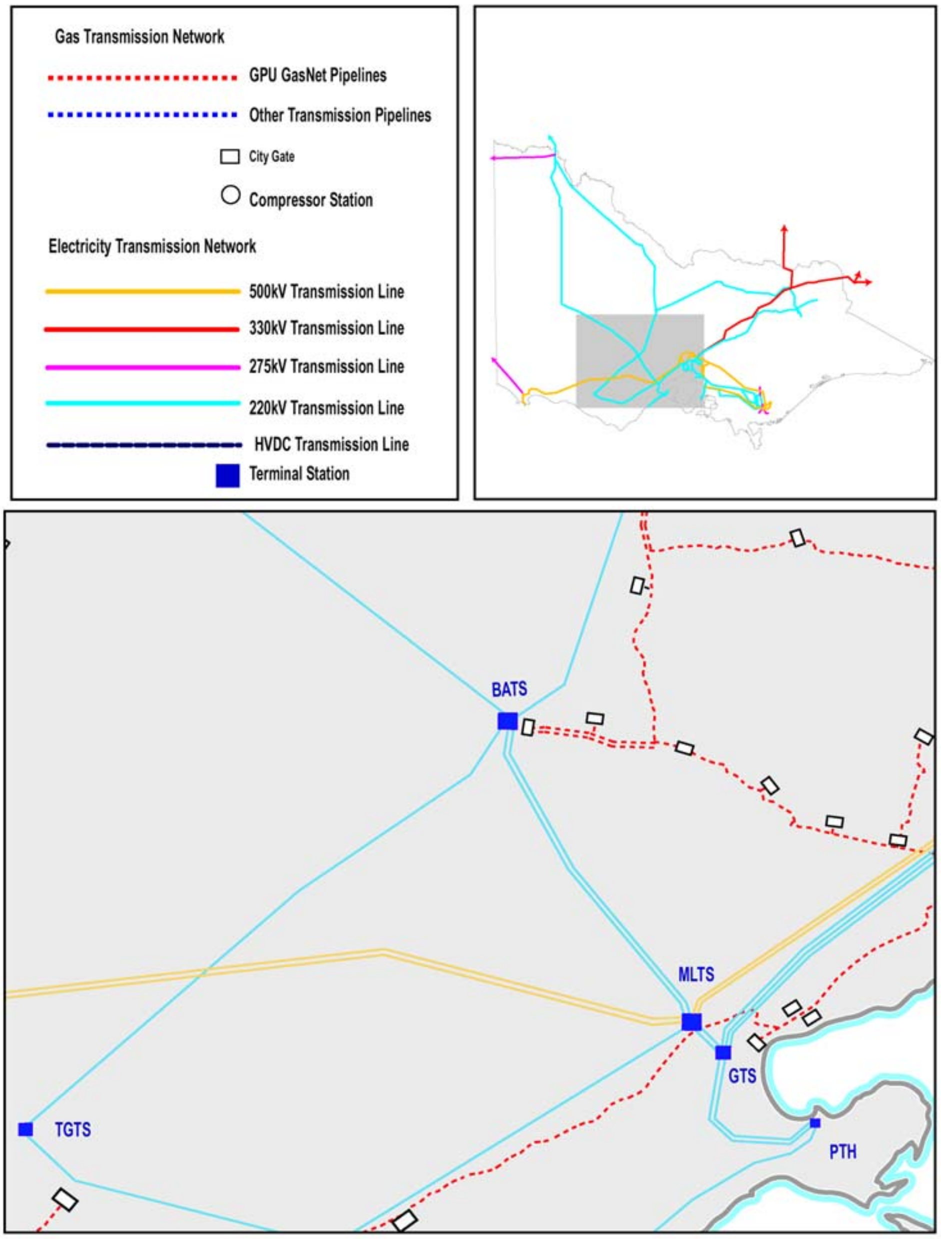
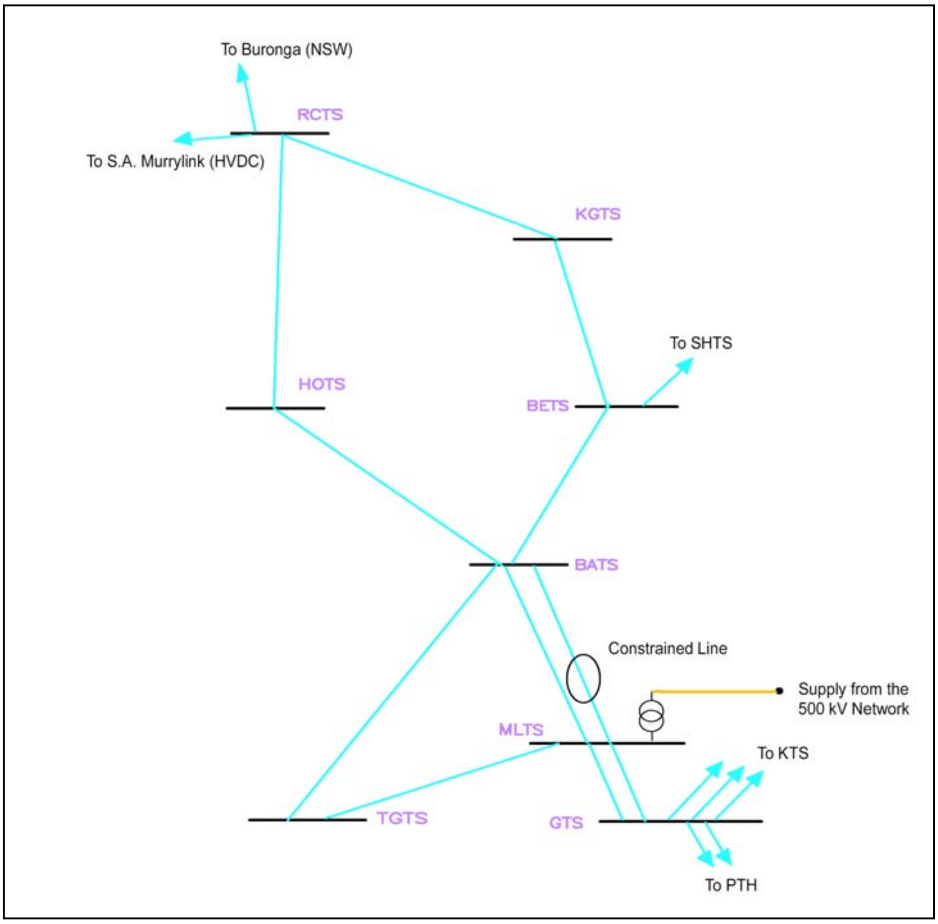


Figure 6.24 - Geographical Representation of the Constraint



Abbreviations: MLTS – Moorabool Terminal Station
BATS – Ballarat Terminal Station
TGTS – Terang Terminal Station
BETS – Bendigo Terminal Station
HOTS – Horsham Terminal Station
RCTS - Red Cliffs Terminal Station
KGTS – Kerang Terminal Station

Figure 6.25 - Electrical Representation of Constraint

(b) Reason for Constraint

The two Moorabool to Ballarat 220 kV lines form one of two main 220 kV supply points for the 'state grid'[42] area in Northern and Western Victoria. These lines are shown in Figures 6.24 and 6.25. The constraint has arisen as a result of progressive load growth in the Victorian state grid. The basis of the constraint is potential overloading on the No.1 circuit following contingent loss of the No.2 circuit.

(c) Conditions of Constraint

Power flow on the Moorabool to Ballarat lines is generally northwards from Moorabool into the state grid. The two circuits are on separate tower lines and have different thermal ratings. The original

[42] Regional Victoria (from Hamilton to Mildura to Glenrowan) excluding Gippsland and further east, is supplied from 220 kV 'state grid'

tower line (No.1 circuit) is rated 270 MVA at 35 degrees. The second circuit has a continuous rating of 450 MVA at 35 degrees.

A third 220 kV circuit passes from Moorabool through Terang to Ballarat via a significantly longer route. The bulk of the power transfer into the state grid from Moorabool is via the two Moorabool to Ballarat direct lines. The lines between Moorabool and Ballarat through Terang primarily support load at Terang, and loading on these circuits does not significantly affect loading on the two direct Moorabool to Ballarat connections.

The following system loading factors contribute to the Moorabool to Ballarat constraint:

- State grid load.
  Flow on the Moorabool to Ballarat lines increases with state grid load.
  This is the most significant factor for loading on the Moorabool to Ballarat lines.
- Interconnection flow between Victoria and Snowy/NSW.
  Flow on the Moorabool to Ballarat lines increases with export from Victoria to Snowy/NSW. Flow reduces with increasing import.
- Kiewa area generation.
  Flow on the Moorabool to Ballarat lines reduces with increased Kiewa generation (at a reduced sensitivity compared with flow between Victoria and Snowy/NSW).
- Interconnection flow between Victoria and SA over Murraylink.
  Flow on the Moorabool to Ballarat lines increases with export from Victoria to SA.
  Flow reduces with increasing import from SA.
  The impact of Murraylink on post-contingent flow is removed by an automatic runback scheme. If the Moorabool to Ballarat No.2 circuit is tripped while Murraylink is exporting to SA, then the scheme will rapidly reduce Murraylink transfer to zero.

The constraint is critically dependent on the following plant characteristics:

- Thermal capability of the lower rated Moorabool to Ballarat No.1 circuit;
- Probability of forced outage of the Moorabool to Ballarat No.2 circuit.

Thermal capability of the lower rated Moorabool to Ballarat No.1 circuit is limited by overhead conductor sag and varies significantly with ambient temperature and wind speed. These effects are included in the economic analysis of the constraint.

The probability of forced outage of the Moorabool to Ballarat No.2 circuit derived from benchmark data is 1.096×10^{-3}. Based on outage records to date, the probability of unplanned outage of the Ballarat to Moorabool No.2 line is only 7.5% of the benchmark figure. Economic assessment in this report is based on the benchmark probability. An assessment will be conducted to determine whether a lower outage rate should be applied in the final analysis prior to commitment to any augmentation works.

(d) Impacts of Constraint

The Moorabool to Ballarat constraint impacts on system operation under conditions of high ambient temperature (above 35^{o}C) and high state grid load. The potential impacts of the constraint are as follows:

- A reduction in Victorian export capability to Snowy/NSW or a requirement for Victorian import from Snowy/NSW; and

- A potential requirement to reduce demand in the Victorian state grid following trip of the Moorabool to Ballarat No.2 line.

The impacts of the constraint are directly related to how the constraint is managed. At present, the constraint can be managed as follows:

- Prior to the contingency, constrain Victorian transfer to Snowy so that post-contingent loading on the Moorabool to Ballarat No.1 line would not exceed 15 minute rating;

- Following the contingency and where loading exceeds the continuous rating, reschedule Victorian transfer to Snowy so that post-contingent loading is reduced to continuous rating within 15 minutes; and

- Where residual overload exists after rescheduling, manually reduce load in the Victorian state grid.

Under extreme conditions beyond 2004/05, it is expected that pre-contingent demand reduction would be required to maintain post-contingent loading on the Moorabool to Ballarat No.1 line within 15 minute rating. Approximately 11 MWh of load shedding would be required by 2006/07. It is proposed that existing control facilities be reprogrammed after 2004/05 to reduce demand in the state grid when imminent overloading is detected on the Moorabool to Ballarat No.1 line. Use of rapid demand reduction in conjunction with rescheduling of Vic to Snowy transfer would be used to manage the constraint as follows:

- Prior to the contingency, constrain Victorian transfer to Snowy so that post-contingent loading on the Moorabool to Ballarat No.1 line does not exceed 5 minute rating;

- Following the contingency and where loading is between 5 and 15 minute rating, automatically shed load in the Victorian state grid so that post-contingent loading is reduced to continuous rating; and

- Where post-contingent loading is between the 15 minute and continuous rating, reschedule Victorian transfer to Snowy and/or increase Kiewa area generation (if available) so that post -contingent loading is reduced to continuous rating within 15 minutes. Where residual overload exists after rescheduling, manually reduce load in the Victorian state grid or utilise automatic load shedding.

The impact of the constraint, when managed in the above manner, is quantified in Table 6.53.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

The Ballarat 220 kV switchyard is scheduled for possible refurbishment within 5 years. The Moorabool to Ballarat No.1 line is presently double switched at Ballarat while the No.2 line is single switched to the No.2 220 kV bus. Disconnection of the Ballarat No.2 bus therefore results in disconnection of the more highly rated No.2 line while the lower rated No.1 line remains on load. It is proposed that swapping over of the No.1 and No.2 Moorabool line connections be investigated as part of the Ballarat refurbishment. This would result in the more highly rated No.2 line being double switched at Ballarat and reduce exposure to outage of this circuit without requiring additional circuit breakers.

(g) Material Inter-Network Impact of Constraint

The Moorabool to Ballarat constraint does affect Victorian transfer between Snowy/NSW and South Australia. However, the sensitivity of Moorabool to Ballarat line loading to variations in inter-regional transfers is <20% of sensitivity to variations in state grid load. The existing arrangement to reduce Murraylink export does not change. The requirement to remove the constraint is mainly due to state grid load growth.

The constraint is therefore considered to be intra-regional. The proposed solutions will not impact on existing inter-regional transfer capability. Rather, they will prevent degradation of transfer capability, which would otherwise occur as Victorian state grid load increases.

6.14.2 Do Nothing – Value of Expected Energy at Risk

Market modelling studies have been undertaken to quantify exposure to the Moorabool to Ballarat constraint assuming the constraint is managed as specified in Section 6.14.1d. Note that this "do nothing" option includes generation rescheduling and demand reduction.

Table 6.53 identifies the exposure to Vic to Snowy rescheduling prior to the contingency and exposure to demand reduction and further Vic to Snowy rescheduling following the contingency. Expected rescheduling and demand reduction following the contingency are weighted by the probability of the critical line outage occurring (=1.096×10^{-3}). Rescheduling of Vic to NSW transfer is valued at $10/MWh based on comparison of short run marginal costs of base load plant in Victoria and NSW. Demand reduction is valued at $29,600/MWh.

	Unit	2004/05	2006/07	2008/09
Prior To Contingency				
Hours of rescheduling Vic to Snowy transfer	Hours	11.8	1.9	3.6
Rescheduled Vic to Snowy transfer	MWh	2,467.8	254.3	1,025.6
Value of rescheduled Vic to Snowy transfer	$K	24.678	2.543	10.26
After Contingency				
Hours exposed to load shedding	Hours	0.60	26.4	45.9
Unserved energy in state grid	MWh	10.24	2,608	4,859
Expected unserved energy	MWh	0.0112	2.86	5.325
Value of Expected unserved Energy	$K	0.332	84.6	157.6
Hours of rescheduling Vic to Snowy transfer	Hours	32.5	32.7	65.8
Rescheduled Vic to Snowy transfer	MWh	9,497	6,688	1,4478
Expected rescheduled Vic to Snowy transfer	MWh	10.4	7.3	15.9
Value of expected rescheduled transfer	$K	0.104	0.073	0.159
Value of Expected Energy at Risk				
Total value of rescheduled transfer prior to contingency plus expected unserved energy and rescheduled transfer following contingency	$K	25.1	87.2	168

Table 6.53 – Exposure To Moorabool to Ballarat Constraint - Do Nothing

The value of expected energy at risk and its components associated with rescheduled transfer and expected unserved energy are illustrated graphically in Figure 6.26. Values for 2005/06 and 2007/08 are interpolated from adjacent years.

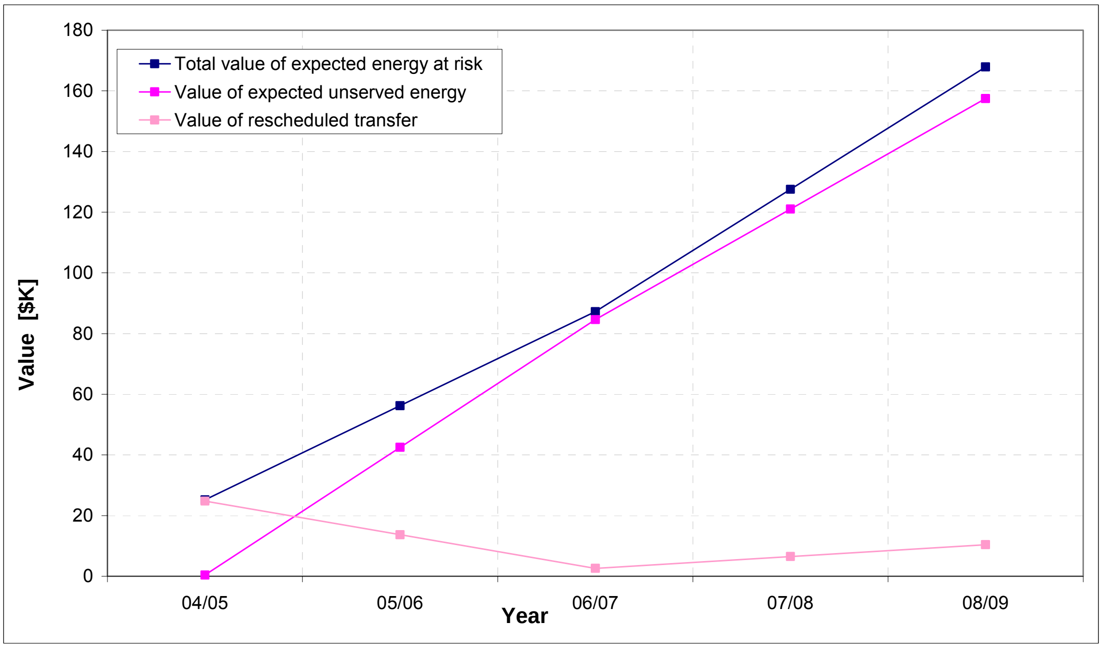


Figure 6.26 – Value of Expected Energy at Risk for Moorabool to Ballarat Constraint - Do Nothing

6.14.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions have been identified to reduce or remove the Moorabool to Ballarat constraint.

Option 1 - Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used by installing wind monitoring stations at each end of the Moorabool to Ballarat lines at a total cost of around $400 K. On high ambient temperature days the wind speed is typically higher than 0.6 m/s. A typical wind speed of 1.2 m/s would provide a 15~20% increase in line capacity and significantly reduce the overall cost of the constraint. An investigation into wind speed between Moorabool and Ballarat needs to be carried out before implementing this scheme.

Economic analysis of this option is based on an assumed applied wind speed of 1.2m/s.

Options 2a and 2b - Increasing the Capacity of the Moorabool to Ballarat No.1 Circuit

The No.1 circuit is presently rated for operation at up to 65°C conductor temperature. A higher maximum conductor temperature and line rating could be obtained by re-tensioning the conductors and/or raising towers on critical spans. Uprating the circuit for 75°C operation would increase the circuit rating by around 25% at 40°C ambient temperature at a cost of around $2.8 M (Option 2a). Uprating the circuit for 82°C operation would increase the circuit rating by around 40% at 40oC ambient temperature at a cost of around $4.8 M (Option 2b).

Continuous rating (in Amps) of the Moorabool to Ballarat No.1 circuit is shown in Figure 6.27 for the existing line and with augmentation Options 1, 2a and 2b.

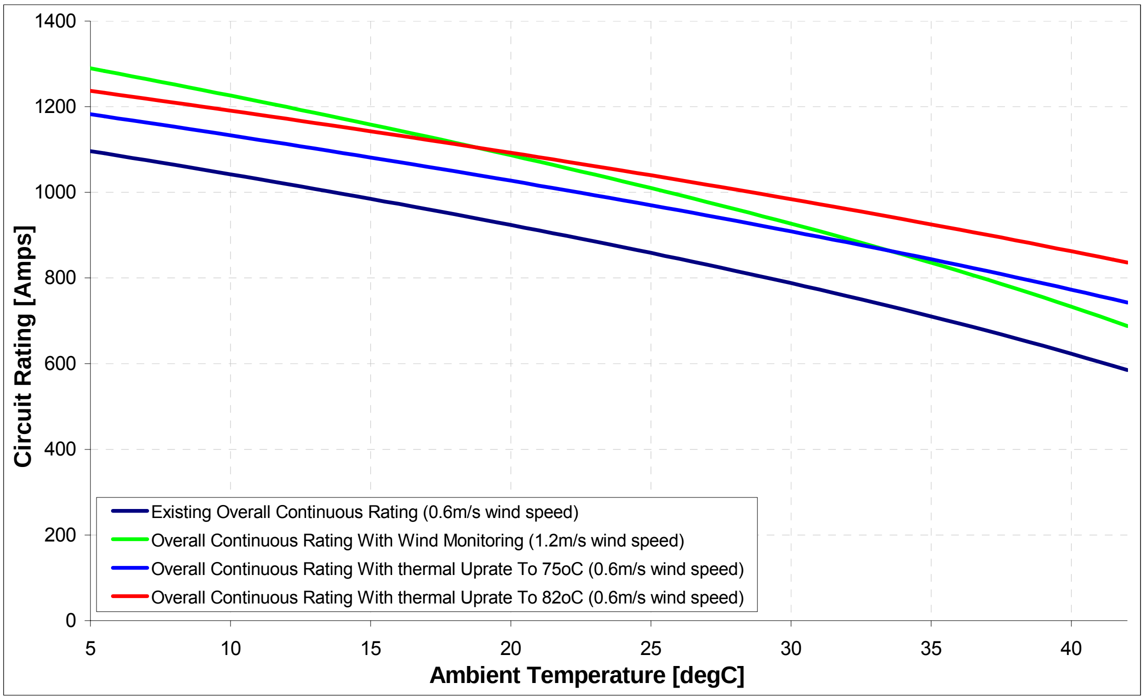


Figure 6.27 – Moorabool to Ballarat No.1 Line Rating – Existing and with Augmentations

Option 3 - Installation of a Third Moorabool to Ballarat 220 kV Circuit

The existing No.2 circuit is built on double circuit towers, with only one side of the towers presently strung. A second circuit could be strung on the vacant side of the tower. The estimated cost of this option and the associated 220 kV switching is around $8 M. This option would eliminate the constraint in the short and medium term. Expected energy at risk is thus eliminated over the analysis period (2004/05 to 2008/09).

(b) Other Options Considered

Option 4 - Controlled Switching of State Grid 220 kV Lines

Loading on the Moorabool to Ballarat No.1 line may be reduced following loss of the No.2 line by opening the Ballarat to Bendigo 220 kV line. A further reduction is achieved by additionally opening the Horsham to Red Cliffs 220 kV line. Opening these two lines leaves the network in a satisfactory state. The lines can be subsequently reclosed after scheduling Victorian import from Snowy. However, a detailed assessment on reliability and security implications of this control scheme needs to be conducted.

If feasible, a control scheme would be developed to open automatically the Ballarat to Bendigo and/or Horsham to Red Cliffs 220 kV lines following loss of the Moorabool to Ballarat No.2 line. One or both lines would be opened depending on system loading conditions.

(c) Non-Network Options Considered

Load transfers, demand management or generation within the state grid, especially at Ballarat, would provide load relief on the Moorabool to Ballarat 220 kV circuits. Around 1.8 MW of load relief in the state grid is required to reduce loading on the critical line by 1 MVA. In the absence of network augmentations, demand reduction will become increasingly necessary to manage the constraint.

Rescheduling of the flow on the Vic to NSW interconnector can be used to reduce loading on the critical circuit following a contingency, with around 13 MW of interconnection rescheduling required to reduce loading on the critical line by 1 MVA. A minimum of 15 minutes is required for any such rescheduling following a contingency. In the absence of network augmentations, rescheduling of Vic to Snowy transfer will become increasingly necessary in managing the constraint. Augmentation to the Vic to Snowy interconnection would provide increased opportunity for rescheduling. However, this would not be cost effective in addressing the Moorabool to Ballarat constraint.

6.14.4 Economic Evaluation

(a) Value of Expected Energy at Risk with Augmentation Options

All augmentation options reduce the expected energy at risk compared to the “do nothing” option. Table 6.54 identifies the value of expected energy at risk of the Moorabool to Ballarat constraint associated with Options 1, 2a, 2b and 3. Expected energy at risk with the augmentations is calculated on the same basis as for the “do nothing” option. The benefit of each option is identified by comparing the value of expected energy at risk with the “do nothing” option.

	Value Of Expected Energy At Risk ($ K)		
	2004/05	2006/07	2008/09
Option 1 - Wind Monitoring Scheme	0.441	6.37	19.5
Option 2a – No.1 circuit uprate to 75°C	0.012	0.58	6.30
Option 2b – No.1 circuit uprate to 82°C	0.0003	0	0.35
Option 3 – Third Moorabool to Ballarat circuit	0	0	0

Table 6.54 - Exposure to Moorabool to Ballarat Constraint with Augmentation Options

The value of expected energy at risk for the “do nothing” case and augmentation options is illustrated graphically in Figure 6.28. Values for 2005/06 and 2007/08 are interpolated from adjacent years.

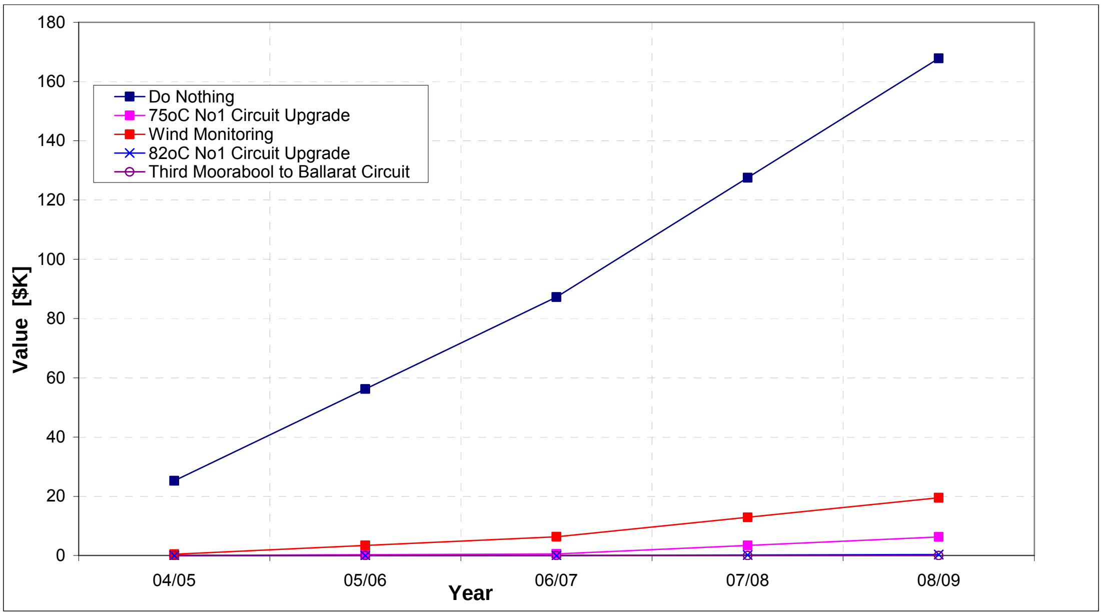


Figure 6.28 – Value of Expected Energy at Risk with Augmentations

(b) Summary of Net Benefits and Present Values Going Forward

Table 6.55 identifies net annual benefits and net present value of the network options over the five year analysis period. An 8% annual discount rate and 30 year life has been applied in determining the annual costs. Net present value is calculated over the five year analysis period only. All values are quoted in $ K. Values for 2005/06 and 2007/08 are interpolated from adjacent years.

Option	Present Value 30 Year Life		Annualised Value All Values $K					Residual Value Remaining 25 Years
			2004/05	2005/06	2006/07	2007/08	2008/09	
Do Nothing	- 1,570		- 25	- 56	- 87	- 128	- 168	- 1,221
Option 1 (Wind Monitoring)	1,399	Benefit	25	53	81	115	148	1,082
	- 406	Equiv Annual Cost	- 36	- 36	- 36	- 36	- 36	- 262
	993	Net Benefit	- 11	17	45	79	112	820
Option 2a (Thermal Upgrade to 75°C)	1,514	Benefit	25	56	87	128	161	1,170
	- 2,817	Equiv Annual Cost	- 250	- 250	- 250	- 250	- 250	- 1,818
	- 1,303	Net Benefit	- 225	- 194	- 163	- 123	- 89	- 648
Option 2b (Thermal Upgrade to 82°C)	1,561	Benefit	25	56	87	128	167	1,213
	- 4,872	Equiv Annual Cost	- 433	- 433	- 433	- 433	- 433	- 3,144
	- 3,311	Net Benefit	- 408	- 377	- 346	- 305	- 266	- 1,931
Option 3 (3rd Circuit)	1,561	Benefit	25	56	87	128	167	1,213
	- 8,120	Equiv Annual Cost	- 721	- 721	- 721	- 721	- 721	- 5,240
	- 6,559	Net Benefit	- 696	- 665	- 634	- 594	- 554	- 4,027

Table 6.55 - Net Benefits of Network Augmentation Options

It can be seen from the above table that only wind monitoring yields a positive net value over the analysis period. The net market assessment was carried out for a 30-year period for each of the network options identified using a discount rate of 8% to calculate the NPV. The benefit identified year 6 for each of the options was carried forward to calculate the residual value. Positive annual benefits are obtained with wind monitoring from 2005/06.

(c) Timing of Options

Wind monitoring is the preferred option for addressing the Moorabool to Ballarat constraint over the next five years and is proposed for installation by November 2005. A wind survey along the line easement will need to be conducted to confirm feasibility. Controlled switching of two state grid 220 kV lines following forced outage of the Moorabool to Ballarat No.2 line is considered as an alternative option to wind monitoring (subject to feasibility study).

Uprating of the No.1 circuit or installation of a third circuit may be justifiable in the five year period after 2008/09. These options will be the subject of future analysis.

(d) Ranking of Options

Table 6.34 shows the NPV and ranking of the proposed network options as applicable to the 5-year period ending 2008/09. Ranking is on the basis of relative NPV.

Subject to further analysis, Options 2 or 3 may yield a positive NPV after 2008/09. The ranking of these options may also change.

