VENCorp

APPLICATION NOTICE

NEW LARGE NETWORK ASSET

ADDITIONAL 500/220kV TRANSFORMATION TO
SUPPORT MELBOURNE METROPOLITAN LOAD GROWTH

JUNE 2005

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DISCLAIMER

VENCorp's role in the Victorian electricity supply industry includes planning and directing augmentation of the electricity transmission network to provide, in an economic manner, a reliable and effective transmission network. This report describes development of a large network asset, involving establishment of a new 500/220kV transformer, to support load growth in the Melbourne metropolitan area.

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1. Executive Summary

This document forms the basis of VENCorp's regulatory test application and public consultation on a proposal to develop a new large network asset to support load growth in the Melbourne metropolitan area. The development involves the installation and switching of a new 500/220kV transformer. This report follows from VENCorp's preliminary review, as reported in its 2004 Electricity Annual Planning Report (Section 6.9).

VENCorp has now completed its detailed analysis and concluded the preferred augmentation is installation of a second 500/220kV, 1000MVA transformer at Rowville Terminal Station available for service in September 2007.

VENCorp estimates it will be required to invest a total capitalised expenditure of \$37.2M ± 25% and the scope of works includes:

- installation of a 500/220kV, 1000MVA continuous (1500MVA for 30 minutes) transformer at Rowville Terminal Station;
- extension of the Rowville Terminal Station 500kV switchyard to include two new bays and four new circuit breakers and associated plant;
- extension of the Rowville Terminal Station 220kV switchyard to include three new circuit breakers and associated plant; and
- the advanced replacement of 14 circuit breakers at both the Rowville and East Rowville Terminal Station 220kV switchyards to allow for increased fault levels.

Over the 45 years of the asset life of the option and for timing of September 2007, the expected present value of the market benefits ranges from \$191.7M to \$108.3[1], delivering an expected net present value of the market benefit of between \$161.5M to \$80.5M, averaging over the sensitivity studies at \$117.6M.

VENCorp considers this project satisfies Part 1(b) of the Regulatory Test on the basis it maximises the expected net present value of the market benefits compared with a number of alternative options and timings, in a majority of reasonable scenarios.

This project primarily improves the reliability of supply to customers in the east and south-east metropolitan area of Melbourne in an economic manner. This project is not by definition a 'reliability augmentation'.

The preferred augmentation has both contestable and non-contestable components as some of the works are integrated with, and associated with improving the capability of, the existing assets of both Rowville Transmission Facility Pty Ltd[2] and SPI PowerNet Pty Ltd. For the purposes of this assessment, VENCorp has not differentiated between these components.

VENCorp does not consider the preferred augmentation will have a material inter-regional impact.

Submissions regarding this Application Notice close on Friday 15th July 2005.

[1] All present values are based on real dollars as of July 2005, unless explicitly stated.
[2] Rowville Transmission Facility Pty Ltd owns the existing Rowville 500kV switchyard and the Rowville A1 transformer.

2. Process

This Application Notice addresses the requirements of Clause 5.6.6 of the National Electricity Code. In respect of this clause, all code participants and interested parties are invited to make relevant submissions to VENCorp. These written submissions or inquiries can be forwarded by email to:

Mr. Joe Spurio
Manager, Electricity Planning
VENCorp
PO Box 413
World Trade Centre, VIC 8005

Email: Vencorp@vencorp.vic.gov.au

The closing date for submissions to this notice is Friday 15th July 2005.

In accordance with the requirements of the National Electricity Code, VENCorp will consider all submissions and present a Final Report that summarises these plus VENCorp's responses.

3. VENCorp's Role and Background of the Constraint

VENCorp is the provider of shared electricity transmission network services in Victoria and has responsibilities under various legal and regulatory instruments to plan and direct the augmentation of the shared network within Victoria.

VENCorp executes its planning role in an independent manner, with the objective of undertaking effective planning and development of the shared transmission network so as to maximise net benefits to electricity participants (including end consumers) as a whole.

As the first step in the development of the network, VENCorp's 2004 Electricity Annual Planning Report identified certain constraints associated with supply of electricity via the shared transmission network to a number of east and south-east Melbourne metropolitan terminal stations.

Section 6.9 of the Annual Planning Report identified that system normal constraints (i.e. prior to any outages occurring) were forecast to occur during summer 2007/08 based on excessive power flows on both the Rowville and the Cranbourne 500/220kV transformers. The increased loading on these transformers is primarily driven by load growth in the east and south-east Melbourne metropolitan area.

Further to these system normal constraints, it was identified that, after an outage of either of the Rowville or Cranbourne transformers, considerable constraints were associated with the metropolitan 220kV lines that were required to pick up additional load, due to their limited thermal transfer capacities. Minor constraints were associated with the need to return the system to a satisfactory operating state after a transformer outage, but much larger and more onerous constraints were associated with securing the system prior to a number of subsequent outages. These constraints were forecast to grow considerably over the planning horizon.

The 2004 Annual Planning Report concluded that subject to the detailed application of the regulatory test, a large network augmentation for the installation and switching of a new metropolitan 500/220kV transformer valued at around $45M could be justified for installation by December 2006.

It also indicated that, subject to the detailed application of the regulatory test, VENCorp could justify small network augmentations covering minor upgrade works on transmission lines and works to mitigate excessive fault levels valued at around $6M prior to December 2005.

Since the 2004 Annual Planning Report, VENCorp has applied the regulatory test to one small network asset ($1M < cost < $10M) and three minor network augmentations (cost < $1M) in the south-east metropolitan area. This has resulted in the following developments being undertaken with expected practical completion dates during summer 2005/06:

1. *Minor Network Augmentation*

   Thomastown to Ringwood 220kV Transfer Capacity Upgrade - Tower Replacements

   An upgrade of the node to node rating of the Thomastown to Ringwood 220kV line from 465MVA to 658MVA (a 41% increase, based on an ambient temperature of 40°C). The scope of work covers the replacement of three 220kV towers and the conversion of another three from suspension to strain type at an estimated capital cost of $915k±25%. The present value of the gross market benefit of this project is $13.8M, and the net present value of the market benefit of this project is $12.9M.

2. *Minor Network Augmentation*

   Thomastown to Templestowe 220kV Transfer Capacity Upgrade - Tower Replacement

   An upgrade of the node to node rating of the Thomastown to Templestowe 220kV line from 465MVA to 658MVA (a 41% increase, based on an ambient temperature of 40°C). The scope of work covers the replacement of one 220kV tower at an estimated capital cost of $245k±25%. The present value of the gross market benefit of this project is $1.72M, and the net present value of the market benefit of this project is $1.47M.

3. *Minor Network Augmentation*

   Latrobe Valley to Melbourne 220kV Transfer Capacity Upgrade - Wind Monitoring

   An upgrade of the node to node rating of the Yallourn and Hazelwood to Rowville 220 kV lines by use of wind monitoring stations and the application of real time wind speed in determination of thermal ratings. Given an ambient temperature of 40°C and a transverse wind speed of 1.2m/s rather than the default level of 0.6m/s, this reflects in an upgrade from 268MVA to 315MVA (18% increase). The scope of work covers installation of wind monitoring stations at an estimated capital cost of $780k±25%. The present value of the gross market benefit of this project is $13.6M, and the net present value of the market benefit of this project is $12.8M.

4. *Small Network Asset*

   Rowville to Richmond 220kV Transfer Capacity Upgrade - Termination Upgrade

   The augmentation is an upgrade to the Rowville to Richmond 220kV Transfer Capacity through upgrades of line terminations. The augmentation upgrades the node to node rating of the Rowville to Richmond 220kV lines from 465MVA to 586MVA (a 26% increase, based on an ambient temperature of 40°C) through replacement of a circuit breaker and four isolators at

Rowville at an estimated capital cost of $1.25M ± 25%. The present value of the gross market benefit of this project is $2.7M, and the net present value of the market benefit of this project is $1.5M.

Given these developments, this Application Notice presents the results of the detailed application of the regulatory test for a new large network asset, involving establishment of a 500/220kV transformer, to support load growth in the east and south-east Melbourne metropolitan area.

4. Location of the Constraints

The constraints underpinning the need for augmentation occur on the meshed 220kV transmission lines to the south east of Thomastown Terminal Station and on the Rowville and Cranbourne 500/220kV transformers as shown in the geographical map of Figure 4-1 and the electrical single line schematic of Figure 4-2.

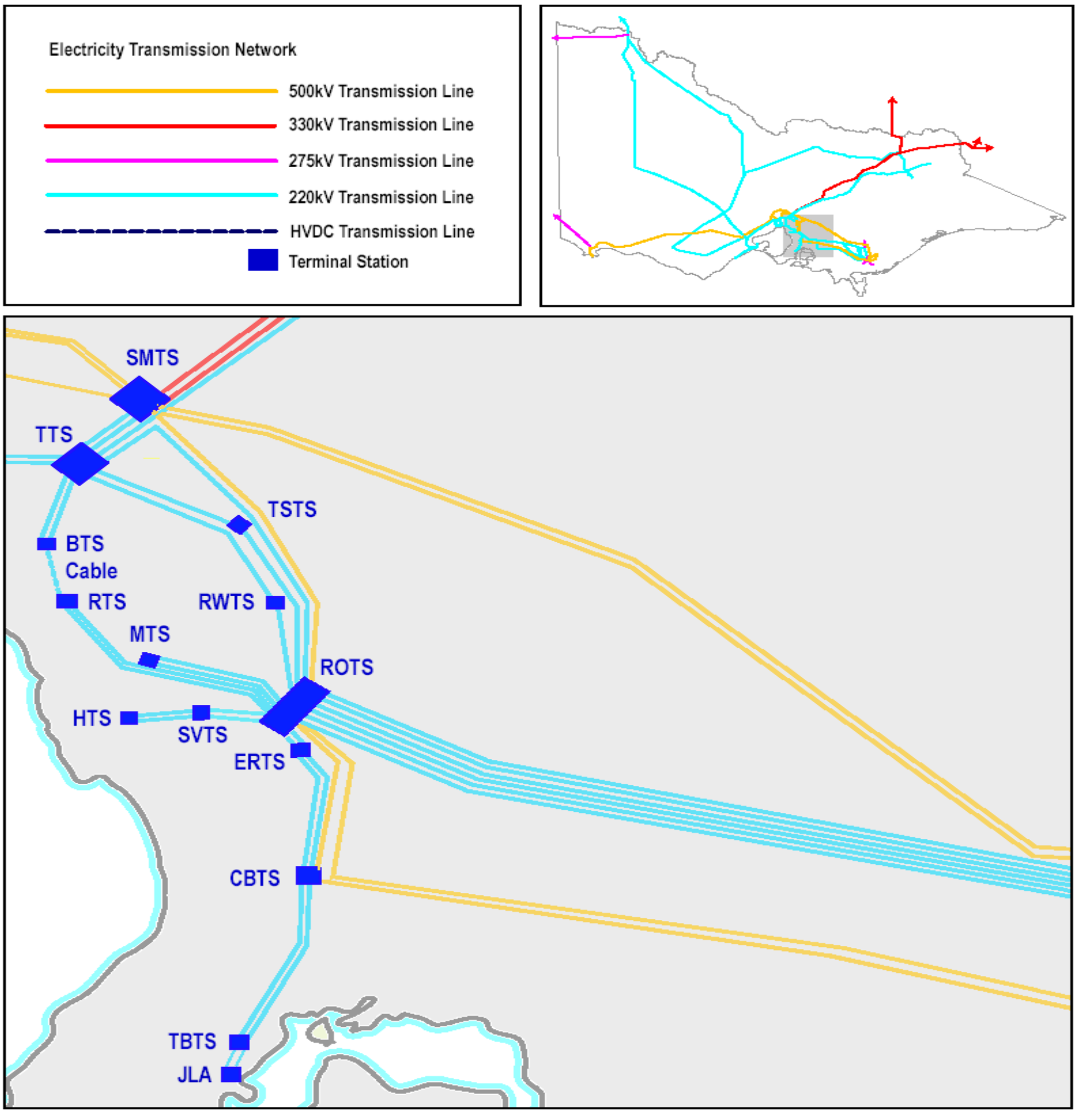

Figure 4-1: Geographical presentation of the terminal stations affected by the forecast constraints.

The affected terminal stations (primarily - Richmond, Cranbourne, East Rowville and Tyabb from the Rowville 1&2 220kV bus group, and Ringwood, Templestowe, Malvern, Springvale and Heatherton from the Rowville 3&4 220kV bus group) supply a wide area covering Melbourne's eastern central business district, St Kilda and Fitzroy, plus areas as far south as Frankston through to Portsea, as far north as Eltham, and as far east as Mitcham through to Cranbourne and Pakenham.

The aggregate demand supplied through these terminal stations accounts for some 35% of the Victorian peak summer demand, and supplies four of the five Victorian distribution businesses.

The two 500/220kV, 1000MVA transformers at Rowville and Cranbourne are critical to the supply into the meshed network. The 220kV spilt bus arrangement at Rowville is an important characteristic of the network. It cannot be closed due to fault level implications which are neither technically or commercially feasible to overcome. The bus split arrangement reduces the reliability and effectiveness of the transmission lines, especially after critical contingencies.

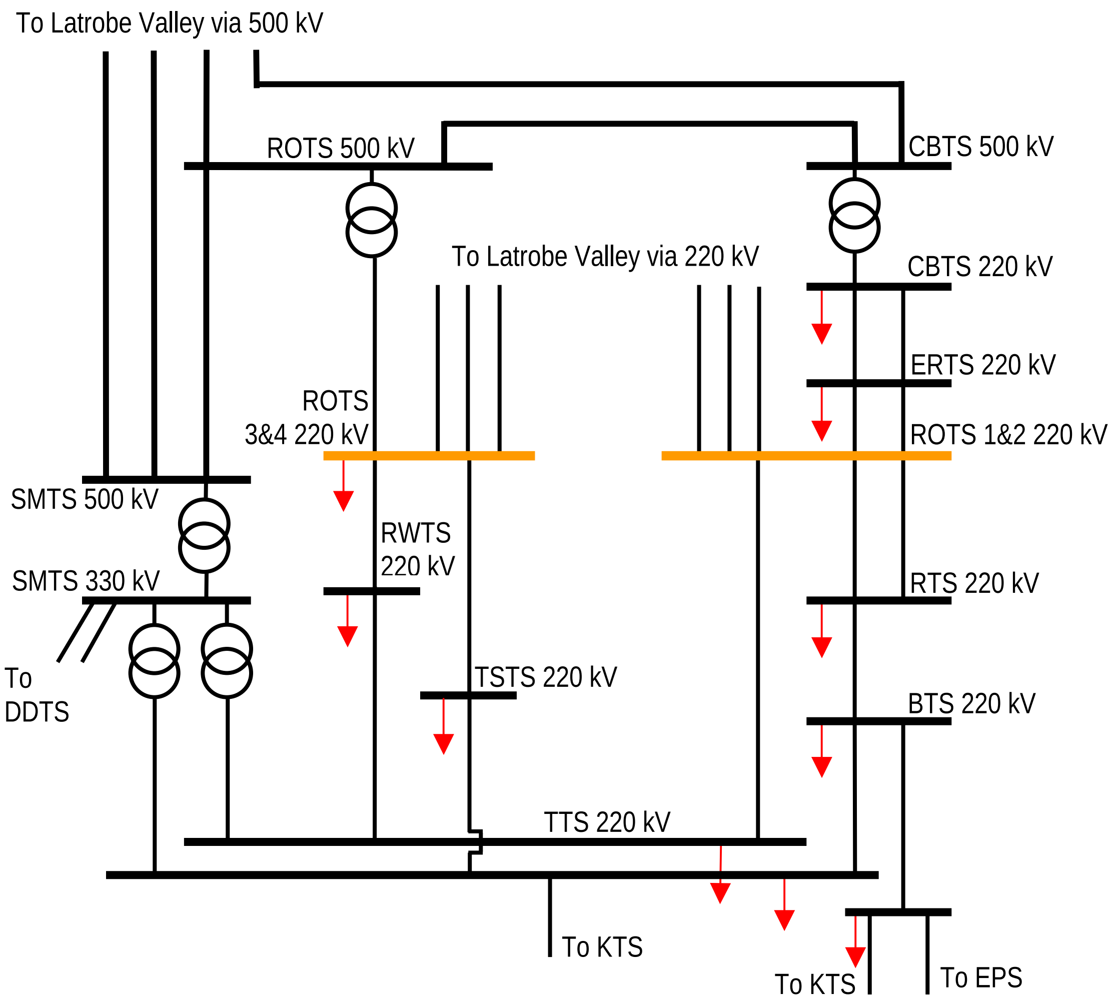

Figure 4-2: Electrical presentation of the terminal stations affected by the forecast constraints.

