Appendices to SPI PowerNet's Revenue Cap Application

For the period 1 January 2003 to 31 March 2008

SPI POWERNET
A subsidiary of Singapore Power International

ABN 78 079 798 173

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Appendix A

Indec Consulting report on the stand alone operating and maintenance cost of undertaking revenue-capped services – Executive summary

Report

Stand-Alone Cost Model

Prepared for:
Mr Geoff Thorn
Senior Financial Analyst
SPI PowerNet Pty Ltd
890 Wellington Road
Rowville VIC 3178

V750J1R5

April 2002

1. EXECUTIVE SUMMARY

1.1. Overview

SPI PowerNet Pty Ltd (SPI PowerNet) is preparing a submission to the Australian Competition and Consumer Commission (ACCC) with regard to electricity transmission tariffs for the next regulatory period. Such regulatory price reviews consider the efficiency of operating expenditure (OPEX) proposed, benchmark this against industry peers, and consider the effect on key performance targets of the proposed OPEX.

To assist the above process, Indec Consulting has developed a Stand-Alone Cost Model which details the functional activities that are required to be undertaken by SPI PowerNet to meet external and internal performance targets. The stand-alone cost model is benchmarked for efficiency, and thus supports SPI PowerNet's submission with regard to the proposed level of OPEX.

This Report, *Stand-Alone Cost Model* (The Report) is an independent assessment of SPI PowerNet's OPEX costs based on efficiency, and taking account the type of network and business environment SPI PowerNet operates within.

The Stand-Alone Cost concept is to review the functions required to be performed by SPI PowerNet in order to meet the external and internal performance targets taking account of non-controllable factors driven by business conditions.

1.2. Stand-Alone Cost Model

Efficiency aspects are incorporated in the cost model by:

- Benchmarking those costs which are most likely to be under managerial control in relation to overheads and indirect cost from recent regulatory decisions in other jurisdictions;
- Developing a direct cost component by reviewing the asset management processes and conducting an efficiency review with regard to the performance targets required in relation to the SPI PowerNet network capital expenditure (CAPEX), OPEX and optimisation of the network;

- Applying general industry best practice or financial analysis benchmarks to the model where applicable; *and*

- Comparing the OPEX cost produced by the Stand-Alone Cost Model with other Australian Transmission Network Service Providers (TNSP's) on a cost and cost to performance ratio relationship, taking account of business conditions and adjusting for external circumstances.

The report details in **Section 5** and Appendix B the functions required to be performed by activity to achieve performance targets based on the asset configuration and condition.

The findings of an Integrated Asset Management Review (which was a separate diagnostic to the stand-alone cost model and the subject of a separate report) is incorporated into the analysis because the networks planning needs and relationship of CAPEX to OPEX needs to be considered. The augmentation planning of the network is conducted by VENCorp, and thus the asset management process is not fully integrated with CAPEX compared to other electricity transmission networks

Indec Consulting conducted a staff audit (as per Appendix B) in relation to the FTE's required to meet the performance targets as detailed in the relevant System Code and Network agreements for the Victorian Transmission System. The audit was in relation to the network direct cost functions namely Network Services, Regulated Transmission Services and Asset Management. The efficiency of these three functions was reviewed in relation to:

- the tasks required to meet the performance targets in relation to the asset configurations;

- the adequacy of the asset management processes as per an Integrated Asset Management Review;

- direct and indirect staffing ratios and cost percentages in Network Services;

- financial analysis benchmarks of total direct cost to total indirect cost, gross profit margin (as a stand-alone business) and a direct to indirect cost percentage in the three direct cost functions; *and*

- a calculated charge-out rate of direct full-time employees (FTE's) in network services for full cost recovery, based on 85% productivity and compared to equivalent market rates.

In developing the SPI PowerNet cost model, the categories of Regulatory, Corporate (including executive remuneration), Finance, Human Resources (HR) and Information Technology (IT) were benchmarked in accordance with the benchmarks developed in the Victorian 2001 Electricity Distribution Price Review by KPMG[1] (KPMG Report). These benchmark costs (escalated to 2001 dollars) were used, as they are generic in nature to electricity networks and would be equally applicable to transmission, as well as distribution networks.

The overhead functions of Regulatory, Corporate, and Finance were assessed on an overall efficiency basis in relation to the other three direct cost functions. The direct cost functions were un-benchmarkable on a functional basis because of lack of industry benchmark data. Whilst the direct costs required to meet the performance targets is not benchmarkable these costs are in effect unavoidable costs in relation to the business conditions to achieve the performance targets. These costs were analysed on a functional basis by performance target requirements, set by outside organisations.

The costs for the three direct cost functions were developed by use of a staff audit with regard to FTE’s (as detailed in **Appendix B**) required to meet the performance targets, the annual salary levels provided in **Section 6.9** (escalated to 2001 dollars), and actual costs in relation to allowances, training, contractors, consultants, materials, motor vehicles, FBT, community welfare, insurance, legal, property leasing, printing and stationery, rates and taxes, travel and entertainment and telephone.

Both the direct and indirect costs are treated as stand-alone costs in **Section 6,** and the stand-alone cost model presented as a notional trading statement in Appendix A modelled from the descriptions of the activities in **Section 5**, and are based on best practice operations cost ratios and benchmarks.

[1] Office of the Regulator General, Victoria, 2001 Price Review – Cost Allocation, KPMG Consulting, 30 May 2000 and Final Report, 9 August 2000.

The Integrated Asset Management Review Diagnostic indicated a reasonably comprehensive asset management process is in place but because of SPI PowerNet's limited augmentation responsibility it is not a full integrated process. This ultimately may mean the assets are not fully optimised based on SPI PowerNet's own risk assessments (balancing risk, whole of life costs, capacity and OPEX).

The Victorian Transmission Network is one of the more reliable networks in Australia. However, the network is ageing placing requirement on renewals. Redundancy in the network has been reduced and this has resulted in an increasing level of OPEX to achieve maximum network availability. Some of the performance targets are not being met which, in conjunction with the above factors, will require additional resources.

Whilst the OPEX task has increased because of the above factors, this is expected to remain fairly static provided the augmentation and renewals CAPEX is prudently and timely implemented to maintain performance targets. However, as identified by the methodology as detailed in **Section 3**, with regard to the staff audit, performance target requirement, efficiency analysis and the Integrated Asset Management Review, additional resources are required with regard to condition monitoring and assessment, risk management and strategic network planning to:

- seek non-asset solutions prior to augmentation;
- maintain performance targets; *and*
- undertake the renewals task over the next price reset period.

In addition to the regulatory performance targets provided in **Section 4**, SPI PowerNet has a series of key performance indicators, (KPI's) detailed in **Section 6** that must be achieved by Network Services and are currently experiencing difficulties in achieving some of these.

Accordingly, further additional FTE's and measures with regard to continuing efficiency are required in the following areas:

- additional FTE's to assist in network coordination functions and general safety issues, and perform quality and health and safety reviews of work performed in this area;

- additional FTE's to assist lines teams in maintenance and refurbishment functions;

- additional FTE's to assist the environmental function; *and*

- additional training and recruitment to replenish an ageing workforce and skill base.

Given the above circumstances, a reduced OPEX figure will place further pressures on achieving the required performance targets and KPI's. **A reduction in OPEX cost would impact on performance and thus reliability.**

A summary of the stand-alone OPEX cost by sub-function is as follows:

Organisational Function	**OPEX ($m)**
Network Services	30.86
Regulated Transmission Services	1.26
Asset Management	3.32
Regulatory	1.21
Property	6.09
Corporate	9.49
Community Welfare	0.54
Information Technology (IT)	3.51
Human Resources (HR)	2.81
Finance	5.11
TOTAL	**64.20**

In terms of financial analysis efficiency measurements by cost ratios, the Stand-Alone Cost Model results in the following ratios:

- a Network Services 3 direct functions/indirect labour cost of 38.7% of total direct function labour cost and an indirect/direct labour ratio of 1:3.8;

- direct functional costs comprising 55.2% of total cost;

- a direct to indirect cost ratio of 46.3% of total cost; *and*

- a direct to indirect cost of 77.4% in Network Services, Regulated Transmission Services and Asset Management.

Major reform in the rail and utilities sector in order to compete with outsourced services has required a major reduction in indirect cost to ensure a gross profit margin of 35-40% and a reduction of direct cost to ensure the labour charge-out rates are competitive. Based on an 85% productive efficiency, the labour charge-out rate plus materials in order to cover total cost in the stand-alone model is competitive with current market rate.

The gross profit margin of 46% reflects the ability to charge out labour at competitive market rates and to cover all indirect costs (profit margin is not included).

Use of the KMPG Report benchmarks results in a:

- a corporate cost of 15% of total cost; *and*

- a corporate and finance cost of below 23% of total cost.

The above cost ratios reflect the requirement of ORG for the electricity distribution review that reasons be given if these costs were above 20% of total cost.

Large increases in the cost of insurance premiums have actually resulted in a distortion of these cost ratios. The exclusion of insurance cost yields the following:

- a corporate cost of 10.5% of total cost; *and*

- a corporate and finance cost of below 18.9% of total cost.

These revised ratios provide a sounder basis for comparison, and are well below previous levels set by ORG.