Option	NPV	Ranking
Option 1 – Wind Monitoring ($K)	993	1
Option 2a – Uprate No.1 Circuit to 75^{o}C ($K)	Not applicable as the value is negative.	-
Option 2b – Uprate No.1 Circuit to 82^{o}C ($K)	Not applicable as the value is negative.	-
Option 3 – 3rd Moorabool to Ballarat Circuit ($K)	Not applicable as the value is negative.	-

Table 6.56 - Ranking of Network Augmentation Options

6.14.5 Conclusions

Analysis indicates that the Moorabool to Ballarat constraint will have an increasing impact on system operation over the next five years and that the cost of this constraint is sufficient to justify installation of a wind monitoring scheme. Optimal timing for installation is November 2005 based on assumed minimum wind speed.

Uprating of the No.1 circuit or installation of a third circuit may be justifiable in the five year period after 2008/09.

6.14.6 Recommendation

The recommended solution for addressing the Moorabool to Ballarat constraint over the next five years is as follows:

- Install a wind monitoring scheme on Moorabool to Ballarat lines by November 2005 with an estimated cost of $400 K– subject to confirmation of feasibility;
- Reprogram existing overload control facilities by November 2005 to reduce demand in the state grid as required to prevent thermal overload on the Moorabool to Ballarat No.1 line;
- If wind monitoring is found to be infeasible, then investigate controlled switching of the Ballarat to Bendigo and Horsham to Red Cliffs lines; and
- Assess the swapping over of No.1 and No.2 Moorabool lines at Ballarat in conjunction with proposed Ballarat Terminal Station refurbishment works.

Project identifier code (M04-08).

6.15 Loading of Ballarat to Bendigo 220 kV Line

6.15.1 Introduction

(a) Location of Constraint

The constraint is located between Ballarat (BATS) and Bendigo (BETS) Terminal Stations in west Victoria. Geographical and electrical representations of the constraint are given in Figures 6.29 and 6.30 respectively.

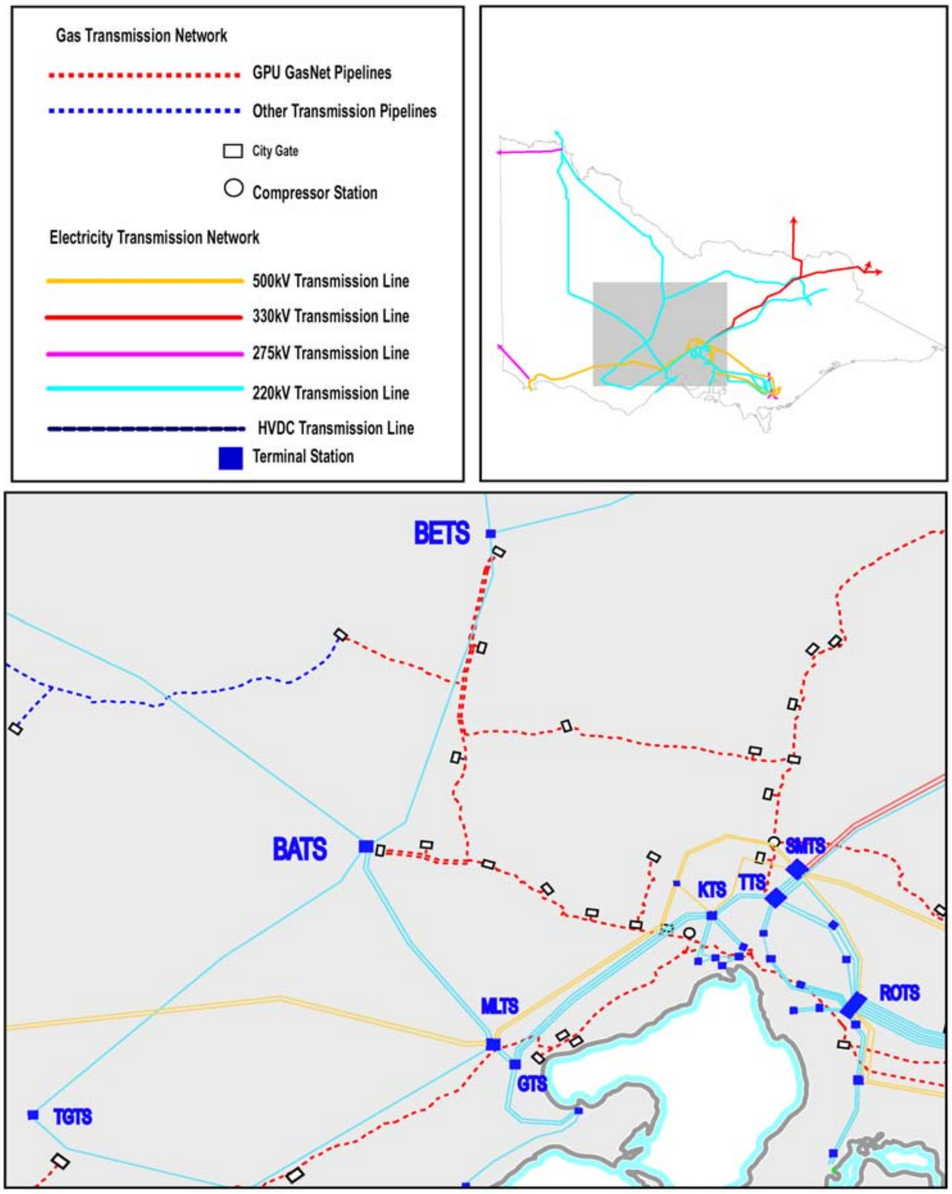
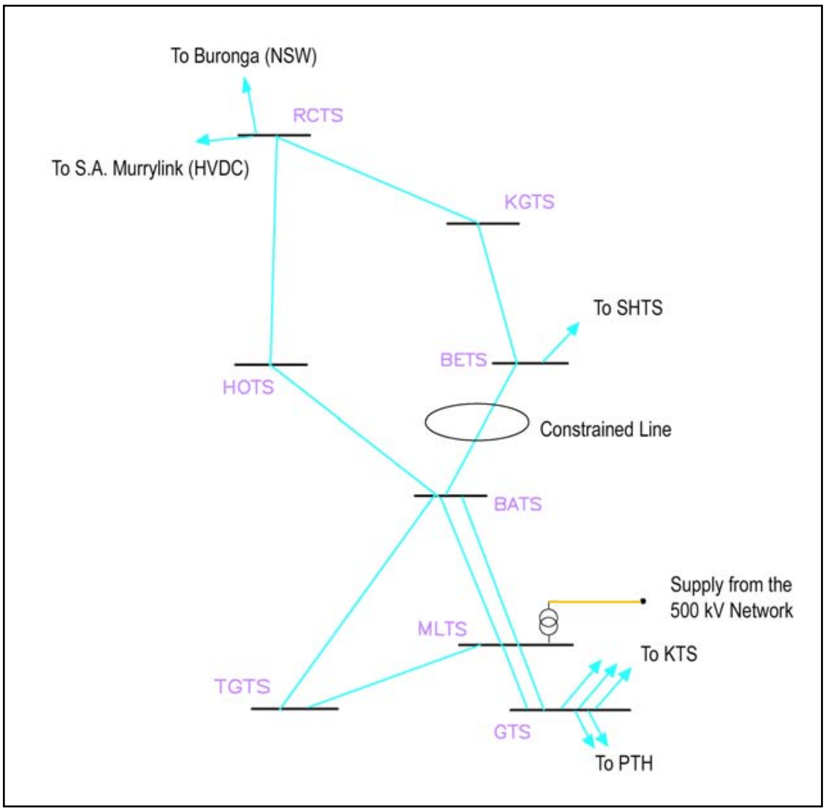


Figure 6.29 - Geographical Representation of the Constraint



Abbreviations: BATS – Ballarat Terminal Station
BETS – Bendigo Terminal Station
HOTS – Horsham Terminal Station
KGTS – Kerang Terminal Station
MLTS – Moorabool Terminal Station
RCTS – Red Cliffs Terminal Station
SHTS – Shepparton Terminal Station

Figure 6.30 - Electrical Representation of Constraint

(b) Reason For Constraint

The Ballarat to Bendigo circuit forms one of the main 220 kV supply points for North Western Victoria. This line is shown in Figures 6.29 and 6.30. The constraint has arisen as a result of progressive load growth at Bendigo, Kerang and Red Cliffs in North Western Victoria. Table 6.57 summarises the 10% and 50% POE demand forecast at Bendigo, Kerang and Red Cliffs up to Summer 2008/09.

Year	Bendigo, Kerang and Red Cliffs Demand (MW)	
	10% POE	50% POE
2004/05	402.1	387.7
2005/06	414.4	400.0
2006/07	425.6	411.2
2007/08	437.5	423.1
2008/09	448.6	434.2

Table 6.57– Summated Maximum Demand Forecast at Bendigo, Kerang and Red Cliffs

(c) Conditions of Constraint

Power flow on the Ballarat to Bendigo circuit is predominately northwards from Ballarat supplying North Western Victoria. The single circuit tower is rated 270 MVA at 35°C. The other main 220 kV supply into North Western Victoria is the Shepparton to Bendigo circuit, and as such contingent loss of this circuit results in the possible overload of the Ballarat to Bendigo circuit.

The following system loading factors contribute to the Ballarat to Bendigo constraint:

- North West Victoria Load.

  Flow on the Ballarat to Bendigo circuit increases with load at Bendigo, Kerang and Red Cliffs.
  This is the most significant factor for loading on the Ballarat to Bendigo circuit;

- Interconnection flow between Victoria and SA over Murraylink.

  Flow on the Ballarat to Bendigo circuit increases with export from Victoria to SA.
  Flow reduces with increasing import from SA.
  The impact of Murraylink on post contingent flow is removed by an automatic runback scheme. If the Shepparton to Bendigo circuit is tripped while Murraylink is exporting to SA, then the scheme will rapidly reduce Murraylink transfer to zero;

- Interconnection flow between Victoria and Snowy/NSW.

  Flow on the Ballarat to Bendigo circuit increases with export from Victoria to Snowy/NSW.
  Flow reduces with increasing import.

The constraint is critically dependant on the following plant characteristics:

- Probability of forced outage of the Shepparton to Bendigo circuit.

- Thermal capability of the Ballarat to Bendigo circuit;

The probability of forced outage of the Shepparton to Bendigo circuit derived from benchmark data is 2.002 $x10^{-3}$. Based on outage records to date, the probability of unplanned outage of the Shepparton to Bendigo circuit is only 68% of the benchmark figure. Economic assessment in this report is based on the benchmark probability.

Critical Outage	Forced Outage Rate
Shepparton to Bendigo 220 kV Circuit	1.169 * 1.5 * 10 / 8,760 = 0.2002 %

Table 6.58 – Critical Outage Table

Thermal capability of the Ballarat to Bendigo circuit is limited by overhead conductor sag and varies with ambient temperature and wind speed.

Critical Plant	Continuous Rating [MVA]		15 minute Short Term Rating [MVA][43]	
	5degC	35degC	5degC	35degC
Ballarat to Bendigo 220 kV Circuit	418	271	473	318

Table 6.59 – Critical Plant Capability

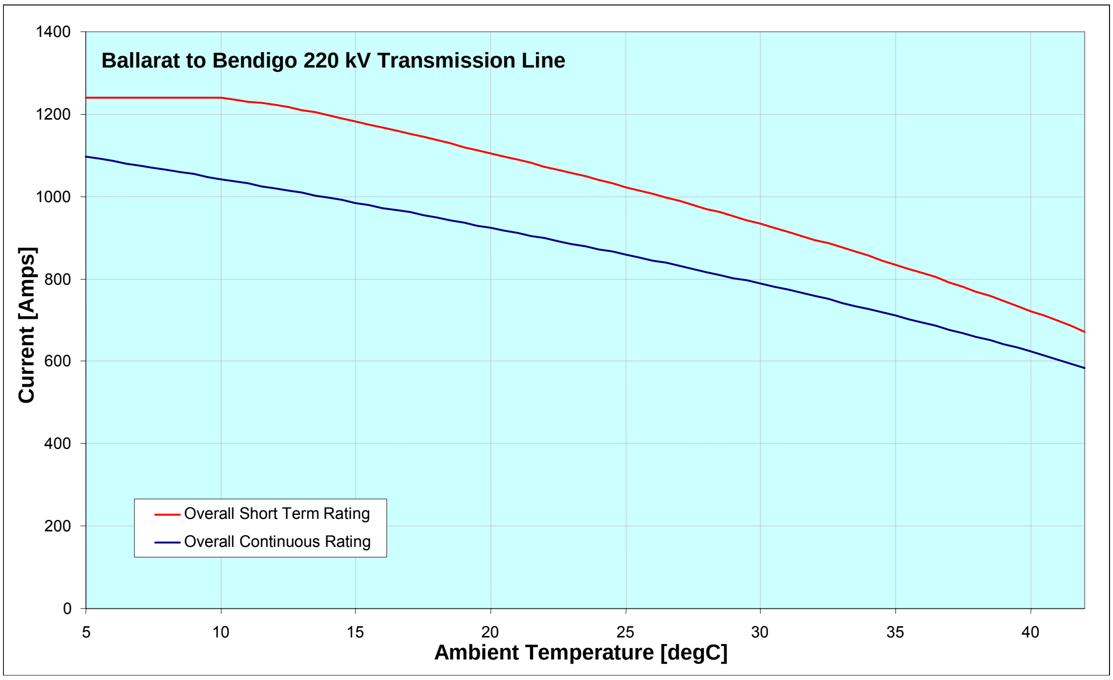


Figure 6.31 – Critical Plant Temperature Ratings

(d) Impacts of Constraint

The Ballarat to Bendigo constraint impacts on system operation under conditions of high ambient temperature (above 35°C) and high load in North West Victoria. The potential impacts of the constraint are as follows:

- A reduction in Victorian export capability to SA over Murraylink or a requirement for Victorian import from SA over Murraylink.
- A reduction in Victorian export capability to Snowy/NSW or a requirement for Victorian import from Snowy/NSW.
- A potential requirement to reduce demand in North West Victoria following trip of the Shepparton to Bendigo circuit.

The impacts of the constraint are directly related to how the constraint is managed. At present, the constraint can be managed as follows:

[43] This is a function of the pre-contingent loading level so ratings presented are to give an idea of typical short term capability.

- Prior to the contingency, constrain Victorian transfer to Snowy/NSW so that post contingent loading on the Ballarat to Bendigo circuit would not exceed the 15 minute rating;
- Following the contingency and where loading exceeds the continuous rating, reschedule Victorian transfer to Snowy/NSW and/or schedule import from SA over Murraylink so that post contingent loading is reduced to continuous rating within 15 minutes. Where residual overload exists after rescheduling, manually reduce load in North West Victoria;
- Following the next credible contingency, loading on the Ballarat to Bendigo circuit is managed by SOCS (automatic load shedding scheme) as defined in Section 6.1.

(e) Impact on Constraint of Distribution Business Planning

Nil.

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-network Impact of Constraint

The sensitivity of Ballarat to Bendigo line loading to variations in inter-regional transfers is <5% of sensitivity to variations in North Western Victorian load. The existing arrangement to reduce Murraylink export does not change. The Ballarat to Bendigo constraint affects Victorian transfer between Snowy/NSW and South Australia, however the requirement to remove the constraint is mainly due to load growth out of Bendigo, Kerang and Red Cliffs.

The constraint is therefore considered to be intra-regional. Any proposed solutions will not impact on existing inter-regional transfer capability. Rather, they will prevent degradation of transfer capability, which would otherwise occur as load in North West Victoria increases.

6.15.2 Do Nothing – Value of Expected Energy at Risk

Market modelling studies have been undertaken to quantify exposure to the Ballarat to Bendigo constraint assuming the constraint is managed as specified in section 6.1.

Table 6.60 identifies the exposure to Victoria to Snowy/NSW rescheduling prior to the contingency and exposure to demand reduction and further rescheduling following the contingency. Expected rescheduling and demand reduction following the contingency are weighted by the probability of the critical line outage occurring (2.002 x10^{-3}). Rescheduling of Victoria to Snowy/NSW transfer is valued at $10/MWh based on comparison of short run marginal costs of base load plant in Victoria and NSW. Demand reduction is valued at $29,600/MWh.

	Unit	2004/05	2006/07	2008/09
Prior To Contingency				
Hours of rescheduling Vic to Snowy transfer	Hours	0	0.8	1.93
Rescheduled Vic to Snowy transfer	MWh	0	40.4	578
Value of rescheduled Vic to Snowy transfer	$K	0	0.404	5.78
After Contingency				
Hours exposed to load shedding	Hours	0	2.47	3.47
Energy at risk in state grid	MWh	0	33.96	101.1
Expected unserved energy	MWh	0	0.068	0.202
Value of Expected unserved Energy	$K	0	2.012	5.99
Hours of rescheduling Vic to Snowy transfer	Hours	0.6	3.33	5.73
Rescheduled Vic to Snowy transfer	MWh	158.6	1926	2766
Expected rescheduled Vic to Snowy transfer	MWh	0.317	3.85	5.54
Value of expected rescheduled transfer	$K	0.003	0.039	0.055
After 2nd Contingency (Controlled by SOCS)				
Hours exposed to load shedding	Hours	105.5	154.3	189.6
Energy at risk in state grid	MWh	4193	7147	9139
Expected unserved energy	MWh	0.083	0.141	0.181
Value of Expected unserved Energy	$K	2.45	4.18	5.35
Value of Expected Energy at Risk				
Total value of rescheduled transfer prior to contingency plus expected unserved energy and rescheduled transfer following contingency	$K	2.45	6.64	17.2

Table 6.60 – Exposure To Moorabool to Ballarat Constraint - Do Nothing

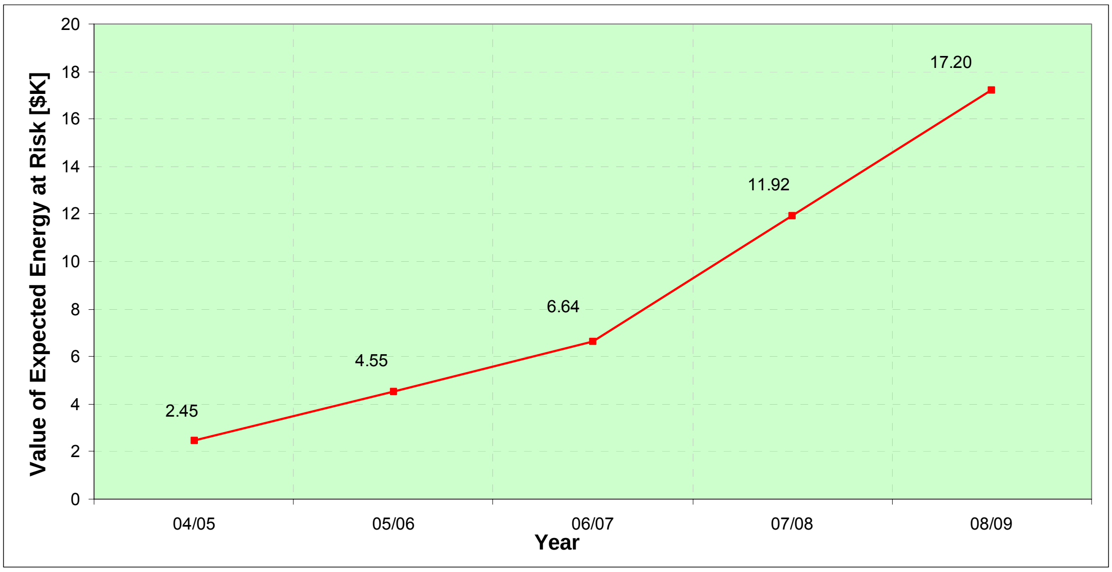


Figure 6.32 – Value of Expected Energy at Risk for Ballarat to Bendigo Constraint (Do Nothing)

6.15.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions have been identified to reduce or remove the Ballarat to Bendigo constraint.

Option 1 – Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used by installing wind monitoring stations at each end of the Ballarat to Bendigo circuit at a cost of around $200 K per station. Total project cost would depend on implementation of wind monitoring on Moorabool to Ballarat circuit. On high ambient temperature days the wind speed is typically higher than 0.6 m/s. A typical wind speed of 1.2m/s would provide a 15~20% increase in line capacity and significantly reduce the overall cost of the constraint. An investigation into wind speed between Ballarat and Bendigo needs to be carried out before implementing this scheme.

Option 2 – Increasing the Capacity of the Ballarat to Bendigo Circuit

The Ballarat to Bendigo circuit is presently rated for operation at up to 65°C conductor temperature. A higher maximum conductor temperature and line rating could be obtained by raising towers on critical spans. Uprating the circuit for 75°C operation would increase the circuit rating by around 25% at 40°C ambient temperature at a cost of around $3.2 M. Uprating the circuit for 82°C operation would increase the circuit rating by around 40% at 40°C ambient temperature at a cost of around $6 M.

(b) Other Options Considered

Nil

(c) Non-Network Options Considered

Nil

6.15.4 Economic Evaluation

As the Value of Expected Energy at Risk for the Ballarat to Bendigo constraint only reaches $17,200 in 2008/09, which is the end of this analysis period, it would only justify around $170,000 capital expense. Economic evaluation of the above options has therefore not been performed. The "Do Nothing" analysis demonstrates that this is only an emerging constraint.

6.15.5 Conclusions

The Ballarat to Bendigo constraint is an emerging constraint caused by increased load in North West Victoria. At this stage implementing a wind monitoring scheme or uprating the circuit are not justified, but as the cost of installing wind monitoring is dependant on other wind monitoring projects, this option will be investigated further.

6.15.6 Recommendation

There is no economic solution for removing this constraint at this stage.

6.16 Loading of Shepparton to Bendigo 220 kV Line

6.16.1 Introduction

(a) Location of Constraint

The constraint is located between Shepparton (SHTS) and Bendigo (BETS) terminal stations in northern Victoria. Geographical and electrical representations of the constraint are given in Figures 6.33 and 6.34 respectively.

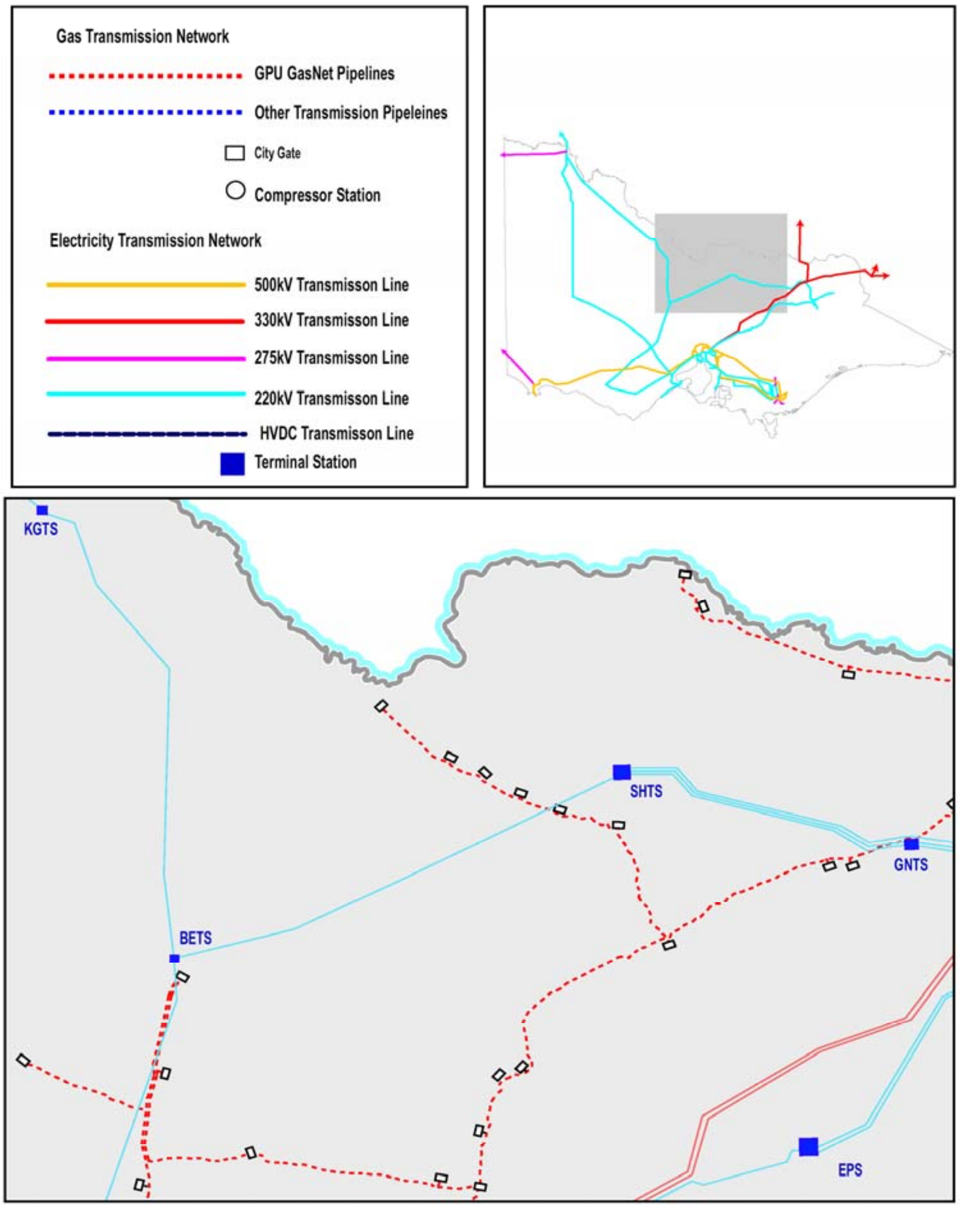
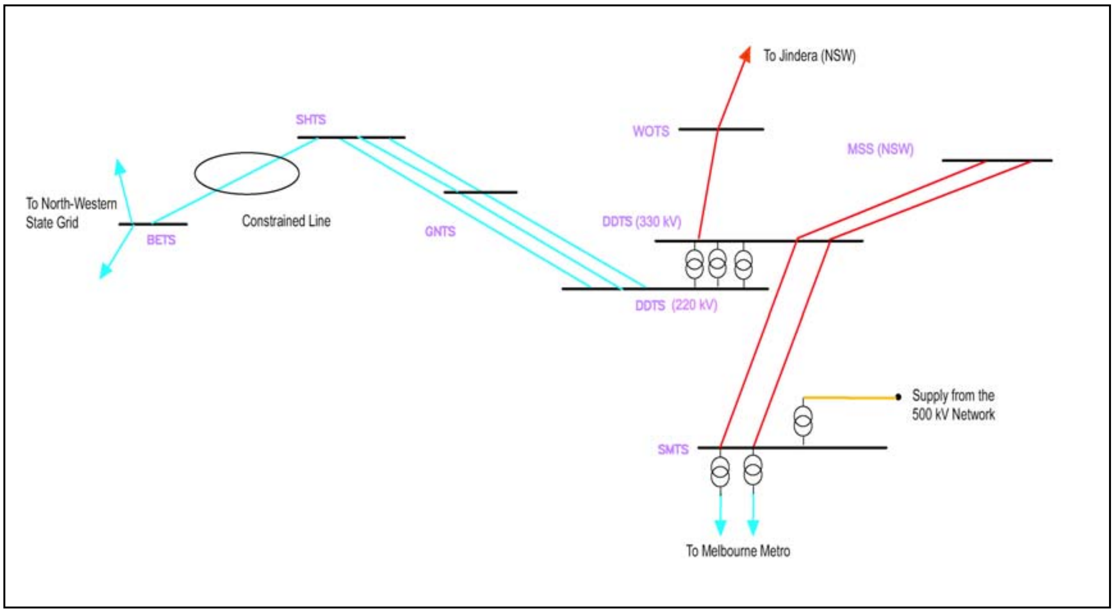


Figure 6.33 - Geographical Representation of the Constraint



Abbreviations: BETS – Bendigo Terminal Station
DDTS – Dederang Terminal Station
GNTS – Glenrowan Terminal Station
MSS – Murray Switching Station
SHTS – Shepparton Terminal Station
SMTS – South Morang Terminal Station
WOTS – Wodonga Terminal Station

Figure 6.34 - Electrical Representation of Constraint

(b) Reason For Constraint

The basis of the constraint is potential loading of the Shepparton to Bendigo 220 kV line beyond its thermal rating. This constraint is emerging because of increasing load in the Victorian state grid at times of high power transfer into Victoria and high ambient temperature. The critical contingency is loss of the Moorabool 500/220 kV transformer or loss of the Darlington Point – Balranald – Buronga 220 kV line in New South Wales.

(c) Conditions of Constraint

Power flow on the Shepparton to Bendigo line can approach thermal capability in a southwest direction from Shepparton to Bendigo. The circuit is continuously rated at 325 MVA at 40°C ambient temperature. The following system loading factors contribute to the Shepparton to Bendigo constraint:

- Victorian state grid load
  Loading on the Shepparton to Bendigo line increases with state grid load.
- Victorian import from Snowy / New South Wales
  Loading on the Shepparton to Bendigo line increases with Victorian import from Snowy/New South Wales.
- Murraylink transfer to South Australia

Loading on the Shepparton to Bendigo line increases with Murraylink transfer to South Australia. However, the impact of Murraylink is limited by a control scheme which reduces Murraylink flow to zero following the critical contingencies for loading on the Shepparton to Bendigo line.

(d) Impacts of Constraint

Based on present system load forecasts, maximum potential loading of the Shepparton to Bendigo line under first contingency conditions will reach the continuous rating at 40^{o}C ambient temperature in 2006/07 and rise to approximately 106% of rating by 2008/09. Overloads can be managed by rescheduling of generation to reduce Victorian import from Snowy/New South Wales or importing from South Australia over Murraylink.

From 2005/06, maximum potential loading of the Shepparton to Bendigo line with all lines in service will exceed 95% of the continuous rating at 40^{o}C ambient temperature. Maximum potential loading will occur under peak Victorian import from Snowy/New South Wales (1,900 MW) and peak Murraylink transfer to South Australia (220 MW). This can be managed by reducing Murraylink transfer to South Australia or Victorian import from Snowy/New South Wales. Murraylink transfer can be reduced automatically using an existing control scheme to detect imminent overload on the Bendigo to Shepparton line.