Where:

ROTS - Rowville Terminal Station	CBTS - Cranbourne Terminal Station	RWTS - Ringwood Terminal Station
TSTS - Templestowe Terminal Station	RTS - Richmond Terminal Station	ERTS - East Rowville Terminal Station
TTS - Thomastown Terminal Station	KTS - Keilor Terminal Station	EPS - Eildon Terminal Station
BTS - Brunswick Terminal Station	SMTS - South Morang Terminal Station	DDTS - Dederang Terminal Station

5. Load Forecast

The VENCorp 2004 Annual Planning Report describes the aggregate Victorian summer peak demand forecasts as presented in Table 5-1 and the process to establish them. These forecasts form the basis of this assessment.

Summer	*10% POE Medium [MW]*	*Annual Growth [MW]*	*Annual Growth [%]*	*50% POE Medium [MW]*	*Annual Growth [MW]*	*Annual Growth [%]*	*90% POE Medium [MW]*	*Annual Growth [MW]*	*Annual Growth [%]*
2005/06	10,103[3]			9,274			8,734		
2006/07	10,373	270	2.67%	9,509	235	2.53%	8,947	213	2.44%
2007/08	10,621	248	2.60%	9,725	216	2.27%	9,140	193	2.16%
2008/09	10,913	292	2.54%	9,981	256	2.63%	9,373	233	2.55%
2009/10	11,231	318	2.47%	10,262	281	2.82%	9,630	257	2.74%
2013/14	12,348	279[4]	2.40%	11,246	246	2.40%	10,528	225	2.34%

Table 5-1: Victorian Aggregate Demand Forecasts in [MW] (Medium Economic Scenario).

The 10%, 50% and 90% Probability of Exceedance (POE) peak demand levels relate to the long term average daily temperature (Maximum + Minimum daily temperature / 2) in Melbourne of 32.9°C, 29.6°C and 27.1°C, respectively. This represents a linear demand/temperature sensitivity of +236MW/°C above a demand of 8,734MW. Network constraints have been assessed based on these three POE peak demand scenarios and energy at risk from each scenario is weighted equally (i.e. 1/3 each).

For the medium economic growth scenario, annual energy forecasts at generator terminals[5] from the 2004 Annual Planning Report are presented in Table 5-2.

Year	*Annual Energy [GWh]*	*Annual Growth [GWh]*	*Annual Growth [%]*
2005/06	51,326		
2006/07	52,256	930	1.81%
2007/08	53,065	809	1.55%
2008/09	54,129	1,064	2.01%
2009/10	55,327	1,198	2.21%

Table 5-2: Victorian Energy Forecasts (Medium Economic Scenario).

In the short to medium term, the annual peak summer demand is growing at a faster rate then the annual energy, indicating that the peakiness of the annual duration curve is increasing. Typically, it is the peak demand/temperature condition and the shape of the top portion of the annual duration curve that dictates the need for network augmentation.

[3] Based on 2004 Annual Planning Report. All demand and energy forecasts are currently under review as part of the 2005 Annual Planning Report, however they are not expected to change considerably in the short to medium term.
[4] Average Annual Growth over four year period
[5] Based on all NEM scheduled Victorian generators and net import

Figure 5-1 presents the Victorian demand duration curve for 2005/06 financial year based on the 10% POE conditions and the medium energy growth scenario. The shape of this curve is reflective of those used in the subsequent years.

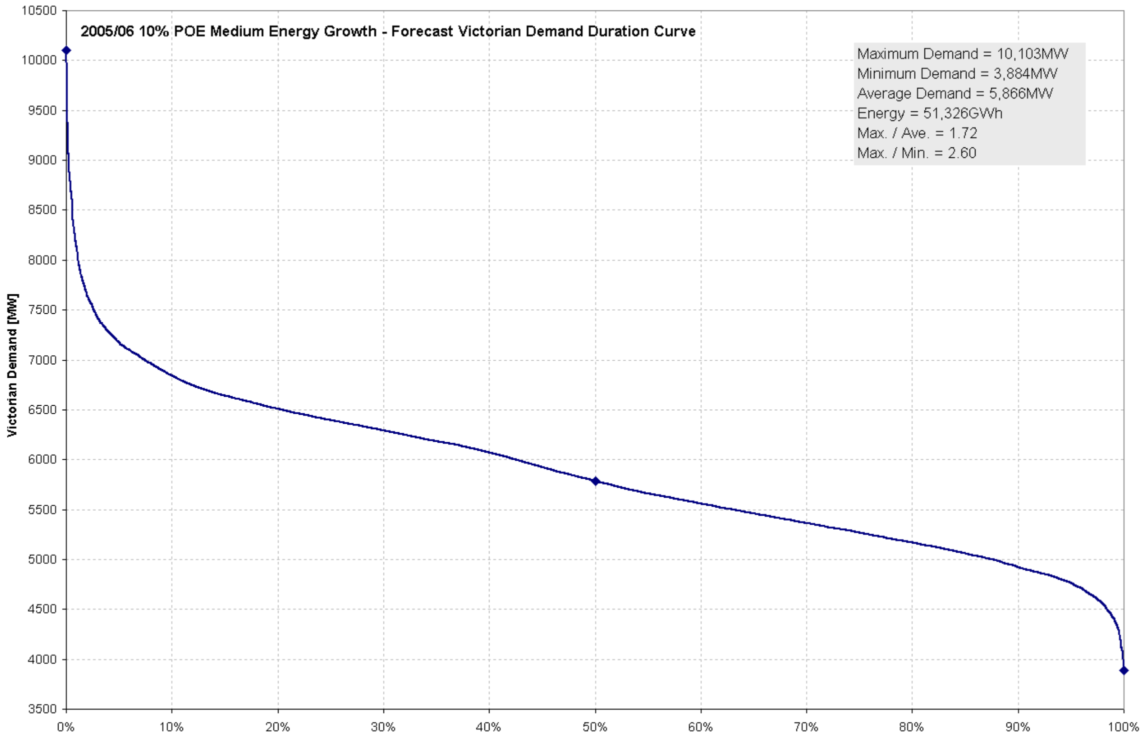

Figure 5-1: The Victorian 2005/06 10% POE Medium Energy demand duration curve.

VENCorp has used the medium economic growth scenario for the purposes of analysing the development of this large network augmentation.

Table 5-3 and Table 5-4 present the 10% POE peak demand forecasts[6] for the load supplied in the east and south-east metropolitan area.

ROTS 1&2 bus group load (primarily supplied by CBTS A1)[7]									
	2005/06	2006/07		2007/08		2008/09		2009/10	
CBTS 66	223	5.4%	235	5.5%	248	4.8%	260	5.0%	273
ERTS 66	495	4.2%	516	4.7%	540	4.8%	566	4.9%	594
RTS 66	539	2.0%	550	2.0%	561	2.3%	574	2.6%	589
RTS 22	106	2.8%	109	2.8%	112	2.7%	115	2.6%	118
TBTS 66	235	3.8%	244	4.1%	254	4.7%	266	5.3%	280
TBTS 220	66	0.0%	66	0.0%	66	0.0%	66	0.0%	66
TOTAL	*1666*	*3.3%*	*1721*	*3.5%*	*1781*	*3.8%*	*1848*	*4.0%*	*1921*

Table 5-3: The ROTS 1&2 Bus group loads and their forecast levels [in MW] for the 10% POE scenario.

[6] As derived from the Distribution Business and Major Customer terminal station forecasts, which have been diversified to the aggregate system peak and scaled to match the National Institute Of Economic and Industry Research's (NIEIR's) aggregate Victorian forecast

[7] The definition of the ROTS 1&2 bus group load is based on the local terminal stations with the highest sensitivity to loading on the CBTS A1 transformer.

ROTS 3&4 bus group load (primarily supplied by ROTS A1)[8]									
	2005/06	2006/07		2007/08		2008/09		2009/10	
SVTS 66	474	2.5%	486	2.9%	500	3.8%	519	3.3%	536
HTS 66	342	2.8%	352	3.4%	364	4.1%	379	4.2%	395
MTS 66	135	3.4%	140	2.9%	144	4.2%	150	4.0%	156
MTS 22	64	2.8%	66	1.5%	67	4.5%	70	2.9%	72
RWTS 66	475	3.6%	492	3.9%	511	2.5%	524	3.1%	540
RWTS 22	97	2.9%	100	3.0%	103	2.9%	106	3.8%	110
TSTS 66	327	2.8%	336	3.0%	346	3.2%	357	3.4%	369
TOTAL	*1915*	*3.0%*	*1972*	*3.2%*	*2036*	*3.4%*	*2105*	*3.5%*	*2178*

Table 5-4: The ROTS 3&4 Bus group loads and their forecast levels [in MW] for the 10% POE scenario.

At the time of system peak demand in 2005/06, the ROTS 1&2 and 3&4 bus group loads (as defined in Table 5-3 and Table 5-4) are 16.5% and 19.0% of the aggregate Victorian system demand, respectively.

The total Victorian load growth from 2005/06 to 2006/07 is +270MW. The ROTS 1&2 and 3&4 bus group loads, as defined above, see an increase of 55MW (20.4%) and 57MW (21.1%), respectively. Over 40% of the annual load growth from 2004/05 to 2005/06 is in the east and south east metropolitan area. This trend is forecast to continue over the 5 year period.

[8] The definition of the ROTS 3&4 bus group load is based on the local terminal stations with the highest sensitivity to loading on the ROTS A1 transformer.

6. VENCorp Shared Transmission Network Planning Criteria

VENCorp undertakes its shared network planning on the basis that any project must maximise the net present value of the market benefits, in accordance with limb 1(b) of the Regulatory Test v2. Implicit in this approach is the improvement of reliability to customers through economic means.

In its application of a probabilistic approach to shared network planning, VENCorp does not plan the network to provide 100% reliability after a single credible contingency. Rather, VENCorp accounts for the probability (often very low) of the event occurring and determines an 'Expected Value' of the constraint using a Value of Customer Reliability (VCR) of $29,600 per MWh, which it then compares with the total cost of the network options. This ensures that the cost of the project is considered in determining whether a project will proceed.

A project will only proceed if the benefits that have been quantified through the application of the regulatory test exceed the costs of the project and if it maximises the net market benefits of all options considered, including the 'do nothing' option.

In its application of a probabilistic approach to shared network planning, VENCorp also considers the need to maintain the system in both a satisfactory and a secure operating state as referred to in the National Electricity Code.

The term 'satisfactory' reflects operation of the network in a state such that all plant is operating at or below either its continuous rating or its applicable short term rating, which ensures all plant is operating below its thermal capability. Typically, VENCorp adopts a short term rating of 15 minutes for critical transmission lines, based on the response time required after a contingency to facilitate manual intervention. Shorter time frames are allowable if automatic control schemes are designed and implemented to respond after a contingency.

The term 'secure' reflects the operation of the network such that should a credible contingency occur, the network will remain in a 'satisfactory' state.

As per NEMMCO's operational practices, VENCorp plans the network such that following a credible contingency, the power system can be returned to a secure state within 30 minutes.

Reference can be made to VENCorp's Transmission Network Planning Criteria (available at www.vencorp.com.au) for full details of the shared transmission network planning criteria.

7. Constraints in the East and South-East Metropolitan Area.

The constraints in the east and south-east metropolitan areas can be classified into three main categories:

a) those that arise under system normal conditions due to excessive loading on the Rowville A1 or Cranbourne A1 500/220kV transformers;

b) those that arise after loss of the Rowville A1 transformer and are required to return the network to a satisfactory and then secure state, and

c) those that arise after loss of the Cranbourne A1 transformer and are required to return the system to a satisfactory and then secure state.

These constraints are primarily driven by demand and its growth at east and south-east metropolitan Terminal Stations. There is some minor sensitivity of loading on the Rowville and Cranbourne A1 transformers to generation in the metropolitan area - such as Somerton, Laverton North and Newport power stations. However, these are not significant enough to materially affect the identified constraints.

Further generation sensitivities include Yallourn W power station in the Latrobe Valley, which provides critical support to the eastern metropolitan area as this power station feeds demand in this area by direct injection at the 220kV transmission level from the Latrobe Valley. For the purposes of this analysis, it is assumed that Yallourn W unit 1 is only connected to the 220kV network under high Victorian demand conditions (i.e. greater then 9000MW) and to the 500kV network in the Latrobe Valley for the remainder of the time. Its connection to the 500kV network increases the dependence on the Rowville and Cranbourne A1 transformers.

The market modeling undertaken for this assessment focused on development of appropriate load duration curves. It treats the dispatch of generation as a secondary matter since, for reasons outlined above, variations in generation modeling would have little influence on loading of the critical transformers and lines. Least cost generation dispatch based on short run marginal costs was adopted, with no forced outage rates (no monte-carlo analysis), while reasonable planned outage assumptions were included. A summary of the market modeling inputs used for this analysis is presented in Attachment 1.

The following sections describe and quantify the constraints associated with loading and loss of the Rowville and Cranbourne A1 transformers given the most effective and viable response of direct load shedding at various terminal stations in the east and south east metropolitan area.

Except where explicitly identified for the purposes of sensitivity studies, the Value of Customer Reliability is assumed as $29,600/MWh.

7.1. Loading on the Rowville and Cranbourne 500/220kV Transformers

Table 7-1 presents the forecast power flows on the Rowville and Cranbourne 500/220kV transformers (as a percentage of their 1000MVA continuous rating) for system normal and the described outage conditions, given the Medium Energy growth scenario and 10% POE peak summer demand forecasts.

Element	*Condition*	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Rowville A1 (1000MVA cont.) (1500MVA 30min)	System Normal	89.5	94.6	97.8	102.2	108.6
	Cranbourne A1 out	123.4	130.5	135.1	141.3	151.0
Cranbourne A1 (1000MVA cont.) (1500MVA 30min)	System Normal	86.4	91.3	94.4	98.2	104.3
	Rowville A1 out	118.4	125.2	129.6	135.1	144.3

Table 7-1: Forecast loading [% of cont. rating] on the Rowville A1 and Cranbourne A1 transformers.

Table 7-1 shows that, from summer 2008/09 and onwards if no action is taken, the loading on these critical transformers will exceed their capability. Furthermore, in 2009/10, the post contingent loading on the Rowville A1 transformer will exceed its 30 minute short term capability. These loading scenarios are unacceptable as the plant may be damaged and action is required to ensure they are not realised.

The consequences of these forecast loading levels will be load shedding as there are no network switching or generation rescheduling opportunities to alleviate the high loading.

For system normal conditions, a reduction in flow on the Rowville A1 transformer is best achieved by load shedding at Springvale Terminal Station with a sensitivity of 0.833MW/Amp.

For system normal conditions, a reduction in flow on the Cranbourne A1 transformer is best achieved by load shedding at Cranbourne Terminal Station with a sensitivity of 0.776MW/Amp.

Detailed analysis of the annual loading patterns on the critical transformers leads to the presentation of Table 7-2 and Table 7-3, which each summarise the frequency and magnitude of constraints and values the potential energy at risk for the forecast system normal conditions.