The resultant Stand-Alone Cost Model benchmark ratios are in accordance with best practice in the recently privatised Victorian rail and electricity distribution industries.

1.3. Comparative Analysis

A comparative analysis of the OPEX cost generated by the Stand-Alone Cost Model together with an allowance for a network planning function was undertaken to order to compare the resultant cost with other TNSP's. This was done on a cost to performance basis involving unit costs, cost to performance ratios and asset base taking account of uncontrollable business conditions (external circumstances). The results of the comparative analysis show that:

- SPI PowerNet is an efficient performer producing high reliability and low OPEX costs.
- SPI PowerNet is in line with other TNSP's on a physical assets basis with regard to the level of energy transported and are using their assets efficiently.
- On the basis of OPEX per physical assets, SPI PowerNet has an efficient level of OPEX and are well below the industry average.
- With respect to total cost (OPEX plus CAPEX), SPI PowerNet has an overall superior cost performance with its total expenditures well below other TNSP's.
- On a total cost basis, SPI PowerNet could increase OPEX and still be well below the TNSP average.

Appendix B

Trowbridge Consulting valuation of non-insured risks

Valuation of Non-Insured Risks

SPI PowerNet

December 2001

21 December 2001

Mr Kelvin Gebert
Project Manager Regulatory Reset
SPI PowerNet Pty Ltd
684 Waverley Road
Chadstone VIC 3148

Dear Kelvin

Valuation of Non-Insured Risks

Please find enclosed our report for your consideration. We look forward to discussing our findings with you and your colleagues. Please do not hesitate to contact us if you have any questions.

Yours sincerely

John Trowbridge
Fellow of the Institute of Actuaries of Australia

Kumar Padisetti

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CONSULTANTS & ACTUARIES
Trowbridge Consulting Limited
ACN 092 651 057

MELBOURNE

Level 39, 140 William Street
Melbourne VIC 3000
Tel: (03) 9269 4000
Fax: (03) 9269 4111

E-mail: melbourne.office@trowbridge.com.au

SYDNEY

Level 38, 1 Macquarie Place
Sydney NSW 2000
Tel: (02) 9324 9000
Fax: (02) 9324 9324

E-mail: sydney.office@trowbridge.com.au

Valuation of Non-Insured Risks

Part III Appendices

A Catastrophic Risks Faced by SPIP

B Adjustment to Central Estimate

C Insurance Market Hardening

D List of Documents

Part I Summary of Findings

1 Introduction and Scope

1.1 Introduction

SPI PowerNet (SPIP) is in the process of preparing an application for revenue reset for the period 2003 – 2007. As part of this reset application SPIP has engaged Trowbridge Consulting (TC) to undertake a valuation of its non-insured risks. These risks were identified in a scoping study conducted by TC.

This study involved a number of meetings with the staff of SPIP, its insurance broker Marsh and a review of a number of documents provided for the study. Documents referred to in our study are listed in Appendix C.

1.2 Scope

The scope for the study was to assess the risks identified in the scoping study and estimate the actuarial cost of those risks.

1.3 Report Structure

A summary of our findings is presented in Part I of this report. A more detail discussion may be found in Part II titled *"Detailed Findings"*.

This report includes those risks that have been classified as uninsured (or non-insured) risks for the purpose of the application for revenue reset and which are not provided for in SPIP's O&M forecast.

2 Rationale for Valuing Non-Insured Risks

Regulated transmission businesses are commonly regarded as having steady cash flow and being exposed to minimal risk. However, these transmission businesses do incur severe losses due to their exposure to diversifiable risks. Examples of incidents are shown in table 2.1.

Table 2.1 - Examples of International Incidents

Date	Country	Event	Amount of damage
3/99	Mexico	Mechanical failure	3 million people without power for several hours
2/99	Argentina	Fire destroyed a transformer plant and the main cable ducts.	$US 1 billion
1/98	USA	Freezing rain downed power lines	500,000 people without power for several hours
2/98	New Zealand	4 major power cables collapsed	$NZ 850 million
1/98	Canada	Collapse of transmission towers	1 in 5 Canadians affected for up to 3 weeks. 66 municipalities declared a state of emergency.
8/96	Malaysia	Power tripping	$US 88 million
8/96	USA	High tension power lines sagged close to trees causing electric arcs that shut down the power system.	Two of the largest blackouts in US history.
1/89	Canada	Solar activity caused a magnetic storm which resulted in a power imbalance.	Total blackout for Quebec.
11/85	USA	Transmission line tripping	30 million people without electricity for up to 30 hours.

Similar to the overseas transmission companies, SPIP is also subject to a number of diversifiable risks. While SPIP has insurance cover for some of these risks (eg. material loss of assets such as buildings, plant, machinery and merchandise) there are a wide range of risks for which SPIP is not currently insured.

It is common business practice for companies to limit the level of insurance they purchase from private insurers or reinsurers. Valid reasons for doing so include:

- the company believes the quoted insurance premium is in excess of the true insurance cost;
- the required insurance is not readily available (for example, asset stranding risk);
- the company has sufficient working capital to withstand the risks in question (for example, the risks within the insurance "deductible" limit);
- the company has accepted an attractive premium on a "standard" insurance policy which includes a range of exclusions, and the cost of "*writing back*" the exclusions exceeds the company's perceived value of the excluded risks; and
- the insurer requires the company to bear a reasonable share of each claim to incentivise it to better manage its claims experience.

If no allowance is made for a company's "non-insured" costs in setting its tariff revenue, then, other things being equal, a business which "over-insures" its risks (possibly on uneconomic terms) would be allowed to recover a greater level of tariffs to offset its insurance costs. We consider this to be a perverse incentive.

In our view, each business should be incentivised to select the most appropriate/efficient insurance program for its diversifiable risks. This would be achieved if for each business, the "non-insured' costs were estimated and were treated by the regulator as a cash flow expense in setting regulated revenue. This approach requires that these uninsured risks be valued using appropriate quantification methodologies.

3 Summary of Valuation of Non-Insured Risks

This section provides a summary of the valuation of major non-insured risks, which have been identified during our discussions with the staff of SPI PowerNet. In our view, these risks are diversifiable and hence they should not be reflected in the company's asset beta. Asset beta by definition reflects only the non-diversifiable or systematic risks borne by the company. In most cases SPIP would be able to obtain insurance for these diversifiable risks. However, the market may not provide insurance cover for certain risks.

Calculation of Risk Premium

Generally, for insurable risks we have obtained quotes from SPIP's insurance broker. These indicative quotes do not allow for the impact of the events of September 11 on insurance costs. A detailed discussion of the impact of the September 11 events on the level of insurance premiums is included in Appendix C. We propose that SPIP obtain revised quotations from its insurance broker prior to ACCC's final reset determination.

We have quantified the uninsurable risks using industry information, our research and other information provided by the staff of SPIP. The approach we have taken in quantifying these uninsurable risks can be summarised by the following formula.

Central Estimate = (Expected Amount at Risk) x (Probability of Occurrence)

We also believe that for some risks an adjustment to the central estimate may be required. This is fully discussed in Appendix B of Part II of this report.

However, for the purpose of this report we have not included any adjustment to the central estimate in our calculation of the risk premium estimate.

Table 3.1 shows the identified non-insured diversifiable risks, and summarises whether or not we were able to obtain quotes from the insurance broker.

Table 3.1 - Availability of Insurance for Non-Insured Risks

Uninsured risks	Insurance availability
Extortion, bomb threat and kidnap	Yes
Claims within insurance policy deductibles	Yes/No
Credit risk - counter party	Yes
Credit risk - Insurance providers	No
Risk of legal costs exceeding expected costs	Yes
Easement related risks	No
Native title risks	No
Asbestos	No
Environmental Issues	No
EMF Issues	No
Key person insurance	Yes
Employment Practices Insurance	Yes

While some of these risks may have a low likelihood of occurrence, they should not be ignored, as their financial impact can be significant. For some of these risks SPIP may obtain insurance (insurable risks) and for others it cannot obtain insurance (non-insurable risks), as the market is reluctant to offer insurance for these risks. As mentioned in section 2 SPIP has decided to self-insure these risks for various reasons. We have grouped these uninsured risks into following six categories:

- Property related risks
- Currently insured risks
- Credit risks
- Contracts related risks
- Public liability risks
- Other risks

Summary of the costs of non-insured risks are tabulated in Table 3.2

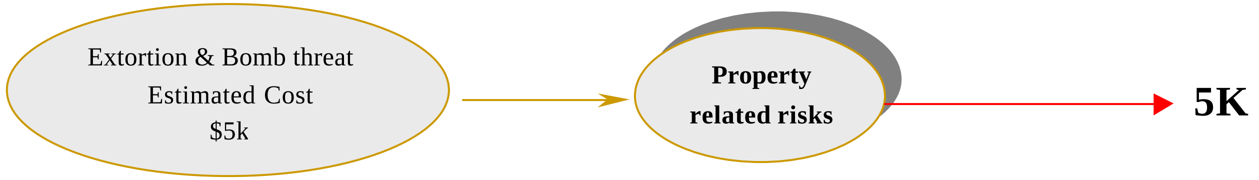
Table 3.2 Summary of Costs of Non Insured Risks to SPIP

Uninsured risks	TC estimate of risk premium ($000s p.a.)
Property Related Risk	5
Current Insurance	385
Credit Risk	63
Risk of Contractual Disputes	215
Public Liability Risk	100
Other Risks	90
Total costs associated with non-insured risks	858

3.1 Property Related Risks

SPIP carries property related risks in regards to extortion and bomb threat that it self-insures.