Augmentation would be required to address the Shepparton to Bendigo constraint as part of any significant upgrade of the Victoria to Snowy/New South Wales interconnection.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

This Shepparton to Bendigo constraint is emerging as a result of increasing load in the Victorian state grid. In the absence of further interconnection augmentations, any works to alleviate this constraint would be to address increasing Victorian load. The solutions would not impact on existing inter-regional transfer capability. Rather, they would prevent degradation of transfer capability over the Victoria to Snowy/New South Wales interconnection and Murraylink, which would otherwise occur as Victorian load increases. Under these circumstances, the solutions are considered not to have a material inter-network impact.

Should the Victoria to Snowy/New South Wales or Murraylink interconnection require upgrading, then the need to address the Shepparton to Bendigo constraint may be increased and/or brought forward to enable any specified increase in transfer capability. The Shepparton to Bendigo constraint, together with any other constraints being alleviated as part of the interconnection upgrade would then be considered to have a material inter-network impact and be addressed in consultation with the Inter-Regional Planning Committee.

6.16.2 Economic Analysis of Constraint

Economic analysis of the Shepparton to Bendigo constraint, including possible major works, would be performed as part of a future proposal to increase capacity of the Victoria to Snowy/New South Wales or Murraylink interconnection.

In the absence of interconnection upgrades, minor works may be justified before 2008/09 (wind monitoring – refer below). A feasibility study is required to determine the feasibility and cost of these works. Economic assessment will be completed following completion of the feasibility study.

6.16.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

The following network solutions have been identified to reduce or remove the Shepparton to Bendigo constraint.

Option 1 - Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used by installing wind monitoring stations at each end of the Shepparton to Bendigo line at a total cost of around $200 K per monitoring station. On high ambient temperature days the wind speed is typically higher than 0.6 m/s. A typical wind speed of 1.2 m/s would provide a 15~20% increase in line capacity and significantly reduce or eliminate the constraint.

A wind survey along the Shepparton to Bendigo line easement needs to be carried out before this scheme could be implemented. Depending on other wind monitoring developments, only one additional monitoring station may be required.

Option 2 - Increasing The Capacity Of The Shepparton to Bendigo Circuit

The Shepparton to Bendigo circuit is presently rated for operation at up to 82°C conductor temperature. Re-tensioning the conductors and/or raising towers would provide a higher maximum conductor temperature and associated line rating. Uprating the circuit for 90°C operation is possible and would increase the circuit rating by around 10% at 40°C ambient temperature at a cost of around $4.7 M. Further uprating would require conductor and tower replacement and be significantly more expensive. Option 2 would not be selected prior to completion of a wind survey and full assessment of wind monitoring.

(b) Other Options Considered

Nil

6.16.4 Conclusions

Major works to alleviate the Shepparton to Bendigo constraint may be justified as part of any proposal to increase the capacity of Murraylink or the Victoria to Snowy/New South Wales interconnection. Should proposals be put forward to upgrade either interconnection, this constraint would be analysed together with other relevant constraints in the process of developing upgrade options.

Minor works (wind monitoring) may be justified before 2008/09 depending on wind survey results.

6.16.5 Recommendation

It is recommended that a wind survey be conducted on the Shepparton to Bendigo line during 2004/05 in conjunction with surveys recommended on other state grid lines. Subsequent installation of wind monitoring equipment may be recommended depending on survey results.

6.17 Loading of Murray to Dederang 330 kV Lines

6.17.1 Introduction

(a) Location of Constraint

The constraint is located between Murray sub station (MSS) in southeast New South Wales and Dederang Terminal Station (DDTS) in northeast Victoria. Geographical and electrical representations of the constraint are given in Figures 6.35 and 6.36 respectively.

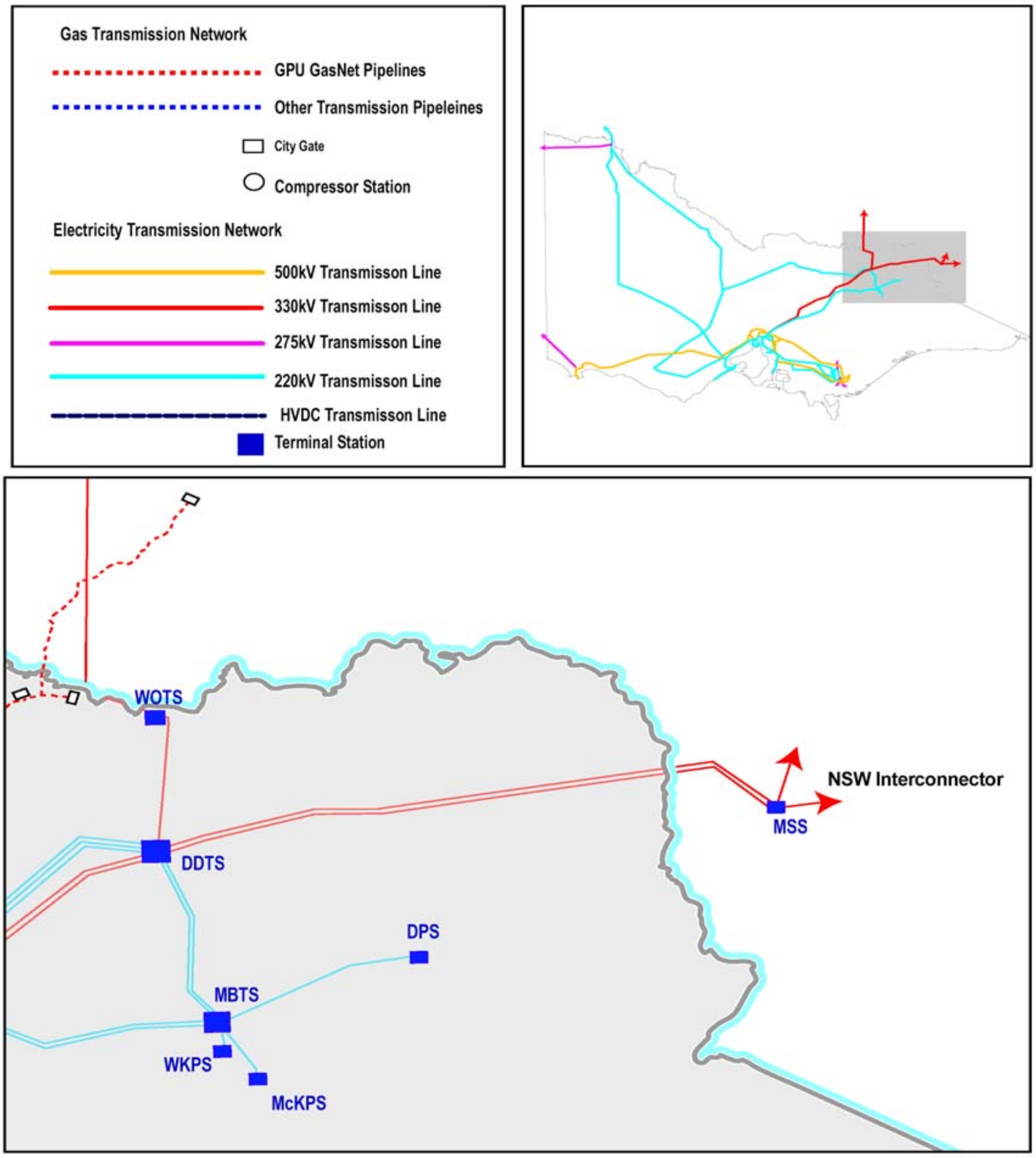
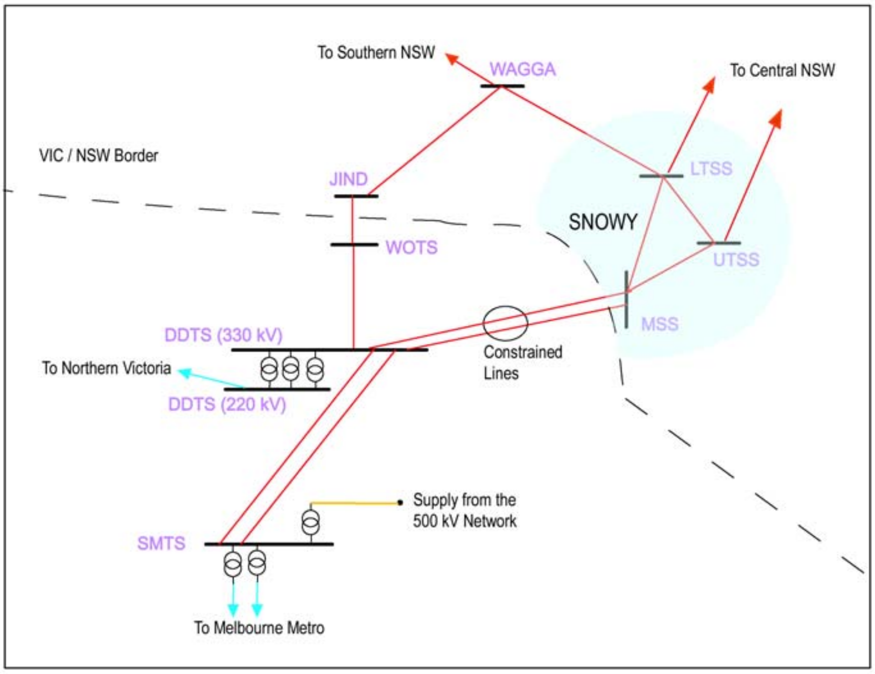


Figure 6.35 – Geographical Representation of the Constraint



Abbreviations:
DDTS – Dederang Terminal Station
JIND – Jindera Switching Station
LTSS – Lower Tumut Switching Station
MSS – Murray Switching Station
SMTS – South Morang Terminal Station
UTSS – Upper Tumut Switching Station
WAGGA – Wagga Switching Station
WOTS – Wodonga Terminal Station

Figure 6.36 - Electrical Representation of Constraint

(b) Reason for Constraint

The basis of the constraint is potential loading of the Murray to Dederang 330 kV lines beyond their thermal capability under post contingent conditions. The constraint exists because of a requirement for high power transfer into Victoria coincident with high load in southern New South Wales and high ambient temperature.

The critical contingency under the majority of system conditions is loss of one Murray to Dederang 330 kV line with the constraint defined by loading on the remaining line. Under high loading conditions in southern New South Wales, the critical contingency can become loss of the Lower Tumut to Wagga 330 kV line, where loading on the two Murray to Dederang lines then defines the constraint.

(c) Conditions of Constraint

Power flow on the Murray to Dederang lines can approach thermal capability in a southwards direction from Murray to Dederang. The two circuits are on separate tower lines and are each continuously rated at 995 MVA at 40^{o}C. A third 330 kV circuit passes from Lower Tumut to Dederang via Wagga, Jindera and Wodonga. This circuit is significantly longer and does not share loading evenly with the Murray to Dederang lines. A control scheme is installed at Dederang to increase utilisation of this circuit following loss of a Murray to Dederang line.

The following system loading factors influence the Murray to Dederang constraint:

- Victorian northern state grid load and Murraylink transfer to South Australia.

  Increasing northern state grid load and Murraylink transfer to South Australia alleviate the constraint by increasing utilisation of the Lower Tumut to Dederang circuits following loss of a Murray to Dederang line and operation of the Dederang control scheme. This results in a higher Victorian import limit as defined by Murray to Dederang line loading for loss of the parallel line.

- Kiewa area and Eildon generation.

  Increasing Kiewa and Eildon generation exacerbates the Murray to Dederang constraint by reducing utilisation of the Lower Tumut to Dederang circuits following loss of a Murray to Dederang line and operation of the Dederang control scheme. This results in a lower Victorian import limit as defined by Murray to Dederang line loading for loss of the parallel line.

- Southwest New South Wales Load

  Increasing southwest New South Wales load exacerbates the Murray to Dederang constraint by diverting power flow on the Lower Tumut to Dederang circuits away from Dederang. This results in a lower Victorian import limit as defined by Murray to Dederang line loading for loss of a Murray to Dederang line or the Lower Tumut to Wagga line.

A Network Control Ancillary Service (NCAS) can be invoked to alleviate the Murray to Dederang constraint under high temperature / high demand conditions where maximum Victorian import is required from Snowy/New South Wales. With NCAS invoked, preselected load is automatically shed in Victoria following detection of an overload above continuous rating on the Murray to Dederang lines.

(d) Impacts of Constraint

All Transmission Plant in Service

The two Murray to Dederang 330 kV lines are major elements of the Victoria to Snowy/New South Wales interconnection. The constraint is a major factor in limiting overall power transfer from Snowy/New South Wales to Victoria. The constraint results in a thermal Victorian import limit from Snowy/New South Wales ranging from approximately 1,600 MW without the NCAS invoked to 1,900 MW with full NCAS (maximum available load selected for post contingent shedding). These import limits apply with all transmission plant in service prior to the contingency.

Prior Outage Conditions

The worst case prior outage affecting the constraint under both import and export conditions is outage of one of the Murray to Dederang lines.

Victorian import from Snowy/New South Wales with the prior outage is between 600 MW and 900 MW depending on load in southern New South Wales. A lower import limit may apply with Snowy generation below around 800 MW. The critical contingency for Victorian import is loss of the remaining Murray to Dederang line.

Victorian export capability is reduced by around 100 MW to 150 MW from normal levels with outage of a Murray to Dederang line. The critical contingency for export is loss of the remaining Murray to Dederang line or a Hazelwood to South Morang 500 kV line.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact of Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

The Murray to Dederang constraint is a major limitation on Victorian transfer from Snowy/New South Wales. Any works to alleviate this constraint are therefore considered to have a material inter-network impact. Analysis of this constraint and development of options for its alleviation or removal will be performed in consultation with the Inter-Regional Planning Committee.

6.17.2 Economic Analysis and Options for Removal of Constraint

The Murray to Dederang constraint will be analysed as part of any future proposal to increase capacity of the Victorian to Snowy/New South Wales interconnection. Options for removal of the Murray to Dederang constraint will be developed and costed in the course of this analysis.

6.17.3 Conclusions

The need to address the Murray to Dederang constraint is tied to the need to upgrade the Victorian to Snowy/New South Wales interconnection. This constraint will be analysed together with several other constraints in the process of developing options to upgrade the interconnection.

6.18 Loading of Dederang to South Morang 330 kV Lines

6.18.1 Introduction

(a) Location of Constraint

The constraint is located between Dederang (DDTS) and South Morang (SMTS) terminal stations. Geographical and electrical representations of the constraint are given in Figures 6.37 and 6.38 respectively.

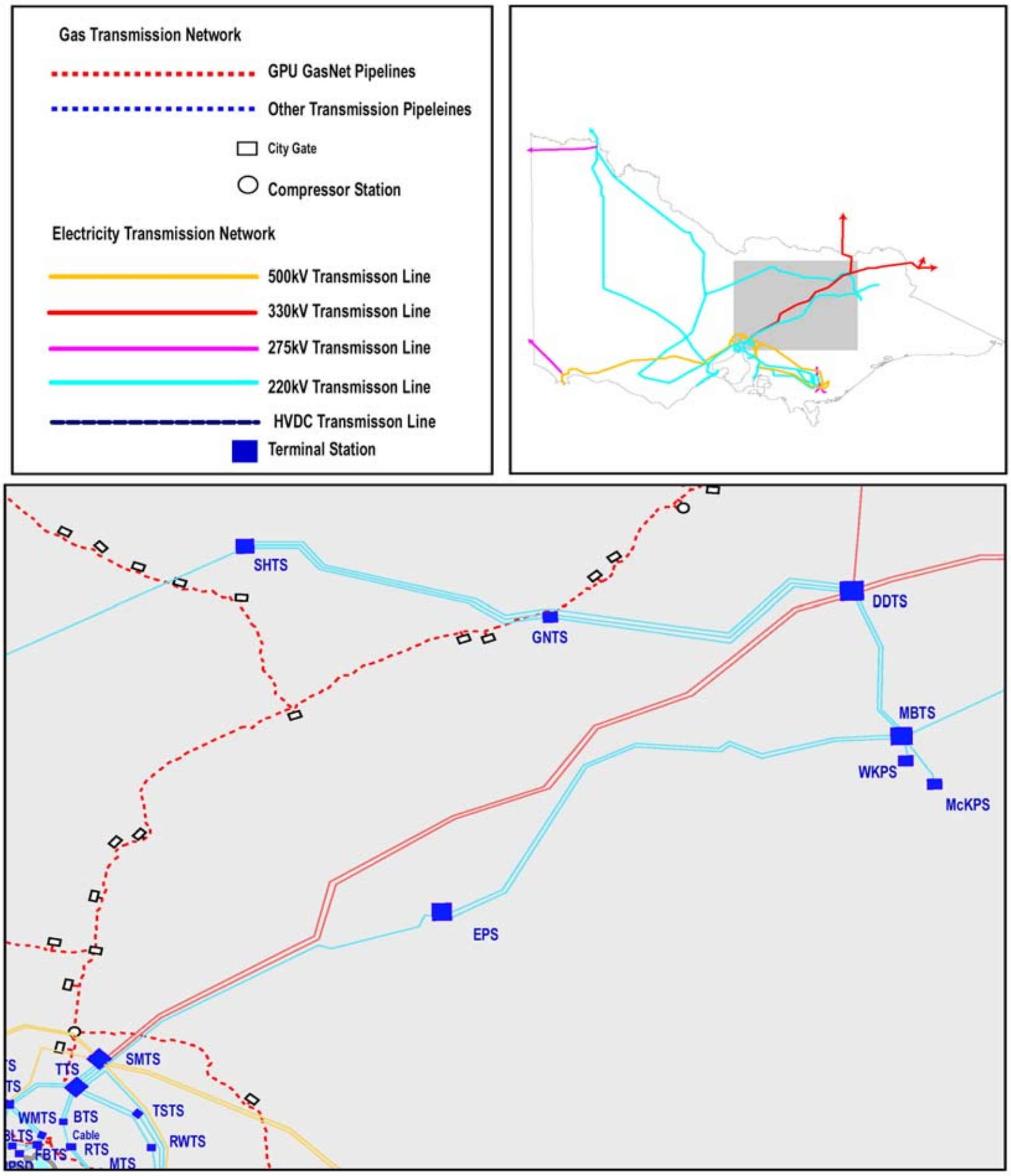
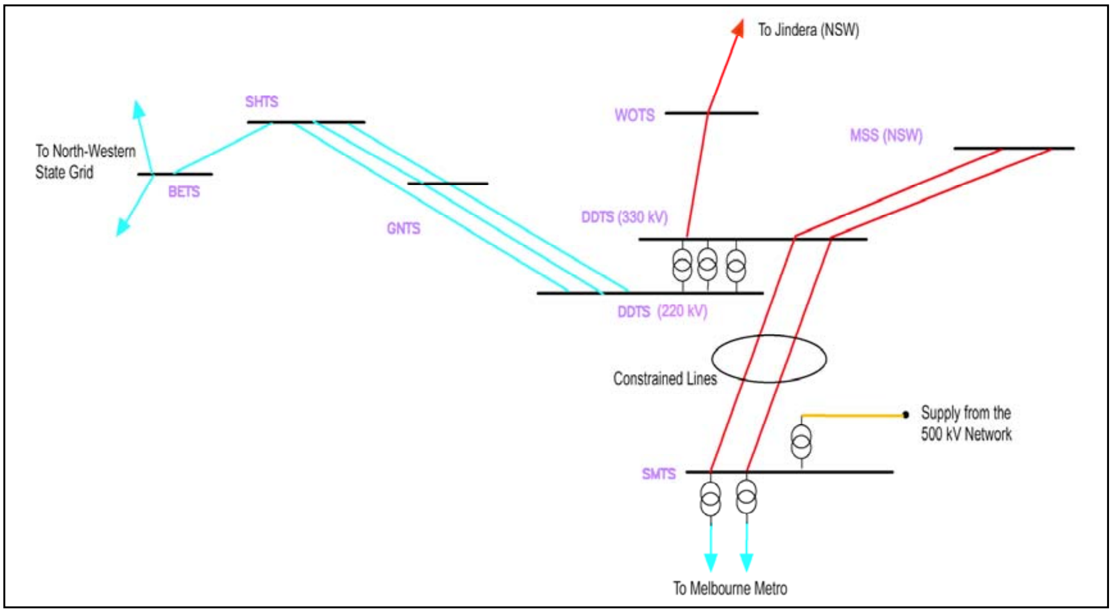


Figure 6.37 - Geographical Representation of the Constraint



Abbreviations: BETS – Bendigo Terminal Station
DDTS – Dederang Terminal Station
GNTS – Glenrowan Terminal Station
MSS – Murray Switching Station
SHTS – Shepparton Terminal Station
SMTS – South Morang Terminal Station
WOTS – Wodonga Terminal Station

Figure 6.38 - Electrical Representation of Constraint

(b) Reason For Constraint

The basis of the constraint is potential loading on the Dederang to South Morang lines beyond their thermal capability under post contingent conditions. The critical contingency is loss of one Dederang to South Morang 330 kV line with the constraint defined by loading on the parallel line. The Dederang to South Morang lines carry a substantial proportion of power flow over the Victoria to Snowy/New South Wales interconnection. Under Victorian export conditions, these lines also support load in the northern Victorian state grid.

(c) Conditions of Constraint

The two Dederang to South Morang circuits are on separate tower lines. A series capacitor bank is installed on each line at South Morang which provides 50% compensation of the line impedance. The continuous MVA rating of each overall circuit at 40°C is defined by the minimum of the line conductor and series capacitor rating as follows:

Series Capacitor	Line Conductor	Overall Circuit
743 MVA	806 MVA	743 MVA

Higher short term ratings are available depending on the timing and extent of action to reduce post contingent loading. Under present operational arrangements, a short term rating of up to 1,000 MVA is available.

Post contingent power flow on the Dederang to South Morang lines can approach thermal capability in either direction. Under Victorian export to Snowy/New South Wales, power flow is from South Morang to Dederang. Principal system loading factors influencing the constraint are as follows:

- Victorian state grid load and Murraylink transfer to South Australia.

  Increasing northern state grid load and Murraylink transfer to South Australia exacerbate the constraint by increasing flow from the 330 kV to 220 kV busbars at Dederang. This results in a lower Victorian export limit as defined by Dederang to South Morang line loading for loss of the parallel line.

- Kiewa area and Eildon generation.

  Increasing Kiewa and Eildon generation alleviates the constraint by reducing flow from the 330 kV to 220 kV busbars at Dederang. This results in a higher Victorian export limit as defined by Dederang to South Morang line loading for loss of the parallel line.

Under Victorian import conditions, power flow is from Dederang to South Morang. The impact of the above system loading factors is reversed as compared to the export case.

A Network Control Ancillary Service (NCAS) can be invoked to alleviate the Dederang to South Morang constraint under high temperature / high demand conditions where maximum Victorian import is required from Snowy/New South Wales. With NCAS invoked, preselected load is automatically shed in Victoria following detection of an overload above continuous rating on the Dederang to South Morang lines.

(d) Impacts of Constraint

The two Dederang to South Morang 330 kV lines are major elements of the Victoria to Snowy/New South Wales interconnection. The constraint can limit power flow in either direction, as summarised below.

Victorian Import from Snowy/New South Wales

Under high temperature / high demand conditions, Victorian import capability is defined by thermal limitations on the Murray to Dederang lines. Under reduced ambient temperature and southern New South Wales load conditions, the Victorian import limit as defined by the Murray to Dederang limit increases above 1,900 MW. Import capability can then be limited to around 2,000 MW by the Dederang to South Morang constraint.

Victorian Export to Snowy/New South Wales

Under the majority of system conditions, Victorian export to Snowy/New South Wales is limited below 1,000 MW by transient stability for a 500 kV line fault between Latrobe Valley and Melbourne. Under certain conditions including Victorian demand below 4,500 MW together with reduced transfer or import from South Australia, Victorian export may be limited between 1,000 MW and 1,150 MW by a Dederang to South Morang thermal or transient stability limit.

At the present stage of system development, the Dederang to South Morang constraint is not the principal constraint for transfer in either direction over the Victoria to Snowy/New South Wales interconnection and its market impacts are relatively minor. However, the constraint would need to be addressed as part of any significant interconnection upgrade.

Impacts Under Prior Outage Conditions

The worst case prior outage affecting the constraint under both import and export conditions is outage of one of the Dederang to South Morang lines. The critical contingency is loss of the remaining line. Victorian import from Snowy/New South Wales with the prior outage is around 1,000 MW to 1,100 MW under favourable generation conditions in the Snowy region (>1,200 MW). Victorian export is limited by transient stability to around 400 MW.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-network Impact of Constraint

The Dederang to South Morang constraint is presently a minor limitation on Victorian transfer to and from Snowy/New South Wales. Any works to alleviate this constraint would form part of a future interconnection upgrade which would be expected to have a material inter-network impact. Analysis of any such upgrade proposal including the Dederang to South Morang constraint would be performed in consultation with the Inter-regional Planning Committee.

6.18.2 Economic Analysis and Options for Removal of Constraint

The Dederang to South Morang constraint will be analysed as part of any future proposal to increase capacity of the Victorian to Snowy/New South Wales interconnection. Options for removal of the Dederang to South Morang constraint will be developed and costed in the course of this analysis.

6.18.3 Conclusions

The need to address the Dederang to South Morang constraint is tied to upgrading the Victorian to Snowy/New South Wales interconnection. This constraint will be analysed together with several other constraints in the process of developing options to upgrade the interconnection.

6.19 Loading of 330 to 220 kV Dederang Tie Transformers

6.19.1 Introduction

(a) Location of Constraint

There are three 330/220 kV transformers in service at Dederang Terminal Station. The constraint is located across these transformers between the 330 kV and 220 kV Dederang busbars. Geographical and electrical representations of the constraint are provided in Figures 6.39 and 6.40.

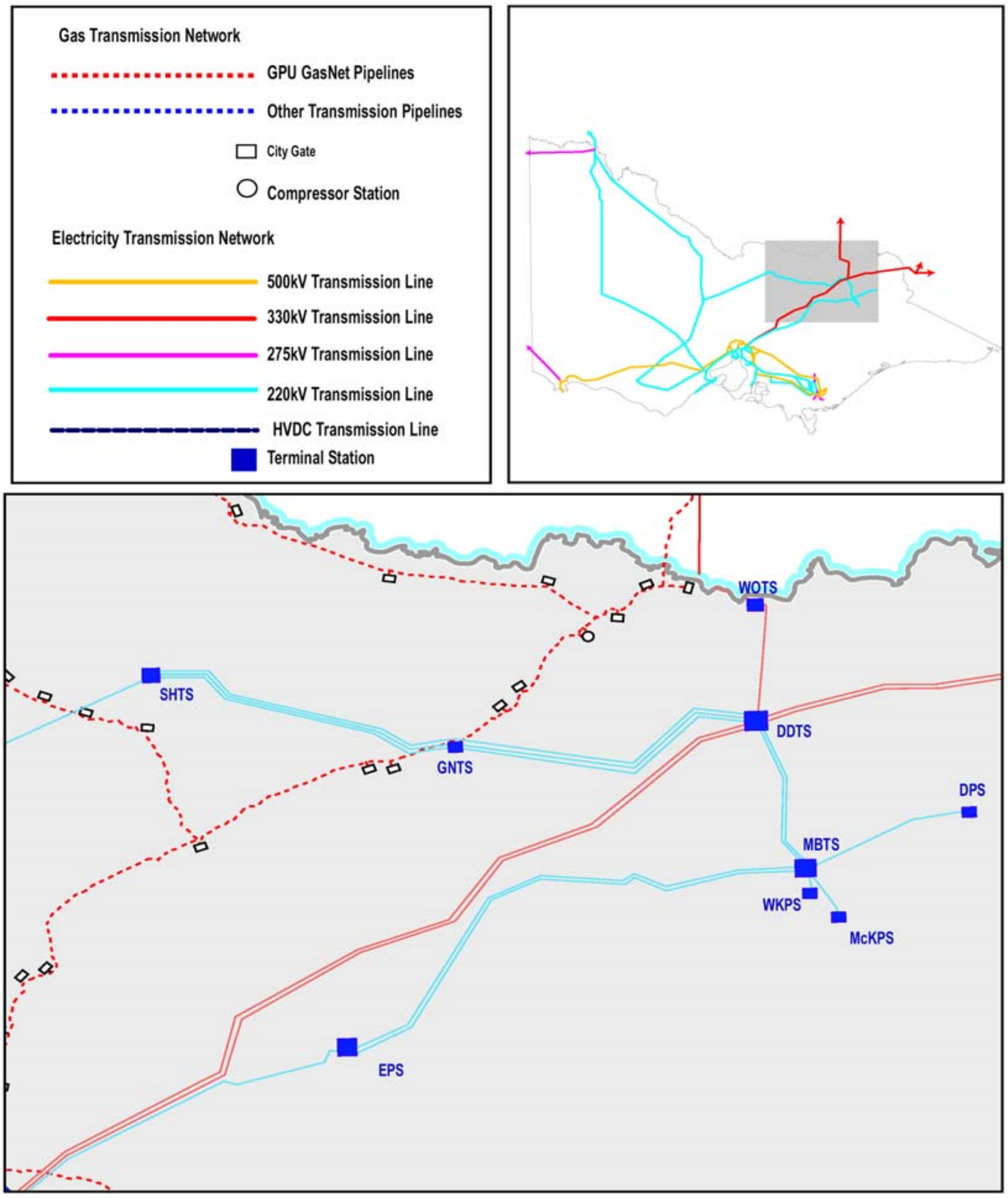


Figure 6.39 - Geographical Representation of the Supply to the Dederang 220kV bus and the Northern State Grid

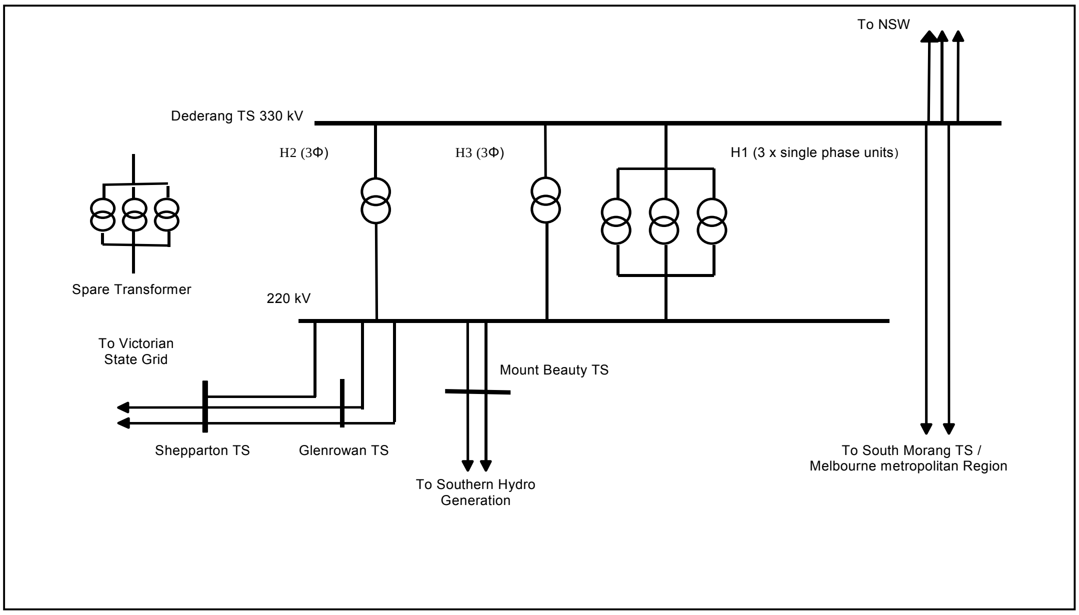


Figure 6.40 - Electrical Representation of the Supply to the Dederang 220 kV bus and the Northern State Grid

Abbreviation:

DDTS – Dederang Terminal Station
MBTS – Mount Beauty Terminal Station
WOTS – Wodonga Terminal Station
GNTS – Glenrowan Terminal Station
WKPS – West Kiewa Power Station
McKPS – McKay Creek Power Station
DPS – Dartmouth Power Station

(b) Reason for Constraint

The basis of the constraint is the thermal capability of the Dederang transformer. The Dederang transformers, and associated 220 kV lines in the state grid support load in the northern state grid area[44] and Melbourne metropolitan load, via a parallel path to the main 330 kV lines which form Victoria's interconnection with the Snowy and NSW regions. Hence, the inter-regional transfer levels between regions strongly influence the loading on the Dederang transformers. Southern Hydro Generation[45] also supports the load in this area.