Flow on Rowville A1 System Normal	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Forecast Hours of Constraint[9]	0.0	0.0	0.0	1.3	2.3
Maximum Single Constraint[10] [MW]	0	0	0	52	187
Energy at Risk[11] [MWh]	0	0	0	50	278
Value of Energy at Risk [$k]	0	0	0	1,488	8,222
Expected Value of Energy at Risk [$k]	0	0	0	1,488	8,222

Table 7-2: Constraints associated with system normal flows on the Rowville A1 transformer

Flow on Cranbourne A1 System Normal	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Forecast Hours of Constraint	0.0	0.0	0.0	0.0	0.3
Maximum Single Constraint [MW]	0	0	0	0	88
Energy at Risk [MWh]	0	0	0	0	29
Value of Energy at Risk [$k]	0	0	0	0	866
Expected Value of Energy at Risk [$k]	0	0	0	0	866

Table 7-3: Constraints associated with system normal flows on the Cranbourne A1 transformer

These results indicate that excess loading on the Rowville A1 transformer occurs earlier than that for the Cranbourne transformer and, in the emerging stages of the constraint, there are only a small number of hours where it will be realised. However, it is important to recognise the high value of these system normal constraints and the considerable growth in their value from one year to the next. If no action is taken, the potential load shedding would grow from 50MW in 2008/09 to a combined level of 275MW in 2009/10. This trend would continue in the future in proportion to load growth in the east and south east metropolitan area.

[9] This is the weighted average (1/3:1/3:1/3) for the 10, 50 and 90% POE scenarios.
[10] This is the single worst constraint and typically arises in the 10% POE scenario.
[11] This is the weighted average (1/3:1/3:1/3) for the 10, 50 and 90% POE scenarios.

7.2. Outage of the Rowville 500/220kV A1 transformer

7.2.1. Action Required to Return the Network to a 'Satisfactory' Condition

Under high demand conditions, outage of the Rowville A1 transformer results in excessive loading on the 1000MVA Cranbourne A1 transformer (as shown in Table 7-1). Short term overloading of the Cranbourne transformer is acceptable as it has a 30 minute rating of 1500MVA.

However, after the short term rating time frame, load shedding is required to return flow on the Cranbourne transformer to a satisfactory level based on its continuous 1000MVA capability.

Subsequent to a Rowville transformer outage, a reduction in flow on the Cranbourne A1 transformer is best achieved by load shedding at Cranbourne Terminal Station with a sensitivity of 0.691MW/Amp.

The probability of a forced outage of the Rowville A1 transformer is determined by the mean time to repair of 31 days and the failure rate of 1 tank every 150 years, giving a forced outage rate of 3*31*24/(8760*150) = 0.1699%[12].

Table 7-4 presents the forecast energy at risk required to return flows on the Cranbourne A1 transformer to a satisfactory level after loss of Rowville A1.

Flow on CBTS A1 satisfied for outage of ROTS A1	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	13.7	19.3	22.0	27.3	68.3
Maximum Single Constraint [MW]	333	457	537	635	699
Energy at Risk [MWh]	1,387	2,222	2,859	4,042	8,118
Value of Energy at Risk [$k]	41,067	65,775	84,629	119,652	240,286
Expected Value of Energy at Risk [$k][13]	70	112	144	203	408

Table 7-4: Constraints associated with satisfying flows on the Cranbourne A1 transformer for outage of Rowville A1.

Returning the flows on the Cranbourne A1 transformer to satisfactory levels after loss of the Rowville A1 transformer potentially requires load shedding in 2005/06 of around 330MW, this grows to around 700MW at the end of the five year period. The expected value of this constraint grows from approximately $70k to over $400k per annum in the five year period.

7.2.2. Action Required to Return the Network to a 'Secure' Condition

In accordance with VENCorp's' planning criteria and NEMMCO's operational requirements, the system must be returned to a secure state in preparation for a subsequent outage within 30 minutes of an outage occurring. This has the consequence that even more load shedding is required to achieve a secure state if the failed plant cannot be returned to service.

[12] The Rowville Transformer is comprised of three single phase tanks and a common spare tank is available at a remote location to minimise the mean time to repair after a catastrophic failure to 1 month.
[13] The expected value of the energy at risk accounts for the probability of the outage event occurring

In the case of prior outage of the Rowville transformer, Table 7-5 summarises the effects of seven further critical outages.

Subsequent Outage		Critically Loaded Plant.[14]
1	Loss of Cranbourne A1	RTS-BTS loaded to 136%
		SMTS H1/H2 loaded to 125%
		TTS-BTS 1 loaded to 118%
		KTS A3 loaded to 112%
2	loss of TTS-RWTS	TTS-TSTS loaded to 150%
		YPS-ROTS 6/7/8 loaded to 117%
		SMTS H1 loaded to 109%
		CBTS A1 loaded to 104%
3	loss of TTS-TSTS	TTS-RWTS loaded to 150%
		YPS-ROTS 6/7/8 loaded to 115%
		CBTS A1 loaded to 107%
		SMTS H2 loaded to 104%
4 - 6	loss of YPS-ROTS 6/7/8	YPS-ROTS 6/7 loaded to 121%
		TTS-RWTS loaded to 105%
7	loss of SMTS H1	CBTS A1 loaded to 117%
		TTS-RWTS loaded to 115%
		SMTS H2 loaded to 113%

Table 7-5: Summary of critical outages with prior outage of the Rowville A1 transformer.

The optimised action required to secure the network in expectation of these seven outages has been considered in two parts:

Part I) Additional load shedding at Cranbourne, Tyabb or East Rowville Terminal Stations (with a sensitivity of 0.691MW/Amps) to reduce the flow on the Cranbourne A1 transformer to 85% of its continuous rating. This has the impact of securing for the subsequent outages 1 and 5 as described in Table 7-5.

Part II) Additional load shedding at Springvale or Heatherton Terminal Stations (with a sensitivity of 0.943MW/Amps) to ensure at least 15 minutes is available for response following the subsequent outages 2, 3 and 4-6 as described in Table 7-5.

These actions are representative of the operational response that would be required to secure the network with outage of the Rowville A1 transformer.

Table 7-6 and Table 7-7 present the forecast energy at risk required to return flows on the network to a secure state with a prior outage of the Rowville A1 transformer.

[14] Loading levels reflect those based on 10% medium growth peak summer demand forecasts for 2007/08.

Part I, to secure for prior outage of ROTS A1 for flow on CBTS A1	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	78.0	101.3	142.7	193.7	319.7
Maximum Single Constraint [MW]	272	272	272	272	272
Energy at Risk [MWh]	9,918	13,246	17,401	24,773	45,747
Value of Energy at Risk [$k]	293,578	392,093	515,057	733,266	1,354,111
Expected Value of Energy at Risk [$k]	499	666	875	1,246	2,300

Table 7-6: Constraints associated with securing flows on the network for a prior outage of Rowville A1, Part I.

Part II, to secure for prior outage of ROTS A1 for flow on TTS-RWTS	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	15.3	19.0	23.0	24.3	30.7
Maximum Single Constraint [MW]	291	362	427	519	640
Energy at Risk [MWh]	1,870	2,203	2,896	3,399	4,300
Value of Energy at Risk [$k]	55,347	65,204	85,710	100,603	127,2907
Expected Value of Energy at Risk [$k]	94	111	146	171	216

Table 7-7: Constraints associated with securing flows on the network for a prior outage of Rowville A1, Part II.

7.2.3. Worst Case Scenario for Outage of the Rowville A1 Transformer

As a summary of the worst case 'Do Nothing' scenario for the 2007/08 forecasts:

- No system normal load shedding would be required, however
- if the Rowville A1 transformer failed over the critical summer period,
    - around 540MW of load shedding may be required from Cranbourne, Tyabb and East Rowville Terminal Stations to return the flow on Cranbourne A1 to a satisfactory level, and
    - a further 270MW of load shedding from Cranbourne, Tyabb and East Rowville Terminal Station, and an additional 430MW of load shedding from Springvale and Heatherton Terminal Stations would be required to secure the network from several further critical outages.
- The energy behind these constraints has been valued by VENCorp, giving due consideration to the low probability of the event occurring, at around $1.2M.

7.3. Outage of the Cranbourne 500/220kV A1 Transformer

7.3.1. Action Required to Return the Network to a 'Satisfactory' Condition

Under high demand conditions, outage of the Cranbourne A1 transformer results in excessive loading on both the 1000MVA Rowville A1 transformer (as shown in Table 7-1) and the 450MVA Richmond to Brunswick 220kV cable (as shown in Table 7-8). Short term overloading of both the Rowville transformer and the cable is acceptable as they both have considerable short term (30 minute) overload capabilities due to their high thermal inertias.

Element	*Condition*	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Richmond to Brunswick cable (450MVA cont.)	System Normal	52.9	54.6	59.8	56.3	62.7
	Cranbourne A1 out	151.0	158.9	169.2	173.8	184.0

Table 7-8: Forecast loading [% of cont. rating] on the Richmond to Brunswick 220kV cable.

However, after the short term rating time frame, load shedding is required to return flow on the Rowville A1 transformer and the Richmond-Brunswick cable to satisfactory levels based on their continuous 1000MVA and 450MVA capabilities, respectively.

Subsequent to a Cranbourne transformer outage, a reduction in flow on the Rowville A1 transformer is best achieved by load shedding at Springvale Terminal Station with a sensitivity of 0.733MW/Amp, and a reduction in flow on the Richmond-Brunswick cable is best achieved by load shedding at Richmond Terminal Station with a sensitivity of 0.436MW/Amp

The probability of a forced outage of the Cranbourne A1 transformer is the same as that for the Rowville A1 transformer and is determined by the mean time to repair of 31 days and the failure rate of 1 tank every 150 years, giving a forced outage rate of 3*31*24/(8760*150) = 0.1699%[15].

Table 7-9 presents the forecast energy at risk required to return flows on the Rowville A1 transformer to a satisfactory level after loss of Cranbourne A1.

Flow on ROTS A1 satisfied for outage of CBTS A1	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	23.0	30.7	35.7	51.3	101.7
Maximum Single Constraint [MW]	449	586	673	735	751
Energy at Risk [MWh]	3,611	5,093	6,106	8,428	16,039
Value of Energy at Risk [$k]	106,893	150,741	180,737	249,475	474,762
Expected Value of Energy at Risk [$k]	182	256	307	424	806

Table 7-9: Constraints associated with satisfying flows on the Rowville A1 transformer for outage of Cranbourne A1.

[15] The Cranbourne Transformer is comprised of three single phase tanks and a spare tank is available to minimise the mean time to repair to 1 month.

Table 7-10 presents the forecast energy at risk required to return flows on the Richmond to Brunswick 220kV cable to a satisfactory level after loss of Cranbourne A1.

Flow on RTS-BTS satisfied for outage of CBTS A1	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	54.0	69.0	90.3	110.0	159.7
Maximum Single Constraint [MW]	264	304	357	381	435
Energy at Risk [MWh]	4,454	5,510	7,023	8,678	12,241
Value of Energy at Risk [$k]	131,840	163,097	207,876	256,878	362,342
Expected Value of Energy at Risk [$k]	224	277	353	436	615

Table 7-10: Constraints associated with satisfying flows on the Richmond to Brunswick cable for outage of Cranbourne A1.

Returning the flows on the Rowville A1 transformer and the Richmond to Brunswick 220kV cable to satisfactory levels after loss of the Cranbourne A1 transformer potentially requires aggregate load shedding in 2005/06 of around 710MW. This grows to around 1180MW at the end of the five year outlook. The expected value of these constraints grows from approximately $405k to over $1,420k per annum in the five year period.

7.3.2. Action Required to Return the Network to a 'Secure' Condition

In accordance with VENCorp's planning criteria and NEMMCO's operational requirements, the system must be returned to a secure state to allow for a subsequent outage within 30 minutes of an outage occurring. This has the consequence that even more load shedding is required to achieve a secure state if the failed plant cannot be returned to service.

The effects of eight further critical outages are summarised in Table 7-11 for the case of a prior outage of the Cranbourne A1 transformer.

	Subsequent Outage	*Critically Loaded Plant.*[16]
1	loss of Rowville A1	RTS-BTS loaded to 133%
		SMTS H1/H2 loaded to 113%
		KTS A3 loaded to 103%
2	loss of RTS-BTS	ROTS A1 loaded to 108%
		YPS/HWPS-ROTS 5/1/2 loaded to 110%
3	loss of SMTS H2	ROTS A1 loaded to 118%
		RTS-BTS loaded to 126%
		SMTS H1 loaded to 102%
		ROTS-RWTS loaded to 102%
4	Loss of ROTS-TTS	RTS-BTS loaded to 134%
		YPS/HWPS-ROTS 5/1/2 loaded to 100%
5 - 7	Loss of YPS/HWPS-ROTS 5/1/2	YPS/HWPS-ROTS 5/1/2 loaded to 110%
		RTS-BTS loaded to 106%
8	Loss of ERTS-ROTS	ERTS-ROTS loaded to 158%

Table 7-11: Summary of critical outages with prior outage of the Cranbourne A1 transformer.

The optimised action required to secure the network in expectation of these eight outages has been considered. Additional load shedding at Richmond or East Rowville Terminal Stations (with a sensitivity of 0.4363 MW/Amps) to reduce the flow on the Richmond to Brunswick cable to 80% of its continuous rating is representative of the operational response that would required to secure the network with outage of the Cranbourne A1 transformer.

Table 7-12 presents the forecast energy at risk required to return flows on the network to a secure state with a prior outage of the Cranbourne A1 transformer.

To secure flow for prior outage of CBTS A1 for Flow on RTS-BTS	*2005/06*	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Hours of Constraint	240.0	283.7	434.7	504.3	688.7
Maximum Single Constraint [MW]	103	103	103	103	103
Energy at Risk [MWh]	12,886	14,471	22,640	25,737	36,382
Value of Energy at Risk [$]	381,425	428,330	670,141	761,817	1,076,907
Expected Value of Energy at Risk [$]	648	728	1,138	1,294	1,829

Table 7-12: Constraints associated with securing flows on the network for a prior outage of Cranbourne A1.

[16] Loading levels reflect those based on 10% medium growth peak summer demand forecasts for 2007/08.

7.3.3. *Worst Case Scenario for Outage of the Cranbourne A1 Transformer*

As a summary of the 'Do Nothing' scenario for the 2007/08 forecasts:

- No system normal load shedding would be required, however
- If the Cranbourne A1 transformer failed over the critical summer period,
    - around 670MW of load shedding may be required from Springvale and Heatherton Terminal Stations to return the flow on Rowville A1 to a satisfactory level,
    - around 360MW of load shedding may be required from Richmond Terminal Station to return the flow on the Richmond-Brunswick cable to a satisfactory level, and
    - a further 100MW of load shedding from Richmond Terminal Station would be required to secure the network from several further critical outages.
- The energy associated with these constraints has been valued by VENCorp, giving due consideration to the low probability of the event occurring, at around $1.8M.

7.4. Summary of 'Do Nothing' Constraints

Table 7-13 presents a summary of the Expected Value of Energy at Risk (in $k) in the 'Do Nothing' scenario associated with potential unserved energy over the next five years. It is based on forecast flows on the Rowville A1 and Cranbourne A1 transformer and for flows on critical plant after outages of these transformers.

	Do Nothing, Expected Value of Energy at Risk [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
System Normal, required to satisfy flow on Cranbourne A1.	0	0	0	0	866
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	70	112	144	203	408
N-1, Loss of Rowville A1, required to secure flow for next event, part I	499	666	875	1,246	2,300
N-1, Loss of Rowville A1, required to secure flow for next event, part II	94	111	146	171	216
System Normal, required to satisfy flow on Rowville A1	0	0	0	1,488	8,222
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	182	256	307	424	806
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	224	277	353	436	615
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	648	728	1,138	1,294	1,829
TOTAL	1,717	2,150	2,963	5,262	15,262

Table 7-13: Summary of the 'Do Nothing' scenario, Expected Value of the Energy at Risk.