Figure 3.1 - Property Related Risks



Extortion, Bomb Threat and Kidnap & Ransom

Ransom or extortion demands not only directly affect a company financially, but also have significant indirect consequences ranging from business interruption to defence of legal liability and sometimes months of confusion and distraction within the company.

Insurance policies in this class of insurance are designed not only to indemnify the company for the exposure to a loss caused by the payment of a ransom or extortion, but also to pay for other related expenses and loss of earnings.

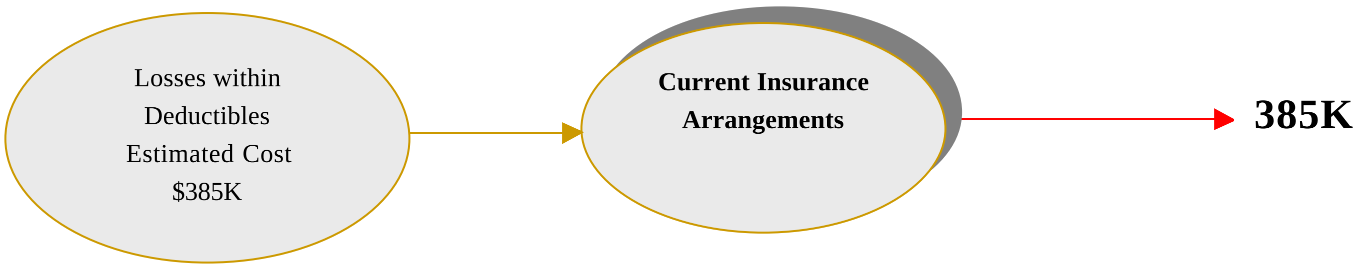
TC has reviewed reported "extortion and threats" against companies in Australia over the last 10 years. The data shows that extortion demands can be as high as $4 million and that losses suffered by companies have gone as high as $100 million.

SPIP currently does not have insurance in respect of Extortion, Bomb Threat and Kidnap. Indicative insurance premium quotations for a sum insured of $5 million is in the vicinity of $3,000 to $5,000 pa, depending on the exact details of the cover.

Indicative premium quotes for insurance cover of $5 million is $5,000 p.a.

3.2 Current Insurance

Figure 3.2 – Current Insurance Arrangements



Claims Within Insurance Policy Deductibles

SPIP is currently insured for a number of risks. However, SPIP can still have a material exposure under its insurance policies since on most policies SPIP must pay an initial amount of the claim (the excess or deductible). Similarly, the insurance cover is limited and SPIP is liable for any claims costs above the limit.

For example, SPIP faces the risk of liability above the $840m limit (other sub limits also apply) it currently has under its public liability insurance. However, we believe the likelihood of any such events to be extremely low.

However, SPIP may wish to review the appropriateness of its current insurance arrangements and in particular the limits of liability. Such a review is outside the scope of this study.

TC has reviewed all SPIP's main insurance policies with respect to losses within deductibles, including:

- Industrial Special Risks and Business Interruption (for example, machinery breakdown);
- public and products liability and professional indemnity insurance (for example, professional liability, bush fire);
- contract works;
- directors and officers;
- aviation; and
- travel insurance.

To calculate the risk premium estimates for deductibles we have used (for each component) the expected average claim size (capped at the size of the deductible) and the estimated claim frequency using SPIP's experience. Other allowances are made where appropriate, eg. in respect of catastrophic bushfires.

Table 3.3 shows the risk premium estimate in respect of the current policy excesses. (In this report we only quantify those material deductibles that are not included elsewhere within SPIP's reset application.)

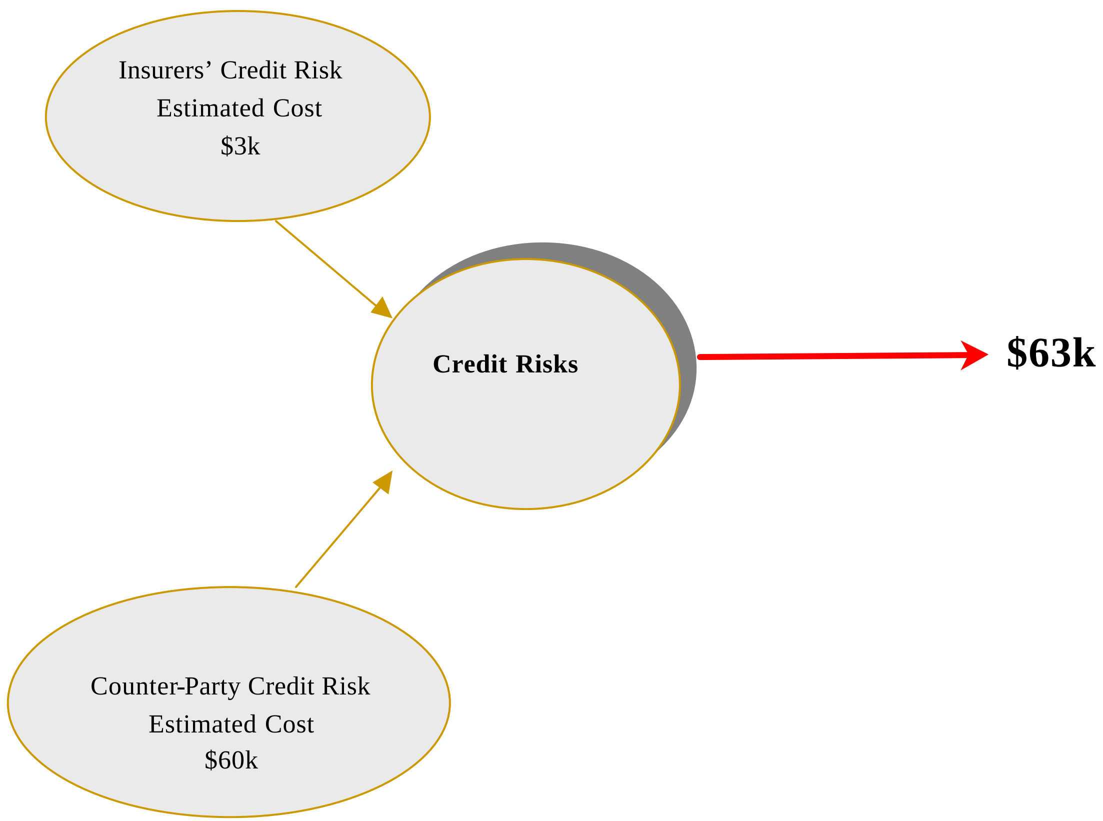
Table 3.3 – Summary of Deductible Risk Premium

Description	Risk Premium Estimate $000s
Bushfire	40
Other Property Damage	42
Liability Insurance	248
Other Insurance	0
Small Claims	55
Total for Deductibles	385

TC's estimate of risk premium for claims within the deductible limits is approximately $ $385,000 p.a.

3.3 Credit Risk

Figure 3.3 – Credit Risks



Counter-party Credit Risk

SPIP has only 12 key customers in respect of its regulated revenue. Its largest customer is the Victorian Energy Networks Corp (VENCorp), which is a State Government-owned entity responsible for planning and directing augmentation of the Victorian transmission network. The Company's other regulated customers are generators and distributors that pay SPIP directly for connection services.

Revenues in respect of SPIP's non-regulated customers have been excluded from this report.

SPIP have obtained indicative insurance quotations from four insurance companies in respect of its counter party credit risks which are based on its existing internal credit management procedures. Indicative insurance premiums for a sum insured of $5 million (equivalent to less than 2% of SPIP's annual revenue) and indemnity cover of 90% of all losses is about $60,000 per annum.

Indicative premium quotes in respect of counter-party credit risk is approximately $ 60,000 p.a.

Insurer credit risk

The risk faced by SPIP is related to the default risk of its insurers. This risk can be considered in terms of:

- Loss of Premium – the loss of the premium paid in respect of the unexpired period of cover; and
- Liability Exposure – in the event that an insurer is unable to honour an insurance policy, SPIP is fully exposed to any outstanding claims (including any incurred but not reported (IBNR) claims).

In recent months, Australia has seen the HIH collapse leave thousands of policyholders out-of-pocket. The collapse has lead to a wide range of businesses being exposed to retrospective product and public liability claims for many years into the future. This is because these types of insurance policies are traditionally written on an "occurrence" basis, where an insured event which occurred during the year of coverage is met from that year's policy, even if the claim is made many years into the future.

In estimating the Loss of Premium risk, we have assumed that bankruptcies occur mid-way through the year, therefore the amount at risk is $1million and not the full $2.0million (based on recent 2001 renewal) of SPIP's total annual premium expense (excluding the cost of Work Compensation Insurance).