The loading on the Dederang transformers is forecast to increase as a result of load growth in the northern state grid and Melbourne metropolitan regions. Table 6.61 summarises the 10% and 50% POE demand forecasts up to Summer 2008/09.

[44] Northern stage grid load in this instance refers to Mount Beauty, Glenrowan, Shepparton and Bendigo load.

[45] Southern Hydro Generation refers to Dartmouth, West Kiewa, McKay Creek, and Eildon generation.

Year	POE %	Northern State Grid Demand (MW)	Melbourne Metro Demand (MW)	Total Demand (MW)
2004/05	10	604	5,817	6,421
	50	574	5,527	6,101
2005/06	10	613	6,017	6,630
	50	582	5,717	6,299
2006/07	10	626	6,187	6,813
	50	595	5,878	6,473
2007/08	10	640	6,347	6,987
	50	609	6,029	6,638
2008/09	10	655	6,515	7,170
	50	624	6,187	6,811

Table 6.61 – Maximum Demand Forecasts for Northern State Grid and Melbourne Metropolitan Regions

(c) Conditions of Constraint

The thermal capability of the Dederang transformers is one of the limiting mechanisms on the inter-regional transfer from the Snowy/NSW regions into Victoria. This is particularly the case with the prior outage of one of the transformers. Under system normal conditions, thermal loading of the Dederang transformers is not a significant constraint on Victorian import from Snowy/NSW, provided Southern Hydro Generation is available.

Table 6.62, provides the thermal ratings and relevant data of the constraining plant at Dederang.

Plant	Type / Age	Thermal Rating – continuous	Thermal Rating – short time
Dederang H1 330/220 kV	3 x 1 phase / 1955	225	315 for 20min
Dederang H2 330/220 kV	1 x 3 phase / 2002	340	400 for 20min
Dederang H3 330/220 kV	1 x 3 phase / 1977	240	400 for 20min

Table 6.62 - Thermal Ratings of Dederang Transformers

There is a spare transformer that can be used to reduce the duration of long term forced outages of any of the three in service units. It is of similar vintage to the H1 transformer (1955) and is also rated 225 MVA continuously. It is comprised of three single phase units but due to its age and condition there is no intention to use this set of transformers as a permanent bank. In fact, if there is a failure of an in service single phase unit, this bank will no longer be available as a back up for the 3 phase units and the expected outage time for a major failure of a three phase bank will increase from around 2 weeks to approximately 1 year.

The forced outage rate for H1 is 0.077% and for H2 and H3 it is 0.103%. This is on the basis that there are three single phase transformers and two three phase transformers in service which have failure rates of 1/150 years. The expected duration for any long term forced outage is 2 weeks for H1 and 4 weeks for H2 or H3 on the basis the spare transformer can be installed within this time frame.

At this stage of development with the VIC-NSW interconnection, the constraint only binds for a prior outage of a Dederang transformer.

(d) Impacts of Constraint

To assess the impact of the Dederang transformer constraint, two simplified variations of the existing prior outage constraint equation have been modelled[46]. The existing constraint is currently modelled in the National Electricity Market Dispatch Engine and would be invoked within 20 minutes of loss of a Dederang transformer.

The first constraint identified considers the prior outage of either H2 or H3 units, then the loss of the remaining unit, and consequential post contingent loading of the H1 unit. The constraint is defined by ensuring the flow on H1 is within its short term rating after a subsequent forced transformer outage. The import is limited by post contingent loading and energy is at risk for this worst case scenario considering H1 has the lowest short term and continuous rating.

The second constraint identified considers the prior outage of H1, then the loss of either H2 or H3, and consequential post contingent loading of the remaining H2 or H3 unit. The constraint is defined by ensuring the flow on H2 or H3 is within its short term rating after a subsequent forced transformer outage. The import is limited by post contingent loading and energy is at risk for this scenario, although not as much as the first constraint considering H2 and H3 both have the highest short term rating.

The impact of this prior outage constraint and ultimately Victoria's import capability is sensitive to Southern Hydro Generation. Under conditions where no Southern Hydro Generation is available Victoria's import capability can be reduced to around 100 MW if one of the transformers is unavailable. With most of Southern Hydro Generation dispatched, the import limit would be substantially increased to around 1,200 MW. This variability has been considered in the Monte Carlo studies by applying Forced Outage Rates for hydro units at around 1%.

6.19.2 Do Nothing – Value of Expected Energy at Risk

Table 6.63 summarises VENCorp's forecast of the expected value of the energy at risk due to a Dederang transformer outage for the existing configuration, with a Value of Customer Reliability of $29.6 K applied. The results from the two constraints have been combined together and weighted to provide the 'Expected' results. For this constraint, generation is rescheduled so as to decrease Victorian import from Snowy / NSW. The value of the rescheduled generation is under these circumstances; the strike marginal price (SMP) difference in Victoria multiplied by the rescheduled generation between the system normal and prior outage scenarios. Additionally the value of the unserved energy is the load shed multiplied by $29.6 K.

[46] Equation P7 is the prior outage of a Dederang transformer from section VE-M in Transfer limits Manual, which is published on VENCorp's website.

Year	Unit	2004/05	2005/06	2006/07	2007/08	2008/09
Maximum Hours of Constraint[47]	Hours	2,827	2,811	2,795	2,769	2,743
Maximum Single Constraint	MW	1,541	1,543	1,545	1,633	1,721
Average Constraint	MW	146	131	116	115	114
Rescheduled Generation	MWh	1,649,095	1,692,783	1,736,471	1,680,087	1,623,703
Value of Rescheduled Generation	$K	35,077	33,130	31,183	35,529	39,875
Unserved Energy	MWh	1,250	1,021	792	1,035	1,279
Value of Unserved Energy	$K	37,003	30,219	23,435	30,644	37,853
Value of Energy at Risk	$K	72,080	63,349	54,618	66,174	77,729
Expected Value of Energy at Risk	$K	70	62	54	66	77

Table 6.63 – Expected Value of Energy at Risk for Dederang Transformer Outage

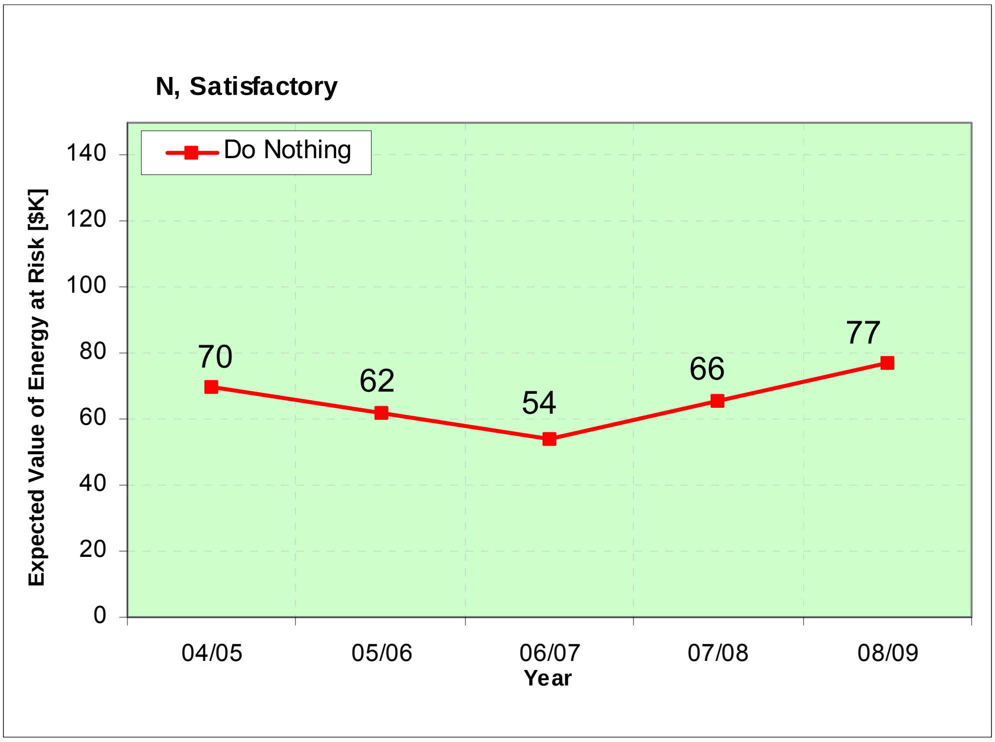


Figure 6.41 – Do Nothing Constraint Costs

47 As expected the maximum hours of constraint in each of the financial years was shown to be with the prior outage of H2 or H3, consequential loss of H2 or H3, and post contingent loading of H1, which has the lowest thermal rating.

6.19.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

A number of network solutions have been identified to reduce or remove the constraint through the Dederang transformers. They include:

Option 1

Modification of the DBUSS control scheme[48] to operate with prior outage of a transformer. Expected capital cost of around $100 K.

Option 2

Installation of a fourth 330/220 kV Dederang transformer, while maintaining the existing spare, and associated fault level mitigation. Expected capital cost of around $9 M.

(b) Non-Network Options Considered

Generation or DSM on the 220 kV side of the Dederang transformers plays a significant role in the inter-regional constraint equations, as indicated in 6.18.1.d. An increase in generation in the Kiewa region[49] increases the import capability considerably in a ratio of about 1:3. Hence one other option could be a support contract with Southern Hydro Generation to ensure they are available and would provide the required generation at the appropriate times.

6.19.4 Economic Evaluation

Option 1

To assess the impact of modifying the DBUSS control scheme, which will ensure operation for prior outage conditions, two simplified variations of the system normal equation have been modelled[50]. Effectively the continuous rating has been substituted for the short term rating in this modified equation for pre-contingent loading.

The first constraint identified considers the prior outage of either H2 or H3 units, and then the pre-contingent loading of the H1 unit while DBUSS is activated. The constraint is defined by ensuring the flow on H1 within its continuous rating before a forced transformer outage. Pre-contingent load at risk for this worst case scenario is about 80% lower than without the DBUSS modification.

The second constraint identified considers the prior outage of the H1 unit, then the pre-contingent loading of the H3 unit while DBUSS is activated. The constraint is defined by ensuring the flow on H3 is within its continuous rating before a forced transformer outage. Pre-contingent load at risk for this scenario is about 15% lower than without the DBUSS modification.

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48 DBUSS is an existing scheme at Dederang which reduces loading on the remaining two transformers after loss of one transformer. The scheme presently operates only when all three transformers are initially in service.

49 Includes generation at West Kiewa, Dartmouth and McKay Creek.

50 Equation T4 is the system normal equation for loading of the Dederang transformers from the Transfer Limits Manual (section VE-M), which is published on VENCorp's website.

Figure 6.43 shows VENCorp's forecast of the impact due to a Dederang transformer outage for the existing configuration with Option 1 implemented. This option reduces the severity of the constraint on import but does not eliminate it.

Option 2

The installation of a fourth 330/220 kV Dederang transformer will effectively eliminate the constraint in the short and medium term as seen in Figure 6.42.

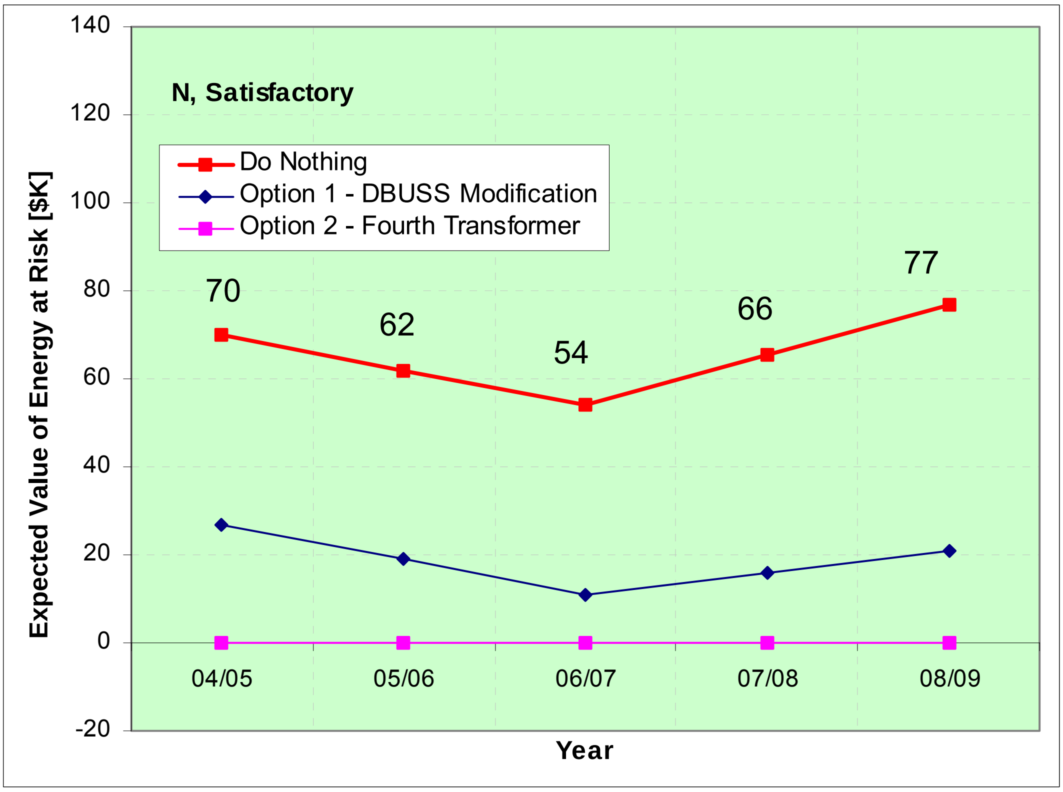


Figure 6.42 – Options for Reduction and Removal of Constraint

(c) Summary of Net Benefits and Present Values Going Forward

A net market benefit assessment is carried out for a 5-year period for each of the network options using a discount rate of 8% to calculate the PV.

Option	Present Value 30 Year Life		Annualised Value All Values $K					Residual Value Remaining 25 Years
			2004/05	2005/06	2006/07	2007/08	2008/09	
Do Nothing	-821		-70	-62	-54	-66	-77	-559
Option 1 (DBUSS Modification)	593	Benefit	43	43	43	50	56	407
	-102	Equiv Annual Cost	-9	-9	-9	-9	-9	-66
	491	Net Benefit	34	34	34	41	47	341
Option 2a (Installation of a new 330/220 kV transformer)	821	Benefit	70	62	54	66	77	559
	-9,135	Equiv Annual Cost	-811	-811	-811	-811	-811	-5,895
	-8,314	Net Benefit	-741	-749	-757	-745	-734	-5,336

Table 6.64 – Reduction in Constraint Costs due to Network Augmentations

(d) Ranking of Options

Options	NPV	Ranking
Option 1, DBUSS modification for prior outage conditions ($ K)	491	1
Option 2, Installation of a new 330/220 kV transformer at Dederang ($ K)	Not applicable as the value is negative.	-

Table 6.65 – Ranking of Options

(e) Timing of Network Solution

Option 1 maximises the net benefit. Optimal timing for option 1 is Summer 2004/05.

6.19.5 Conclusions

Option No.1 is economically justified based on a probabilistic assessment. The augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios.

Option No. 2 is not economically justified until after 2008/09. Although, if a major interconnection upgrade were commissioned, such as NEWVIC, then a fourth Dederang transformer would be required as part of the network augmentations. Additionally if a prolonged drought period were to reduce the generation capacity of Southern Hydro this will bring forward the need for a fourth Dederang transformer.

(f) Material Inter-Network Impact of Constraint

This project does not alter the maximum transfer level but makes the transfer less sensitive to local load and generation conditions for prior outage of one Dederang transformer. It does not impose additional power transfer constraints or quality of supply impacts on neighbouring Transmission Network Service Providers networks. On this basis VENCorp does not believe that the proposed augmentation has a material inter-network impact.

(g) Reliability of Market Augmentation

This augmentation satisfies the regulatory test because it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. This augmentation is not a reliability augmentation.

6.19.6 Recommendation

Option 1 is recommended with an indicative cost of approximately $100 K and timing of December 2004. Project identifier code (M04-09).

6.20 Loading of Eildon to Thomastown 220 kV Line

6.20.1 Introduction

(a) Location of Constraint

The constraint is located between Eildon (EPS) and Thomastown (TTS) terminal stations. Geographical and electrical representations of the constraint are given in Figures 6.43 and 6.44 respectively.

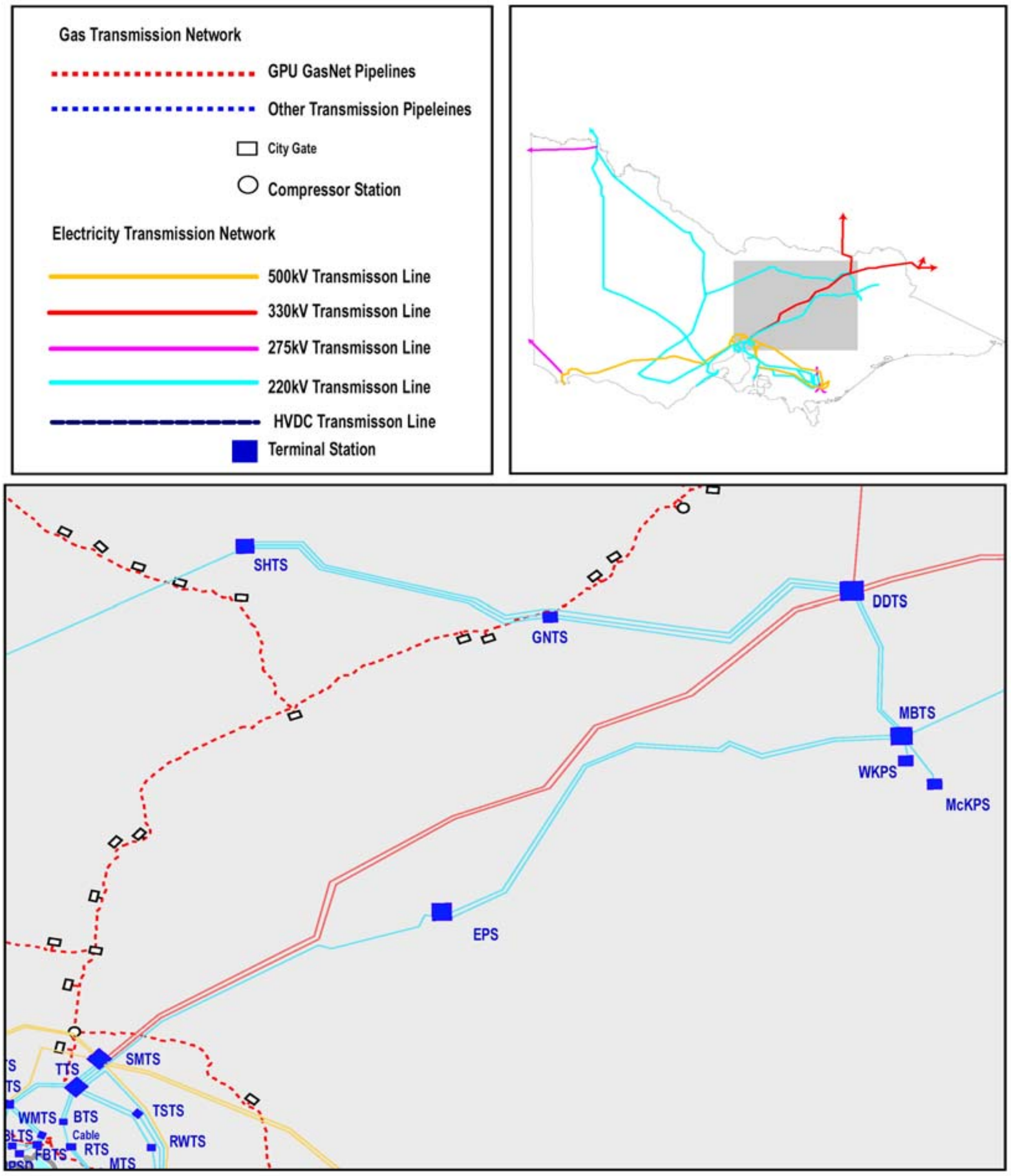
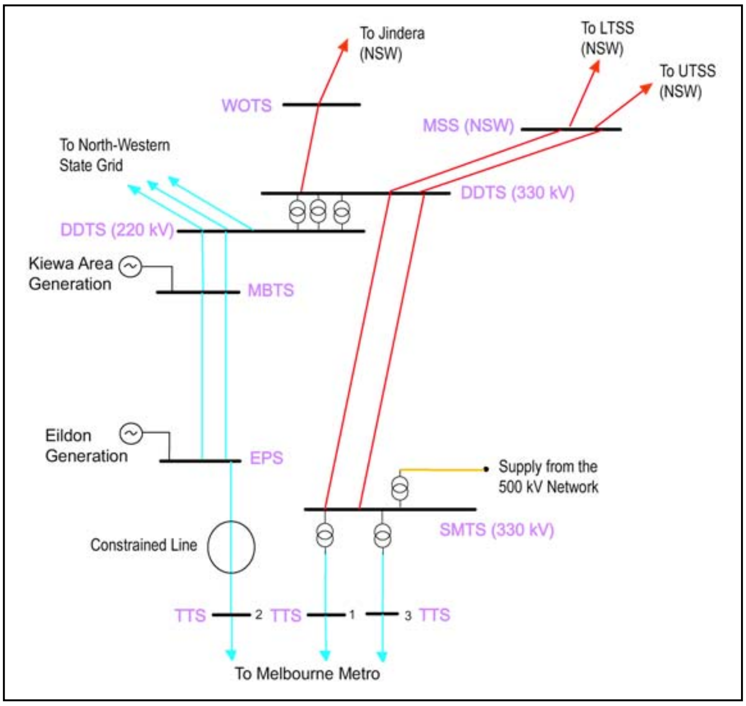


Figure 6.43 - Geographical Representation of the Constraint



Abbreviations: DDTS – Dederang Terminal Station
EPS – Eildon Power Station
MSS – Murray Switching Station
MBTS – Mount Beauty Terminal Station
SMTS – South Morang Terminal Station
TTS – Thomastown Terminal Station
WOTS – Wodonga Terminal Station

Figure 6.44 - Electrical Representation of Constraint

(b) Reason for Constraint

The basis of the constraint is potential loading on the Eildon to Thomastown line beyond its thermal capability under post contingent conditions. The critical contingency is loss of one Dederang to South Morang 330 kV line. The Eildon to Thomastown line forms part of the Victoria to Snowy/New South Wales interconnection. Under Victorian export conditions, this line also supports load in the northern Victorian state grid.

(c) Conditions of Constraint

The Eildon to Thomastown line consists of two paralleled circuits on a double circuit tower line. The continuous MVA rating of the combined circuit at 40°C ambient temperature is 459 MVA.

Higher short term ratings are available depending on the timing and extent of action to reduce post contingent loading.

Post contingent power flow on the Eildon to Thomastown line can approach thermal capability under high Victorian import from Snowy/New South Wales and high ambient temperature. Principal system loading factors influencing the constraint are as follows:

- Victorian state grid load and Murraylink transfer to South Australia.

  Increasing northern state grid load and Murraylink transfer to South Australia alleviates the constraint by diverting power into the Victorian state grid via Glenrowan and Shepparton and away from the Eildon to Thomastown line. This results in a higher Victorian import limit as defined by Eildon to Thomastown line loading.

- Kiewa area and Eildon generation.

  Increasing Kiewa and Eildon generation exacerbates the constraint by increasing southward flow on the Mount Beauty to Eildon to Thomastown lines. This results in a lower Victorian import limit as defined by Eildon to Thomastown line loading.

(d) Impacts of Constraint

The Eildon to Thomastown line forms part of the Victoria to Snowy/New South Wales interconnection. The constraint can potentially limit Victorian import to around 2,080 MW with all transmission plant in service. At the present stage of system development, this is above the maximum limit imposed by other constraints including the principal Murray to Dederang constraint. However, the constraint would need to be addressed as part of any significant interconnection upgrade.

(e) Impact on Constraint of Distribution Business Planning

Nil

(f) Impact on Constraint of Asset Replacement Program

Nil

(g) Material Inter-Network Impact of Constraint

The Eildon to Thomastown constraint is not presently a limitation on Victorian transfer to or from Snowy/New South Wales with all transmission plant in service. Works to alleviate this constraint may form part of a future interconnection upgrade, which would be expected to have a material inter-network impact. Analysis of any such upgrade proposal including the Eildon to Thomastown constraint would be performed in consultation with the Inter-Regional Planning Committee.

6.20.2 Economic Analysis of Constraint

Economic analysis of the Eildon to Thomastown constraint would be performed as part of a future proposal to increase capacity of the Victoria to Snowy/New South Wales interconnection.

6.20.3 Options and Costs for Removal of Constraint

(a) Network Options Considered

Two network solutions have been identified to alleviate the Eildon to Thomastown constraint sufficiently to allow an augmentation of the Victoria to Snowy/New South Wales interconnection of between 400 MW and 600 MW. Each provides a potential increase in line rating of approximately 80 MVA at 40^{o}C ambient temperature.

Option 1 - Wind Monitoring Scheme

By default, a fixed wind speed of 0.6 m/s is used in the calculation of conductor thermal limits. Actual wind speed could be used by installing wind monitoring stations at each end of the Eildon to Thomastown line at a total cost of around $200 K per monitoring station. On high ambient temperature days the wind speed is typically higher than 0.6 m/s. A typical wind speed of 1.2 m/s would provide an increase in line capacity of approximately 80 MVA at 40°C ambient temperature.

Prior to implementing this scheme, a wind survey along the Eildon to Thomastown line easement needs to be carried out to enable full assessment of probable wind speed.

Option 2 - Increasing the Capacity of the Eildon to Thomastown Line

The Eildon to Thomastown line is presently rated for operation at up to 65°C conductor temperature. Re-tensioning the conductors and/or raising towers would provide a higher maximum conductor temperature and associated line rating. Uprating the line to 73°C operation would increase capacity by approximately 80 MVA at 40°C ambient temperature.

6.20.4 Conclusions

The need to address the Eildon to Thomastown constraint is tied to upgrading the Victorian to Snowy/New South Wales interconnection. This constraint will be analysed together with several other constraints in the process of developing options to upgrade the interconnection.

6.20.5 Recommendation

In the absence of interconnection augmentations, augmentation of the Eildon to Thomastown line is not justified within the next four years. However, it is recommended that a wind survey be conducted during 2004/05 to determine the feasibility of wind monitoring on this line. This could be performed in conjunction with wind surveys recommended in the same timeframe for other state grid lines.

6.21 Reactive Support for Maximum Demand Conditions

6.21.1 Introduction

(a) Location Of Constraint

Adequate reactive power support at appropriate locations in the Victorian transmission network is required to meet increased load growth, transfer power across the network and maintain the system voltage stability. Potential constraint locations are the Melbourne metropolitan area, Victorian State Grid and Victorian to NSW interconnector. Figure 6.45 shows the map of the Victorian Transmission Network.