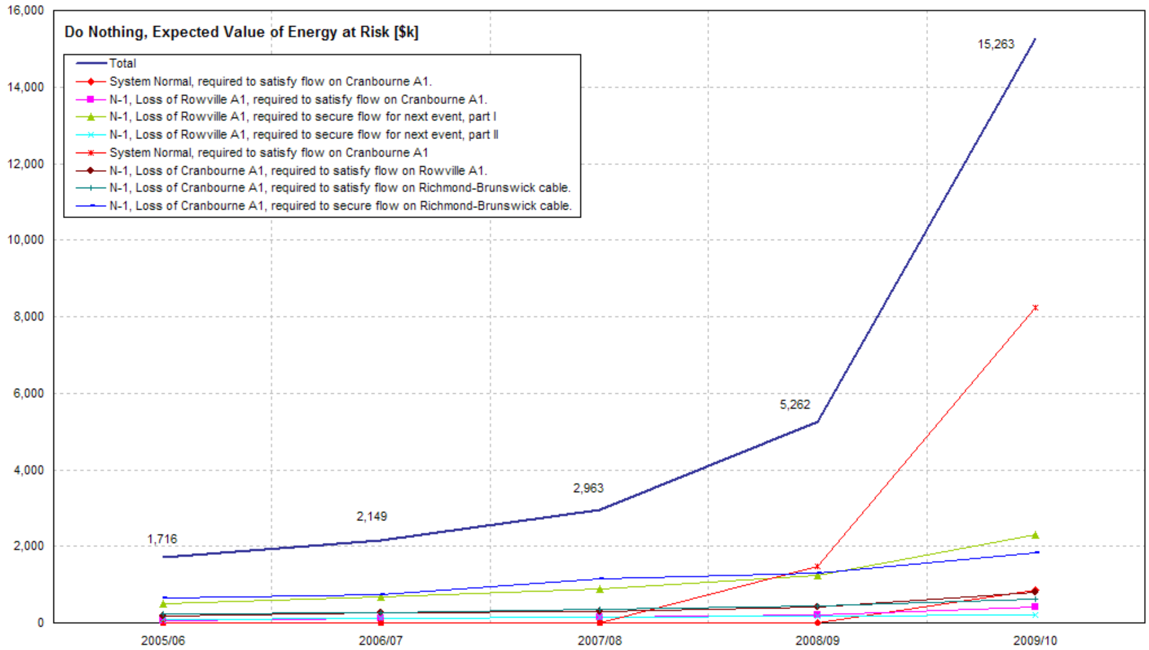

Figure 7-1: The 'Do Nothing' Scenario, Expected Value of Energy at Risk over the short term outlook.

Based on the constraint costs in the final year of the technical analysis, 2009/10, these figures indicate that the four most critical areas that require resolution are constraints associated with:

- System normal loading on the Rowville transformer;
- Loss of Rowville A1 and securing for the next event (Part I);
- Loss of Cranbourne A1 and securing the flow on the Richmond-Brunswick cable; and
- System normal loading on the Cranbourne transformer.

8. Network Options for Removal of Constraints

Part 1(b) of the regulatory test states that an option satisfies the regulatory test if in all other cases – the option maximises the expected net present value of the market benefit compared with a number of alternative options and timings, in a majority of reasonable scenarios.

VENCorp has identified a number of network options, which it considers to be genuine alternatives in that they deliver similar outcomes, in a similar timeframe, and they are both technically and commercially feasible.

Four network options have been short listed to address the constraints associated with flows on the Rowville A1 and Cranbourne A1 500/220kV transformers and the outages of these critical transformers.

The four network options are all associated with the installation of a new 500/220kV transformer in the east or south-east metropolitan network and they consider four separate sites, namely:

- Option 1, installation at Rowville Terminal Station
- Option 2, installation at Cranbourne Terminal Station
- Option 3, installation at Ringwood Terminal Station
- Option 4, installation at South Morang Terminal Station

Other network options to alleviate the forecast constraints, such as improvements in the 220kV capacity into the Rowville bus groups, were considered. Three minor network augmentations and a new small network asset, as discussed in Section 3, have already been justified. These projects complement the options under consideration in this assessment.

Furthermore, alternative sites for the proposed transformer and the application of an automatic control scheme were also reviewed. No other sites were considered to be as effective or feasible as those short-listed, and the adoption of an automatic control scheme was considered impractical due to its complex design requirements and its limited ability to resolve all of the forecast constraints.

When considering the cost of the options, VENCorp has considered the total cost of the option to all those who produce, distribute or consume electricity in the National Electricity Market.

8.1. Option 1 – New 500/220kV Transformer at Rowville Terminal Station

The proposed scope of works for Option 1 involves the development and switching of a new 500/220kV A2 transformer (1000MVA continuous, 1500MVA 30minute) at the existing Rowville Terminal Station, as shown schematically in Figure 8-1.

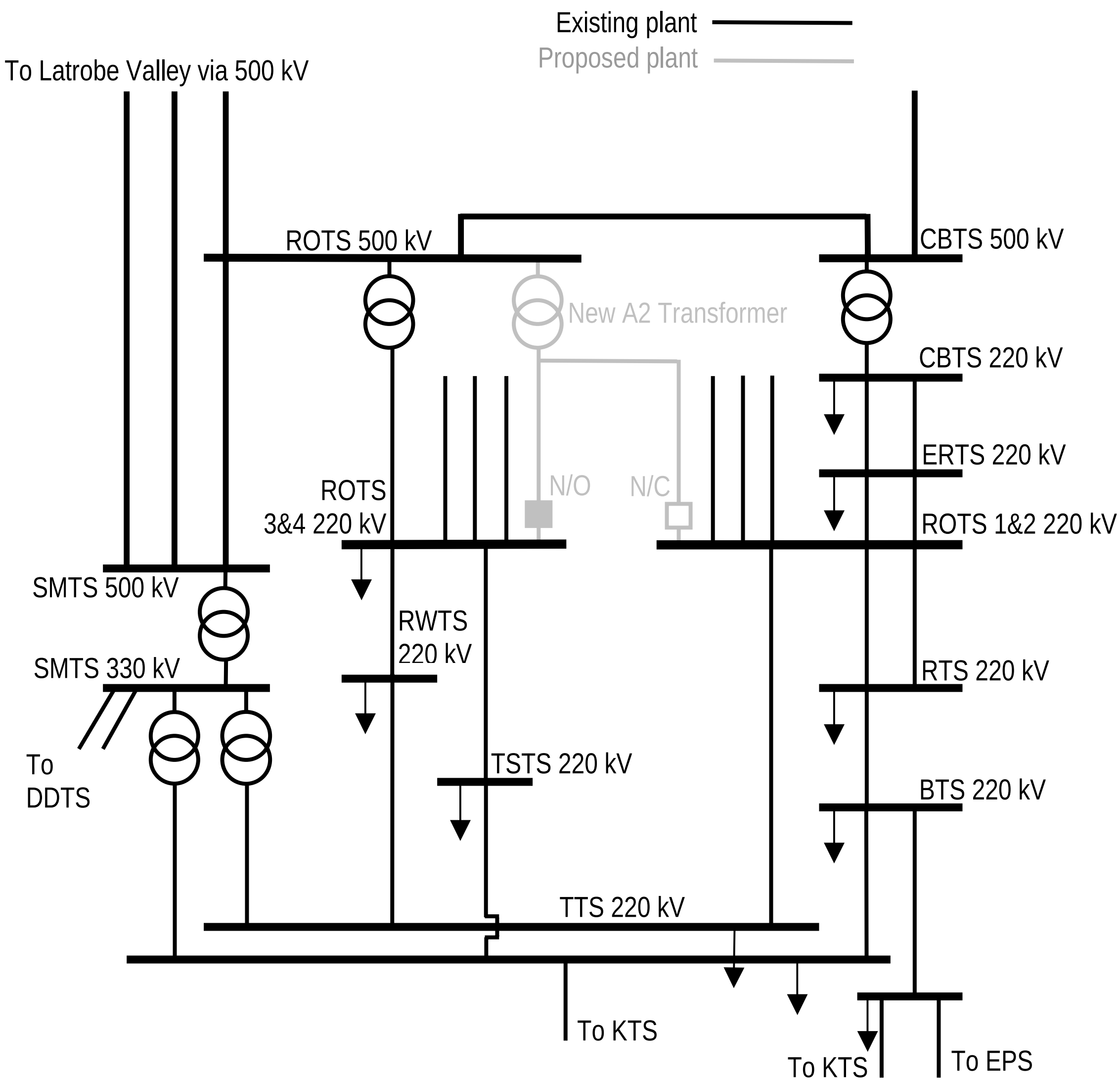

Figure 8-1: The proposed Electrical Representation of Option 1, a new transformer at Rowville

The transformer will be switched and supplied from the existing Rowville 500kV switchyard as per Figure 8-2. On its low voltage side, it will be connected to both the 1&2 and 3&4 bus groups at the 220kV switchyard, as per Figure 8-3.

There will be both contestable and non contestable components associated with this scope as some of the works are integrated with, and associated with improving the capability of, the existing assets of both Rowville Transmission Facility Pty Ltd and SPI PowerNet Pty Ltd.

Under system normal conditions, the new Rowville A2 transformer will only be switched to the 1&2 busgroup and connection to the 3&4 bus group is only necessary for outages of the existing Rowville A1 transformer. Excessive fault levels preclude all 220kV busses at Rowville being tied at any time.

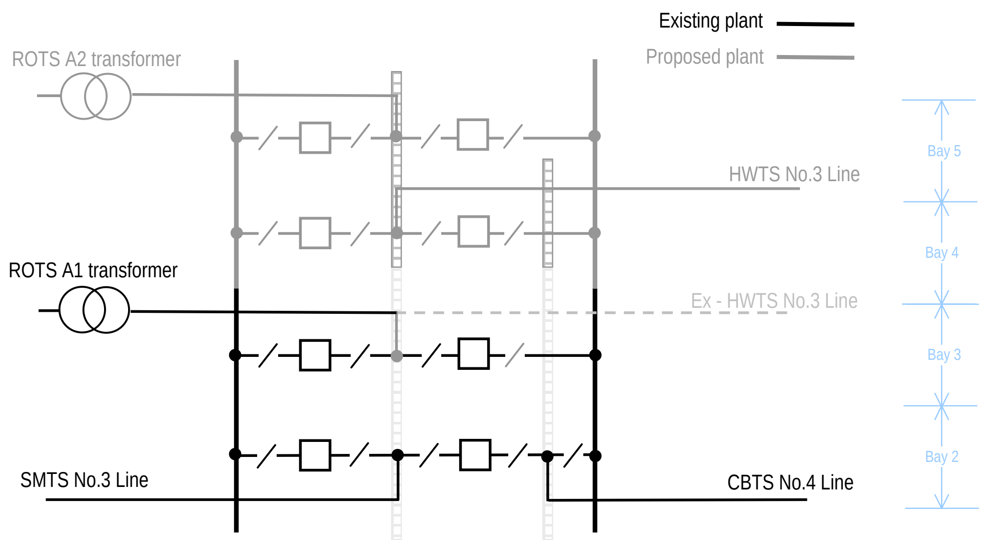

Figure 8-2: Option1 – The proposed Rowville 500kV switching arrangement.

This proposed 500kV schematic indicates that the primary plant includes two new 500kV bays, three new rack structures, four new 500kV circuit breakers, up to nine new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required.

Included in the development cost is considerable civil works as required to develop a new bench for the two 500kV bays, plus modifications to the physical terminating locations for all existing plant switched at the 500kV yard (the Hazelwood No.3 Line, the Cranbourne No.4 Line, the South Morang No.3 Line and the A1 transformer).

The proposed 220kV schematic, as shown in Figure 8-3, indicates that the primary plant includes three new 220kV circuit breakers, up to six new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required. No new bays are required.

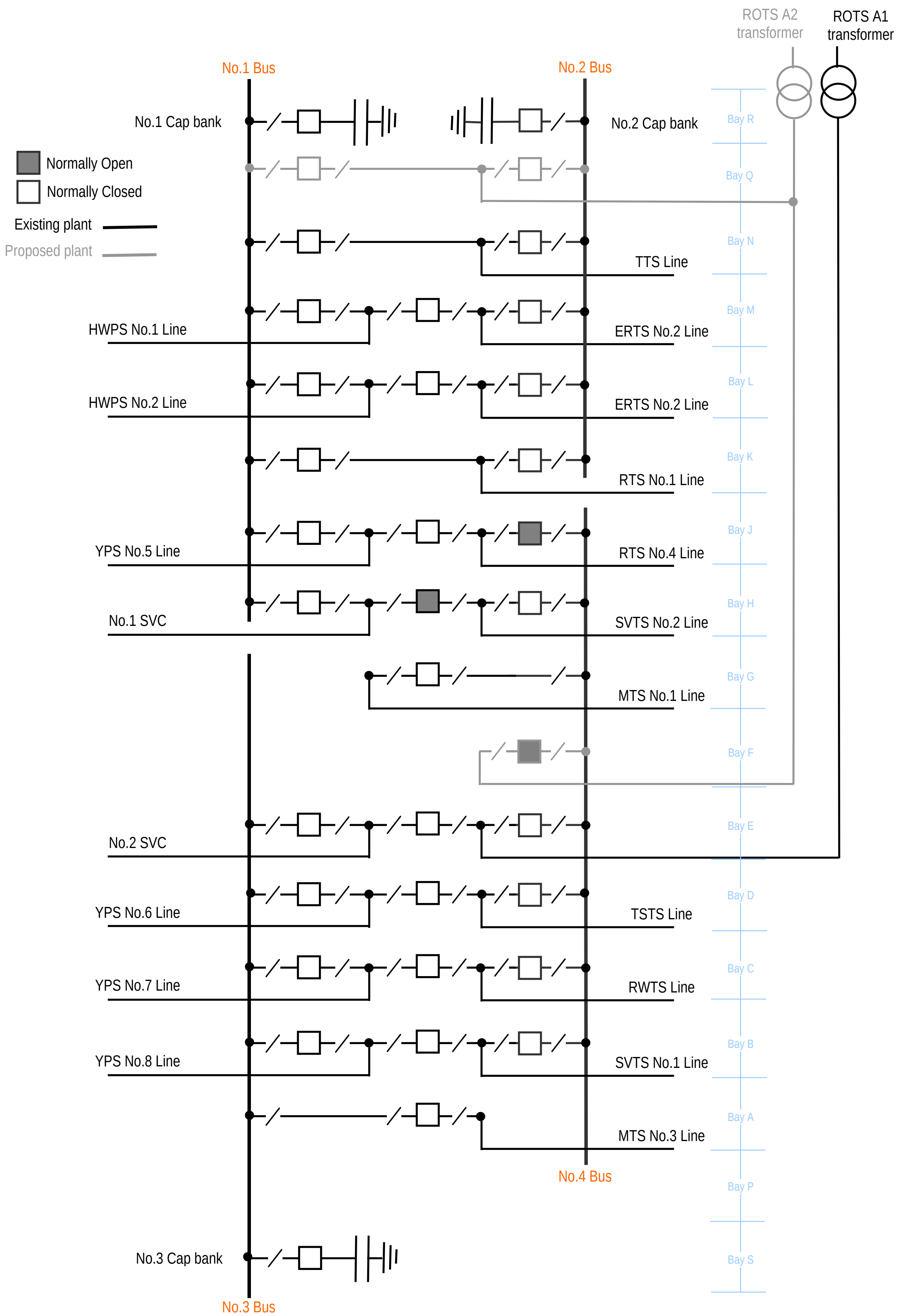

Figure 8-3: Option 1 – The proposed Rowville 220kV switching arrangement.

With Option 1, a new Rowville A2 transformer, in addition to the primary scope of works as outlined above, consequential works are required to account for the increased fault levels. Fault levels at the Rowville 1&2 bus group increase by around 9kA from 25kA to 34kA. VENCorp has identified that 14 circuit breakers at Rowville will need to be replaced to accommodate this increase.

8.1.1. Cost Estimates and Lead Times for Option 1, Rowville

The capitalised cost estimate for Option 1 is $35M ± 25% for the primary requirements and $10.5M for consequential works required to replace circuit breakers due to excessive fault levels. Without the circuit breakers being replaced, this option would not be considered technically feasible. Based on these costs, Option 1 would be defined as a new large network asset. The asset life for Option 1 is assumed to be 45 years. Table 8-1 compares the annualised costs for the primary scope of works given a range of discount rates.