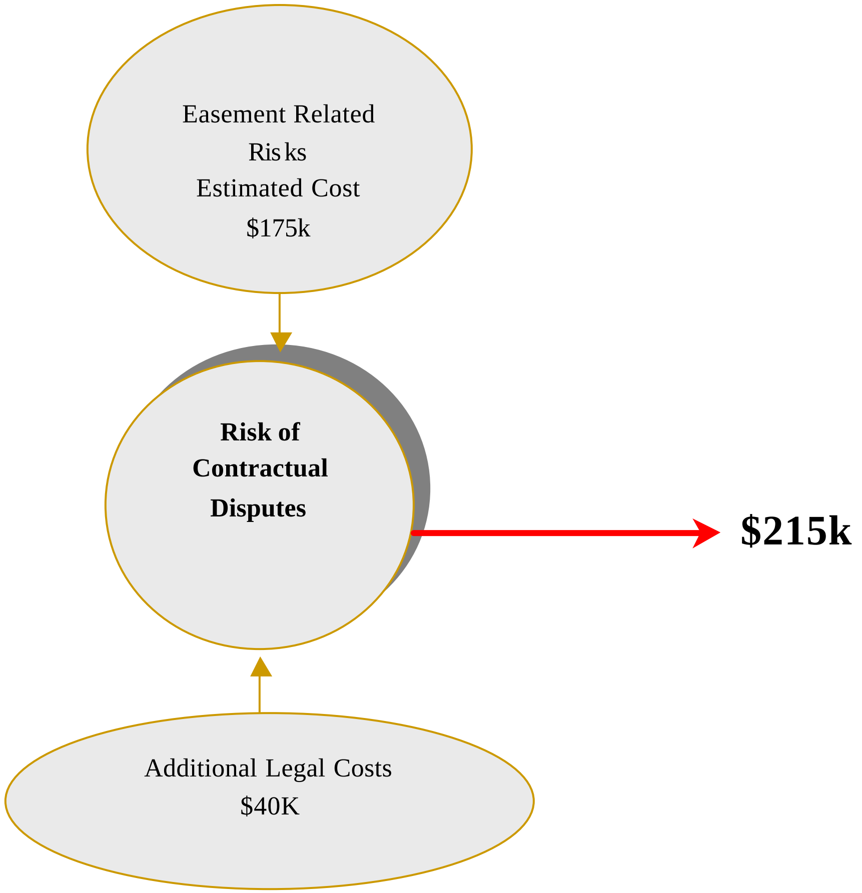
We have estimated the annual liability exposure risk as an insurance premium equivalent. This reflects expected loss experience. However the exposure to loss could be considerably larger given the large insured loss limits (up to $840 million on certain liability risks).

The estimated risk premium is equal to the amounts at risk multiplied by probability of default. Probability of default was derived from the insurance companies' credit ratings.

The insurer credit risk premium has been estimated at $ 3,000 p.a.

3.4 Risk of Contractual Disputes

Figure 3.4 – Risk of Contractual Disputes



Risk of Legal Costs Exceeding Expected Costs

Unexpected extreme situations can arise where SPIP needs to take legal advice or to defend or pursue legal actions. The legal costs associated with the risks of such actions are in addition to the normal expected costs. We have termed this cost “Additional Legal Costs”.

Details of potential additional legal costs are included in a separate report titled “Valuation of Non-Insured Risks, Confidential Documentation”.

The risks of “additional legal costs” can be mitigated by the purchase of Commercial Legal Expenses insurance.

Based on an indicative premium scale in respect of this class of insurance quotation, we estimate that the annual risk premium for this policy is about $35,000-$45,000.

The risk premium in respect of legal expenses is estimated as $40,000 pa

Easement Related Risks

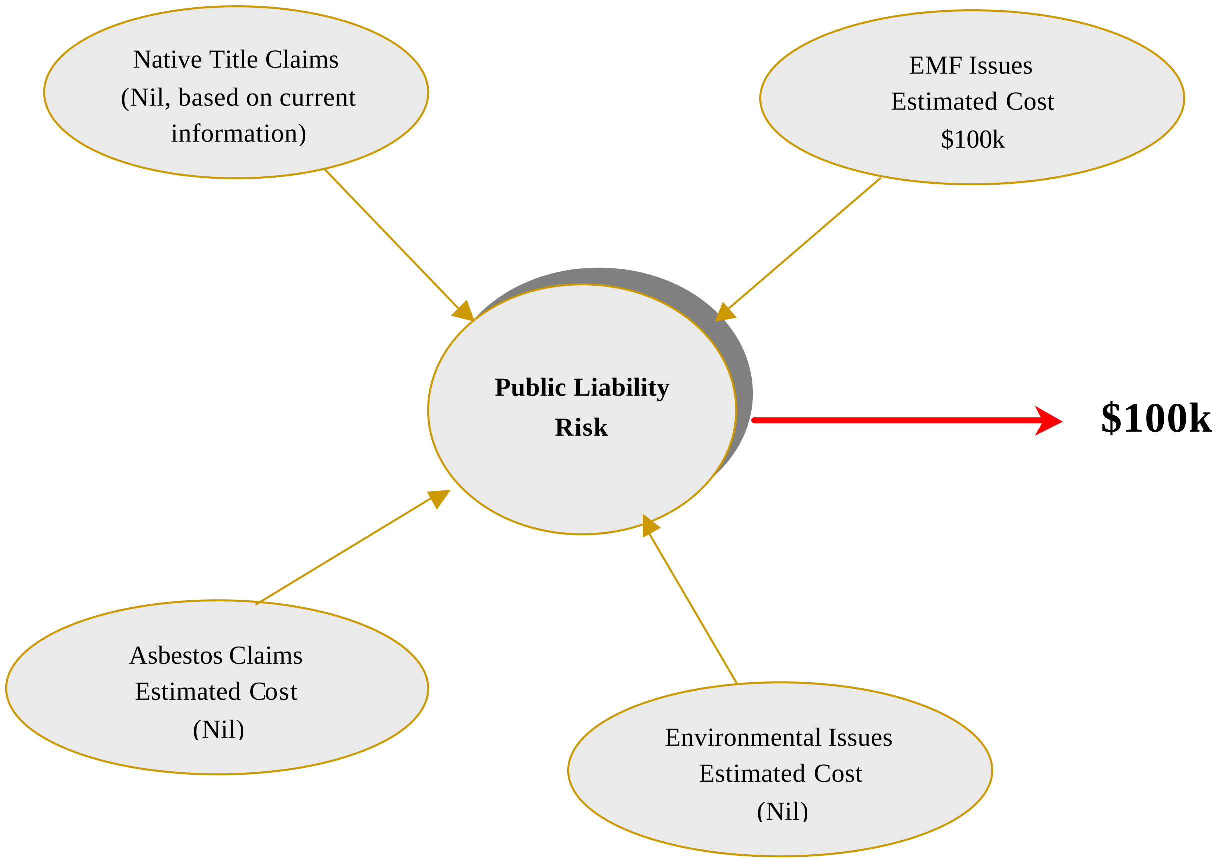
SPIP has about 3,560 kilometres of electricity transmission line easements throughout Victoria. These easements secure a “right of way” to a corridor of land for existing or future lines. SPIP does not usually own the land within the easement. Ownership of the land remains with the landowner, who has restricted use of the easement.

These arrangements introduce risks to SPIP’s business. Full details are included in a separate report titled “Valuation of Non-Insured Risks, Confidential Documentation”.

The total risk premium estimated by TC in relation to easement-related cost is $ 175,000 p.a.

3.5 Public Liability Risk

Figure 3.5 – Public Liability Risk



Native Title Insurance

The risk of a native title claim against SPIP has been estimated to be very low and should be able to be mitigated through purchase of insurance on a case by case basis therefore the cost of it has been considered negligible.

TC estimate of the cost of native title insurance is Nil p.a.

Asbestos

It is TC's understanding that SPIP's assets contain very little exposure to asbestos. Further, it is our understanding that SPIP has no legal liability for asbestos related claims incurred before 1994. Hence any potential liability in relation to asbestos exposure for SPIP will only be in relation to public liability in respect of the post 1994 period and hence can be expected to be minimal.

TC estimate of the cost of asbestos risk is Nil p.a.

Environmental Issues

SPIP recover expected costs in relation to managing environmental issues through its normal O&M costs. However, there is also the risk that expected costs would not be adequate due to the hardening attitude towards environmental issues. We believe that no allowance should be made for this risk in this study as we believe SPIP should seek to recover any additional costs over the longer term through OPEX or CAPEX.