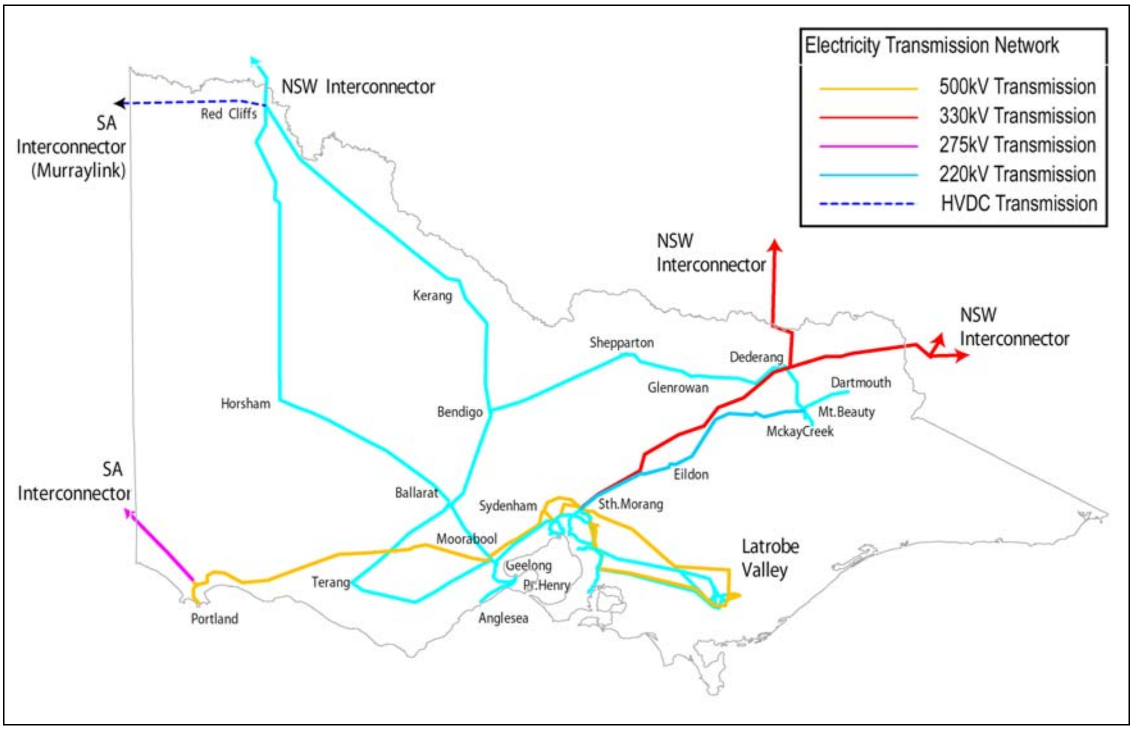


Figure 6.46 - Map of Victorian Transmission Network

(b) Reason for Constraint

In order to maintain a satisfactory operating state, following the most severe credible contingency event, the voltage stability of the power system must be maintained. The consequence of not having adequate reactive support is a potential system wide voltage collapse resulting in loss of load. The Victorian demand is forecasted to increase as shown in Table 6.66. The system maximum demand due to voltage collapse limit (network reactive capability) for Summer 2004/05 is 9,885 MW. Additional reactive power support required to meet the increased demand forecast and to maintain the voltage stability following the most critical contingency.

Summer	90% Probability of Exceedence	50% Probability of Exceedence	10% Probability of Exceedence
2004/05	8,432	8,997	9,787
2005/06	8,734	9,274	10,103
2006/07	8,947	9,509	10,373
2007/08	9,140	9,725	10,621
2008/09	9,373	9,981	10,913

Table 6.66 - Summer Maximum Demand Forecasts (medium growth)

The critical contingences are:

- Outage of the 500 MW generator at Newport;
- Outage of a 500 kV line from Latrobe Valley to Melbourne;
- Outage of a Murray to Dederang 330 kV line;
- Outage of a Dederang to South Morang 330 kV line;
- Outage of the Moorabool transformer;
- Outage of 220 kV line in north-west Victoria; and
- Outage of the Basslink 600 MW import (following commissioning of Basslink).

(c) Network Reactive Capability

The Victorian network reactive capability is assessed on the basis of forecasted Victorian MW demand and available MW supply. The Victorian supply is considered as a total of the existing and committed generators in Victoria, 1,900[51] MW import from Vic-NSW inter-connector and 600 MW import from planned Vic-Tasmania interconnector (target service date November 2005). Export to South Australia is reduced to meet the Victorian 10% POE forecast demand from the total supply to Victoria. Table 6.67 provides the demand forecast and import and export levels used in the network assessment.

[51] Import from NSW to Victoria limited to 1,885 MW for low Murraylink transfer. However, with 100 MW on Murraylink to South Australia, 1,900 MW import from NSW to Victoria is possible.

Year	Forecast Demand (10% Probability of Exceedence)	Import from NSW	Import from Tasmania	Export to South Australia
2004/05	9,787 MW	1,900 MW	0	416 MW
2005/06	10,103 MW	1,900 MW	600 MW	739 MW
2006/07	10,373 MW	1,900 MW	600 MW	485 MW
2007/08	10,621 MW	1,900 MW	600 MW	248 MW
2008/09	10,913 MW	1,900 MW	600 MW	-35 MW

Table 6.67 - Interconnector Transfer Levels for the Network Reactive Capability Assessment

As part of Murraylink Regulation Project, a total of 290 MVAr switched shunt capacitor banks are planned to be added to the Victorian State Grid area and modifications to the very fast run-back of Murraylink for transmission outages by mid 2005. The shunt capacitor banks to be added are:

- 1x150 MVAr, 220 kV at Moorabool Terminal Station;
- 2x40 MVAr, 220 kV at Red Cliffs Terminal Station;
- 2x15 MVAr, 66 kV at Horsham Terminal Station; and
- 2x15 MVAr, 66 kV at Kerang Terminal Station.

Following service of the Murraylink regulation project, the network reactive capability would be increased. Table 6.68 provides the network reactive capability for the next 5 years.

Year	Forecast Demand (10% Probability of Exceedence)	Network Reactive Capability
2004/05	9,787 MW	9,885 MW
2005/06	10,103 MW	10,110 MW
2006/07	10,373 MW	10,285 MW
2007/08	10,621 MW	10,425 MW
2008/09	10,913 MW	10,570 MW

Table 6.68 - Network Reactive Capability for 2004/05-2008/09

(d) Impact on Constraint of Distribution Business Planning

The power factor at the point of connection is based on the data provided by Distribution Businesses and customers directly connected with the transmission system. If Distribution Businesses install additional capacitor banks and/or reduce the reactive load, the power factor at the point of connection will improve. In addition, when additional transformers installed at the terminal station reactive losses will decrease. These actions will increase network reactive capability and reduce the amount of additional reactive support at transmission level.

6.21.2 Network Solutions

The following network solutions can increase the network reactive capability:

- Installation of shunt and/or series capacitors at transmission level

  Space availability in existing terminal stations is becoming an issue when considering the placement of new shunt capacitor banks. This has the potential to increase the cost of capacitors at high voltage levels. Furthermore, shunt capacitors produce a harmonic resonance, the frequency of which has to be controlled by designing an appropriate series reactor with each capacitor bank. The issue of harmonic resonance is requiring increasingly more detailed technical analysis and this is also tending to increase the reactive augmentation costs, as larger series reactors are needed.

  The continued installation of large capacitor banks combined with the improvement of Distribution Businesses/Customers power factor may lead to problems with local voltage control and this may further limit the use of large shunt capacitor banks.

- Installation of shunt capacitors by Distribution Businesses.

- Under-voltage load shedding scheme – this can increase the network reactive capability before a contingency but will not avoid load shedding following a contingency.

The existing level of dynamic reactive plant is considered adequate. VENCorp has undertaken a strategic review of reactive support to identify the long-term need for the static/dynamic reactive support to the network.

6.21.3 Non-network Solutions

The following non-network solutions can also increase the networks reactive capability or contain the maximum demand within the network reactive capability:

- Power factor correction by customers – this will be reflected in Distribution Businesses annual load forecast at each point of connection;

- New generators in the Metropolitan and/or state grid areas;

- Ancillary services arrangements; and

- Demand side management.

6.21.4 Preferred Solution

No reactive support augmentations are needed prior to Summer 2006/07. Future requirements will be continuously reviewed with the latest load forecast and power factor improvement at the points of connection.

7. INTRA-REGIONAL POSSIBLE NETWORK DEVELOPMENTS WITHIN 10 YEARS

The intention of this section is to give an indication of potential network constraints that may occur in the period up to 2013/14, together with transmission options to remove the constraints, assuming the full forecast Victorian demand is to be supported.

For this study the network has been modelled with a demand of 12,350 MW. Assuming 300 MW export to South Australia, 1,900 MW import from NSW, 600 MW import from Tasmania and 265 MW Victorian local reserve[52] requirement, approximately 2,050 MW of new generation capacity will need to be added by 2013/14. As the location and size of generation will impact on the transmission needs, a range of supply scenarios, which load up different parts of the network, have been examined. These are as shown in Table 7.1.

	Increased LV Gen	Increased Import from NSW/Snowy	Metro Generation/DSM
Scenario 1	1,450 MW	0 MW	600 MW
Scenario 2	1,270 MW	180 MW	600 MW
Scenario 3	670 MW	180 MW	1,200 MW
Scenario 4	850 MW	600 MW	600 MW
Scenario 5	1,150 MW	600 MW	300 MW
Scenario 6	150 MW	1,600 MW	300 MW

Table 7.1 - Supply Scenarios for 10-year Outlook

In considering this period, the network constraints and solutions outlined for the period up to 2008/09, and described earlier in this chapter, are included. For the constraints beyond this period a probabilistic analysis of the amount of energy at risk due to these network constraints has not been undertaken so the timing is only indicative and would be confirmed by full economic assessment closer to the requirement.

7.1 Increased Latrobe Valley Generation

In the case of the Latrobe Valley, it is assumed that all 1,450 MW can be made available to the market. This 1,450 MW generation is in addition to 600 MW import from Basslink. As described earlier, the Hazelwood Terminal Station transformers are a limit on the dispatch of generation at 220 kV and until this limit is removed the addition of further generation connected at the 220 kV in the Latrobe Valley will not add to the supportable demand. There are a number of proposals of wind generation in the Latrobe Valley area which would fall into this category. These wind generators can provide energy support but would not increase the capacity support. The additional generation is assumed to be from gas fired plant and/or new technologyl brown coal plant.

7.2 Metropolitan Generation/ Demand Side Management

The effect of generation or significant demand side management within the metropolitan area is modelled by including new generation on the 220 kV network at Moorabool, Keilor, and Rowville

52 Victoria and South Australia combined regional reserve requirement is 530 MW

areas, which have coincidence of adequate gas and electricity infrastructure and possible environmentally suitable locations for gas fired generation. The actual timing and location of any new embedded generation or large scale demand side management may have a significant impact on the timing and nature of any transmission augmentations. The locations selected are representative of possible locations, and should provide an indication of the effects of this new generation. Based on the interest shown in recent times an amount of 600 MW has been assumed, with sensitivity checked for 300 MW and 1,200 MW.

7.3 Increased Import

The import level considered is in addition to the current import level of 1900 MW from NSW. Joint planning between VENCorp and TransGrid has identified an initial outline of works required to increase the import capability into the Victorian/SA region to 2,080 MW, 2,500 MW and 3,500 MW, and these works form the basis of the 180 MW, 600 MW and 1,600 MW increase in import applied in the scenario studies.

These scenarios were selected because they give a reasonable extreme for the transmission system. However, a range of other scenarios are possible, and they are likely to result in different transmission requirements.

7.4 Summary of Results

A summary of the impact of the different supply scenarios and of the major projects arising from transmission constraints over the next 10 years is given below:

- In scenarios with high levels of new generation added in the Latrobe Valley, the existing 500 kV lines (after the current project to bring the fourth 500 kV line to 500 kV operation is complete) may not provide sufficient power transfer capability into the metropolitan area towards the end of the ten year period. In addition, the capacity of the existing 500/220 kV and 330/220 kV transformation in the Melbourne metropolitan area will become a constraint on delivery of this power into the metropolitan 220 kV network. An additional metropolitan 1,000 MVA 500/220 kV transformer is expected to be required by around 2006/07 and a second transformer by the end of the ten-year period. The location of any new 500/220 kV transformation would be sited to maximise the benefits and minimise the costs, having regard to the impact on fault levels, thermal loading of existing assets and the reliability of supply.

- In the scenarios where additional capacity is obtained from Snowy/NSW, enhancement of the existing interconnection would be required. All the scenarios considered here assume either no increase at all in the Snowy to VIC interconnection capability beyond the existing committed level of 1,900 MW, or an upgrade, which would provide 180 MW, 600 MW and 1,600 MW of additional interconnection capability. The 1,600 MW upgrade would require significant capital works, including augmentation of the transformation tying the 330 kV lines from Snowy/NSW with the Victorian 500 kV and 220 kV networks, additional 330 kV lines between Dederang and South Morang, and Dederang and Wagga, series compensation of several existing lines, additional shunt reactive plant, and some line upgrading works in New South Wales. Any works required in NSW have not been costed or included in the summary of works.

- New generation developments and transmission system augmentations will generally result in higher fault levels across the transmission system. Management of fault levels is already a critical issue at a number of locations within the Melbourne metropolitan area, and a combination of circuit breaker replacement (to permit operation at higher fault levels) and operational measures such as segregation of the transmission network to limit fault current in feed will likely continue over the next 10 years. The appropriate balance between containing the fault level and allowing the fault level to increase will require ongoing investigation, and this work will consider SPI PowerNet plans for circuit breaker replacement as part of their asset management procedures. The issue of fault levels will be particularly impacted by higher levels of generation connected at 220 kV and lower voltage levels, and a higher cost is assigned for the higher embedded generation scenarios. Demand management would not cause fault levels to rise. To address the long term fault level issues, a strategic fault level review is summarised in section 4.7.

- Some uprating and/or re-configuration of the 220 kV transmission circuits within the Melbourne metropolitan area is likely to be required, particularly lines between and around Thomastown and Rowville, both to provide for increased power transfer capacity across the metropolitan area, and to manage the loading of critical radial systems such as Springvale and Heatherton.

- Augmentation of the 500/220 kV transformation at Moorabool is currently related more to local issues around Moorabool and Keilor following loss of this transformer, than to system wide 220 kV supply issues. However, over time, augmentation of the transformation at Moorabool also becomes more important from a system wide perspective.

- Some reinforcement of the supply to the State Grid will be required. Augmentation of the transformation at Moorabool and Dederang, and the 220 kV lines supplying, and forming part of, the state grid is shown to be necessary during this period. The location of any new generation is particularly important here, as significant levels of generation at or near Moorabool or Geelong can defer or remove the need for transformer augmentation at Moorabool. Scenarios involving a substantial increase in import capability are likely to advance augmentation of Dederang transformation.

- The increased reactive support required in all scenarios is due to load growth, to compensate increased reactive losses and to maintain system voltage stability.

- In scenarios 4, 5 & 6, which assume increase in interconnector capability, the supply into the 220 kV network is augmented with 330/220 kV transformation. Scenario 6 also requires the construction of new 330 kV transmission lines in Victoria and NSW, and associated series compensation. This accounts for a large portion of the increased costs associated with these options, compared to scenarios where a large portion of the supply comes from the Latrobe Valley.

- The different balance between embedded generation, Latrobe Valley generation and increased import from NSW/Snowy would have a significant impact on the level of energy at risk if the augmentation were not to proceed, and hence the timing for many of these projects would be different between the scenarios.

Table 7.2, gives a summary of the works required to remove transmission constraints emerging over the next 10-year period for each of the five supply scenarios. Table 7.3 indicates the estimated capital cost for network solutions over the 1-5 year and 6-10 year periods. The capital cost in the first 5 years is similar because there is little difference in the augmentation requirements across the 5 scenarios in this time. This is because there is more certainty on the generation scenario's in this period.

The capital cost for network solutions in the 6-10 year period varies more significantly across the scenarios. The scenarios that rely on transporting the bulk of the additional generation from a specific location such as the Latrobe Valley (scenarios 1 & 2) or NSW (scenario 6) require more investment in transmission capacity and therefore the higher capital cost. Those scenarios that have a high level of embedded generation (scenario 3) or rely on moderate increases in generation from the Latrobe Valley and NSW reduce the amount of new transmission needed and therefore have a lower capital cost.

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Latrobe Valley to Melbourne 500 kV transmission for outage of a 500 kV line.	4th 500 kV line project, works to upgrade 4th 500 kV line, Latrobe Valley work, associated work for 1,000 MVA transformer at Cranbourne	42	December 2004	December 2004	December 2004	December 2004	December 2004	December 2004	Project in progress
Keilor to Geelong 220 kV lines and Keilor 500/220 kV transformers for outage of Moorabool transformer	Control scheme at Keilor	0.5	December 2004	December 2004	December 2004	December 2004	December 2004	December 2004	Project in Progress
	Spare Moorabool 500/220 kV single phase transformer	4.0	May 2005	May 2005	May 2005	May 2005	May 2005	May 2005	Project in progress The spare also serve as a spare for the Rowville and Cranbourne 500/220 kV single-phase transformer banks
	Wind monitoring scheme on Keilor to Geelong lines	0.4	December 2004	December 2004	December 2004	December 2004	December 2004	December 2004	
	Second 500/220 kV transformer at Moorabool	26	Around 2006	Around 2006	Around 2006	Around 2006	Around 2006	Around 2006	Economic timing subjected to generation development in Keilor/Moorabool areas

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Murraylink regulation project – Voltage collapse and thermal limits in the state grid area during peak periods	7 new shunt capacitor banks (290 MVAr) in the State Grid area, modify existing 5 shunt capacitor banks and a control scheme to provide very fast runback on Murraylink for transmission outages	15	April 2005	April 2005	April 2005	April 2005	April 2005	April 2005	Project in progress
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	Remedial works on 220 kV Lines between Rowville to Thomastown	5	December 2005	December 2005	December 2005	December 2005	December 2005	December 2005	
	One 500/220 kV 1,000 MVA transformer in the eastern metropolitan area and fault level mitigation 50	45	December 2006	December 2006	December 2006	December 2006	December 2006	December 2006	
Outage of a metropolitan 500/220 kV transformer overloads the remaining transformer.	One 1,000 MVA 500/220 kV transformer at SMTS	50	Around 2012	Around 2012					

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
South Morang – Thomastown 220 kV circuit for outage of parallel circuit	Formation of a South Morang 220 kV bus & cutting of existing Rowville to Thomastown 220 kV circuit into South Morang 220 kV bus to form 3rd South Morang to Thomastown 220kV circuit	4	Around 2012	Around 2012		At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	About 2006 or with increased import from NSW
Inadequate thermal capacity on LV to Melbourne 500 kV lines	Fifth 500 kV line from LV to Melbourne	100	Around 2014	Around 2014					Economic timing depends on generation development behind the constraint and the reliance of Victorian demand on the generation
Dederang transformers for outage of a Dederang transformer. 4th transformer causes fault levels to increase at Mount Beauty.	Modification to existing Dederang 330 kV bus control scheme	0.10	December 2004	December 2004	December 2004	December 2004	December 2004	December 2004	
	4th Dederang 330/220 kV transformer and Mount Beauty 220 kV switchgear replacement	12	Around 2010	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade or around 2010

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Low power flow from Wodonga to Dederang and voltage collapse at Wodonga and Dederang	Installation of a 100 MVAr capacitor bank at Wodonga and control & communications	5.5		At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	At the time of interconnection upgrade by 180 MW	Timing with increased import from NSW
South Morang toDederang 330 kV line and series capacitors for outage of parallel circuit	Upgrade of South Morang to Dederang 330 kV line & increase in rating of South Morang to Dederang series compensation to match line uprate	4				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
Low power flow from Wodonga to Dederang and voltage collapse	60~65% series compensation on Wodonga to Dederang 330 kV lines & 150 MVAr shunt cap at Wodonga	9				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Eildon-Thomastown line for outage of South Morang to Dederang line	Upgrade of Eildon – Thomastown 220 kV line to 70^{O}C operation & 25% series compensation on the Eildon to Thomastown 220 kV line	4				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
South Morang 330/220 kV transformer for outage of a parallel transformer	3rd 700 MVA 330/220 South Morang transformer	17				At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	At time of Interconnection Upgrade by 600 MW	Timing with increased import from NSW
South Morang 330/220 kV transformer for outage of a parallel transformer	4th 330/220 kV transformer at South Morang	17						At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
South Morang 500/330 kV transformer for outage of a parallel transformer	2nd 500/330 kV transformer at South Morang	50						At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
South Morang to Dederang line for outage of a parallel circuit	3rd South Morang to Dederang 330 kV circuit	100						At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
South Morang-Thomastown line for outage of a parallel circuit	Cutting of existing Eildon to Thomastown 220 kV circuit onto South Morang 220 V bus to form 4th South Morang to Thomastown 220 kV circuit	4						At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
Voltage collapse at Dederang and South Morang	Controlled series compensation of South Morang to Dederang lines	(included in the 3rd circuit cost)						At time of Interconnection Upgrade to 1,600 MW	Timing with increased import from NSW
Hazelwood transformers constrain for system normal	Additional 220/500 kV transformation at Hazelwood	25	December 2008	December 2008	December 2008	December 2008	December 2008	December 2008	Economic timing depends on generation development behind the constraint and the reliance of Victorian demand on the generation
Rowville-Springvale circuit for outage of parallel circuit.	Upgrade line terminations at Rowville and Springvale	2.0	December 2005	December 2005	December 2005	December 2005	December 2005	December 2005	Replace isolators, circuit breakers
	Upgrade Rowville to Springvale 220 kV line	0.5	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	Tower works

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Rowville to Malvern circuit outage for parallel circuit	Wind monitoring scheme on Rowville to Malvern circuits and a control scheme for load shedding	0.3	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	Around 2008	CitiPower plans to transfer about 100 MW load from Rowville to Malvern, following refurbishment of Malvern by SPI PowerNet
	Rowville to Malvern 220 kV line upgrade	3	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	
Ringwood toThomastown circuit for outage of Rowville to Ringwood circuit at high Summer load.	Upgrade Ringwood 220 kV supply	0.15 4	December 2004 Around 2013	December 2004 Around 2013	December 2004 Around 2013	December 2004 Around 2013	December 2004 Around 2013	December 2004 Around 2013	Fast load shedding scheme in progress Switching of lines
Rowville to Richmond circuit for outage of parallel circuit	Rowville to Richmond 220 kV line upgrade	4	Around 2009	Around 2009	Around 2009	Around 2009	Around 2009	Around 2009	
Keilor to West Melbourne- circuit for outage of parallel circuit	Keilor to West Melbourne 220 kV line upgrade	0.4 5	December 2004 Around 2010	December 2004 Around 2010	December 2004-Around 2010	December 2004 Around 2010	December 2004 Around 2010	December 2004 Around 2010	Subjected additional new generation in Keilor-Altona-Brooklyn-Fisherman's Bend-West Melbourne loop
Ballarat to Moorabool circuit for outage of parallel Ballarat to Moorabool circuit at high load.	Wind monitoring scheme on the Ballarat to Moorabool circuit	0.4	December 2005	December 2005	December 2005	December 2005	December2005	December2005	

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
	Uprate the Ballarat to Moorabool No.1 circuit to 75°C conductor temperature	2.8	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	Around 2010	
Bendigo to Shepparton circuit for outage of a Ballarat to Bendigo circuit as high load.	Wind monitoring scheme on the Bendigo to Shepparton circuit	0.2	December 2007	December 2007	December 2007	December 2007	December 2007	December 2007	
	Bendigo to Shepparton 220 kV line upgrade	5	-	-	At time of Interconnection Upgrade by 600MW	At time of Interconnection Upgrade by 600MW	At time of Interconnection Upgrade by 600MW	At time of Interconnection Upgrade to 1,600 MW	
Dederang to Glenrowan circuit for outage of parallel Dederang to Glenrowan circuit.	Switch Dederang to Shepparton 220 kV line at Glenrowan	3	Around 2011	Around 2011	Around 2011	Around 2011	Around 2011	Around 2011	
Ballarat to Bendigo line for outage of Bendigo to Shepparton line at high Summer load.	Wind monitoring scheme on the Ballarat to Bendigo circuit	0.2	Around 2009	Around 2009	Around 2009	Around 2009	Around 2009	Around 2009	
	Ballarat to Bendigo 220 kV line upgrade to 75°C conductor temperature	3.2	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	Around 2014	
System voltage collapse for trip of Newport generation, 500 kV line, 330 kV line or 220 kV line	1,500 MVAr to 2,500 MVAr Reactive Support	35-55	On-going 2,500 MVAr from 2007	On going 2,500 MVAr from 2007r	On going 1,500 MVAr from 2007	On going 2,000 MW from 2007	On going 2,000 MW from 2007	On going 2,000 MW from 2007	Location of circuit breakers depends on sequence of upgrade works

Constraint	Network Solution	Estimated Capital Cost $M	Estimated Time						Comments
			Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
in the state grid area at time of peak Summer load.	(including currently committed)								
Fault level issues	Fault limiting devices and upgrade selected 220 kV switchgear in the metropolitan area	20	On-going as required	On-going as required	On going as required	On-going as required	On going as required	On going as required	$30 M for Scenario 3
Line terminations, protection etc limiting capability of plant to economically meet demand.	Miscellaneous Works	30	On-going	On-going	On-going	On-going	On-going	On-going	On-going

Table 7.2 - Summary of Network Constraints over the Next 10 Years

	Estimated Total Capital Cost		
Scenario	Years 1 –5 $M	Years 6-10 $M	Total $M
1	220	244	465
2	238	232	470
3	233	73	306
4	233	111	344
5	233	111	344
6	233	287	520

Table 7.3 - Estimated Total Capital Cost for Network Solutions

7.5 Non-Constraint Issues

7.5.1 System Continuity Planning

As discussed in the 2003 APR system continuity planning is being progressed to ensure preparedness for catastrophic events.

Although the network is designed to minimise the risk of failure of multiple elements from a single event, there are a number of low probability events with high consequential loss that can be brought about by major equipment failures or external influences.

A review of credible events, vulnerabilities and threats carried out during 2002/03 categorised events into those that could be caused by major plant or equipment failures and those that could be caused as a result of terrorism or sabotage.

A number of strategies were identified to:

- reduce plant exposure and vulnerability;
- reduce consequential damage and system impact; and
- provide for fast recovery on critical facilities.

The strategies include development of continuity plans, increased protection of plant through surveillance and screening, identification of strategic spares within the network and available from other utilities for repairing or replacing damaged facilities, and the development of emergency by-pass facilities for lines and stations.

In the order of $6M is economically justified when likelihood, supply loss and reduction in repair and restoration times are assessed.

VENCorp is continuing to work together with SPI PowerNet to implement those continuity plans that are identified as being economically justified.

7.5.2 Upgrade of Dynamic System Monitoring Equipment

VENCorp has Dynamic System Monitors installed at 14 key locations on the EHV transmission network. They continuously monitor the dynamic performance of the power system and automatically trigger for voltage, frequency and power disturbances. Installation of these monitors commenced in 1994 and are generally located at points of generation and at points of interconnection.

The equipment is approaching the end of its serviceable life and a replacement program is expected to be initiated in the next few years. It is anticipated the replacement program will include an increase in the number of dynamic system monitors and to enhance their performance to improve monitoring throughout the Victorian network. This program is expected to cost in excess of $1 M.

ELECTRICITY ANNUAL PLANNING REPORT

2004

APPENDICES

JUNE 2004

A1 TERMINAL STATION DEMAND FORECASTS

VENCorp

TERMINAL STATION DEMAND FORECASTS 2003/04 - 2012/13

ENERGY INFRASTRUCTURE DEPARTMENT
VICTORIAN ENERGY NETWORKS CORPORATION

DISCLAIMER

VENCorp's role in the Victorian electricity supply industry includes planning and directing augmentation of the transmission network. To enable VENCorp to carry out that function, certain participants in the electricity supply industry must provide long-term forecasts of demand at each of their connection points to VENCorp in accordance with clause 260 of the Electricity System Code and clause 5.6.1 of the National Electricity Code.

The purpose of this document is to comply with VENCorp's obligations (under clause 260.1.3 of the Electricity System Code and clause 5.6.2A section b.1 of the National Electricity Code), to aggregate those demand forecasts and make that information available to system participants. This document is not intended to be used and should not be used for other purposes, such as decisions to invest in future generation, transmission or distribution capacity.

VENCorp has not independently verified and checked the accuracy, completeness, reliability and suitability of the information provided by the participants under clause 260 of the Electricity System Code and clause 5.6.1 of the National Electricity Code. Anyone proposing to use the information in this document should independently verify and check the accuracy, completeness, reliability and suitability of the information in this document and the information used by VENCorp in preparing it.

The document presents aggregate forecasts of demand at terminal stations over the next ten years, which are based on distributor and EHV consumer forecasts and various assumptions. Those assumptions may or may not prove to be correct. The forecasts may change from year to year and should be confirmed with VENCorp or the relevant participant before any action is taken based on this document.

VENCorp makes no representation or warranty as to the accuracy, reliability, completeness or suitability for particular purposes of the information in this document. VENCorp and its employees, agents and consultants shall have no liability (including liability to any person by reason of negligent misstatement) for any statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or any omissions from, the information in this document, except insofar as liability under any statute cannot be excluded.

A1.1 Introduction

VENCorp has prepared and makes available load forecasts for points of connection within the transmission network as required by the Electricity System Code (section 260.1.3) and clause 5.6.2a section b.1 of the National Electricity Code. This document provides for each terminal station:

- the peak active power demands forecast to occur for Summer and Winter on average one year in two (50% POE) and one year in ten (10% POE), for each of the financial years 2003/2004 to 2012/2013 inclusive;
- the reactive power demands forecast to occur at the same times as the terminal station's peak active demands (both 50% POE and 10% POE);
- the daily active and reactive load curves for its days of peak active power demand; and
- the peak active and coincident reactive actual demands for Summer and Winter.

VENCorp has prepared these forecasts using the 10% POE and 50% POE forecast peak levels of active load and coincident levels of reactive load provided by System Participants in June 2003. System Participants forecast the peak levels of active load (based on 15 minute energy), and the associated reactive load levels that they expect to be supplied to their licensed distribution area from each terminal station in Summer and Winter for the coming ten years.

The forecast demands which the Distribution Businesses provided VENCorp in June 2003 were also an input to the Distribution Businesses' subsequent connection planning report, which may result in further changes to planned transmission network connections and their forecast demands.

A1.2 Determination of Aggregate Terminal Station Demand Forecasts

Where only one System Participant has a point of connection at a terminal station, demand forecasts are presented as provided by the System Participant.

Where more than one System Participant has a point of connection at a terminal station, VENCorp has scaled each demand forecast by a diversity factor determined by VENCorp from historical information. The scaled demand forecasts are summed to obtain aggregate demand forecasts for these terminal stations.

Where appropriate, in VENCorp's view, it requests the relevant System Participant to review their forecasts, but VENCorp only amends these forecasts as updated by System Participants.