Total Capitalised Primary Cost [$k]	*Discount Rate*	*Annualised Cost [$k]*
35,000	6%	$2,265
	8%	$2,891
	10%	$3,549
Upper Tolerance: 35,000 x 1.25 = 43,750	6%	$2,831
	8%	$3,613
	10%	$4,436
Lower Tolerance: 35,000 x 0.75 = 26,250	6%	$1,698
	8%	$2,168
	10%	$2,662

Table 8-1: The primary costs for Option 1, assuming a 45 year asset life.

SPI PowerNet Pty Ltd, the existing asset owner of the 220kV circuit breakers that require replacement, has identified its intent to replace these circuit breakers in December 2010 as part of its ongoing asset maintenance / operational expenditure plan. As the regulatory test is an economic cost benefit analysis, VENCorp will only incorporate the net present value of advancing the installation of these circuit breakers in this analysis.

Table 8-2 shows an example of the treatment of the circuit breaker advancement costs used for Option 1 (based on a 45 year asset life).

		Advanced Timing Compared with December 2010		
		December 2007	*December 2008*	*December 2009*
Net Present Value of Advancement Cost [$k]	*Discount Rate*	3 years	2 years	1 year
	6%	1,684	1,155	594
	8%	2,165	1,498	778
	10%	2,611	1,822	955

Table 8-2: The treatment of advancement costs for circuit breaker replacement associated with Option 1.

The estimated construction lead time for the proposed development of Option 1 is 23 months from the execution of all necessary contracts.

8.2. Option 2 - New 500/220kV Transformer at Cranbourne Terminal Station

The proposed scope of works for Option 2 involves the development and switching of a new 500/220kV A2 transformer (1000MVA continuous, 1500MVA 30minute) at the existing Cranbourne Terminal Station, as shown schematically in Figure 8-4.

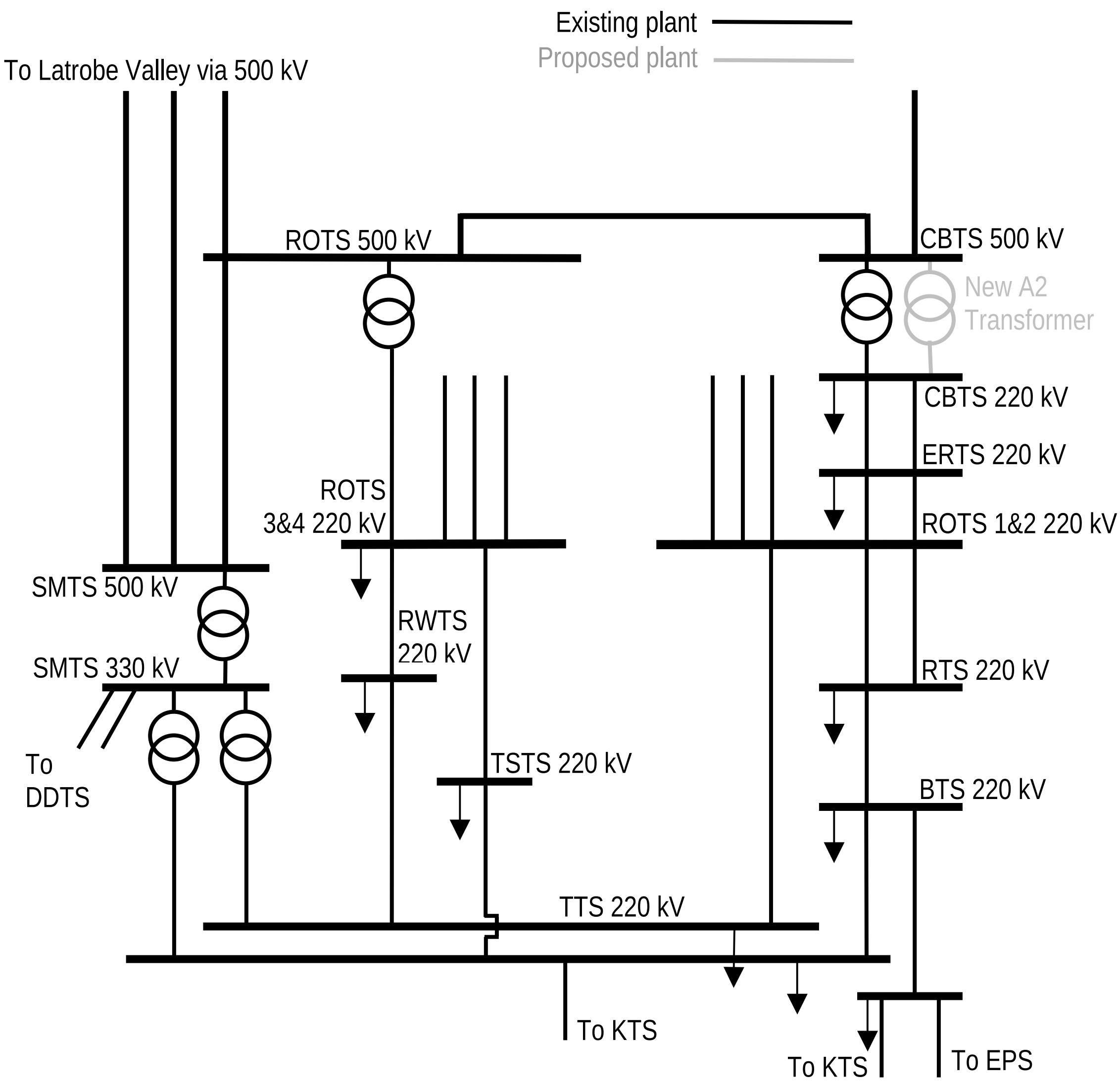

Figure 8-4: The proposed Electrical Representation of Option 2, a new transformer at Cranbourne.

The transformer will be switched and supplied from the existing Cranbourne 500kV switchyard as per Figure 8-5. On its low voltage side, it will be connected to the 220kV switchyard as per Figure 8-6.

There will be both contestable and non contestable components associated with this scope as some of the works are integrated with, and associated with improving the capability of, the existing assets of SPI PowerNet Pty Ltd.

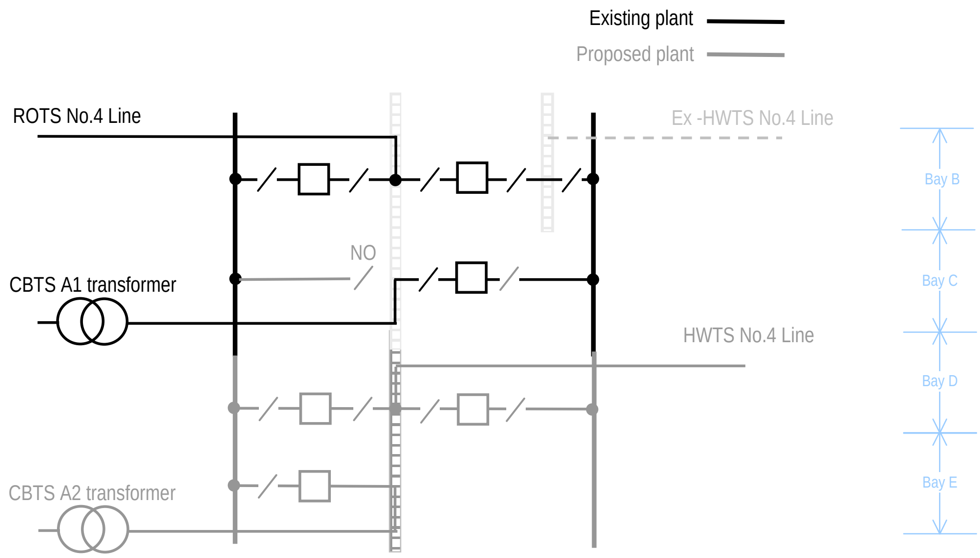

Figure 8-5: Option 2 – The proposed Cranbourne 500kV switching arrangement.

This proposed 500kV schematic indicates that the primary plant includes two new 500kV bays, two new rack structures, three new 500kV circuit breakers, up to six new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required.

Modification of the physical terminating locations for all existing plant switched at the 500kV yard (the Hazelwood No.4 Line, the Rowville No.4 Line, and the A1 transformer) is included in the cost estimate development.

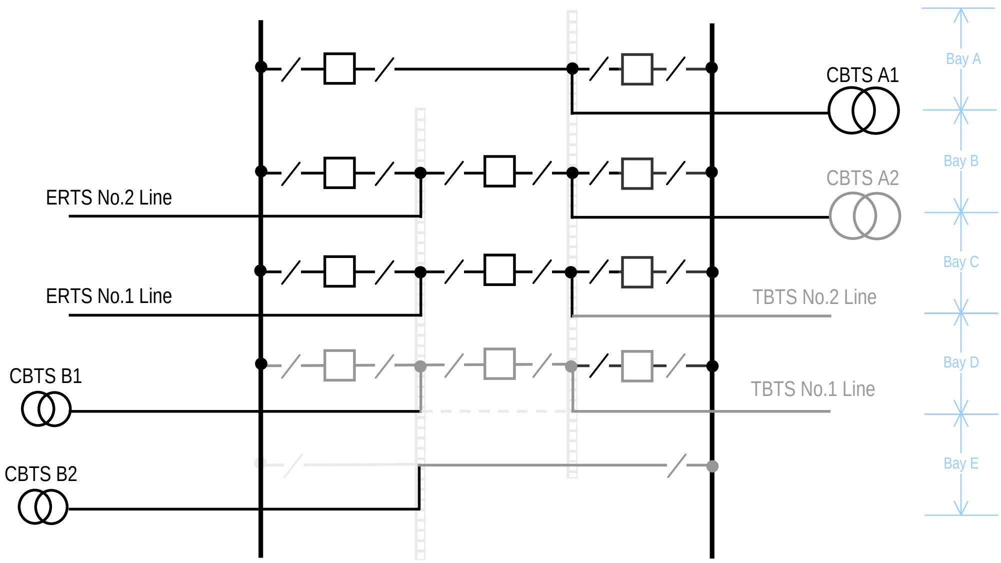

Figure 8-6: Option 2 – The proposed Cranbourne 220kV switching arrangement.

The proposed 220kV schematic indicates that the primary plant includes three new 220kV circuit breakers, up to five new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required. No new bays are required.

Modification to the physical terminations of the Tyabb (TBTS) lines and the 220/66kV B2 transformer has been included in the cost estimate development.

With Option 2, a new Cranbourne A2 transformer, in addition to the primary scope of works as outlined above, consequential works are required to account for the increased fault levels. Fault levels at the Cranbourne 220kV bus increase by around 6.5kA from 25.5kA to 32kA and the Rowville 1&2 bus group fault level increases by around 1.6kA from 25kA to 26.6kA. VENCorp has identified that 7 circuit breakers at Rowville will need to be replaced to accommodate this increase.

8.2.1. Cost Estimates and Lead Times for Option 2, Cranbourne

The capitalised cost estimate for Option 1 is $32.25M ± 25% for the primary requirements and $5.3M for consequential works required to replace circuit breakers due to excessive fault levels. Without the circuit breakers being replaced, this option would not be considered technically feasible. Based on these costs, Option 2 would be defined as a new large network asset. The asset life for Option 2 is assumed to be 45 years. Table 8-3 compares the annualised costs for the primary scope of works given a range of discount rates.

Total Capitalised Primary Cost [$k]	*Discount Rate*	*Annualised Cost [$k]*
32,250	6%	$2,087
	8%	$2,663
	10%	$3,270
Upper Tolerance: 32,250 x 1.25 = 40,313	6%	$2,831
	8%	$3,613
	10%	$4,436
Lower Tolerance: 32,250 x 0.75 = 24,188	6%	$1,698
	8%	$2,168
	10%	$2,662

Table 8-3: The primary costs for Option 2, assuming a 45 year asset life.

SPI PowerNet Pty Ltd, the existing asset owner of the circuit breakers that require replacement, has identified its intent to replace these circuit breakers in December 2010 as part of its ongoing asset maintenance / operational expenditure plan. As the regulatory test is an economic cost benefit analysis, VENCorp will only incorporate the net present value of advancing the installation of these circuit breakers in this analysis.

Table 8-4 shows an example of the treatment of the circuit breaker advancement costs used for Option 2 (based on a 45 year asset life).

		Advanced Timing Compared with December 2010		
		December 2007	*December 2008*	*December 2009*
Net Present Value of Advancement Cost [$k]	*Discount Rate*	3 years	2 years	1 year
	6%	850	583	300
	8%	1,093	756	393
	10%	1,318	920	482

Table 8-4: The treatment of advancement costs for circuit breaker replacement associated with Option 2.

The estimated construction lead time for the proposed development of Option 2 is 23 months from the execution of all necessary contracts.

8.3. Option 3 – New 500/220kV Transformer at Ringwood Terminal Station

The proposed scope of works for Option 3 involves the development and switching of a new 500/220kV A1 transformer (1000MVA continuous, 1500MVA 30minute) at the existing Ringwood Terminal Station, as shown schematically in Figure 8-7.

A new 500kV switchyard would need to be developed at Ringwood and space is available for this at the existing site. The 500kV supply would be made available by cutting into the existing Rowville to South Morang 500kV No.3 line that passes through the site.

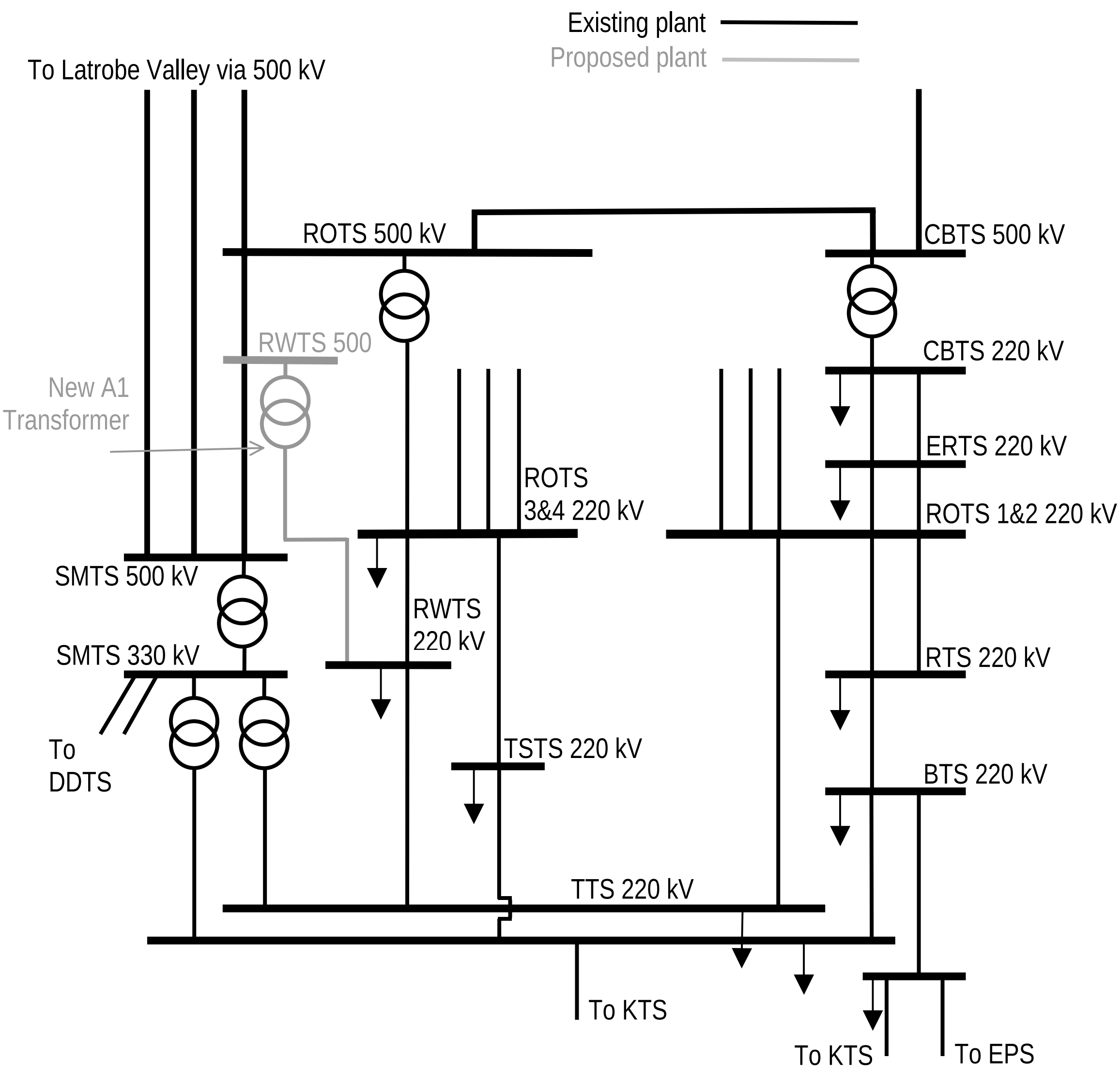

Figure 8-7: The proposed Electrical Representation of Option 3, a new transformer at Ringwood.