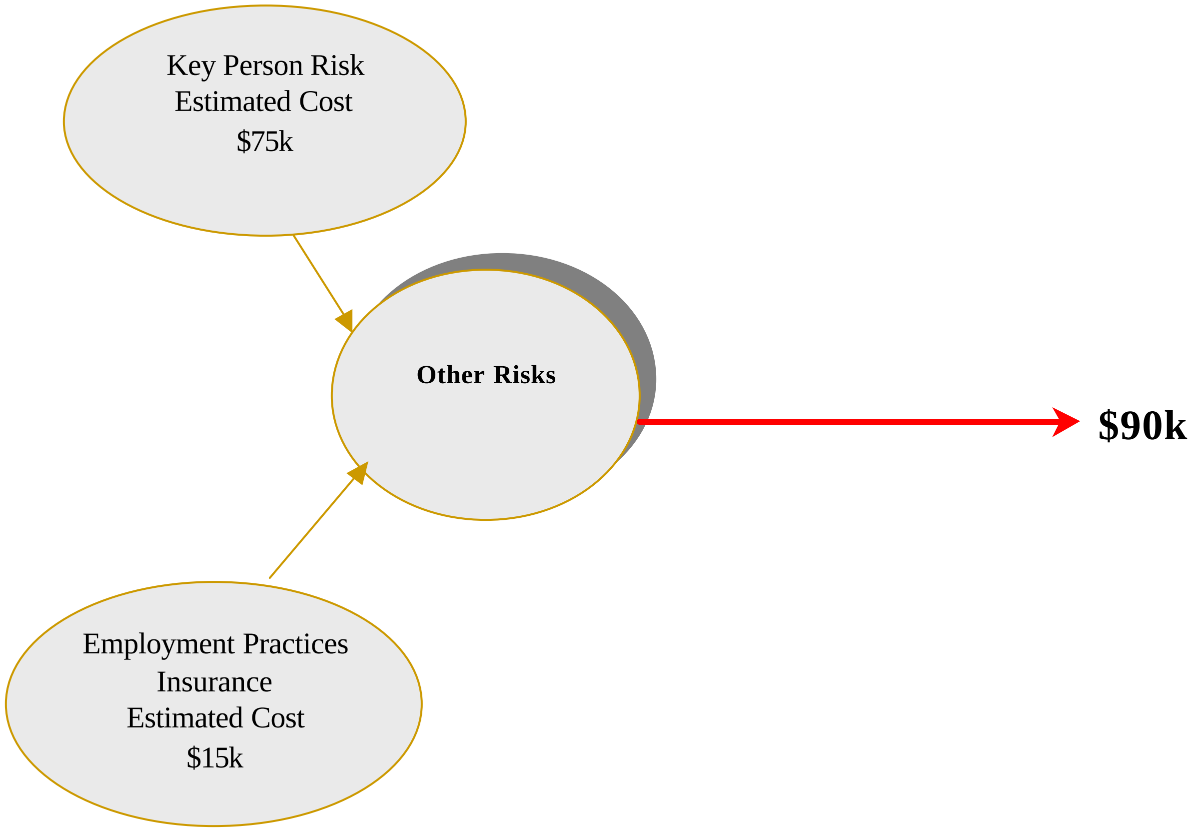
TC estimate of the cost of environmental issues is Nil p.a.

EMF Issues and Related Costs

SPIP is currently insured against EMF liability claims but is exposed to claim costs within the $100,000 policy deductible. The calculation of the risk premium estimate for this deductible is detailed in a separate report titled "Valuation of Non-Insured Risks - Confidential Documentation".

3.6 Other Risks

Figure 3.6 – Other Risks



Key Person Insurance

Companies normally purchase key person insurance to cover against business interruption and costs arising from sudden departure of key employees. Nevertheless, SPIP currently self-insures against this risk in respect of 8 key personnel. An analysis has been conducted for each of the 8 key staff and a risk premium has been calculated for each. Our analysis has been based on the additional replacement costs and the business disruption costs associated with any one of these key staff leaving service. The probability of leaving service is based on the decrements used in the SPIP superannuation fund's latest actuarial review.

The risk premium in respect of key person insurance is estimated at $75,000 p.a.

Employment Practices Insurance

Employment Practices Liability insurance is intended to protect both SPIP and its employees from actions arising out of any wrongful acts in relation to employment practice claims. This insurance cover includes damages, judgements, settlements, costs and defence costs for actions alleging wrongful acts such as harassment (sexual or otherwise), unlawful discrimination, breach of privacy, victimisation and misrepresentation or defamation.

SPIP have obtained indicative insurance quotations in respect of Employment Practices liability insurance. An indicative insurance premium for a sum insured of $5 million and deductible of $25,000 of all losses is about $15,000 per annum. Due to the small deductible we make no further allowance for claims within the deductible.

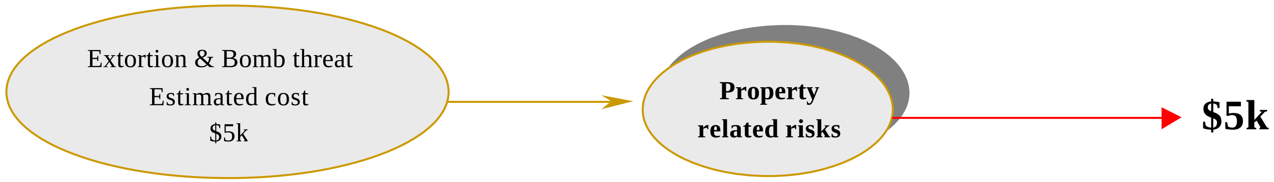
The insurance is expected to cost $15,000 p.a.

Part II Detailed Findings

4 Property Related Risks

SPIP carries property related risks in regards to extortion and bomb threat which it self-insures.

Figure 4.1 – Property Related Risks



4.1 Extortion, Bomb Threat and Kidnap & Ransom

Ransom or extortion demands not only directly affect a company financially, but also have significant indirect consequences ranging from business interruption to defence of legal liability and sometimes months of confusion and distraction in the company.

Resolution of these traumatic events can be protracted, stressful and very disruptive. The focus of the resolution is the negotiation of the safe release of the victim or the avoidance of the threatened act. However, this process must be achieved with the minimum of disruption to normal operations but without attracting future attempts at extortions.

Insurance policies in this class of insurance are designed to not only indemnify the company for the exposure to a loss caused by the payment of a ransom or extortion, but also to pay for other related expenses and loss of earnings.

The following Table 4.1 provides a summary of a number of reported extortion, bomb threats and acts of terrorism in Australia over the past decade:

Table 4.1 – Reported Extortions in last decade

Company	Industry	Year	Description	Duration	Extortion Amount	Cost to Company
Herron Pharmaceuticals	Pharmaceuticals	Mar-00	Herron tablets laced with strychnine poisons 2 people, Extortionist demands $50,000	2 months	$50,000	$40 million products recalled and destroyed & loss of market share
SmithKline Beecham	Pharmaceuticals	Jun-00	Panadol tablets laced with strychnine poisons 2 people	6 months	$2,000,000	Losses of $100 million , recall of products & loss of significant market share
Nestle (AAC)	Food products	May-97	Threat to contaminate yoghurt at a Sydney supermarket		$4,000,000	
Cologate Palmolive	Consumer Products	Aug-91	Threat to place cyanide contaminated toothpaste in shops around Australia		$250,000	Products recalled & loss of market share
BP Australia	Energy	Feb-92	Demands made for $1 million from BP		$1,000,000	
Arnotts Biscuts	Food products	Feb-97	Threat to distribute contaminated Arnotts biscuts			Lay-off of 300 casual staff & losses of $10 million
Sanitarium	Food products	Jul-98	Threat to contaminate food products			$600,000 worth of food products recalled
Gartell White	Food Products	Jun-93	Extortoinist claims to have put cyanide in Big Ben pies			1,110 tonnes of pies destroyed , three month factory closure
Qantas	Transport	Aug-90	Extortionist threatens to kill a passenger a month		$200,000	
Ansett Airlines	Transport	Jun-89	Extortionist threatens Ansett with the words "Remember Lockerbie"		$1,000,000	
Australian Poultry Foods	Food Products	Mar-90	10,000 chickens poisoned and APL processing plant bombed for revenge			
	Food products	Jun-90	Employee poisons food products at a family owned chocolate factory			
Ansett Airlines and Qantas	Transport	Aug-91	Ransom demands made against Qantas and Ansett			
	Food products	Oct-91	Extortionists demand money after putting glass in breakfast cereal		$200,000	
	Retailing	Apr-92	Extortionist threatens to poison supermarket products		$500,000	
Heinz	Food products	May-92	Heinz baby food poisoned by group protesting "rigged trial" of Rodney King in Los Angeles			Recall of food products , significant loss of market share
NSW Municpal Offices	Government	May-92	Woman threatens to bomb NSW municipal offices			
	Food products	Jun-93	Contamination of Thailand imported pineapple with arsenic			Brands withdrawn
	Food Products	Jul-92	Employee puts acid in licorice		$500,000	
Franklins	Retailing	Aug-92	Supermarkets torched for revenge			
State Bank	Financial Services		Threats against State Bank staff in protest to farmer evictions			

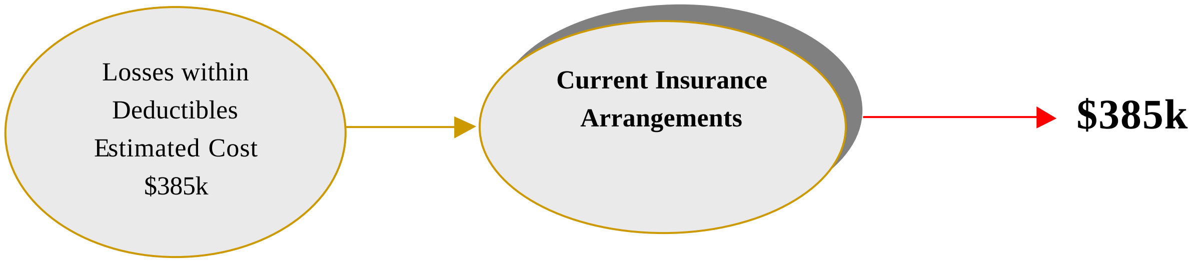
The above table shows that extortion demands can be as high as $4 million and that losses suffered by companies have gone as high as $100 million. We understand that in the UK the cost of insuring against terrorist acts form a large part of the insurance expense for transmission companies. These threats are not as acute in Australia, but given technological advances, computer virus related extortions could only be expected to increase in the future.