A1.2.1 Determination and Application of Diversity Factors

VENCorp determines and applies two sets of diversity factors namely: Station diversities and System diversities. Station diversities are multiplied by the System Participant forecast peak loads at terminal stations which supply more than one System Participant. This in turn provides the aggregate terminal station seasonal demand forecasts as seen in the Appendix. System diversities are multiplied by System Participant forecast peak loads at all terminal stations, to forecast the contribution from each terminal station towards the Victorian system peak seasonal demand. Once each terminal station's contribution is summated the resulting seasonal forecast demands contribute a major component towards the aggregate system seasonal demand forecasts that are compared with the NIEIR and previous year's forecasts.

Explicitly these diversity factors estimate the portion of station and system MD for the maximum active (MW) demand and coincident reactive demand that is supplied to each System Participant at each of the terminal stations.

Each Station diversity factor for active power is the ratio of a System Participant's active demand at a terminal station (supplying multiple participants) at the time of the terminal station's MD (maximum MW demand) to the System Participant's MD (maximum MW demand), at that terminal station. Both parts of the ratio also need to relate to the same season and percentile (probability) conditions. The System Participant's estimated portion of the station's MD is that participant's relevant (i.e. of appropriate season and percentile) forecast MD at the station multiplied by this Station diversity factor.

For example, consider the case where a terminal station supplies System Participants A and B. This terminal station has a maximum demand at 3 pm on a Summer day and System Participant A's demand on the station at this time is 90 MW and 60 MVAr. However, the maximum Summer demand at this station for System Participant A is 100 MW and 80 MVAr at 10 am on another day. The forecast load is assumed to represent the 10 am value and is diversified to 3 pm on the day the station has its peak Summer load with a diversity factor of 0.90 (90 / 100 MW). A similar approach is taken for Participant B at this point of connection.

The reactive load reported in the forecast is coincident with the maximum active load. Therefore, the diversity factor for the reactive demand is defined as the ratio of the System Participant's reactive load at the time of the terminal station's MW MD to the reactive load at the time of the System Participant's MW MD. This corresponds to the same times of maximum demand used to calculate the MW diversity factor. Using the example above, System Participant A's MVAr diversity factor is 0.75 (60 / 80 MVAr).

Diversity factors are calculated by examining the historical active and reactive loads at times of high active load for each of multiple participants supplied from the station, for the station, and for the system, for both Summer and Winter over a number of years. More importance is placed on recent years.

Metering data sourced from Metering Data Agent (Data and Measurement Solutions) is used to provide the historical records for this analysis.

A1.3 Forecast Notes

A1.3.1 Altona and Brooklyn

The Altona and Brooklyn 66 kV demands (excluding Brooklyn B5 transformer supply) are presented as a single aggregate demand because both stations jointly supply this aggregate demand, and their relative contributions vary with network conditions.

A1.3.2 Cranbourne, East Rowville and Frankston

Prior to issue of this report the 66 kV circuits supplying Frankston Terminal Station ceased to be part of the shared transmission network. Consequently the shared transmission network connection point for the associated (Frankston area) load became East Rowville. This

Frankston area load is included in the forecast demand presented as being supplied from East Rowville for Winter 2003 and Summer 2003/04, and from Cranbourne subsequently, as outlined next.

A new terminal station under construction at Cranbourne is expected to be in service prior to Winter 2004. It is expected to supply mainly Berwick, Pakenham, Frankston and Carrum area loads currently supplied from shared transmission network connection points at East Rowville and Heatherton. Demands forecast for Cranbourne, East Rowville and Heatherton Terminal Stations are presented on this basis.

A1.3.3 Morwell and Loy Yang Switching

Load supplied from Loy Yang Terminal Station forms a component of the load supplied from the Morwell Terminal Station. Therefore, the forecast Loy Yang switching station load is included in Morwell Terminal Station load forecasts.

A1.3.4 Thomastown

Thomastown (TTS) Terminal Station is reported as two separate load blocks: Thomastown Bus 1&2 (TTS12) and Thomastown Bus 3&4 (TTS34). This is to align forecasts with transformation loadings for the usual station configuration.

A1.3.5 Eastern Standard Time

Time of day where shown in this document is Australian Eastern Standard Time: that is Daylight Saving Time is not used for Summer.

A1.3.6 Embedded Generation

Actual demands at a terminal station from distribution network/s connected to the station will be the total of:

- customer load connected to the distribution network/s; plus
- losses in the distribution network/s; less
- generation exported into the distribution network/s (from generators embedded in the distribution network/s).

In forecasting terminal station peak demands presented in this report System Participants have assessed the aggregate level of export, at times of each station's peak demand, from small generators embedded in the distribution network/s connected to the station. This aggregate export has been treated as negative load- i.e. the terminal station peak demand has been reduced by this amount.

Terminal station peak demands will be reduced further by any export at the time of peak demand from larger generators embedded in the distribution network/s connected to the station. However, peak demands presented include demand actually supplied by larger embedded generators. That is, rather than reducing terminal station peak demands by the amount actually supplied by embedded generation, this demand is presented as being supplied from the terminal station – effectively preventing larger embedded generator output as nil at time of terminal station MD. This envisages that these installations (eg Morwell Power Station units G1-

3, and Clover, Hume, Somerton, and Bairnsdale Power Stations) not treated as negative load will be considered individually, on a case-by-case basis, in performing planning.

A1.3.7 Loy Yang Power Station Unit Supplies

If an outage of a Loy Yang Power Station unit transformer occurred up to approximately 50 MW additional load could be drawn from Morwell Terminal Station. This is not included in the demand forecast but is noted in the comments with the Loy Yang switching station forecasts and also in the Morwell Terminal Station forecasts as this potential load needs to be recognised in planning the connection assets at Morwell.

A1.3.8 Treatment of Capacitance and Reactance

Reactive loading forecasts presented are the reactive loading levels expected to be imposed on terminal stations by licensed distribution areas. Thus they incorporate the reactive losses of the distribution network, including any reactors, and are offset by line and cable charging and those capacitors in the distribution network assessed by System Participants to be in service at the relevant time. Terminal station capacitors, compensators, reactors and transformation reactive losses are not considered as part of the load.

A1.4 Comparison of 2002 and 2003 Aggregate System Demand Forecasts

The forecasts provided by the System Participants were adjusted and aggregated to reflect the load expected on the days of system maximum demand in Summer and Winter. In general, the forecasts have decreased noticeably, especially for the earlier years being forecast.

Figure A1 shows the difference between this year's aggregate Summer active demand forecasts and the aggregate forecasts in 2002. The differences are substantial for the first year forecast (2004), exceeding 180 MW in both 10% POE and 50% POE forecasts. The differences gradually decrease beyond 2003 and are approximately 110 MW for the year 2012. The ranges of these differences are –190 MW to -108 MW for the 10% POE forecasts and –187 MW to -112 MW for the 50% POE forecasts.

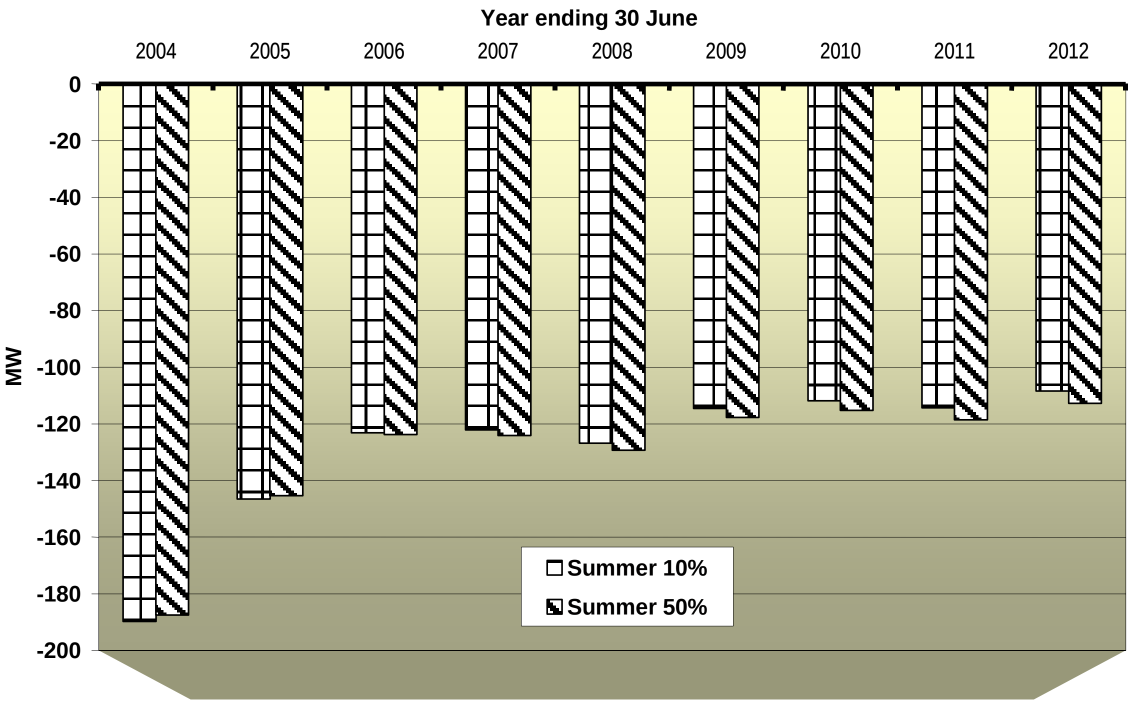


Figure A1 - System Participants' Summer Active Demand differences - forecasts issued 2003 and 2002

Figure A2 shows the difference between this year's aggregate Winter active demand forecasts and the aggregate forecasts issued in 2002. As for Summer, the forecasts have decreased compared to those issued in 2002. The ranges of these differences are -128 MW to -18 MW for the 10% POE forecasts and –115 to -6 MW for the 50% POE forecasts.

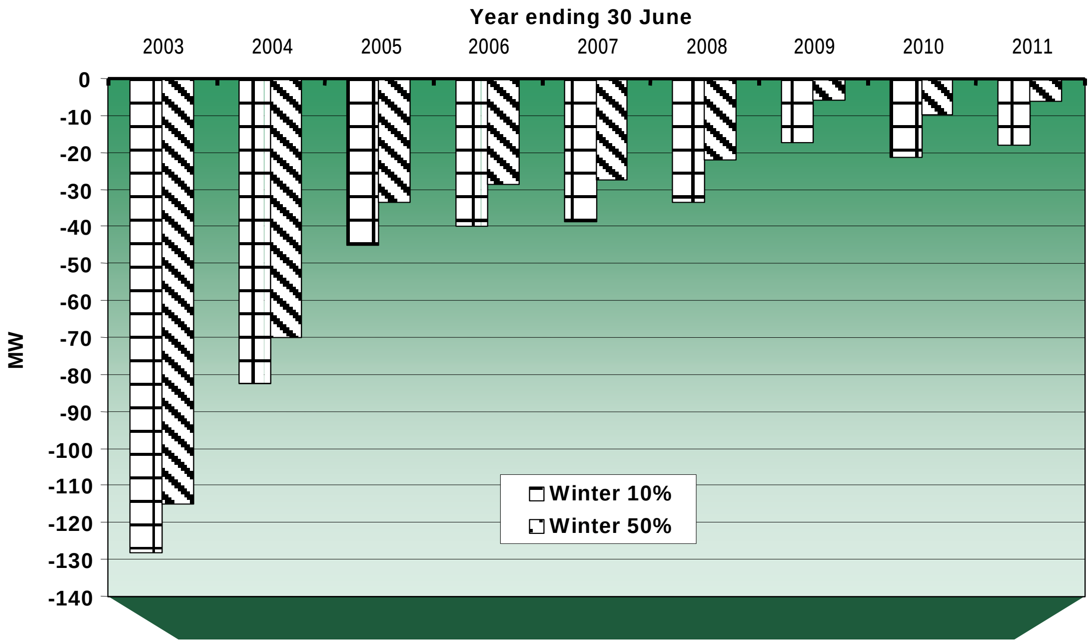


Figure A2 - System Participants' Winter Active Demand differences - forecasts issued 2003 and 2002

A similar comparison was made between the reactive forecasts for both Summer and Winter prepared in 2002 and 2003. Figure A3 shows that the aggregate Summer reactive demand forecasts have reduced significantly by approximately 184 MVAr at the 10% POE level and by approximately 170 MVAr at the 50% POE level for Summer 2003/04.

The differences for the outlook drop from 184 MVAr to approximately 120 MVAr in 2012 for 10% POE level. The large differences between the Summer reactive forecasts in the 2002 and 2003 reports can be partially attributed to power factor improvements across the system and reductions in the active load forecasts.

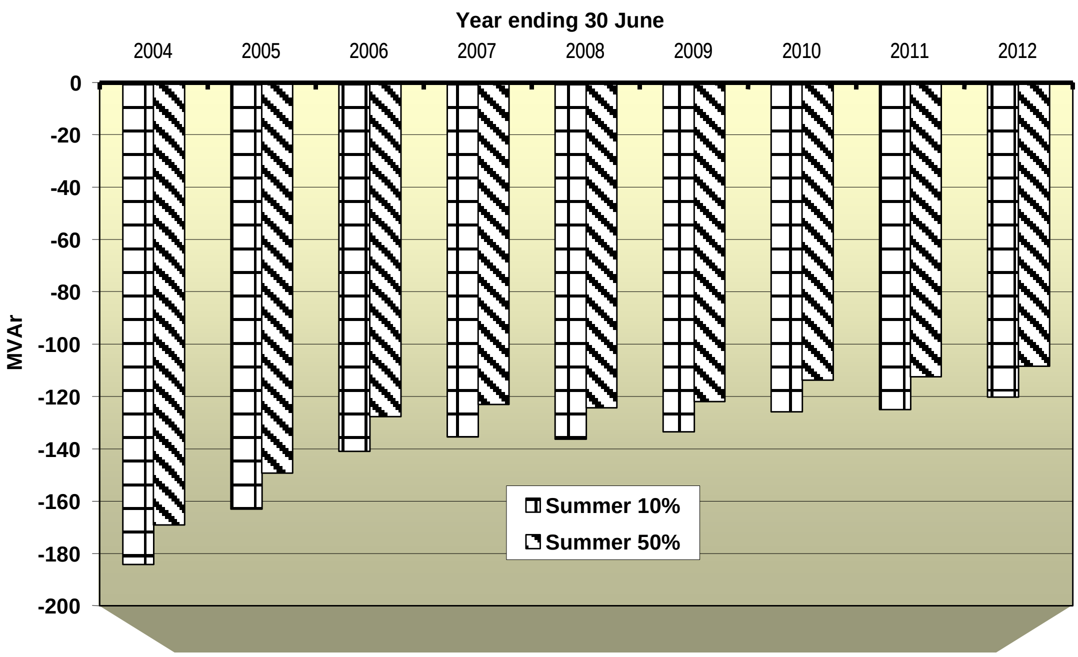


Figure A3 - System Participants' Summer Reactive Demand differences - forecasts issued 2003 and 2002

Figure A4 shows that the aggregate Winter reactive demands forecast in 2003 are noticeably lower than the aggregate forecasts in 2002 in the first half of the forecast period. For the Winter 2003, reactive demand forecast is 100 MVAr lower. The difference becomes smaller in later years and is positive after 2008. The differences between the Winter reactive forecasts in the 2002 and 2003 reports can be partially attributed to power factor improvements across the system and reductions in the active load forecasts.

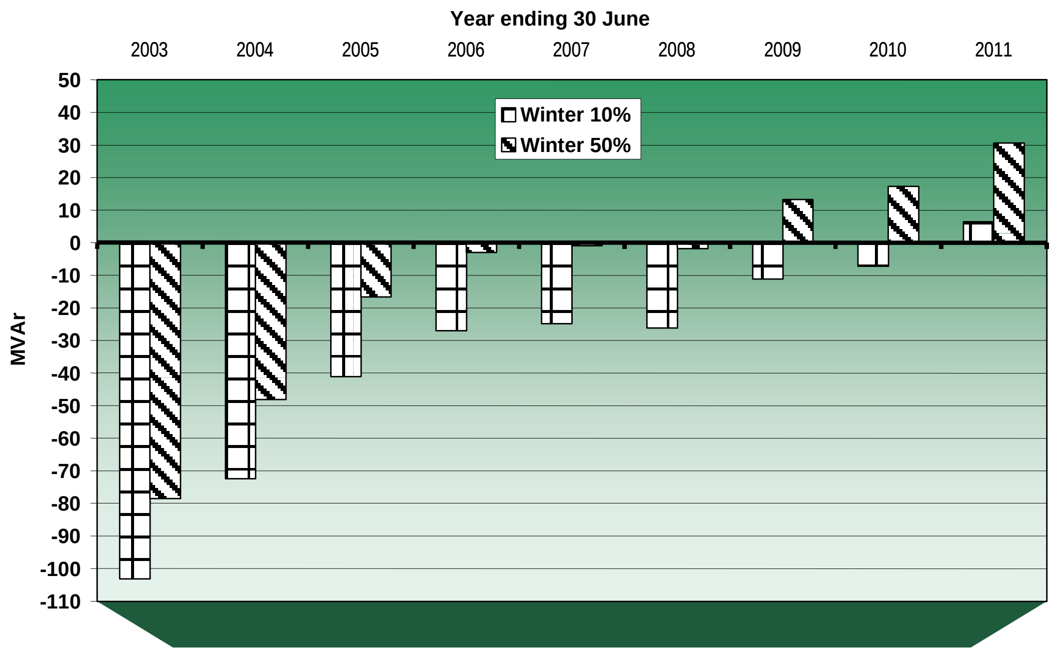


Figure A4 - System Participants' Winter Reactive Demand differences - forecasts issued 2003 and 2002

A1.5 System Peak Demand Forecasts and Comparison with NIEIR Demand Forecasts

The Victorian electricity system peak demand forecasts, based on the System Participants' forecasts, are derived by combining the terminal station forecasts, diversified to day and time of system peak demand as described in section 2.1. Adjustments include for transmission system losses and Victorian electricity system demand not supplied through the distribution networks, such as power station internal usage. The forecast Summer and Winter peak demands based on the System Participants' 10% POE and 50% POE forecasts are shown in Figures A5 and A6.

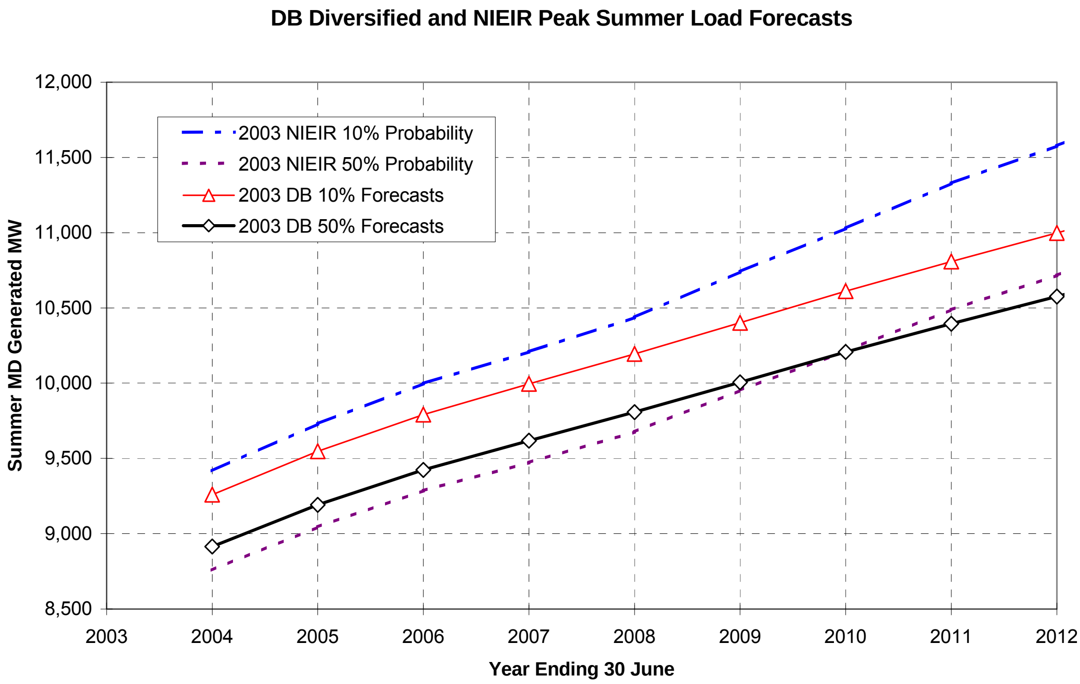


Figure A5 – Comparison of System Participant and NIEIR Victorian Summer Peak Electricity Load Forecasts

Victorian electricity system peak demand forecasts, published in June 2003 in VENCorp's Electricity Annual Planning Review[53], are also included in Figures A5 and A6. NIEIR forecasts for the "medium" economic growth scenario, with average daily ambient temperatures having 50% and 10% probability of being exceeded and leading to peak load conditions for a season are shown. This indicates the assessment of the sensitivity of peak Summer and Winter loads to ambient temperatures.

As shown in Figure A5, the 50% POE Summer demands forecast by System Participants are similar to the NIEIR forecasts throughout the forecast period, varying steadily from 160 MW above NIEIR forecasts initially to 200 MW below them in 2012/13. The 10% POE Summer demands forecast by System Participants are also similar to NIEIR values for the first five forecast periods, being about 200 MW lower, after which this deficit increases steadily to 630 MW in 2012/13.

The year-to-year growth rate of NIEIR's 10% and 50% POE Summer demand forecasts steadily decreases from 3.3% to 2.1% during the first five years, then increases to 2.9% and steadily decreases to 2.2% during the second five years, averaging 2.6% pa. Correspondingly, System Participant annual growth rates fall steadily from 3.1% to 1.8% over the decade, averaging 2.1% pa.

Given the underlying assumptions, VENCorp considers that NIEIR and System Participant 50% POE Summer forecasts agree well, and that the corresponding 10% forecasts also agree well over the first five years. However, the temperature sensitivity implied by the difference between

53 VENCorp retained the National Institute of Economic and Industry Research ("NIEIR") to develop Victorian peak electricity demand forecasts which were provided in early 2003. VENCorp Electricity Annual Planning Review 2003, which includes these forecasts, is available from the VENCorp web site www.vencorp.com.au.

the System Participants' 50% and 10% POE Summer forecasts is much lower than experienced in recent years.

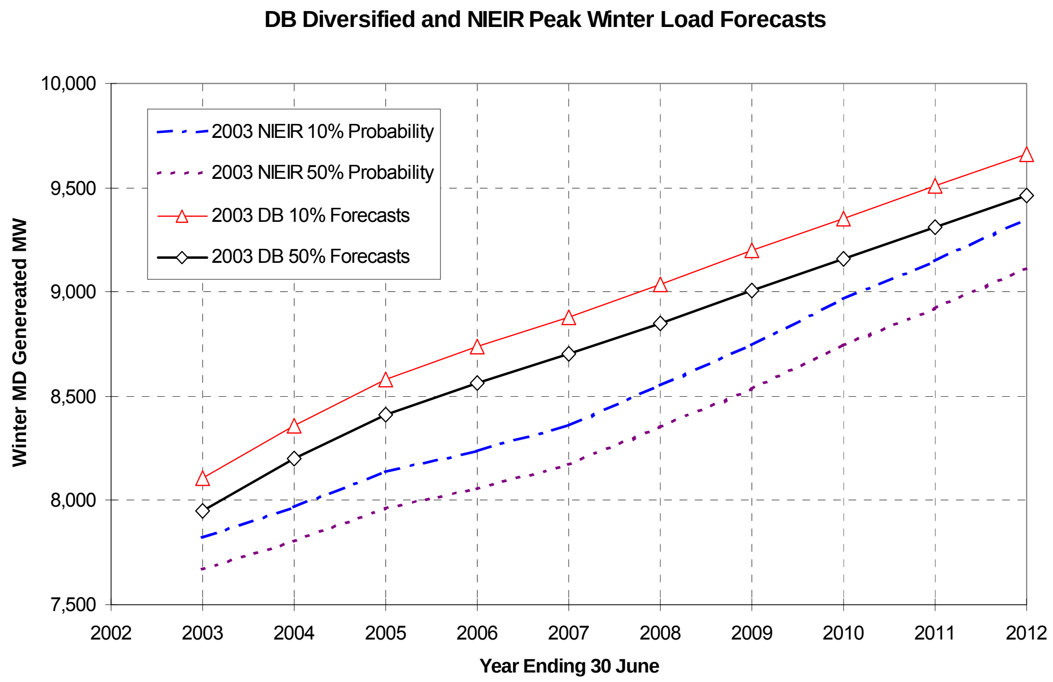


Figure A6 - Comparison of System Participant and NIEIR Victorian Winter Peak Electricity Load Forecasts

System Participants' Winter peak demand forecasts grow at steadily decreasing rates, averaging 2.0% pa over the decade. This growth is similar to, but slightly less than, their Summer forecasts' growth pattern. NIEIR's 10% and 50% POE Winter forecasts also average 2.0% pa over the decade, but their annual growth rate is approximately constant.

A1.6 Reactive Demand Forecasts

Figure A7 shows the aggregate reactive demands forecast by System Participants to be drawn from terminal station points of connection (usually stations' lower voltage terminals) at the times of Victorian system peak Summer and Winter active power demand. The higher levels of motorised cooling load in Summer are considered mainly responsible for the higher reactive demand in Summer compared to Winter.

This aggregate (10% POE) reactive load is forecast to increase from 3,065 MVAr to 3,975 MVAr over the 10 years to 2012/13 while the corresponding active power drawn from terminal stations is forecast to rise from 7,320 MW to 9,160 MW, indicating little change in the power factor of the aggregate terminal station load over the period.

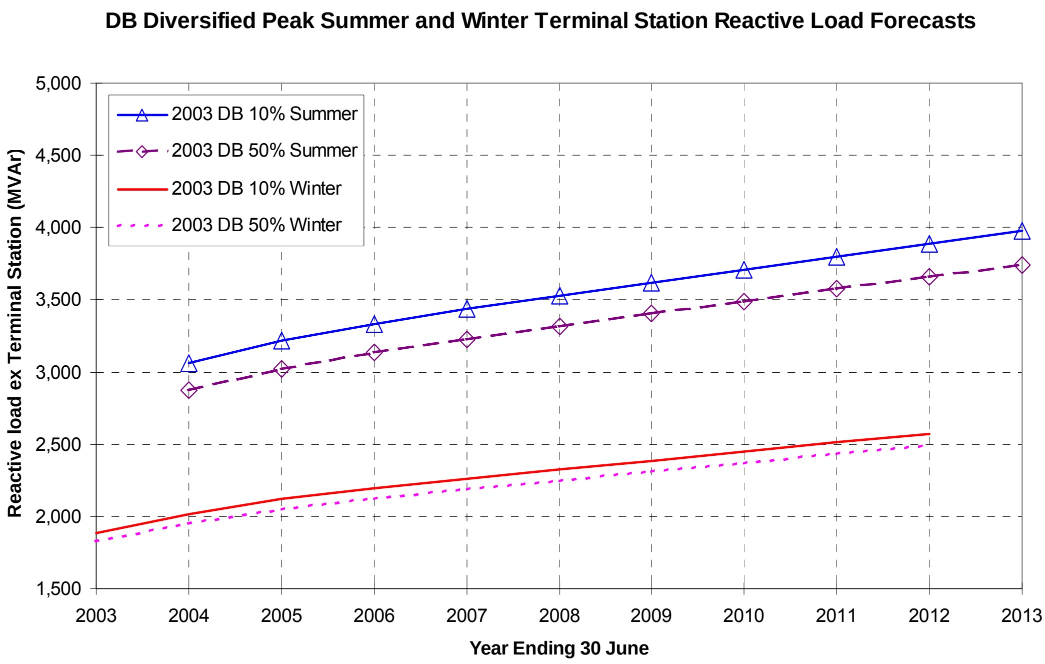


Figure A7 - Forecast of Reactive Load Drawn from Terminal Station Low Voltage Busbars

A1.7 Terminal Station Load Forecasts and Comparison with Actual Loads

A comparison was carried out between the load forecasts, by terminal station, presented in the 2002 report and the actual recorded peak loads supplied for Summer 2002/03.

Figure A8 compares the peak actual and forecast active load, showing (in each main bar) the actual MW load at each of the terminal stations and (as the top and bottom respectively of each subsidiary bar) the 10% POE and 50% POE forecast values. Similarly Figure A9 compares the 10% POE and 50% POE reactive load forecasts and actual reactive loads for each of the terminal stations in Summer 2002/03.

VENCorp assessed the temperature conditions, when peak Victorian potential maximum demand of 8,203 MW was recorded for the half hour ending 5:30 pm on Monday, 24 February 2003 for Summer 2002/03. Melbourne's overnight minimum temperature was 24.5 °C and the daily maximum temperature was 35.6 °C a daily average temperature of 30.05 °C.

This was the second highest Melbourne daily average temperature for Summer 2002/03, assessed to be a 35th percentile Summer in relation to maximum electricity demand. In previous Summers over 100 MW of demand side participation has been recorded, and in the past this has been considered to have not had a material impact on most terminal station peak Summer active demands. For 2002/03 this issue was not applicable, as there was no recorded demand side participation on the day of system MD.

Actual aggregate terminal station loading at the Summer 2002/03 system peak was 5,765 MW and 1,815 MVAr, compared to forecasts of 6,890 MW and 2,878 MVAr (50% POE) and 7,208 MW and 3,073 MVAr (10% POE).

A comparison was also carried out between the load forecasts, by terminal station, presented in this report and the actual recorded peak loads supplied for Winter 2003.

VENCorp has assessed the temperature conditions, when peak Victorian potential maximum demand of 7,491 MW was recorded for the half hour ending 6:30 pm on Wednesday, 30 July 2003 for Winter 2003. Melbourne's overnight minimum temperature was 6 ^{o}C and the daily maximum temperature was 11.2 ^{o}C a daily average temperature of 8.6 ^{o}C. This was the second lowest Melbourne daily average temperature for Winter 2003, assessed to be an 90th percentile Winter in relation to maximum electricity demand.