The transformer would be switched and supplied from a new 500kV switchyard as per Figure 8-8. On its low voltage side, it will be connected to the 220kV switchyard as per Figure 8-9.

There will be both contestable and non contestable components associated with this scope as some of the works are integrated with, and associated with improving the capability of, the existing assets of both Rowville Transmission Facility Pty Ltd and SPI PowerNet Pty Ltd.

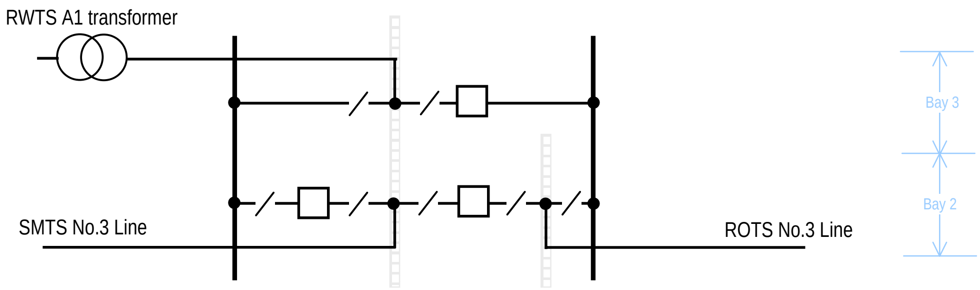

Figure 8-8: Option 3 – The proposed Ringwood 500kV switching arrangement.

This proposed 500kV schematic indicates that the primary plant includes two new 500kV bays, three new rack structures, three new 500kV circuit breakers, up to seven new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required.

Included in the development cost is the appropriate civil works as required to develop the new 500kV switchyard for the two 500kV bays.

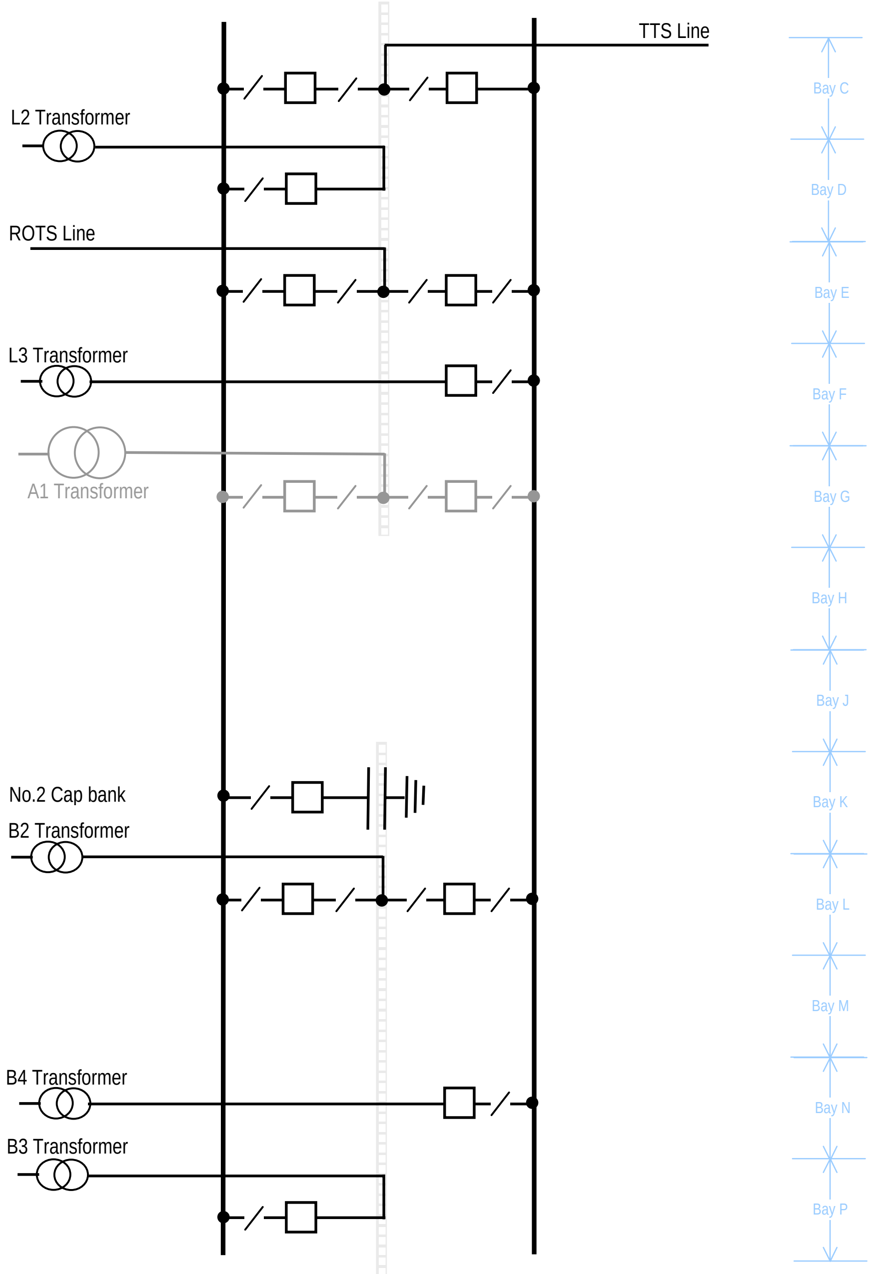

Figure 8-9: Option 3 – The proposed Ringwood 220kV switching arrangement.

The proposed 220kV schematic indicates that the primary plant includes two new 220kV circuit breakers, up to four new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required. No new bays are required.

With Option 3, a new Ringwood A1 transformer, in addition to the primary scope of works as outlined above, consequential works are required to account for the increased fault levels. Fault levels at the Ringwood 220kV bus group increase by around 10kA from 20kA to 30kA and at the Rowville 3&4 bus group they increase by around 2.5kA from 30kA to 32.5kA. VENCorp has identified that 6 circuit breakers at Rowville will need to be replaced to accommodate this increase.

8.3.1. Cost Estimates and Lead Times for Option 3, Ringwood

The capitalised cost estimate for Option 3 is $32.15M ± 25% for the primary requirements and $5.5M for consequential works required to replace circuit breakers due to excessive fault levels. Without the circuit breakers being replaced, this option would not be considered technically feasible. Based on these costs, Option 3 would be defined as a new large network asset. The asset life for Option 3 is assumed to be 45 years. Table 8-5 compares the annualised costs for the primary scope of works given a range of discount rates.

Total Capitalised Primary Cost [$k]	*Discount Rate*	*Annualised Cost [$k]*
32,150	6%	$2,080
	8%	$2,655
	10%	$3,260
Upper Tolerance: 32,150 x 1.25 = 40,188	6%	$2,600
	8%	$3,319
	10%	$4,075
Lower Tolerance: 32,150 x 0.75 = 24,113	6%	$1,560
	8%	$1,991
	10%	$2,445

Table 8-5: The primary costs for Option 3, assuming a 45 year asset life.

SPI PowerNet Pty Ltd, the existing asset owner of the circuit breakers that require replacement, has identified its intent to replace these circuit breakers in December 2010 as part of its ongoing asset maintenance / operational expenditure plan. As the regulatory test is an economic cost benefit analysis, VENCorp will only incorporate the net present value of advancing the installation of these circuit breakers in this analysis.

Table 8-6 shows an example of the treatment of the circuit breaker replacement costs used for Option 1 (based on a 45 year asset life).

		Advanced Timing Compared with December 2010		
		December 2007	*December 2008*	*December 2009*
Net Present Value of Advancement Cost [$k]	*Discount Rate*	3 years	2 years	1 year
	6%	882	605	311
	8%	1,134	785	407
	10%	1,368	955	500

Table 8-6: The treatment of advancement costs for circuit breaker replacement associated with Option 3.

The estimated construction lead time for the proposed development of Option 3 is 23 months from the execution of all necessary contracts.

8.4. Option 4 - New 500/220kV Transformer at South Morang Terminal Station

The proposed scope of works for Option 4 involves the development and switching of a new 500/220kV A1 transformer (1000MVA continuous, 1500MVA 30minute) at the existing South Morang Terminal Station, as shown schematically in Figure 8-10.

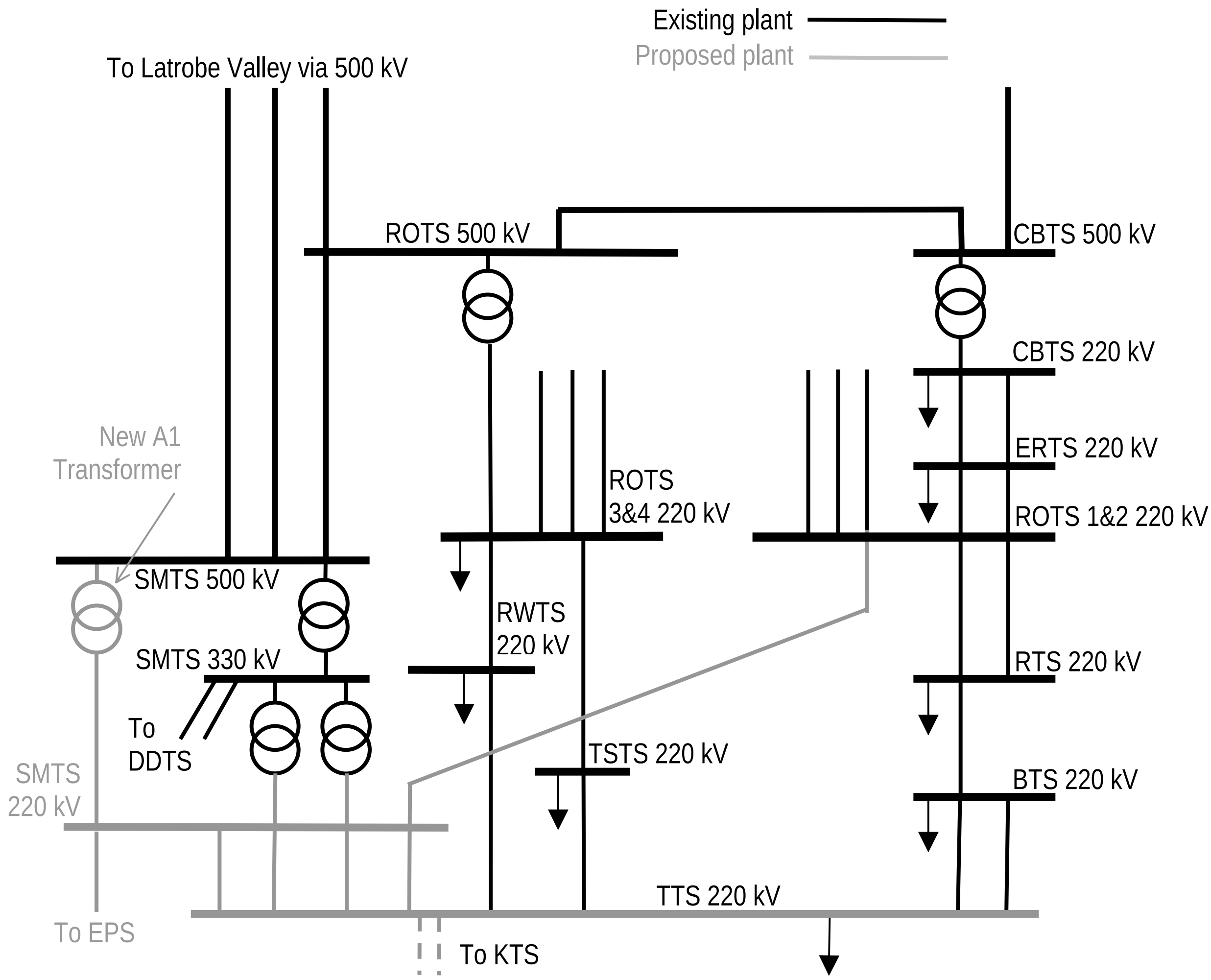

Figure 8-10: The proposed Electrical Representation of Option 4, a new transformer at South Morang.

There is an existing 500kV circuit breaker at South Morang that will be made available for the new A1 transformer. Costs to re-commission this circuit breaker have been included.

At present there is no 220kV switching at South Morang Terminal Station. Considerable development of the 220kV switchyard would need to be undertaken to secure suitable 220kV line exits to Thomastown in order to fully utilize the new A1 transformer. Further, closing the bus ties at Thomastown Terminal Station (which are currently operated as three separate bus groups) is required to balance the forecast power flows on the lines between South Morang and Thomastown. Option 4 therefore, has a pre-requisite that Thomastown Terminal Station is redeveloped to accommodate considerably higher fault currents. This is currently planned by SPI PowerNet as part of its asset maintenance / operational expenditure program and the timing is expected to be within the next five years. Costing for the Thomastown Terminal Station re-development has not been included in this analysis.

Furthermore, there is an advanced proposal by the distribution businesses TXU Networks and AGL Electricity Ltd to develop 220/66kV transformation at South Morang to support load growth in the northern metropolitan area. The tentative timing for this proposal is December 2007. A considerable portion of the 220kV switching required to develop the 500/220kV transformer would be common to that required to introduce the 220/66kV transformation. At this stage, the economies of scale and the capital cost sharing opportunities of the two projects progressing together have not yet been considered.

There will be both contestable and non contestable components associated with this scope as some of the works are integrated with, and associated with improving the capability of, the existing assets of SPI PowerNet Pty Ltd.

The proposed 220kV switching arrangement at South Morang, as required to support the installation of a new 500/220kV A1 transformer is described in Figure 8-11.

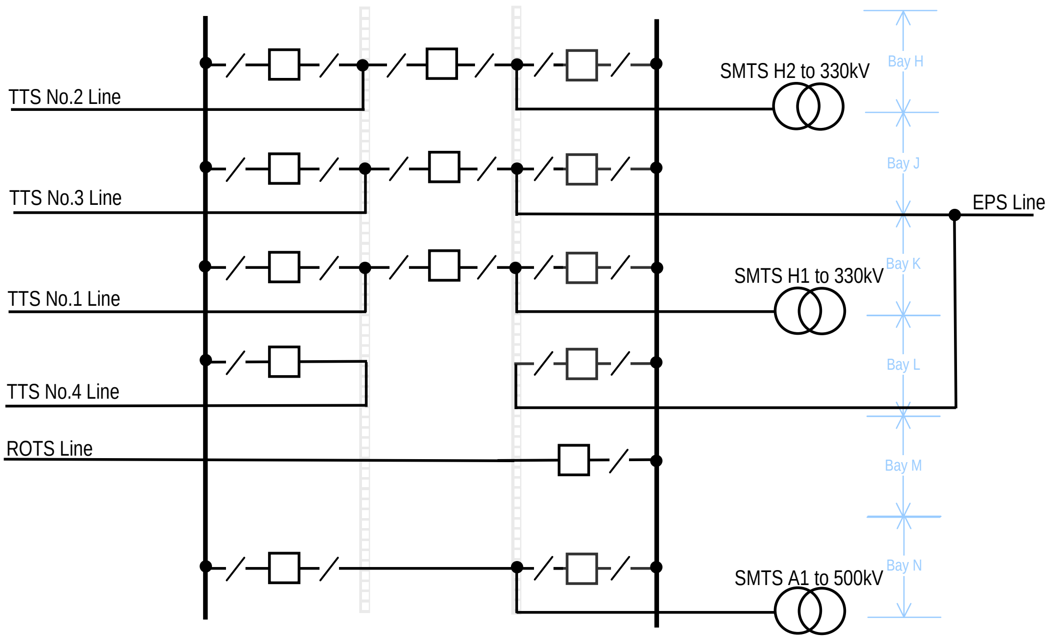

Figure 8-11: Option 4 – The proposed South Morang 220kV switching arrangement.