We understand that there have been a number of bomb threats directed at SPI PowerNet in the past, however, these threats did not involve demands for money. These threats were politically motivated and came to a head during the period leading up to the recent Sydney Olympics.

SPI PowerNet currently does not have insurance in respect of extortion, bomb threat and kidnap and ransom. Indicative insurance premium quotations for a sum insured of $5 million is in the vicinity of $3,000 to $5,000 pa, depending on the exact details of the cover. We have adopted a cost of $5,000 assuming that coverage will extend to the majority of SPIP's assets.

5 Current Insurance Arrangements

Figure 5.1 Current Insurance Arrangements



5.1 Claims within Insurance Policy Deductibles

Although SPIP insures itself against a number of risks, it is still exposed to potential claims because most of the insurance coverage includes an excess or deductible. This means that SPIP is required to meet claims up to an agreed limit specified in the insurance policy.

Further, SPIP faces a limit of liability for most policies. This means that there is potential for SPIP to exhaust its cover and therefore the liability will fall back on SPIP for claims cost in excess of the limit. However, we believe that the probability of exhaustion of the policy limits is extremely low. Although scenarios could be constructed, we have not quantified the impact as we believe the extremely low likelihood of these events makes it hard to justify an allowance. Under a number of the policies, SPIP would also be required to pay a reinstatement premium to the issuers to *"buy back"* the cover consumed by the claim. The potential for payment of a reinstatement premium also appears to be remote and as such no allowance has been built into the deductible cost estimates.

Not withstanding that no allowance has been made, SPIP should be aware that the risk is real. Recent events including the Longford incident and the Auckland black-out show that while these events are extremely rare they can occur. The potential for a class action against SPIP could also be damaging. This may involve a review of SPIP's current insurance arrangements and in particular the limits of liability. Such a review is outside the scope of this study.

Current Deductibles

There are a number of reasons why deductibles are generally included in policies. These include:

- The sharing of the risk to encourage better risk management;
- To reduce an insurer's exposure to small claims which are relatively expensive (as percentage of claim size) to administer; or
- The premium reduction more than offsets the expected costs of claims within the deductible.

SPIP's current insurance deductibles (based on insurance policies generally applicable for 2001 year - SPIP insurance is renewed in November of each year) are:

- ISR and Business Interruption
  - Section 1 (assets), Terminal Station and Power Station Switch Yards ($500,000), Machinery Breakdown ($500,000), other ($250,000)
  - Section 2 (consequential loss), 14 days each and every loss

- Public and Products Liability and Professional Indemnity Insurance
  - General $100,000
  - Products and Completed Operations ($100,000)
  - Professional Liability ($100,000)
  - Bushfire ($5,000,000)
  - Automobile ($100,000)
  - Some for retrospective cover (minor)

- Contract Works
  - $50,000 any occurrence of listed items (generally natural hazards)
  - $10,000 on other items

- Directors and Officers
  - Nil on D&O
  - $50,000 on Reimbursement Section

- Aviation
  - Rotor Wing $10,000
  - Fixed Wing $2,000
- Travel Insurance
  - Nil except $250 on Electronic equipment.

Since undertaking this study in September 2001, SPIP has renewed their insurance program. The renewed terms differ from those shown above, in particular for the ISR and business interruption insurance. In particular, our understanding is that the deductible in regards to terminal station assets has increased to $750,000 (assets) and 30 days (consequential loss). The asset cover is also now on a sliding scale depending on age of asset (previously new for old cover.) Where appropriate we have adjusted our quantification to reflect these changed insurance conditions.

We consider that the most significant deductible costs will arise under the property insurance and liability insurance policies.

Deductible costs in relation to transformer and circuit breaker damage and workers compensation insurance are included directly in Operations and Maintenance expenditure and thus excluded from this report.

Bushfire

SPIP face a deductible of $5,000,000 for any bushfire claim arising from one occurrence. An *"occurrence"* for the purpose of the policy is defined as any related or unrelated bushfires that occur within a 168-hour period. Victoria is very susceptible to bushfires and SPIP's transmission assets have the potential to cause major bushfires. Therefore, although insured, SPIP still has a large exposure to this potential risk.

To date there is no known claim for bushfire damage against Victorian transmission assets. This includes the Ash Wednesday bushfire in 1983. However, electricity distribution assets have caused bushfires.

In the Marsh report on *"Insurance and Risk Management"* to GPU PowerNet as part of the due diligence prior to the sale to SPIP, Marsh discussed a number of incidents that had potential to cause bushfires. Over a 12-year span they identified five incidents where a conductor had fallen and three incidents where a ground wire had fallen. While not all incidents will cause a bushfire, given the right conditions (eg: dry weather, long grass etc) each of these incidents had the potential to cause a bushfire.

SPIP's other assets also have the potential to start bush fires, particularly from incidents at its terminal stations.

On this basis there is potentially an 8/12 per annum chance of an incident (ignoring terminal station incidents) occurring involving SPIP assets that under particular condition, could cause a bushfire. We assume that only 25% of these would actually cause a bushfire. This gives an incident rate of 17% per annum of bushfire caused by SPIP's assets. We also allow for a 10% to 15% per annum chance of a bushfire being caused by other incidents (in particular terminal station incidents).

In Appendix A.1 we discuss the likelihood of bushfires in general. The analysis shows that SPIP assets could be considered to potentially cause 0.5 bushfires per year. We have adopted the lower 30% per year claim frequency for our analysis.

Using this information in conjunction with our general understanding of potentia l bushfire damage, we have built up a distribution of potential claim sizes for non-catastrophic bushfires. This distribution is shown in Table 5.1. The distribution is necessarily approximate, but appears reasonable when considered in the context of the limited information available.

Table 5.1Non-Catastrophic Bushfire

Range of Claim Size	Basis	Average Claim Size ($'000s)	Probability %	Size * Probability ($'000s)
$0-$20,000	Minor damage to forests/land	10	60	6
$20,000-$100,000	Minor property damage to animals/buildings	50	30	15
$100,000-$1,000,000	Major Multiple Property Damage (eg: 1 or 2 houses)	500	8	40
$1,000,000-$5,000,000	Major Multiple Property Damage (eg: > 2 houses)	2,500	2	50
			Total	111

Hence, we estimate the risk premium associated with SPIP's exposure to bushfire liability as 30% of $111,000 = $33,300.

An allowance is also required for the low likelihood of SPIP's assets causing a major catastrophic bushfire. SPIP would be required to pay only the first $5,000,000 if such an event occurred, as this is the deductible under the bushfire insurance policy. In Appendix A.1 we attach a likelihood of 1 in 1000 to this scenario, and thus our risk premium estimate is $5,000.

The total risk premium estimate for SPIP's liability within the deductible of its insurance policy in regards to bushfire damage is therefore approximately $40,000.

Other Property Damage

SPIP also faces major deductible levels on other property damage (excluding transformers and circuit breakers). The only claim we are aware of in terms of other property was in 1995 when the roof of the Morwell terminal station was blown off onto the bus bars causing approximately $100,000 worth of damage and repair costs. It is reasonable to allow for other less frequent events in estimates of appropriate risk premiums.

In Table 5.2 we show a break down of our estimated risk premium. Given the lack of past claims history this estimate is necessarily uncertain.

Table 5.2 Other Property Damage Risk Premium

Scenario	Example of Cause	Likelihood	Estimated Cost	Risk Premium Estimate
			$	$
Major Damage to Terminal Station or Power Station Switch Yard	Major Fire	1 in 20	500,000	25,000
Major Damage to Other Property	Fire destroy Building	1 in 100	250,000	2,500
Minor Damage to Terminal Station or Power Station Switch Yard	Wind Damage	1 in 10	100,000	10,000
Minor Damage to Other Property	Wind Damage	1 in 5	20,000	4,000
Risk Premium Estimate				41,500

We include the cost of small claims as a separate item.

Liability Insurance (excluding Bushfires)

SPIP has a deductible (excluding bushfires) within its liability insurance program. Due to the confidential nature of this risk our quantification is included in a separate report titled “Valuation of Non-Insured Risks, Confidential Documentation”.

An estimate for the risk premium associated with the value of the deductible for liability insurance is approximately $248,000.

Other Insurance Policies

As discussed earlier, SPIP also has low levels of deductibles associated with its other insurance polices. However, the combination of low deductibles with unlikely occurrences means we have made no allowance in this regulatory price review (order of magnitude will be less than $10,000 in total).