Similar to Figures A8 and A9, Figures A10 and A11 compare the peak actual and forecast active and reactive load for Winter 2003, showing the actual loads, aggregated across the system, are broadly consistent with the forecasts, in light of the very mild Winter conditions.

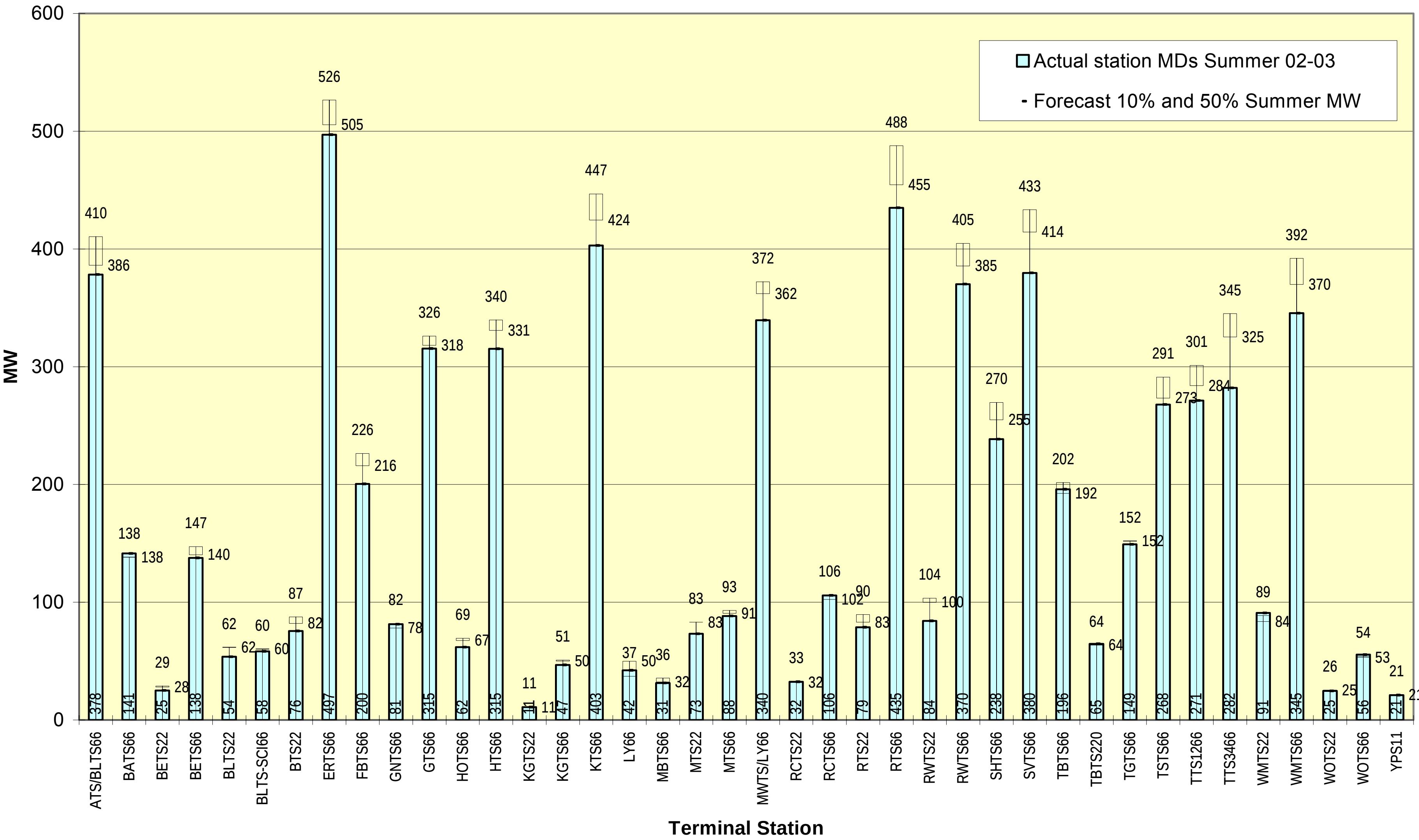


Figure A8 – Comparison of Actual Summer 02-03 Station MDs and Forecasts issued in 2002

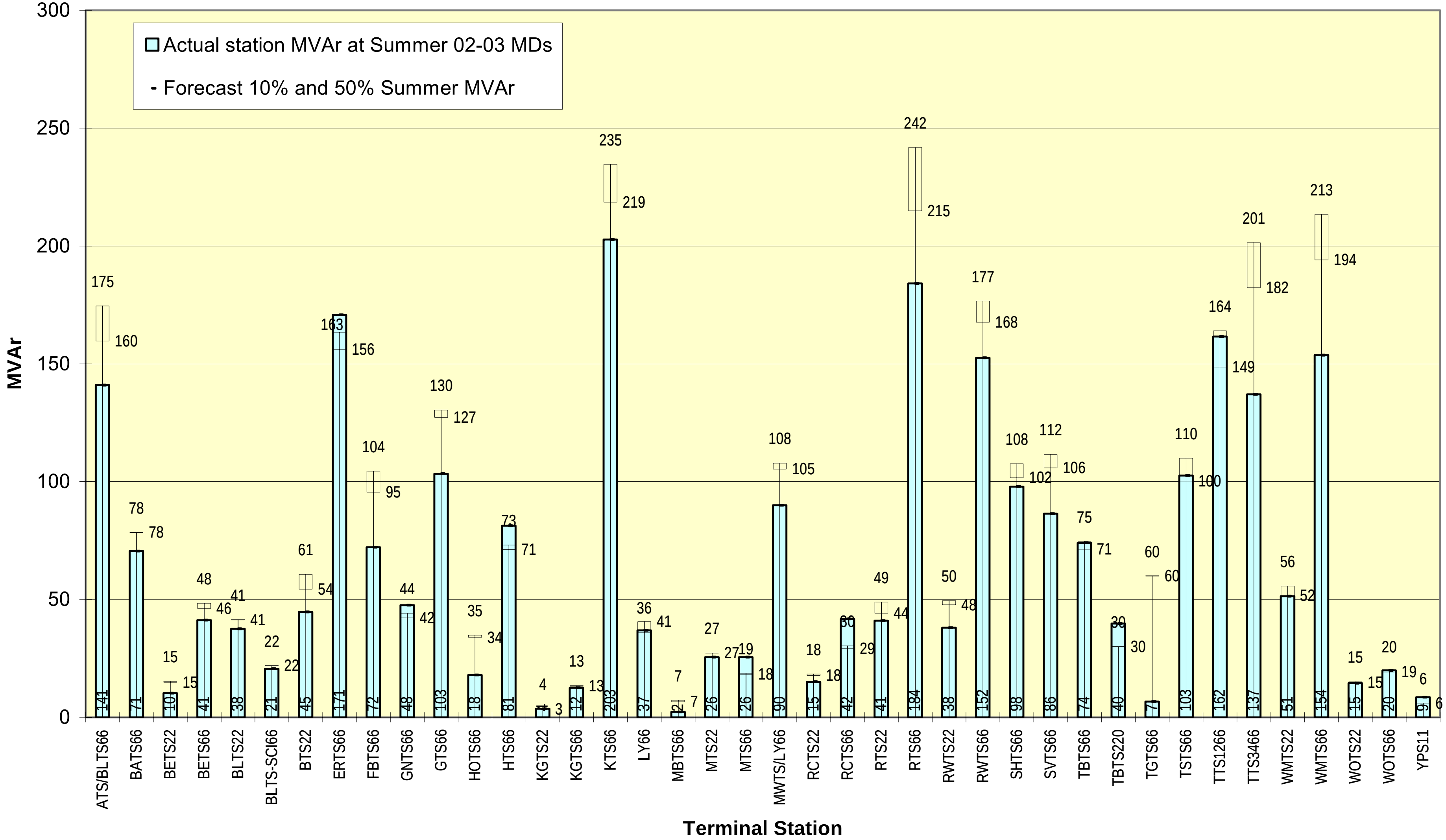


Figure A9 - Comparison of Station Actual Reactive Load at Time of Summer 02-03 Station MDs and 2002 Forecasts

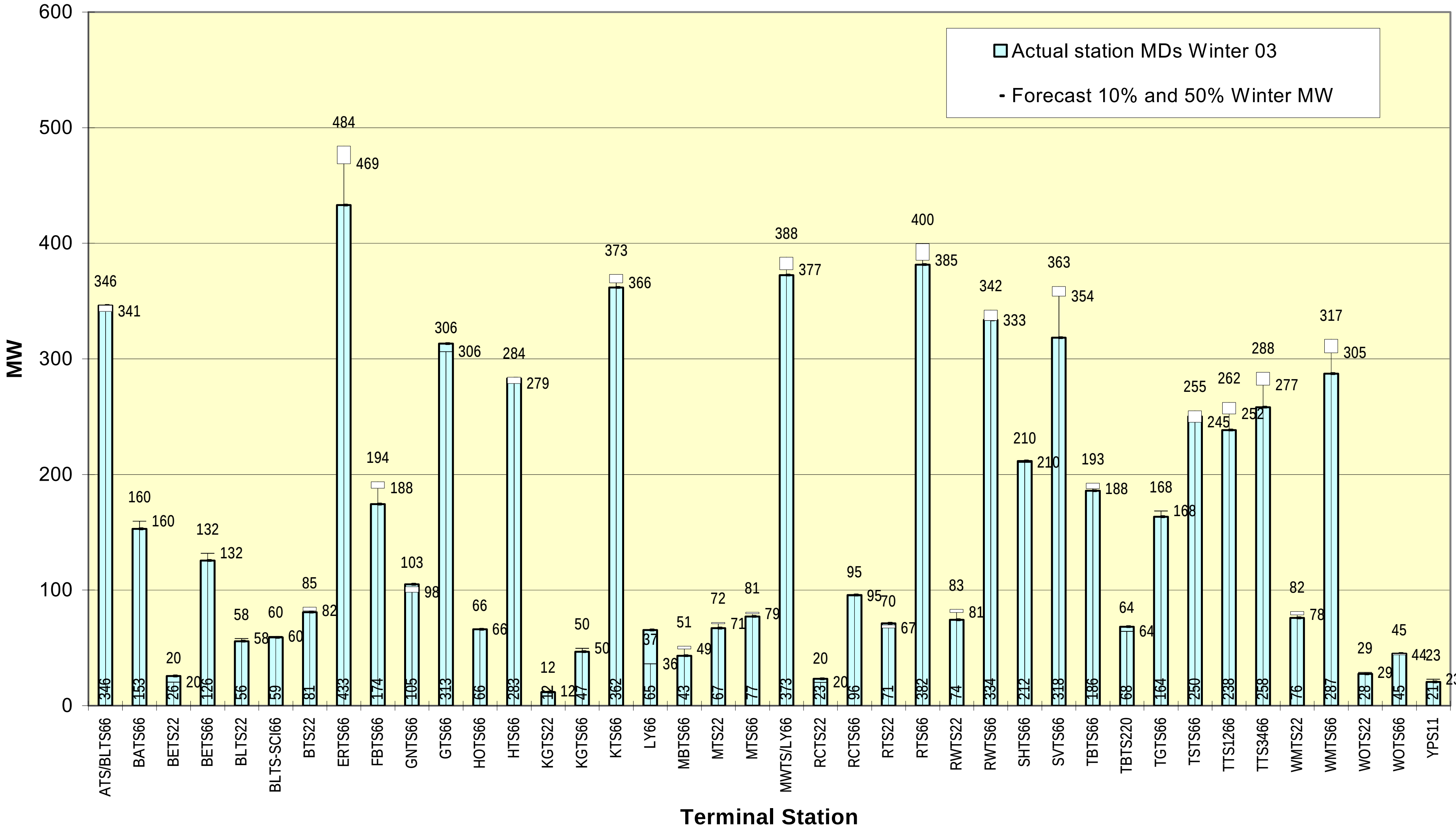


Figure A10 – Comparison of Actual Winter 2003 Station MDs and Forecasts issued in 2003

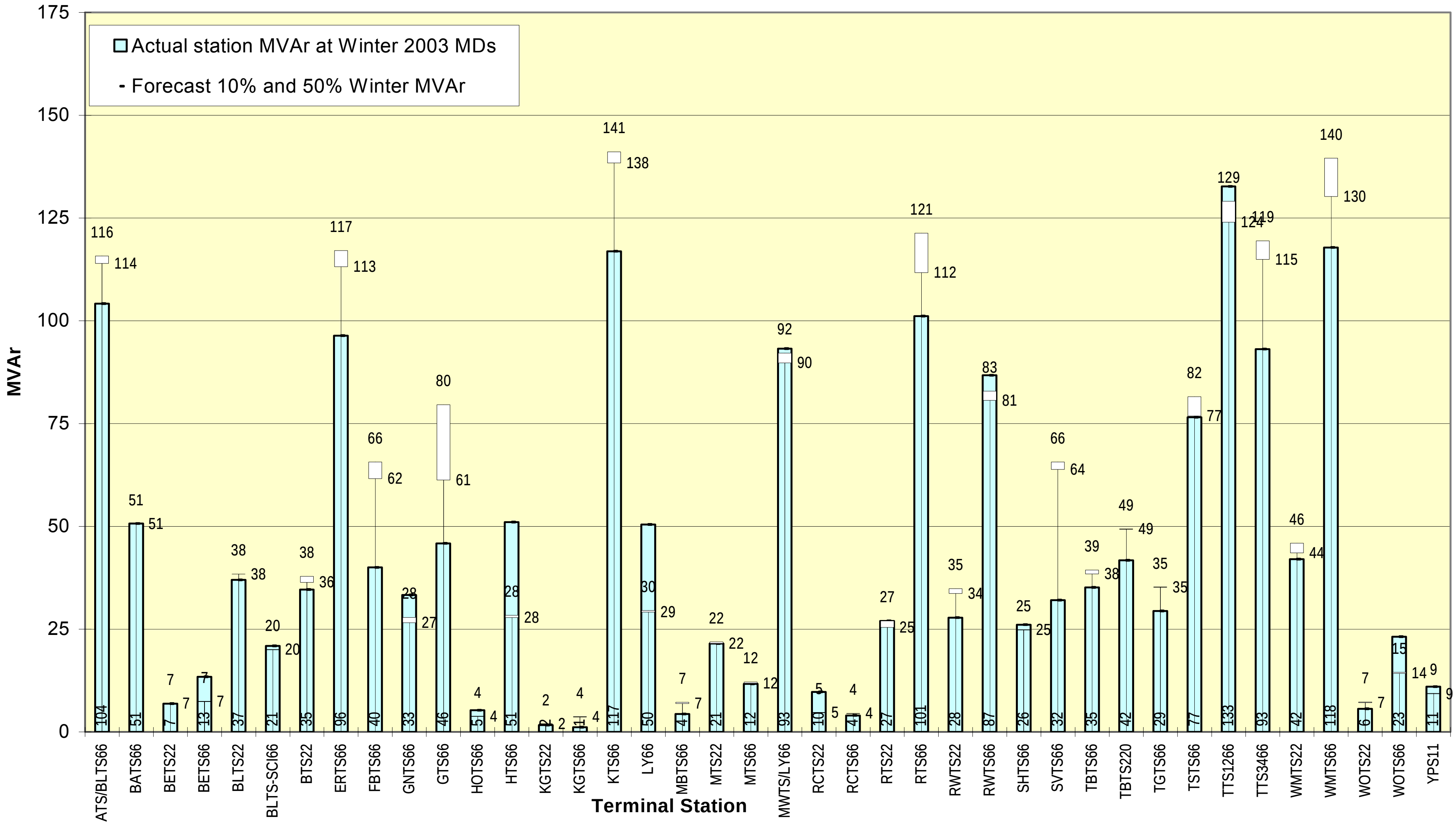


Figure A11 – Comparison of Station Actual Reactive Load at Time of Winter 2003 Station MDs and 2003 Forecasts

AGGREGATE
TERMINAL STATION
DEMAND FORECASTS

Alinta Summer Peak Forecasts by Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Heatherton 66 kV [54]	10	351.8	90.7	315.1	81.2	326.6	84.2	335.2	86.4	343.6	88.6	353.7	91.2	364.3	93.9	375.3	96.8	385.5	99.4	396.0	102.1
	50	339.3	87.5	302.9	78.1	313.8	80.9	321.8	83.0	329.5	85.0	338.9	87.4	348.8	89.9	359.3	92.6	368.9	95.1	378.7	97.6
Malvern 22 kV	10	79.8	27.9	82.6	28.8	85.6	29.9	87.6	30.6	89.9	31.4	92.7	32.3	94.9	33.1	96.9	33.8	98.9	34.5	100.9	35.2
	50	78.6	27.4	81.3	28.4	84.2	29.4	86.0	30.0	88.3	30.8	90.9	31.7	93.0	32.5	94.9	33.1	96.7	33.8	98.6	34.4
Malvern 66 kV	10	98.1	22.4	100.8	23.0	104.3	23.8	107.2	24.5	110.6	25.3	114.5	26.2	118.2	27.0	121.4	27.7	124.8	28.5	128.4	29.3
	50	94.4	21.3	96.9	21.9	100.2	22.7	102.8	23.3	106.1	24.0	109.8	24.8	113.2	25.6	116.2	26.3	119.4	27.0	122.7	27.8
Tyabb 66 kV	10	220.2	83.2	228.9	86.5	238.5	90.1	246.6	93.2	255.3	96.5	266.1	100.6	276.2	104.4	285.0	107.7	293.5	110.9	302.3	114.2
	50	211.9	80.1	220.0	83.1	229.0	86.6	236.6	89.4	244.8	92.5	255.0	96.4	264.5	100.0	272.9	103.1	280.9	106.2	289.1	109.3

Alinta Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Heatherton 66 kV [1]	10	284.1	28.4	244.1	24.4	250.5	25.0	254.0	25.4	257.0	25.7	262.4	26.2	267.7	26.7	275.3	27.5	282.4	28.2	289.7	28.9
	50	278.5	27.8	238.2	23.8	244.2	24.4	247.5	24.7	250.2	25.0	255.3	25.5	260.3	26.0	267.6	26.7	274.4	27.4	281.3	28.1
Malvern 22 kV	10	72.1	21.9	74.1	22.5	76.3	23.2	77.3	23.5	78.5	23.9	80.6	24.5	81.9	24.9	83.6	25.4	85.2	25.9	87.0	26.4
	50	70.8	21.5	72.7	22.1	74.8	22.7	75.7	23.0	76.9	23.4	78.9	24.0	80.2	24.4	81.7	24.8	83.3	25.3	85.0	25.8
Malvern 66 kV	10	80.9	12.2	82.2	12.4	84.1	12.7	85.4	12.9	87.1	13.1	89.6	13.5	91.6	13.8	93.8	14.1	96.3	14.5	98.9	14.9
	50	79.4	11.8	80.6	12.0	82.5	12.3	83.6	12.5	85.2	12.7	87.6	13.1	89.5	13.3	91.7	13.7	94.1	14.0	96.5	14.4
Tyabb 66 kV	10	192.5	39.4	197.8	40.5	203.8	41.7	208.1	42.6	212.6	43.5	219.8	45.0	225.9	46.2	232.4	47.6	238.8	48.9	245.3	50.2
	50	187.6	38.4	192.6	39.4	198.3	40.6	202.3	41.4	206.6	42.3	213.5	43.7	219.4	44.9	225.6	46.2	231.7	47.4	237.9	48.7

[54] Forecast assumed load transfer to the new CBTS after next Summer season.

CitiPower Winter Peak Forecasts by Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	92.8	51.4	101.3	57.9	105.0	60.8	109.0	64.0	111.1	65.6	113.2	67.2	115.3	68.9	117.4	70.5	119.5	72.2	121.6	73.9
	50	85.9	46.4	93.8	52.5	97.2	55.2	101.0	58.1	102.9	59.6	104.8	61.1	106.7	62.6	108.7	64.2	110.6	65.7	112.6	67.2
West Melbourne 22 kV	10	97.6	64.2	106.5	72.6	116.3	82.1	121.8	87.4	124.1	89.7	126.3	91.9	128.4	94.0	130.6	96.2	132.8	98.4	135.0	100.6
	50	92.1	59.6	100.5	67.6	109.7	76.5	114.9	81.5	117.1	83.7	119.1	85.7	121.2	87.7	123.2	89.8	125.3	91.8	127.4	93.9
West Melbourne 66 kV	10	394.8	207.8	414.8	227.5	426.7	240.9	438.3	252.2	464.0	265.5	471.9	272.7	479.9	280.1	487.9	287.6	496.1	295.2	504.4	303.0
	50	372.2	190.1	391.1	208.6	402.3	221.3	413.3	231.9	437.5	244.4	444.9	251.3	452.4	258.2	460.0	265.3	467.7	272.5	475.5	279.8

CitiPower Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richmond 22 kV	10	69.9	27.0	78.2	33.0	84.1	37.2	86.6	39.1	88.8	40.6	90.5	41.9	92.3	43.1	94.1	44.4	96.0	45.7	97.8	47.0
	50	67.2	25.4	75.2	31.1	80.8	35.2	83.3	37.0	85.3	38.4	87.1	39.7	88.8	40.9	90.5	42.1	92.3	43.4	94.0	44.6
West Melbourne 22 kV	10	81.5	45.9	90.6	54.0	99.1	61.9	105.7	68.0	109.4	71.5	111.4	73.4	113.4	75.3	115.5	77.2	117.5	79.2	119.6	81.2
	50	78.4	43.5	87.1	51.3	95.3	58.8	101.7	64.8	105.2	68.1	107.1	69.9	109.1	71.8	111.0	73.6	113.0	75.5	115.0	77.4
West Melbourne 66 kV	10	316.8	139.6	339.3	161.1	354.8	176.4	364.4	187.8	373.6	196.9	394.0	204.6	400.6	210.8	407.3	217.1	414.0	223.5	420.8	230.0
	50	305.1	130.2	326.7	150.9	341.6	165.7	350.8	176.6	359.7	185.4	379.4	192.8	385.8	198.7	392.2	204.8	398.7	211.0	405.3	217.2

Powercor Summer Peak Forecasts by Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV	10	145.5	72.6	149.1	74.4	152.0	75.8	155.0	77.3	158.0	78.8	163.3	81.5	166.2	82.9	169.0	84.3	172.0	85.8	175.0	87.3
	50	145.5	72.6	149.1	74.4	152.0	75.8	155.0	77.3	158.0	78.8	163.3	81.5	166.2	82.9	169.0	84.3	172.0	85.8	175.0	87.3
Bendigo 22 kV	10	26.7	14.1	28.3	15.0	29.0	15.4	33.8	17.9	34.7	18.3	35.6	18.8	36.5	19.3	37.5	19.8	38.5	20.4	39.5	20.9
	50	25.7	13.6	27.3	14.4	28.0	14.8	32.8	17.3	33.7	17.8	34.6	18.3	35.5	18.8	36.5	19.3	37.5	19.8	38.5	20.4
Bendigo 66 kV	10	148.6	48.9	150.6	49.6	153.6	50.5	151.7	49.9	154.4	50.8	157.2	51.7	160.0	52.6	162.9	53.6	165.8	54.6	168.8	55.5
	50	141.6	46.6	143.6	47.3	146.6	48.2	144.7	47.6	147.4	48.5	150.2	49.4	153.0	50.3	155.9	51.3	158.8	52.3	161.8	53.2
Brooklyn 22 kV	10	58.3	38.9	61.2	40.8	62.3	41.5	64.3	42.8	65.6	43.7	66.9	44.6	68.2	45.4	69.5	46.3	70.9	47.2	72.2	48.1
	50	58.3	38.9	61.1	40.7	62.3	41.5	64.3	42.8	65.6	43.7	66.9	44.6	68.2	45.4	69.5	46.3	70.8	47.2	72.2	48.0

Powercor Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ballarat 66 kV	10	159.6	50.6	163.4	51.8	168.5	53.4	172.5	54.7	176.6	56.0	180.6	57.2	187.0	59.3	190.9	60.5	194.9	61.8	199.1	63.1
	50	159.6	50.6	163.4	51.8	168.5	53.4	172.5	54.7	176.6	56.0	180.6	57.2	187.0	59.3	190.9	60.5	194.9	61.8	199.1	63.1
Bendigo 22 kV	10	20.3	6.9	20.8	7.1	22.0	7.5	22.6	7.7	26.7	9.0	27.4	9.3	28.2	9.5	28.9	9.8	29.7	10.1	30.6	10.4
	50	20.3	6.9	20.8	7.1	22.0	7.5	22.6	7.7	26.7	9.0	27.4	9.3	28.2	9.5	28.9	9.8	29.7	10.1	30.6	10.4
Bendigo 66 kV	10	131.8	7.4	135.4	7.6	137.7	7.7	140.3	7.9	138.2	7.7	140.7	7.9	143.2	8.0	145.8	8.2	148.5	8.3	151.2	8.5
	50	131.8	7.4	135.4	7.6	137.7	7.7	140.3	7.9	138.2	7.7	140.7	7.9	143.2	8.0	145.8	8.2	148.5	8.3	151.2	8.5
Brooklyn 22 kV	10	58.2	38.4	59.4	39.2	59.7	39.4	59.0	39.0	60.0	39.6	58.9	38.9	59.9	39.6	58.8	38.9	59.8	39.5	60.7	40.1
	50	58.1	38.4	59.4	39.2	59.7	39.4	59.0	39.0	59.9	39.6	58.9	38.9	59.9	39.6	58.8	38.9	59.7	39.5	60.7	40.1

Powercor Summer Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Brooklyn-SCI 66 kV	10	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0
	50	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0
Geelong 66 kV	10	337.6	135.0	351.4	140.6	354.5	141.8	357.3	142.9	360.6	144.2	363.8	145.5	367.2	146.9	370.0	148.0	372.9	149.2	375.8	150.3
	50	329.6	112.1	343.4	116.8	346.5	117.8	349.3	118.8	352.6	119.9	355.8	121.0	359.2	122.1	362.0	123.1	364.9	124.1	367.8	125.1
Horsham 66 kV	10	66.3	19.2	67.1	19.4	68.0	19.6	68.8	19.9	69.7	20.2	70.6	20.4	71.5	20.7	72.4	20.9	73.4	21.2	74.3	21.5
	50	64.3	18.6	65.1	18.8	66.0	19.1	66.8	19.3	67.7	19.6	68.6	19.8	69.5	20.1	70.4	20.4	71.4	20.6	72.3	20.9
Kerang 22 kV	10	11.5	3.7	11.5	3.7	11.6	3.7	11.8	3.8	12.0	3.9	12.2	3.9	12.5	4.0	12.7	4.1	12.9	4.1	13.1	4.2
	50	11.1	3.5	11.1	3.6	11.2	3.6	11.4	3.7	11.6	3.7	11.8	3.8	12.1	3.9	12.3	3.9	12.5	4.0	12.7	4.1
Kerang 66 kV	10	53.1	13.9	55.0	14.4	56.8	14.9	58.8	15.4	60.8	15.9	62.8	16.5	64.4	16.9	66.0	17.3	67.6	17.7	69.3	18.2
	50	52.1	13.7	54.0	14.1	55.8	14.6	57.8	15.1	59.8	15.7	61.8	16.2	63.4	16.6	65.0	17.0	66.6	17.5	68.3	17.9

Powercor Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Brooklyn-SCI 66 kV	10	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0
	50	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0	60.0	20.0
Geelong 66 kV	10	306.1	79.6	326.0	84.8	331.5	86.2	334.6	87.0	337.7	87.8	340.9	88.6	343.9	89.4	347.3	90.3	350.0	91.0	352.9	91.8
	50	306.1	61.2	326.0	65.2	331.5	66.3	334.6	66.9	337.7	67.5	340.9	68.2	343.9	68.8	347.3	69.5	350.0	70.0	352.9	70.6
Horsham 66 kV	10	65.9	3.8	66.7	3.8	67.5	3.8	68.3	3.9	69.2	3.9	70.0	4.0	70.8	4.0	71.7	4.1	72.6	4.1	73.4	4.2
	50	65.9	3.8	66.7	3.8	67.5	3.8	68.3	3.9	69.2	3.9	70.0	4.0	70.8	4.0	71.7	4.1	72.6	4.1	73.4	4.2
Kerang 22 kV	10	12.3	2.0	12.5	2.0	12.6	2.0	12.8	2.0	13.0	2.1	13.1	2.1	13.3	2.1	13.4	2.1	13.6	2.2	13.8	2.2
	50	12.3	2.0	12.5	2.0	12.6	2.0	12.8	2.0	13.0	2.1	13.1	2.1	13.3	2.1	13.4	2.1	13.6	2.2	13.8	2.2
Kerang 66 kV	10	49.6	3.7	51.0	3.8	52.5	3.9	54.0	4.0	55.5	4.1	57.1	4.2	58.7	4.3	60.4	4.5	62.1	4.6	63.9	4.7
	50	49.6	3.7	51.0	3.8	52.5	3.9	54.0	4.0	55.5	4.1	57.1	4.2	58.7	4.3	60.4	4.5	62.1	4.6	63.9	4.7

Peak Summer Forecasts by Shared Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [55]	10	417.5	160.7	431.6	166.0	440.7	169.5	442.2	169.4	433.8	165.1	445.5	169.4	454.6	172.9	467.0	177.5	477.1	181.3	488.8	185.6
	50	394.2	151.7	408.1	156.9	417.0	160.3	418.9	160.4	411.3	156.5	422.8	160.8	431.8	164.1	444.1	168.7	454.0	172.4	465.6	176.7
Brunswick 22 kV	10	87.1	55.1	88.8	56.3	90.9	57.6	91.6	58.2	93.0	59.2	94.7	60.3	96.4	61.5	98.1	62.7	99.9	63.9	101.7	65.1
	50	81.2	51.3	82.8	52.4	84.7	53.7	85.4	54.2	86.7	55.1	88.3	56.2	89.9	57.3	91.5	58.4	93.1	59.5	94.8	60.7
Cranbourne 66 kV [56]	10	0.0	0.0	204.0	80.4	213.5	84.7	223.0	89.1	232.9	93.6	243.2	98.2	253.5	102.8	262.7	106.9	271.6	110.9	280.0	114.7
	50	0.0	0.0	197.3	77.5	206.3	81.6	215.3	85.6	224.6	89.9	234.5	94.3	244.3	98.7	253.0	102.6	261.4	106.4	269.4	109.9
East Rowville 66 kV [4]	10	541.8	190.8	417.2	140.5	437.1	148.1	455.7	155.3	474.3	162.7	493.3	170.0	512.9	177.5	531.0	184.5	547.7	191.0	564.6	197.4
	50	517.9	181.9	398.3	133.8	417.0	140.9	434.4	147.8	451.7	154.7	469.6	161.5	487.9	168.6	504.9	175.2	520.6	181.3	536.3	187.3
Fishermen's Bend 66 kV	10	244.1	104.4	267.9	122.7	284.1	135.2	293.1	142.4	301.7	149.7	309.2	156.3	316.7	163.0	324.2	169.8	331.8	176.6	339.4	183.5
	50	232.7	96.0	255.4	113.4	271.0	125.4	279.5	132.2	287.7	139.2	294.8	145.5	302.0	151.8	309.1	158.3	316.3	164.8	323.6	171.4

Peak Winter Forecasts by Shared Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Altona/Brooklyn 66 kV [2]	10	346.4	115.8	358.2	119.6	368.4	123.0	375.7	125.4	377.1	125.5	370.6	122.7	380.1	125.8	388.0	128.4	398.1	131.6	406.2	134.3
	50	341.0	113.9	352.7	117.7	362.9	121.1	370.1	123.5	371.7	123.7	365.4	121.0	374.9	124.1	382.7	126.6	392.8	129.9	400.9	132.5
Brunswick 22 kV	10	85.3	37.8	86.5	38.4	87.8	39.0	89.6	39.9	90.2	40.1	91.3	40.7	92.6	41.3	94.0	41.9	95.3	42.5	96.7	43.2
	50	81.9	36.3	83.1	36.9	84.4	37.5	86.1	38.3	86.7	38.5	87.7	39.0	89.0	39.6	90.3	40.2	91.6	40.8	92.9	41.4
Cranbourne 66 kV [3]	10	0.0	0.0	177.0	47.7	184.2	50.9	191.4	54.2	198.6	57.5	206.3	60.8	214.3	64.3	221.8	67.5	229.2	70.6	236.2	73.6
	50	0.0	0.0	172.3	46.3	179.2	49.4	186.0	52.5	192.8	55.7	200.2	58.9	207.9	62.2	215.1	65.2	222.2	68.2	229.0	71.1
East Rowville 66 kV [57]	10	484.1	117.1	377.5	91.0	390.9	96.1	402.1	100.6	412.5	105.0	424.8	109.5	436.9	114.0	448.3	118.1	459.9	122.3	471.9	126.5
	50	468.5	113.1	365.7	88.0	378.4	92.8	389.0	97.1	398.9	101.3	410.6	105.6	422.1	109.9	433.0	113.8	444.0	117.7	455.6	121.8
Fishermen's Bend 66 kV	10	193.7	65.7	225.8	85.5	244.1	99.4	254.8	107.4	264.6	115.2	271.5	121.2	278.5	127.3	285.6	133.4	292.6	139.7	299.7	146.0
	50	188.1	61.6	219.4	80.9	237.2	94.4	247.6	102.2	257.1	109.8	263.8	115.6	270.6	121.5	277.5	127.5	284.3	133.5	291.2	139.6

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[55] Air Liquide load is included in load forecasts. Air Liquide may be directly supplied from ATS 66 kV bus in 2003.
[56] Cranbourne terminal station is expected to supply mainly Berwick, Pakenham and Frankston area loads transferred from East Rowville and Heatherton terminal stations.
[57] Forecast assumed load transfer to the new CBTS after next Summer season. 15 MW of embedded generation is considered as negative load.