The proposed 220kV schematic indicates that the primary plant includes fourteen new 220kV circuit breakers, up to twenty-six new remote operated isolators, and associated earth switches, voltage transformers, current transformers, etc, as required. New bays along with their rack structures are required.

With Option 4, a new South Morang A1 transformer, there are no consequential works required to account for the increased fault levels. This is however, subject to further detailed review concerning the redevelopment of Thomastown Terminal Station. No costs have been associated with remedial works for the increased fault levels.

8.4.1. Cost Estimates and Lead Times for Option 4, South Morang

The capitalised cost estimate for Option 4 is \$38M ± 25% for the primary requirements and zero for consequential works required to replace circuit breakers due to excessive fault levels. Based on these costs, Option 4 would be defined as a new large network asset. The asset life for Option 4 is assumed to be 45 years. Table 8-7 compares the annualised costs for the primary scope of works given a range of discount rates.

Total Capitalised Primary Cost [\$k]	*Discount Rate*	*Annualised Cost [\$k]*
38,000	6%	\$2,459
	8%	\$3,138
	10%	\$3,853
Upper Tolerance: 38,000 x 1.25 = 47,500	6%	\$3,073
	8%	\$3,923
	10%	\$4,816
Lower Tolerance: 38,000 x 0.75 = 28,500	6%	\$1,844
	8%	\$2,354
	10%	\$2,890

Table 8-7: The primary costs for Option 4, assuming a 45 year asset life.

The estimated construction lead time for the proposed development of Option 4 is 23 months from the execution of all necessary contracts.

9. Benefits Associated with Relieving Constraints for the Network Options

The regulatory test defines market benefits as the total benefits of an option to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of reasonable scenarios.

This regulatory assessment predominantly considers the benefits of changes in involuntary load shedding caused through savings in reduction in lost load, using a reasonable forecast of the value of electricity to consumers. It also considers the changes in costs through the deferral and advancement of transmission investments.

The four network options considered have different market benefits when assessing their ability to eliminate or minimise the expected constraints over the forthcoming years. Table 9-2 summarises the ability of each of the four options to alleviate the various constraints presented in section 7.

	Option 1 - Rowville	*Option 2 - Cranbourne*	*Option 3 - Ringwood*	*Option 4 – South Morang*
System Normal, required to satisfy flow on Cranbourne A1.	✓	✓	✓	✓
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	✓	✓	✓	✗ Note 4
N-1, Loss of Rowville A1, required to secure flow for next event, Part I	✓	✓	✓	✓
N-1, Loss of Rowville A1, required to secure flow for next event, Part II	✓ Note 1	✗ Note 2	✓	✗ Note 4
System Normal, required to satisfy flow on Rowville A1	✓	✓	✓	✓
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	✓	✓	✓	✗ Note 4
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	✓	✓	✗ Note 3	✗ Note 5
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	✓	✓	✗ Note 3	✗ Note 5

Table 9-1: The opportunity for each option to alleviate network constraints.

All options eliminate the forecast need for load shedding under system normal conditions. However, the Rowville option is the only one that eliminates all of the exposure to the identified constraints allowing for the outage scenarios. The Rowville option is closely followed by the Cranbourne option, which also eliminates most of the expected energy at risk.

Note 1 - The ability of Option 1 to secure the Part II component of energy at risk following loss of the Rowville A1 transformer is dependent on the flexibility for the Rowville A2 transformer to be switched to either the 1&2 or the 3&4 bus groups at the Rowville 220kV switchyard. This important feature allows the new transformer to act as a direct replacement for both the Cranbourne A1 and Rowville A1 transformers. This is the only option that has this flexibility.

Note 2 - Option 2 actually increases the expected energy at risk for this component because of its tendency to push more power from Thomastown to Ringwood and Templestowe.

Note 3 - Since the location of the new transformer at Ringwood for Option 3 is on the supply side of the Richmond to Brunswick cable, it has no effect in alleviating its constraints, rather it marginally increases them.

Note 4 - The location of the new transformer at South Morang for Option 4 is electrically too far from Cranbourne to have sufficient impact in reducing flows on the Cranbourne A1 transformer.

Note 5 - Since the location of the new transformer at South Morang for Option 4 is on the supply side of the Richmond to Brunswick cable it has no effect in alleviating its constraints, rather it marginally increases them.

9.1. Annual Market Benefits of Option 1, Rowville

Option 1 alleviates all of the identified constraints and this is summarised in Table 9-2.

	Option 1, Market Benefits [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
System Normal, required to satisfy flow on Cranbourne A1.	0	0	0	0	866
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	70	112	144	203	408
N-1, Loss of Rowville A1, required to secure flow for next event, part I	499	666	875	1,246	2,300
N-1, Loss of Rowville A1, required to secure flow for next event, part II	94	111	146	171	216
System Normal, required to satisfy flow on Rowville A1	0	0	0	1,488	8,222
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	182	256	307	424	806
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	224	277	353	436	615
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	648	728	1,138	1,294	1,829
TOTAL	1,717	2,150	2,963	5,262	15,262

Table 9-2: The Market Benefit in alleviating constraints by Option 1.

9.2. Annual Market Benefits of Option 2, Cranbourne

Option 2 alleviates the majority of the identified constraints and this is summarised in Table 9-3.

	Option 2, Market Benefits [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
System Normal, required to satisfy flow on Cranbourne A1.	0	0	0	0	866
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	70	112	144	203	408
N-1, Loss of Rowville A1, required to secure flow for next event, part I	499	666	875	1,246	2,300
N-1, Loss of Rowville A1, required to secure flow for next event, part II	0	0	0	0	0
System Normal, required to satisfy flow on Rowville A1	0	0	0	1,488	8,222
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	182	256	307	424	806
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	224	277	353	436	615
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	648	728	1,138	1,294	1,829
TOTAL	1,623	2,039	2,817	5,091	15,046

Table 9-3: The Market Benefit in alleviating constraints by Option 2.

9.3. Annual Market Benefits of Option 3, Ringwood

Option 3 alleviates the majority of the identified constraints and this is summarised in Table 9-4.

	Option 3, Market Benefits [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
System Normal, required to satisfy flow on Cranbourne A1.	0	0	0	0	866
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	70	112	144	203	408
N-1, Loss of Rowville A1, required to secure flow for next event, part I	499	666	875	1,246	2,300
N-1, Loss of Rowville A1, required to secure flow for next event, part II	94	111	146	171	216
System Normal, required to satisfy flow on Rowville A1	0	0	0	1,488	8,222
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	182	256	307	424	806
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	0	0	0	0	0
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	0	0	0	0	0
TOTAL	845	1,145	1,472	3,532	12,818

Table 9-4: The Market Benefit in alleviating constraints by Option 3.

9.4. Annual Market Benefits of Option 4, South Morang

Option 4 alleviates the majority of the identified constraints and this is summarized in Table 9-5.

	Option 4, Market Benefits [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
System Normal, required to satisfy flow on Cranbourne A1.	0	0	0	0	866
N-1, Loss of Rowville A1, required to satisfy flow on Cranbourne A1.	0	0	0	0	0
N-1, Loss of Rowville A1, required to secure flow for next event, part I	499	666	875	1,246	2,300
N-1, Loss of Rowville A1, required to secure flow for next event, part II	0	0	0	0	0
System Normal, required to satisfy flow on Rowville A1	0	0	0	1,488	8,222
N-1, Loss of Cranbourne A1, required to satisfy flow on Rowville A1.	0	0	0	0	0
N-1, Loss of Cranbourne A1, required to satisfy flow on Richmond-Brunswick cable.	0	0	0	0	0
N-1, Loss of Cranbourne A1, required to secure flow on Richmond-Brunswick cable.	0	0	0	0	0
TOTAL	499	666	875	2,734	11,388

Table 9-5: The Market Benefit in alleviating constraints by Option 4.

9.5. Summary of Market Benefits

Table 9-6 presents the annual market benefits of each of the network options considered.

	Annual Market Benefits [$k]				
	2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/10*
Option 1, Rowville	1,717	2,150	2,963	5,262	15,262
Option 2, Cranbourne	1,623	2,039	2,817	5,091	15,046
Option 3, Ringwood	845	1,145	1,472	3,532	12,818
Option 4, South Morang	499	666	875	2,734	11,388

Table 9-6: A summary of the annual market benefits for each network option.

10. Longer Term Planning

Each of the network options considered to remove the forecast constraints will have long term benefits. In principle, the new 1000 MVA transformer will, irrespective of location, carry on a time based average between 500 to 600MVA with a high load factor of around 0.95 over its 45 year asset life. These long term benefits will be realised however they are difficult to quantify as the system will change for other reasons over the transformers asset life. The following considerations have been made to address the longer term impacts as part of this assessment

10.1. Ongoing Benefits

The development of any of the network options under consideration will have the impact of reducing flows on both the existing Rowville A1 and Cranbourne A1 transformers as well as the majority of the meshed 220kV metropolitan network. Each option will do this to a differing extent over its entire 45 year asset life.

For the purposes of representing these benefits, a conservative approach has been taken in the economic assessment where the annual benefits in the last year of the technical assessment (i.e. 2009/10) are carried through without any escalation for the remaining years of the asset life. This is taken to be a conservative approach as, in practice, it is expected the benefits of the transformer will increase in a linear or even quadratic nature as demand grows. This approach also allows for differentiation between each option based on the variation in benefits as quantified for 2009/10.

10.2. Deferral of the Subsequent Metropolitan Transformation

Table 10-1 presents forecasts flows (as a percentage of 1000MVA continuous ratings) on critical 500/220kV transformers for the Do Nothing scenario and for each of the network options

The flows for 2010/11 and onwards are linearly extrapolated from the technical analysis.

	Monitored Transformer	*% Loading on Transformer*							
		2005/06	*2006/07*	*2007/08*	*2008/09*	*2009/010*	*2010/11*	*2011/12*	*2012/13*
'Do Nothing'	CBTS A1	86.4	91.3	94.4	98.2	104.0	108.4	112.8	117.2
	ROTS A1	89.5	94.6	97.8	102.0	109.0	113.9	118.8	123.6
Option 1 - ROTS	CBTS A1	63.3	66.8	69.1	71.7	76.1	79.3	82.5	85.7
	ROTS A1	75.2	79.4	82.1	85.8	91.2	95.2	99.2	103.2
	ROTS A2	58.7	62.2	64.2	66.9	71.5	74.7	77.9	81.1
Option 2- CBTS	CBTS A1/A2	54.9	58.0	59.9	62.2	66.3	69.2	72.0	74.9
	ROTS A1	80.3	84.7	87.6	91.6	97.5	101.8	106.1	110.4
Option 3- RWTS	CBTS A1	76.2	80.4	83.2	86.3	91.9	95.8	99.8	103.7
	ROTS A1	64.8	68.4	70.7	73.9	78.8	82.3	85.8	89.3
	RWTS A1	57.2	60.3	62.4	65.1	69.1	72.1	75.1	78.0
Option 4- SMTS	CBTS A1	73.5	77.6	80.4	83.5	89.3	93.3	97.2	101.2
	ROTS A1	76.6	80.7	83.5	87.2	93.2	97.4	101.5	105.7
	SMTS A1	53.1	55.9	57.8	60.4	65.0	68.0	71.0	73.9

Table 10-1: Longer term transformer power flow forecasts for each network option.

From this analysis, and using a simplified criteria whereby another transformer is required as soon as the loading on an any of the existing ones exceeds its continuous capability, this simplistic but representative approach indicates that a subsequent metropolitan transformer may be required by;

- 2012/13 for Option 1;
- 2010/11 for Option 2;
- 2012/13 for Option 3; and
- 2011/12 for Option 4.

Given an assumed capitalised cost of this subsequent transformer of $30M, and that it would have an asset life of 45 years, and using a discount rate of 8%, the following transformer deferral benefits have been assigned to each of the network options:

	Capitalised to July 2005 [$k]	*Annual transformer deferral benefit in Year 20010/11 [$k]*	*Annual transformer deferral benefit in Year 20011/12 [$k]*
Option 1, Rowville	2,910	2,400	2,400
Option 2, Cranbourne	0	0	0
Option 3, Ringwood	2,910	2,400	2,400
Option 4, South Morang	1,510	2,400	0

Table 10-2: Additional transformer deferral benefits for each network option.

11. Other Benefits

Each of the network options considered provide, to some relatively minor extent, some technical and economic benefits in addition to the reduction in potential load shedding due to the loading on the Rowville A1 and Cranbourne A1 transformers.

Each option will reduce the reactive transmission losses in the shared transmission network so as to provide improved voltage control and reactive reserve margins. This improved reactive power balance will, in the medium term, assist in deferring the need for additional shunt capacitor banks to support peak demand conditions. Furthermore, each option will reduce real transmission losses in the shared network, but this has been quantified to be on average less than 0.5MW per hour per year. Neither of these benefits has been economically quantified as they would be similar in magnitude for all options and not have a material impact in the overall cost benefit assessment.

- The proposed options also:
- focus on the development of existing sites to minimise environmental impacts;
- considerably increase the windows of opportunity for planned outages of existing transmission plant; and
- provide additional network security to account for unusual market or network conditions which can arise during multiple plant outages and which aren't specifically considered as part of the planning process.

12. Consideration of Non-Network Alternatives

The new large network asset options considered as part of this analysis avoid considerable volumes of load shedding that may be required as a consequence of very low probability events occurring at times of moderate to high demand in Victoria.

Further, the load shedding may be required at locations varying from Springvale and Heatherton, to Cranbourne and East Rowville or Richmond, depending on the specific outage scenario.

Non-network options, such as demand side participation or embedded generation, would require reliability commensurate with the network options considered. They would also need to be available at multiple locations and have a capacity growing from around 1000MVA in 2005/06 to 1700MVA in 2009/10 to be considered as a technically and commercially feasible alternative to the proposed network options. This is in part due to the large (1000MVA) size of the existing Rowville A1and Cranbourne A1 transformers and their critical role in supporting load at many terminal stations.

Based on VENCorp's experience, it does not consider there are any technically or commercially feasible non-network options that would be available in the near future to sufficiently alleviate loading on the critical transformers in the east and south-east metropolitan area of Melbourne.

13. Economic Cost-Benefit Analysis

Table 13-1 presents calculations of the net present value of the market benefits, in $k, comparing Options 1, 2, 3 and 4 assuming the network options are completed at the earliest feasible time of September 2007 and given the tabulated assumptions.