Small Claims

SPIP does not insure for any small property claims. This includes general damage to property (broken windows etc), vandalism, stolen or damaged property (lap tops, mobile phones etc) and other miscellaneous property.

The largest risk is the loss of computer equipment. Table 5.3 shows a breakdown of SPIP's computer assets that are potentially at risk.

Table 5.3 Inventory of Computers and Mobile Phones

Asset	Number (Approximate)	Estimated Average Cost
		$
Laptops	120	5,500
Desktops	150	3,000
Mobile Phones	150	500
Other Miscellaneous (eg printers etc)	50	3,000
Total Asset Base		1,335,000

For example, SPIP recently had three laptops stolen within one month.

We have based the risk premium calculated on the following assumptions regarding average annual thefts (this also allows for partial loss through damaged property).

- 5 laptops
- 5 mobile phones
- 2 desktops (from remote locations)

We ignore other miscellaneous losses.

We also assume that 1 in every 20 years SPIP has a major break-in resulting in the loss of 10% of its computer and related assets.

With remote offices, SPIP's risk in terms of damage to property also increases, particularly due to vandalism. We have assumed total cost of miscellaneous damage (such as broken windows) to be about $10,000 per annum.

We ignore all other small costs.

Table 5.4 shows the expected annual claim costs from small miscellaneous claims not covered by insurance.

Table 5.4 Costs for Small Miscellaneous Claims

Event	Estimated Annual Cost
	$000s
Loss of Computer Equipment	36.0
Major Break-In	6.7
Other Property Damage	10.0
Risk Premium Estimate	52.7

Deductible Summary

In Table 5.5 we show the break down of our risk premium estimate for the risk SPIP has within its insurance deductibles.

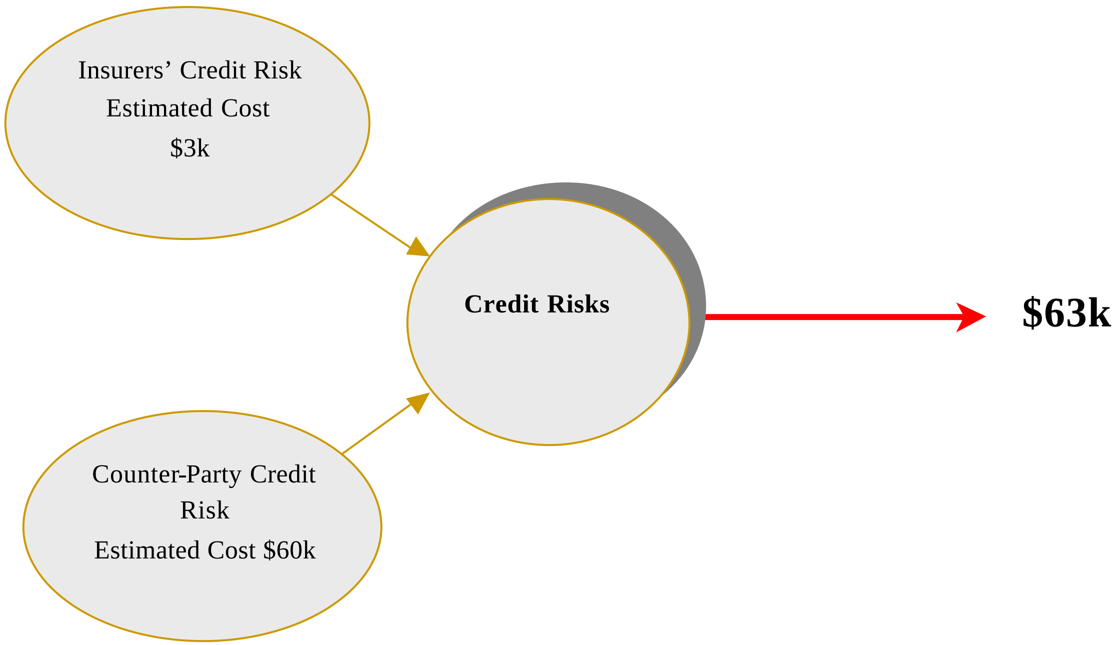
Table 5.5

Description	Risk Premium Estimate
	$
Bushfire	40,000
Other Property Damage	42,000
Liability Insurance	248,000
Other Insurance	0
Small Claims	55,000
Total for Deductibles	385,000

An estimate for the risk premium associated with the value of the deductible within SPIP's current insurance policies is therefore approximately $385,000 per annum.

6 Credit Risk

Figure 6.1 – Credit Risk



6.1 Insurer Credit Risk

SPIP is currently insured with external insurers for the following classes of insurance:

Table 6.1

Policy Class	Insurer	Limit of Insurance Cover	Annual Premium
Industrial Special Risks and Business Interruption	Royal & Sun – 29% ACE – 19% HSB Eng Ins – 19% Liberty – 14% Gerling HIH – 14% American Home – 5%	$250m (sub-limits apply)	$548k
Public and Product Liability and Professional Indemnity	Lloyds of London and Others	$840M (sub-Limits apply)	$398k
Contract Works	QBE Insurance	$5M (sub-limits apply)	$97k
Directors and Officer Legal Liability (GPU PowerNet - Run-Off Insurance)	QBE Insurance	$10M	$123K
Aviation Non-Ownership Liability	Australian Aviation Underwriting	$20M (Sub-Limits apply)	$4K
Travel Insurance	ACE Insurance	$2.5M (Sub-Limits apply)	$1K
Workers Compensation Insurance	Victorian WorkCover Authority	As per legislation	$90K

The above table shows that SPIP purchases approximately $1.2 million of insurance a year (excluding the cost of Workers Compensation Insurance). These premiums were for the 2000 renewal (for 2001 year). *Recently SPIP has renewed their insurance premium for the coming year (2001 renewal for 2002 year). This renewal has seen an increase from the current $1.2 million in premiums to approximately $2.0 million. In particular the ISR and BI insurance has seen an increase from the previous $548k to $1.2 million. Our analysis has been adjusted to reflect these new premiums.*

The risk faced by SPIP is related to the default risk of its insurers. This risk can be considered in terms of:

- Loss of Premium – the loss of the premium paid in respect of the unexpired period of cover; and
- Liability Exposure – in the event that an insurer is unable to honour an insurance policy, SPIP is fully exposed to any outstanding claims (including any incurred but not reported (IBNR) claims).

In recent months Australia has seen the HIH collapse which left thousands of policyholders out-of-pocket. The collapse has led to a wide range of businesses exposed to retrospective product and public liability claims for many years into the future. This is because these types of insurance policies are traditionally written on an “occurrence” basis, where an insured event which occurred during the year of coverage is met from that year’s policy, even if the claim is made many years into the future.

Policyholders can purchase product and public liability coverage from another insurer in respect of future events. However, it must be noted that they will remain exposed for many years to come in respect of the IBNR claims.

In estimating the Loss of Premium risk, we have assumed that bankruptcies occur mid-way through the year; therefore the amount at risk is $1 million and not the full $2 million.

Our estimate of the annual Liability Exposure risk is based on our central estimate of the likely exposure. Assuming appropriate pricing by the insurers this central estimate will be lower than the premium charged. This is because the insurer also adds an additional margin to cover expenses and profit. However, the insurer also gains the benefit of investment return for the period between receiving premium and paying claims. Allowing for these offsetting factors we have estimated a Liability Exposure risk of $1 million (again assuming mid-year failure and no recovery).

The following Table 6.2 summarises the results of our analysis:

Table 6.2 – Results Summary

Loss Scenario	Amount at Risk ($'000)	Probability of Occurrence	Risk Premium ($'000)
Loss of Premium	1,000	0.00125	1.3
Liability Exposure	1,000	0.00125	1.3
Total			**$3**

This risk premium is small, but is subject to considerable volatility. There is potential for SPIP to be exposed to millions of dollars of uninsured losses if insurer failure occurs at a time when SPIP has significant outstanding claims. We have assumed no correlation between these events, reducing the annual risk premium to small levels.