Peak Summer Forecasts by Shared Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Keilor 66 kV	10	468.7	223.3	486.3	231.7	504.2	240.2	528.6	252.1	544.6	259.5	559.0	266.1	573.6	272.9	589.0	279.9	603.4	286.6	618.6	293.6
	50	441.8	210.5	458.9	218.6	476.3	226.9	499.9	238.3	515.5	245.6	529.6	252.0	544.0	258.6	559.1	265.6	573.3	272.1	588.2	278.9
Loy Yang 66 kV [58]	10	36.5	29.2	36.8	29.4	37.0	29.6	37.3	29.8	37.6	30.0	37.8	30.3	38.1	30.5	38.4	30.7	38.6	30.9	38.9	31.1
	50	36.0	28.8	36.3	29.0	36.5	29.2	36.8	29.4	37.0	29.6	37.3	29.8	37.5	30.0	37.8	30.2	38.1	30.5	38.3	30.7
Morwell/Loy Yang 66 kV [59]	10	359.2	95.3	363.6	97.5	368.0	99.7	372.3	101.9	376.6	104.0	380.9	106.2	385.3	108.3	389.7	110.5	394.1	112.7	398.4	114.9
	50	349.0	92.8	353.3	94.9	357.6	97.0	361.7	99.1	365.9	101.2	370.1	103.3	374.3	105.4	378.6	107.6	382.9	109.7	387.1	111.8
Richmond 66 kV	10	495.1	237.7	512.1	252.4	523.8	262.1	532.0	268.9	540.2	275.7	548.6	282.7	557.2	289.8	565.7	296.8	574.1	303.9	582.7	311.1
	50	460.6	210.7	476.4	224.3	487.2	233.3	494.9	239.6	502.4	246.0	510.2	252.4	518.2	259.0	526.1	265.5	533.9	272.1	541.9	278.7
Ringwood 22 kV	10	97.0	43.7	100.5	45.3	104.4	47.1	107.6	48.5	110.5	49.8	113.5	51.2	116.7	52.7	119.6	54.0	122.3	55.2	125.0	56.5
	50	92.8	41.8	96.1	43.3	99.8	45.0	102.8	46.3	105.5	47.6	108.3	48.9	111.3	50.2	114.0	51.5	116.5	52.6	119.0	53.7

Peak Winter Forecasts by Shared Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Keilor 66 kV	10	373.0	141.1	393.8	148.4	412.2	155.1	427.4	160.8	447.6	168.7	461.8	173.8	473.7	178.0	485.8	182.3	502.7	188.2	515.5	192.7
	50	365.7	138.4	386.4	145.6	404.7	152.3	419.8	157.9	439.8	165.7	453.9	170.8	465.8	175.0	477.8	179.2	494.6	185.1	507.4	189.6
Loy Yang 66 kV [5]	10	36.5	29.5	36.8	29.8	37.1	30.0	37.3	30.2	37.6	30.4	37.9	30.6	38.2	30.9	38.4	31.1	38.7	31.3	39.0	31.6
	50	36.0	29.1	36.3	29.3	36.5	29.5	36.8	29.8	37.1	30.0	37.3	30.2	37.6	30.4	37.9	30.6	38.2	30.9	38.4	31.1
Morwell/Loy Yang 66 kV [6]	10	388.0	92.2	393.6	95.0	398.3	97.3	403.0	99.6	407.6	101.9	412.2	104.3	416.8	106.6	421.5	108.9	426.1	111.2	430.8	113.6
	50	377.0	89.7	382.5	92.5	387.0	94.7	391.5	97.0	396.0	99.2	400.5	101.5	405.0	103.7	409.5	106.0	414.0	108.2	418.6	110.5
Richmond 66 kV	10	399.6	121.3	419.7	136.9	431.8	146.2	438.8	151.5	445.3	156.6	452.2	161.8	459.1	167.0	466.2	172.4	473.5	177.8	480.7	183.3
	50	385.2	111.7	404.4	126.6	416.1	135.6	422.8	140.7	429.0	145.5	435.6	150.5	442.3	155.6	449.1	160.7	456.1	165.9	463.0	171.2
Ringwood 22 kV	10	83.5	34.8	86.2	35.9	89.3	37.2	91.5	38.1	93.7	39.0	96.4	40.1	99.1	41.3	102.1	42.5	105.3	43.8	108.7	45.1
	50	80.5	33.7	83.1	34.7	86.0	35.9	88.1	36.8	90.2	37.6	92.7	38.7	95.3	39.8	98.1	40.9	101.2	42.1	104.3	43.4

[58] Forecasts allow for continuous Loy Yang Power Station load of 10 MW and 15 MW of open-cut load. For an outage of unit transformer Loy Yang load could increase by up to 50 MW.

[59] Forecasts are on the basis that Morwell G1-3 units (80 MW), Duke (80 MW) and Toora wind farm (21 MW) generators are not operating, but that full output is provided by small embedded generators (26 MW), ie:considered as negative loads. Forecasts allow for continuous Loy Yang Power Station load of 10 MW and 15 MW of open-cut load. For an outage of unit transformer Loy Yang load could increase by up to 50 MW.

Peak Summer Forecasts by Shared Terminal Station

Terminal Station	POE	2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ringwood 66 kV	10	407.5	177.7	419.0	182.8	430.6	187.7	441.5	192.4	452.0	197.0	461.7	201.0	471.1	204.8	479.8	208.4	488.1	211.8	496.5	215.3
	50	386.6	167.9	397.4	172.7	408.3	177.3	418.5	181.7	428.3	186.0	437.5	189.9	446.3	193.4	454.5	196.8	462.3	200.0	470.2	203.3
Springvale 66 kV [60]	10	431.6	100.1	444.3	103.1	458.3	106.3	471.6	109.4	484.9	112.6	500.2	116.1	515.6	119.7	529.3	122.9	542.0	125.9	555.1	129.0
	50	416.2	95.6	428.0	98.3	440.9	101.3	453.3	104.2	465.7	107.1	480.0	110.5	494.4	113.8	507.2	116.8	519.1	119.6	531.2	122.4
Templestowe 66 kV	10	294.8	109.8	302.9	113.5	311.7	117.3	318.8	120.6	325.1	123.6	332.4	126.8	339.9	130.2	346.1	132.9	352.3	135.7	358.6	138.7
	50	277.4	100.8	285.0	104.2	293.2	107.8	299.6	110.8	305.6	113.5	312.4	116.5	319.3	119.6	325.0	122.2	330.6	124.8	336.5	127.5
Thomastown Bus 1&2 66 kV [61]	10	308.5	163.2	326.7	172.8	338.6	178.9	348.9	184.2	358.7	189.3	367.9	194.1	377.1	198.8	385.7	203.3	393.8	207.5	402.0	211.8
	50	292.2	154.5	309.4	163.6	320.7	169.4	330.4	174.5	339.7	179.3	348.5	183.8	357.2	188.3	365.4	192.5	373.0	196.5	380.9	200.6
Thomastown Bus 3&4 66 kV [62]	10	324.2	181.7	336.7	188.4	346.8	193.8	355.2	198.2	364.2	202.9	372.8	207.5	380.7	211.6	388.7	215.9	396.8	220.2	405.1	224.6
	50	307.0	172.1	318.9	178.4	328.4	183.5	336.4	187.7	344.9	192.2	353.1	196.5	360.5	200.4	368.1	204.4	375.8	208.5	383.7	212.7

Peak Winter Forecasts by Shared Terminal Station

Terminal Station	POE	2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
		MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Ringwood 66 kV	10	342.3	82.9	352.1	87.5	361.4	91.6	370.0	95.4	377.6	98.9	385.6	102.4	393.1	105.6	400.5	108.6	407.4	111.4	414.0	114.1
	50	333.2	80.6	342.6	85.0	351.6	89.0	359.9	92.7	367.3	96.1	375.0	99.5	382.3	102.6	389.4	105.5	396.1	108.2	402.5	110.8
Springvale 66 kV [7]	10	362.6	65.7	370.2	67.1	378.4	68.6	385.6	69.9	392.3	71.2	402.5	73.1	411.9	74.8	422.6	76.8	432.8	78.7	443.3	80.6
	50	354.1	63.8	361.1	65.1	368.7	66.6	375.4	67.8	381.7	69.0	391.4	70.8	400.3	72.4	410.4	74.3	420.2	76.1	430.1	77.9
Templestowe 66 kV	10	255.0	81.6	258.0	81.3	265.0	84.1	269.5	86.1	274.4	88.4	280.0	90.6	285.6	92.8	290.8	94.9	296.1	97.0	301.5	99.2
	50	244.9	76.8	247.8	76.6	254.4	79.2	258.5	81.1	263.2	83.2	268.6	85.3	273.9	87.5	278.8	89.4	283.8	91.4	288.9	93.5
Thomastown Bus 1&2 66 kV [8]	10	262.4	129.1	273.1	134.3	287.5	141.3	296.2	145.5	303.8	149.2	310.2	152.4	316.6	155.6	323.1	158.8	329.1	161.7	335.2	164.7
	50	252.1	124.0	262.4	129.0	276.3	135.7	284.6	139.8	291.9	143.4	298.0	146.4	304.1	149.4	310.4	152.5	316.1	155.3	322.0	158.2
Thomastown Bus 3&4 66 kV [9]	10	288.4	119.4	296.7	123.5	307.0	128.5	314.3	132.1	320.8	135.3	327.9	138.7	333.6	141.5	339.4	144.4	345.3	147.3	350.4	149.8
	50	277.1	114.9	285.0	118.8	294.9	123.6	301.9	127.0	308.2	130.1	314.9	133.4	320.4	136.1	325.9	138.8	331.6	141.6	336.5	144.0

[60] 16 MW of embedded generation is considered as negative load.
[61] Somerton Power Station is not included in the forecasts. However, other small embedded generators (21 MW in total) are considered as negative loads (i.e: assumed to be exporting energy).
[62] 10 MW of embedded generation is considered as negative load.

Powercor Summer Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	35.0	19.5	35.8	19.9	36.6	20.4	37.5	20.9	38.3	21.4	39.2	21.9	40.2	22.4	41.1	22.9	42.1	23.5	43.1	24.0
	50	34.0	18.9	34.8	19.4	35.6	19.8	36.5	20.3	37.3	20.8	38.2	21.3	39.2	21.8	40.1	22.4	41.1	22.9	42.1	23.5
Red Cliffs 66 kV	10	116.0	33.1	120.9	34.4	126.8	36.1	132.0	37.6	137.3	39.1	141.6	40.4	145.6	41.5	149.8	42.7	154.0	43.9	158.4	45.1
	50	112.0	31.9	116.9	33.3	122.8	35.0	128.0	36.5	133.3	38.0	137.6	39.2	141.6	40.4	145.8	41.6	150.0	42.7	154.4	44.0
Shepparton 66 kV	10	267.4	106.7	269.6	107.6	271.9	108.5	279.3	111.5	287.1	114.5	296.1	118.1	304.5	121.5	313.2	125.0	322.2	128.6	331.5	132.3
	50	252.4	100.7	254.6	101.6	256.9	102.5	264.3	105.5	272.1	108.6	281.1	112.2	289.5	115.5	298.2	119.0	307.2	122.6	316.5	126.3
Tyabb 220 kV	10	62.3	47.1	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4
	50	62.3	47.1	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4	65.3	46.4
Terang 66 kV	10	155.4	61.5	159.2	63.0	162.8	64.5	165.8	65.7	168.9	66.9	172.1	68.2	175.4	69.4	178.7	70.8	182.1	72.1	182.1	72.1
	50	155.4	61.5	159.2	63.0	162.8	64.5	165.8	65.7	168.9	66.9	172.1	68.2	175.4	69.4	178.7	70.8	182.1	72.1	182.1	72.1

Powercor Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Red Cliffs 22 kV	10	20.2	4.7	20.5	4.8	20.9	4.9	21.2	5.0	21.6	5.0	22.0	5.1	22.4	5.2	22.8	5.3	23.2	5.4	23.6	5.5
	50	20.2	4.7	20.5	4.8	20.9	4.9	21.2	5.0	21.6	5.0	22.0	5.1	22.4	5.2	22.8	5.3	23.2	5.4	23.6	5.5
Red Cliffs 66 kV	10	94.8	4.5	97.2	4.6	99.6	4.7	102.2	4.8	104.8	4.9	107.5	5.1	110.2	5.2	113.0	5.3	115.9	5.4	118.8	5.6
	50	94.8	4.5	97.2	4.6	99.6	4.7	102.2	4.8	104.8	4.9	107.5	5.1	110.2	5.2	113.0	5.3	115.9	5.4	118.8	5.6
Shepparton 66 kV	10	210.5	24.8	212.8	25.1	215.3	25.4	221.3	26.1	227.6	26.9	234.1	27.6	243.0	28.7	250.0	29.5	257.3	30.4	264.8	31.3
	50	210.5	24.8	212.8	25.1	215.3	25.4	221.3	26.1	227.6	26.9	234.1	27.6	243.0	28.7	250.0	29.5	257.3	30.4	264.8	31.3
Tyabb 220 kV	10	64.3	49.3	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8
	50	64.3	49.3	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8	67.3	47.8
Terang 66 kV	10	168.3	35.2	173.4	36.2	177.7	37.1	181.7	38.0	184.5	38.6	188.0	39.3	191.5	40.0	195.1	40.8	198.7	41.5	202.5	42.3
	50	168.3	35.2	173.4	36.2	177.7	37.1	181.7	38.0	184.5	38.6	188.0	39.3	191.5	40.0	195.1	40.8	198.7	41.5	202.5	42.3

TXU Summer Peak Forecasts by Terminal Station

		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [63]	10	86.1	48.7	87.6	49.5	89.0	50.2	90.5	50.9	91.9	51.7	93.4	52.4	94.9	53.1	96.3	53.8	97.8	54.6	99.2	55.3
	50	82.0	46.4	83.4	47.1	84.8	47.8	86.2	48.5	87.6	49.2	88.9	49.9	90.3	50.6	91.7	51.3	93.1	52.0	94.5	52.7
Mount Beauty 66 kV [64]	10	35.8	6.3	36.4	6.6	37.1	6.9	37.7	7.2	38.4	7.6	39.1	8.0	39.8	8.3	40.5	8.6	41.1	8.9	41.8	9.3
	50	32.5	5.7	33.1	6.0	33.7	6.3	34.3	6.6	34.9	6.9	35.6	7.2	36.2	7.5	36.8	7.8	37.4	8.1	38.0	8.4
Wodonga 22 kV	10	25.9	15.2	26.2	15.3	26.4	15.5	26.7	15.6	26.9	15.7	27.2	15.9	27.5	16.0	27.7	16.1	28.0	16.2	28.2	16.4
	50	25.4	14.9	25.7	15.0	25.9	15.2	26.2	15.3	26.4	15.4	26.7	15.5	26.9	15.7	27.2	15.8	27.4	15.9	27.7	16.1
Wodonga 66 kV [65]	10	55.1	19.7	55.6	20.0	56.2	20.3	56.8	20.6	57.3	20.9	57.9	21.1	58.4	21.4	59.0	21.7	59.5	22.0	60.1	22.3
	50	54.0	19.4	54.5	19.6	55.1	19.9	55.6	20.2	56.2	20.5	56.7	20.7	57.3	21.0	57.8	21.3	58.4	21.6	58.9	21.8
Yallourn 11 kV	10	22.0	8.9	22.4	9.1	22.7	9.2	23.0	9.3	23.4	9.5	23.7	9.6	24.1	9.8	24.5	9.9	24.8	10.0	25.2	10.2
	50	21.6	8.7	21.9	8.9	22.3	9.0	22.6	9.1	22.9	9.3	23.3	9.4	23.6	9.6	24.0	9.7	24.3	9.8	24.7	10.0

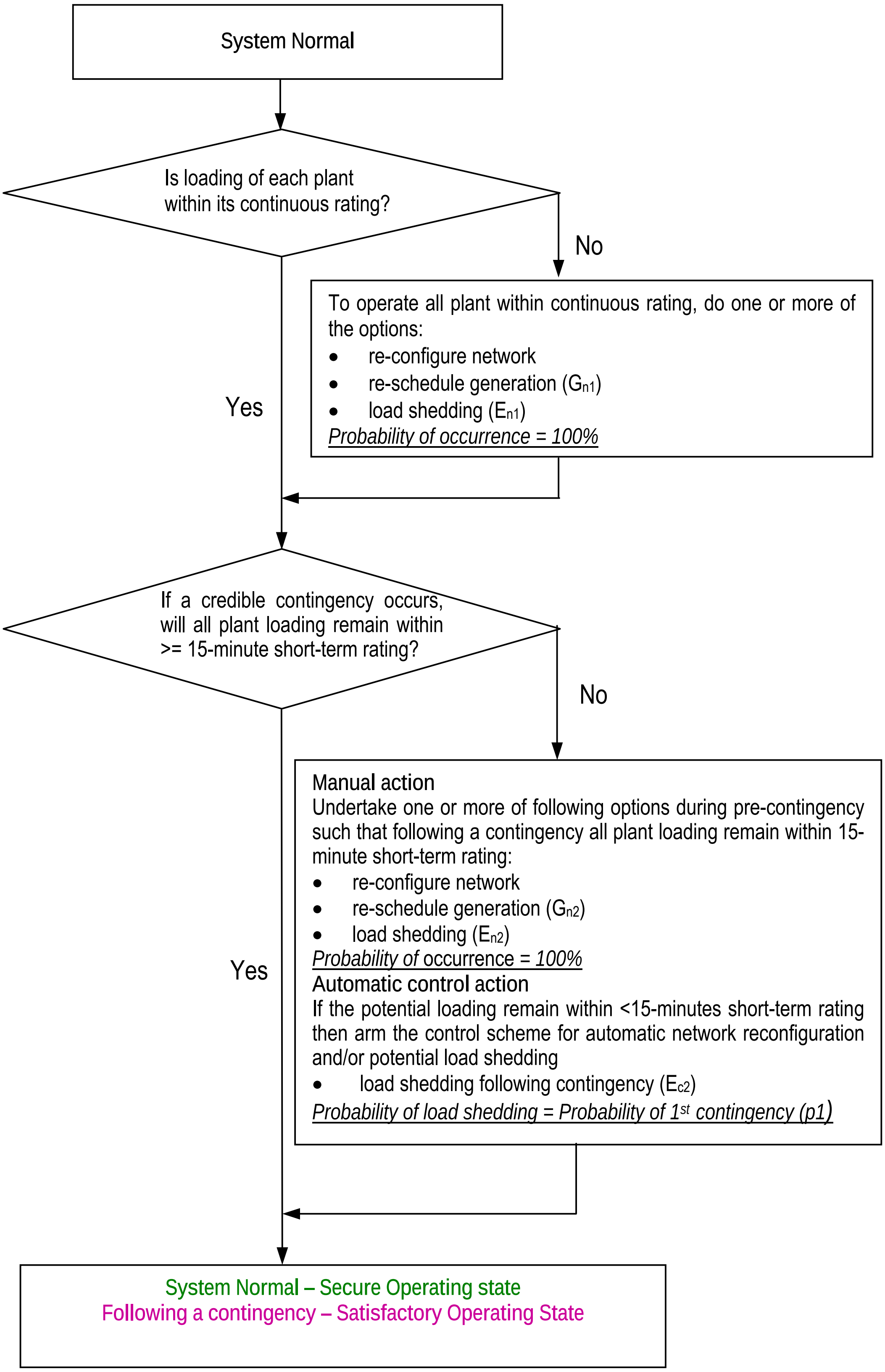
TXU Winter Peak Forecasts by Terminal Station

		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012	
Terminal Station	POE	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Glenrowan 66 kV [10]	10	102.9	27.9	103.2	28.1	104.6	28.7	106.0	29.4	107.3	30.1	108.7	30.8	110.1	31.5	111.4	32.2	112.8	32.8	114.2	33.5
	50	98.0	26.6	98.3	26.7	99.6	27.4	100.9	28.0	102.2	28.7	103.5	29.3	104.8	30.0	106.1	30.6	107.4	31.3	108.7	31.9
Mount Beauty 66 kV [11]	10	51.5	7.2	52.7	7.8	53.9	8.4	55.1	9.0	56.3	9.6	57.6	10.3	58.8	10.9	60.1	11.5	61.3	12.1	62.5	12.7
	50	49.0	6.9	50.2	7.4	51.3	8.0	52.5	8.6	53.6	9.2	54.9	9.8	56.0	10.4	57.2	11.0	58.3	11.5	59.5	12.1
Wodonga 22 kV	10	29.1	7.3	29.4	7.4	29.7	7.6	30.0	7.7	30.3	7.9	30.6	8.0	30.9	8.2	31.2	8.3	31.5	8.5	31.8	8.6
	50	28.5	7.1	28.8	7.3	29.1	7.4	29.4	7.6	29.7	7.7	30.0	7.9	30.3	8.0	30.6	8.2	30.9	8.3	31.2	8.5
Wodonga 66 kV	10	44.8	14.5	45.2	14.7	45.6	14.9	46.0	15.1	46.4	15.3	46.8	15.5	47.2	15.7	47.6	15.9	48.0	16.1	48.4	16.3
	50	43.9	14.2	44.3	14.4	44.7	14.6	45.1	14.8	45.5	15.0	45.9	15.2	46.3	15.4	46.7	15.6	47.1	15.8	47.5	16.0
Yallourn 11 kV	10	23.2	9.4	24.0	9.7	24.7	10.0	25.4	10.3	26.2	10.6	26.7	10.8	27.2	11.1	27.8	11.3	28.3	11.5	28.9	11.7
	50	22.7	9.2	23.5	9.5	24.2	9.8	24.9	10.1	25.7	10.4	26.2	10.6	26.7	10.8	27.2	11.1	27.8	11.3	28.3	11.5

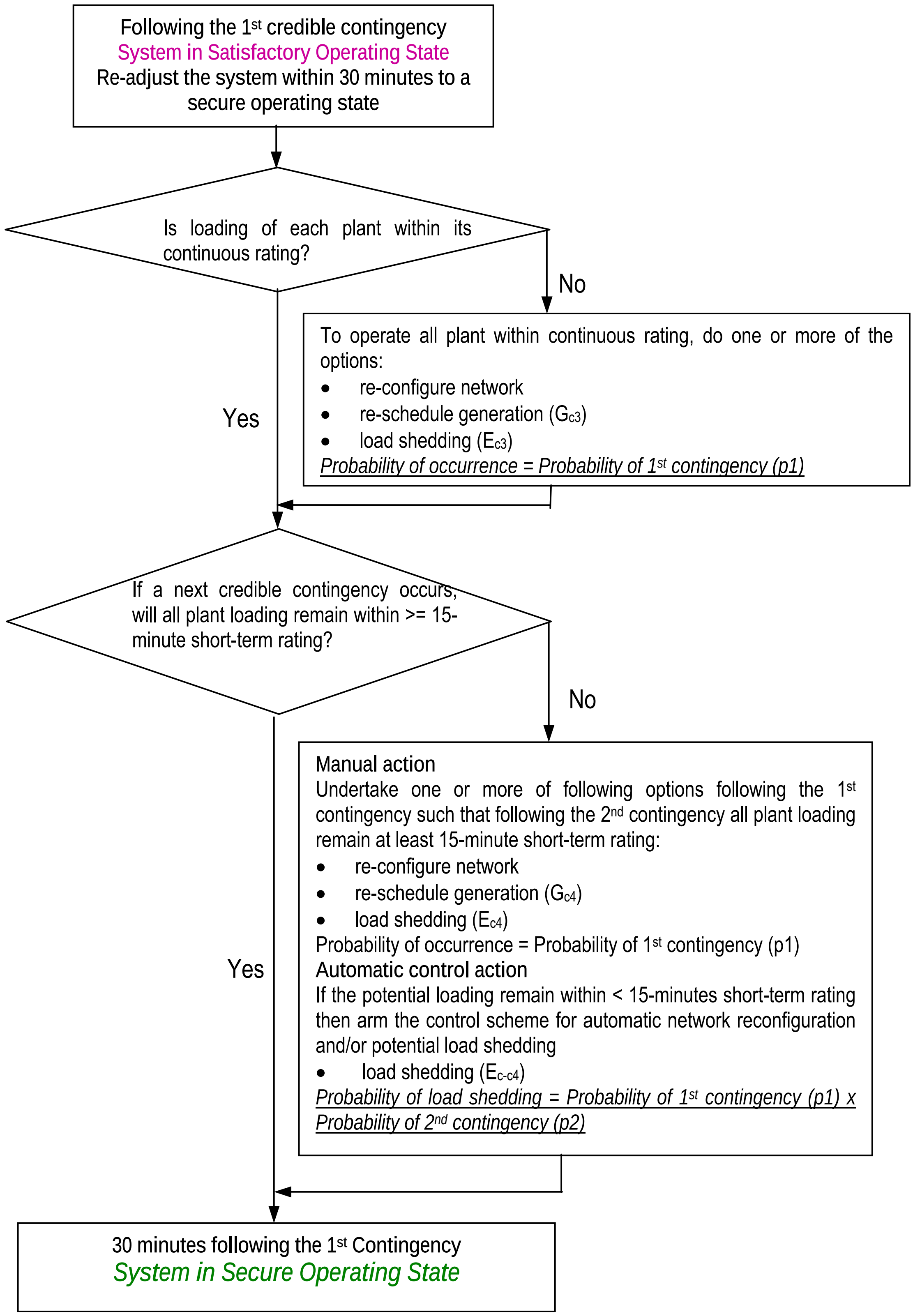
[63] Lake William Hovell embedded generator is considered as negative load.
[64] Forecasts are on the basis Clover Power Station (24 MW) embedded generation is not operating.
[65] Forecast excludes generation from Hume Power Station.

A2 ELECTRICITY TRANSMISSION PLANNING – ASSESSMENT OF SECURE OPERATING STATE

System Normal



Within 30 minutes following the 1st Credible Contingency



Definitions of secure operating state and satisfactory operating state are as referred in the National Electricity Code.

A2.1 Probabilistic Assessment

Expected rescheduled generation $= G_{n1} + G_{n2} + G_{c3} \times p1 + G_{c4} \times p1$

Expected unserved energy $= E_{n1} + E_{n2} + E_{c2} \times p1 + E_{c3} \times p1 + E_{c4} \times p1 + E_{c\text{-}c4} \times p1 \times p2 +$ expected unserved energy due to inadvertent operation of the control scheme + expected unserved energy due to failure of the control scheme + risk due to failure of the control scheme.

Authorised by VENCorp Level 2 Yarra Tower, World Trade Centre, Melbourne 3005.