8.00%	Discount Rate
45	Economic Life
0.16986%	Probability of Event
1.00	Cost Multiplier Factor

$ 29,600	VCR at SVTS
$ 29,600	VCR at RTS
$ 29,600	VCR at CBTS
1.00	Ongoing Benefit Factor

		Present Value	2005-06	2006-07	2007-08	2008-09	2009-10	20010-11	20011-12	20012-13	2013-14	2014-15	PV Residual
'Do Nothing'	Exp. Energy @ Risk	-143,910	-1,716	-2,149	-2,963	-5,262	-15,263	-15,263	-15,263	-15,263	-15,263	-15,263	-194,106
Option 1 Rowville	Market Benefits	141,330	0	0	2,963	5,262	15,263	15,263	15,263	15,263	15,263	15,263	194,106
	Total Costs	-31,870	0	0	-3,070	-3,070	-3,070	-3,070	-3,070	-3,070	-3,070	-3,070	-39,039
	Next Transformer Deferral	2,910	0	0	0	0	0	2,400	2,400	0	0	0	0
	Net Market Benefits	112,380	0	0	-107	2,192	12,193	14,593	14,593	12,193	12,193	12,193	155,067
Option 2 Cranbourne	Market Benefits	139,180	0	0	2,817	5,091	15,047	15,047	15,047	15,047	15,047	15,047	191,356
	Total Costs	-28,580	0	0	-2,753	-2,753	-2,753	-2,753	-2,753	-2,753	-2,753	-2,753	-35,016
	Next Transformer Deferral	0	0	0	0	0	0	0	0	0	0	0	0
	Net Market Benefits	110,590	0	0	64	2,338	12,294	12,294	12,294	12,294	12,294	12,294	156,340
Option 3 Ringwood	Market Benefits	117,230	0	0	1,471	3,532	12,819	12,819	12,819	12,819	12,819	12,819	163,015
	Total Costs	-28,530	0	0	-2,749	-2,749	-2,749	-2,749	-2,749	-2,749	-2,749	-2,749	-34,953
	Next Transformer Deferral	1,510	0	0	0	0	0	2,400	0	0	0	0	0
	Net Market Benefits	90,220	0	0	-1,277	783	10,070	12,470	10,070	10,070	10,070	10,070	128,062
Option 4 South Morang	Market Benefits	103,510	0	0	875	2,734	11,388	11,388	11,388	11,388	11,388	11,388	144,819
	Total Costs	-32,580	0	0	-3,138	-3,138	-3,138	-3,138	-3,138	-3,138	-3,138	-3,138	-39,911
	Next Transformer Deferral	2,910	0	0	0	0	0	2,400	2,400	0	0	0	0
	Net Market Benefits	68,020	0	0	-2,263	-405	8,249	5,849	5,849	8,249	8,249	8,249	104,909

Table 13-1: The cost benefit analysis of network options assuming timing is prior to Summer 2007/08. All annualised and present values are in [$k].

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This scenario indicates that Option 1 maximises the expected net present value of the market benefits at $112,380k, followed closely by Option 2 at $110,590k. The benefits of Options 3 and 4 are considerably lower.

These results are not unexpected as the estimated project costs for all options are relatively close (range from $33 to $38M), yet some options provide considerably more economic benefits than the others.

14. Sensitivity Analysis and Project Timing

The regulatory test requires that the calculation of market benefits encompass sensitivity testing on key input variables.

In accordance with this requirement, VENCorp has identified the following key variables to include in sensitivity testing of the net present value of the market benefits:

- Base case discount rate of 8%, sensitivity at 6% and 10%;
- Capitalised cost estimates varying by ±25%;
- Base transformer Mean Time To Repair (MTTR) of 31 days, sensitivity at 26 and 36 days; and
- Base Value of Customer Reliability (VCR) of $29,600, sensitivity at $35,600 for the Springvale connection point, $44,200 for the Richmond connection point, and $26,000 for the Cranbourne connection point.[17]

The results of these sensitivity studies are presented in Table 14-1 to Table 14-3, which are based on project timings of summer in 2007/08, 2008/09 and 2009/10, respectively.

The full cost-benefit analysis for each of these scenarios is presented in Attachment 2.

	Net Present Value of the Market Benefits [$k] with Timing Summer 2007/08.							
	8% discount rate	*6% discount rate*	*10% discount rate*	*Costs up by 25%*	*Costs down by 25%*	*MTTR of 36 days*	*MTTR of 26 days*	*Connection point VCR*
Option 1 Rowville	112,380	161,530	80,490	105,140	119,620	122,020	102,730	137,160
Option 2 Cranbourne	110,590	159,370	78,920	103,440	117,730	119,890	101,300	134,940
Option 3 Ringwood	90,220	131,320	63,610	83,460	96,970	95,970	84,460	103,110
Option 4 South Morang	68,020	104,680	44,370	59,140	76,890	71,560	64,470	79,390

Table 14-1: The net present value of the market benefits given various sensitivities for the network options considered and based on project timing of Summer 2007/08.

[17] This sensitivity is aimed at considering the implications of shedding considerable amounts of metropolitan load (which has a relatively high proportion of commercial based load) rather than using the standard state wide composite figure of $29,600. The connection point figures for VCR are derived from the 2004 Connection Asset Planning Report

	Net Present Value of the Market Benefits [$k] with Timing Summer 2008/09.							
	8% discount rate	*6% discount rate*	*10% discount rate*	*Costs up by 25%*	*Costs down by 25%*	*MTTR of 36 days*	*MTTR of 26 days*	*Connection point VCR*
Option 1 Rowville	113,300	162,250	81,840	106,790	119,820	122,590	104,010	137,590
Option 2 Cranbourne	111,110	159,810	79,780	104,560	117,670	120,070	102,150	134,980
Option 3 Ringwood	91,750	132,750	65,460	85,590	97,910	97,330	86,170	104,710
Option 4 South Morang	70,020	106,550	46,690	61,750	78,290	73,460	66,580	81,510

Table 14-2: The net present value of the market benefits given various sensitivities for the network options considered and based on project timing of Summer 2008/09.

	Net Present Value of the Market Benefits [$k] with Timing Summer 2009/10.							
	8% discount rate	*6% discount rate*	*10% discount rate*	*Costs up by 25%*	*Costs down by 25%*	*MTTR of 36 days*	*MTTR of 26 days*	*Connection point VCR*
Option 1 Rowville	112,460	161,140	81,490	106,610	118,310	121,320	103,590	136,000
Option 2 Cranbourne	109,930	158,430	79,010	103,930	115,930	118,480	101,370	133,080
Option 3 Ringwood	91,660	132,490	65,750	86,060	97,270	97,020	86,310	104,470
Option 4 South Morang	70,510	106,850	47,520	62,800	78,220	73,810	67,210	81,910

Table 14-3: The net present value of the market benefits given various sensitivities for the network options considered and based on project timing of Summer 2009/10.

Option 1, involving the installation of a new 1000MVA 500/220kV transformer located at Rowville, maximises the net present value of the market benefits, having regard to a number of alternative projects irrespective of the year of installation, in all scenarios. The range of benefits is from $162.3M to $80.5M with the average around $117.9M.

The next most beneficial project was Option2, involving the transformer located at Cranbourne. The range of benefits was very similar to, but slightly lower than that for option 1, and varied from $159.8M to $78.9M with the average around $115.7M.

The most influential sensitivity is the change in the discount rate, followed by the change in the connection point VCR, the change in the Mean Time To Repair, and then the change in costs.

These characteristics are presented in Figure 14-1 and Figure 14-2.

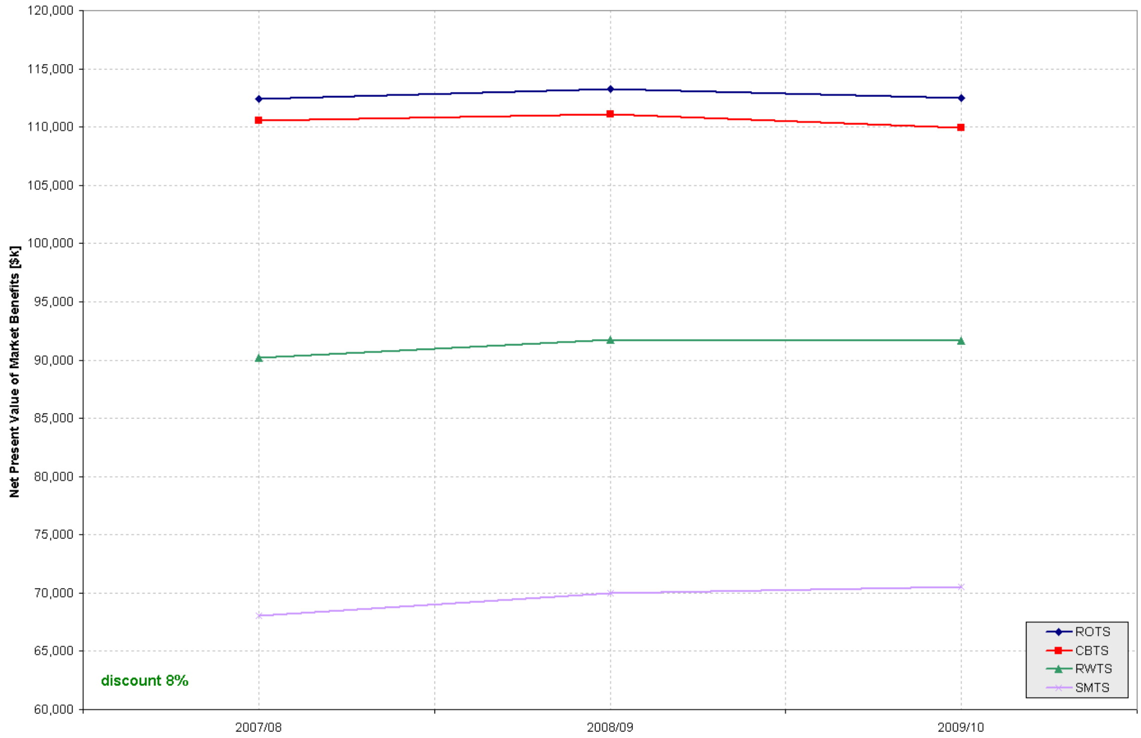

Figure 14-1: The net present value of market benefits of each Option based on different timings for an 8% discount rate.

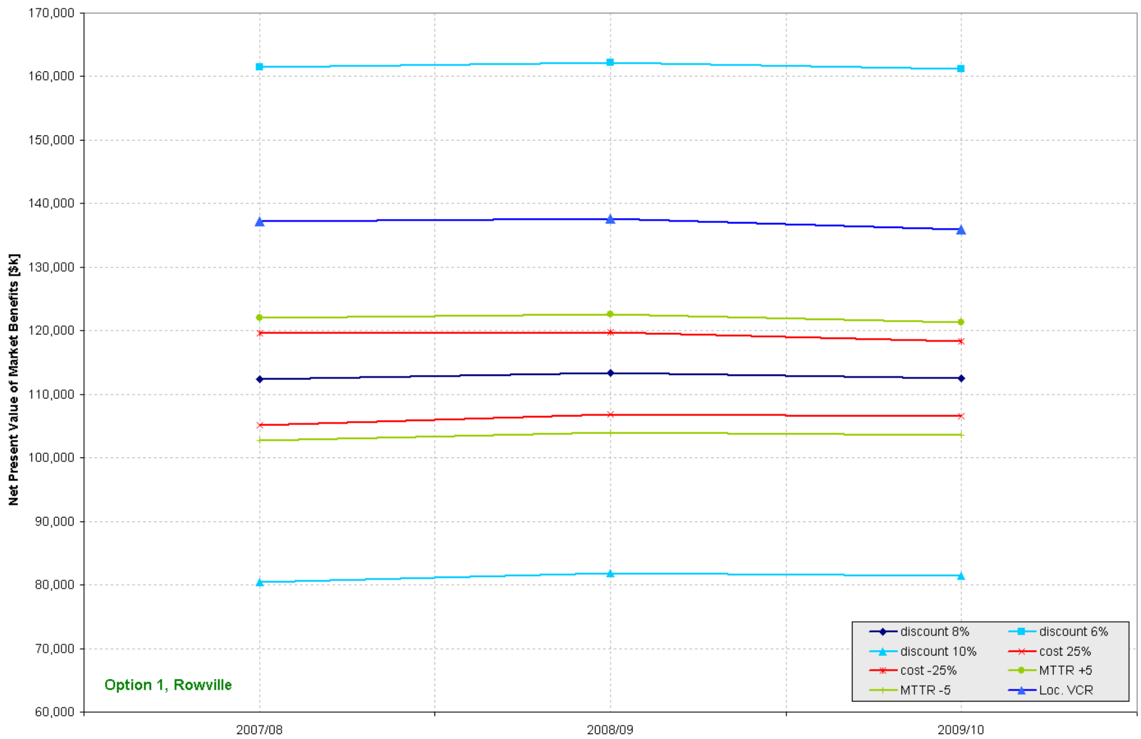

Figure 14-2: The net present value of market benefits for Option 1 as effected by the various sensitivity studies.

15. Ranking of Options

Table 15-1 presents the expected net present value of the market benefits for each option considered, and ranks them based on the number of scenarios the option maximises the net present value of market benefits and then from highest to lowest benefit.

Option	*Range of Net Present Value of the Market Benefit [$M]*	*Average Net Present Value of the Market Benefit [$M]*	*Number of Scenarios Option Maximises the Net Present Value of the Market Benefit*	*Ranking*
1, Rowville	162.3 – 80.5	117.9	24 from 24	1
2, Cranbourne	159.8 – 78.9	115.7	0 from 24	2
3, Ringwood	132.8 – 63.6	94.7	0 from 24	3
4, South Morang	106.9 – 44.4	72.6	0 from 24	4

Table 15-1: The ranking of Options to address constraints caused by flows on and outages of the Rowville and Cranbourne 500.220kV transformers.

Option 1 maximises the net present value of the market benefit in all 24 of the scenarios assessed. On this basis VENCorp considers it is the preferred network option.

Over the 45 years of the asset life for Option 1 and for all 24 scenarios, the expected present value of the market benefit of this augmentation ranges from $191.7M to $102.8, delivering an expected net present value of the market benefit of between $162.3M to $80.5M, averaging at $117.9M.

Therefore, VENCorp considers this project satisfies Part 1(b) of the Regulatory Test on the basis it maximises the expected net present value of the market benefits in a majority of reasonable scenarios and considering a number of alternative options. Note, that this project primarily improves the reliability of supply to customers in the east and south east metropolitan area in an economic manner. This project it is not by definition a 'reliability augmentation'.

Having regard to the timing of the project, it is evident that Option 1 marginally optimises the market benefits when it is completed for Summer 2008/09.

However, VENCorp considers it prudent that the transformer be completed for Summer 2007/08 on the basis that:

- there is a very small difference in the large net market benefits of this project when considering the sensitivity to timing ($112.4M compared with $113.3M for completion in 2007/08 or 2008/09, respectively),
- over the critical summer 2008/09 period, VENCorp is forecasting system normal constraints based on loading of the existing Rowville A1 transformer and therefore the risk of project delays if aiming for 2008/09 would not be tolerable.

Given these considerations, VENCorp recommends the project be completed for Summer 2007/08.

16. Consideration of Material Inter-regional Network Impacts

In accordance with clause 5.6.6B of the National Electricity Code, the Inter-Regional Planning Committee must prepare an augmentation technical report if any augmentation is reasonably likely to have a material inter-network impact. VENCorp has assessed the preferred augmentation against the screening criteria published by the Material Inter Network Impact Working Group and has determined that:

(1) Power transfer capability criteria: no material impact, as the peak transfer capacity between inter-regional networks will not be reduced or increased by 3% or 50MW nor will the intra-regional peak transfer capacity within another TNSP's network reduce by 3% or 50MW.

(2) Fault level increase criterion: no material impact, as fault levels will not increase by more than 10MVA at any station in another TNSP's network.

(3) Series capacitor criteria: no material impact, as there is no proposal to install series capacitors.

Note, that VENCorp has identified that installation of a 500/220kV transformer at Rowville will have the impact of reducing flows on the critical South Morang 500/330kV F2 transformer. High loading on this transformer can force a limit on the transfer from Victoria to the Snowy/NSW regions. However, VENCorp does not consider that the net increase in this single limit will be material with respect to network impacts, as the peak transfer capacity from Victoria to the Snowy/NSW regions is defined by other limits and this will not change. The preferred augmentation will widen the range of system conditions under which the peak transfer capacity can be delivered and therefore have some beneficial market impacts. These market impacts have not been quantified as part of this assessment.

As none of the proposed projects have a material inter-network impact, the Inter Regional Planning Committee has not been requested to prepare a technical report for this augmentation.

17. Recommendation

VENCorp considers Option 1, a new 1000MVA, 500/220kV transformer at Rowville Terminal Station, satisfies Part 1(b) of the Regulatory Test on the basis it maximises the expected net present value of the market benefits compared with a number of alternative options and timings, in a majority of reasonable scenarios.

This project considerably improves the reliability of supply to customers in the east and south east metropolitan area of Melbourne and does so in an economic manner. The capitalised cost estimate of the project is $37.2M ± 25% and the recommended completion date is September 2007. Given this timing, it delivers an expected net present value of the market benefit of between $161.5M to $80.5M, averaging over the sensitivity studies at $117.6M.

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