6.2 Counter-Party Credit Risk

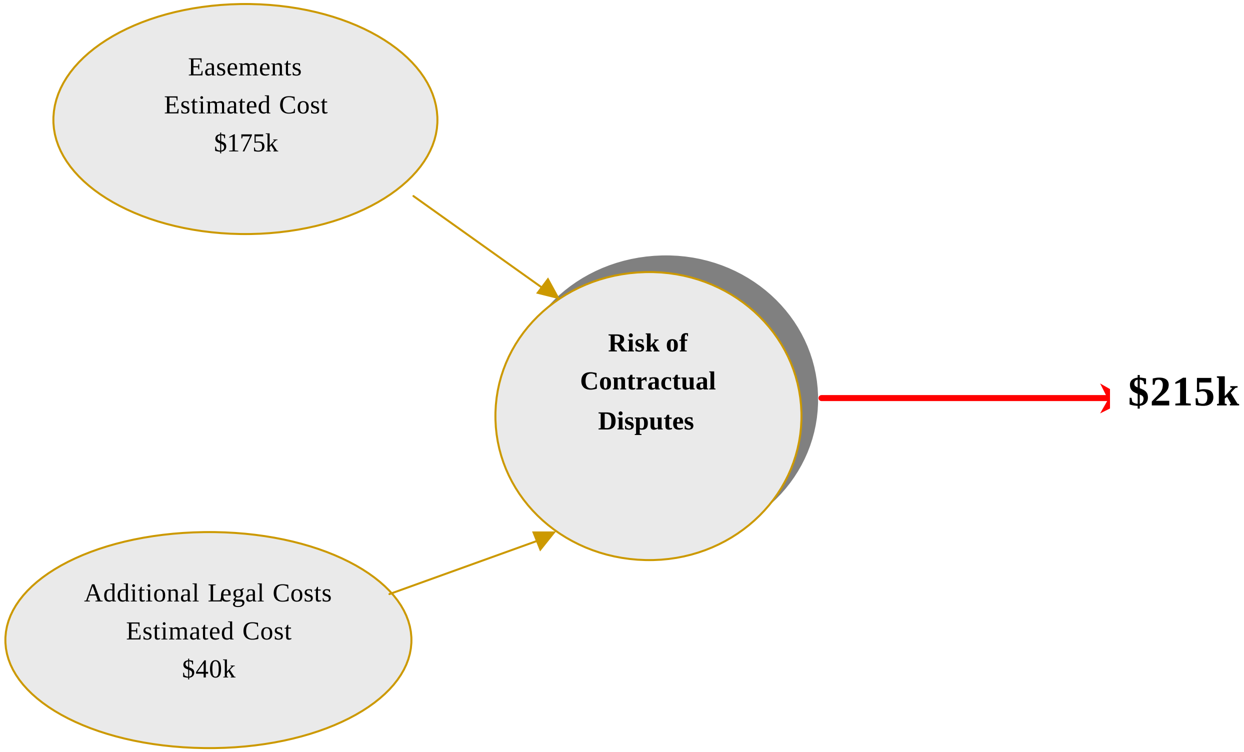
Currently, SPIP's regulated revenue is calculated on the basis of a tariff order put in place by the Victorian Government. This tariff order will apply until a new revenue determination is made by the ACCC in respect of the next regulatory period. The company's estimated annual revenue is about $277 million.

SPIP has only 12 key customers in respect of its regulated revenue. Its largest customer is the Victorian Energy Networks Corp (VENCorp), which is a State Government-owned entity responsible for planning and directing augmentation of the Victorian transmission network. The Company's other customers are generators and distributors that pay SPIP directly for connection services.

SPIP have obtained insurance quotations from four insurance companies in respect of its counter-party risks based on its existing internal credit management procedures. Indicative insurance premiums for a sum insured of $5 million (equivalent to less than 2% of SPIP's annual revenue) and indemnity cover of 90% of all losses is about $60,000 pa.

7 Risk of Contractual Disputes

Figure 7.1 Risk of Contractual Disputes



7.1 Easement Related Disputes

SPIP has about 3,560 kilometres of electricity transmission line easements throughout Victoria. These easements secure a “right of way” to a corridor of land for existing or future lines. SPIP does not usually own the land within the easement. Ownership of the land remains with the landowner, who has restricted use of the easement.

Due to the confidential nature of the potential costs related to easement disputes, details of our quantifications are included in a separate document titled “Valuation of Non-Insured Risks, Confidential Documentation”.

The estimated annual risk premium in respect of SPIP’s exposure to easement related claims is approximately $175,000 p.a.

7.2 Risk of Legal Costs Exceeding Expected Costs

In the course of carrying on its normal business SPIP incurs a level of legal related expense. This expense level can be viewed as an “expected cost” and will be subject to minor fluctuations from year to year. The expected costs include both the cost of maintaining an internal legal team and the cost of engaging external legal professionals.

However, unexpected extreme situations can arise where SPIP needs to take legal advice or to defend or pursue legal actions. The legal costs associated with the risks of such actions are in addition to the normal expected costs. We have termed this cost “additional legal costs”.

Due to the confidential nature of these potential additional legal costs details of our quantification are included in a separate document titled “Valuation of Non-Insured Risks, Confidential Documentation”.

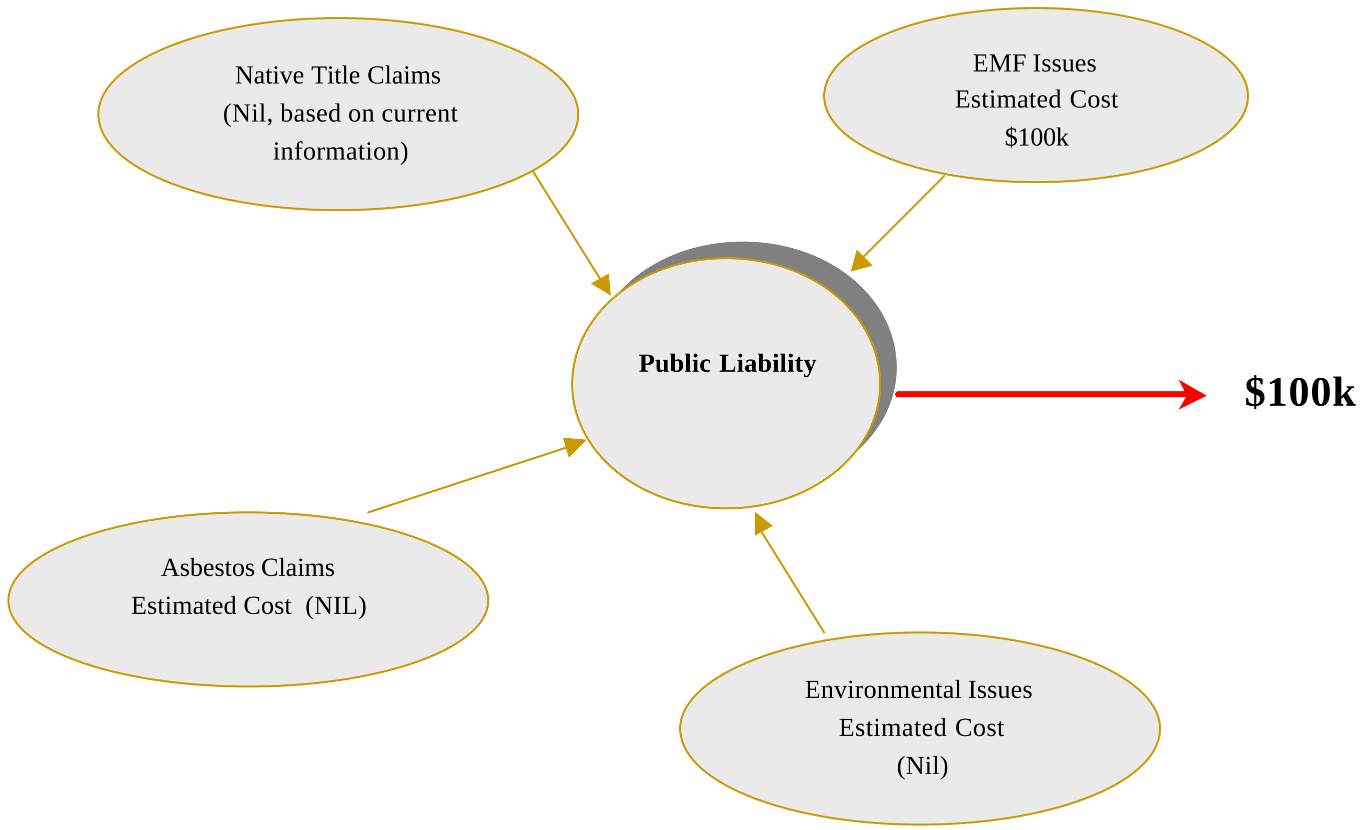
Insurance Cover

The risks of ”additional legal costs” can be mitigated by the purchase of Commercial Legal Expenses insurance.

Based on an indicative premium quotation, we estimate that the annual risk premium for this policy is about $35,000 - $45,000. We have adopted a premium estimate of $40,000.

8 Public Liability Risk

Figure 8.1 Public Liability Risk



8.1 Native Title Insurance

In general terms, native title insurance is similar to business interruption insurance. It is designed to provide protection against financial loss on nominated contracts/projects caused by an unexpected native title claim subsequent to a Native Title Agreement being entered into.

Discussions with SPIP officers suggest that the risk of a native title claim against the Company's existing operations is extremely low given that the legal framework for easements is very strong. Where we feel that there is a potential risk is in the area of new connections/extensions through land where the risk of a native title claim is high. However, we believe that this risk can be mitigated through the purchase of insurance on a case-by-case basis.

8.2 Asbestos

Products containing asbestos have been used as high temperature insulation by the SECV in thermal power stations. The SECV led the Australian power industry in asbestos removal and replacement.

It is our understanding that SPIP has no equipment or assets containing asbestos except for a few buildings where there may be asbestos in the roof linings. Generally, prolonged exposure to asbestos dust is seen as the cause for asbestos related diseases and solid asbestos poses little risk. The exception to this would be the situation where, for example, a roof collapsed exposing workers to asbestos dust.

The current SPIP insurance policy does not provide coverage for removal or disposal of asbestos. However, such work is specialised and it is anticipated that a specialist contractor would be engaged who themselves would carry the required insurance. SPIP has in place work practices to ensure that any contractors have appropriate insurance.

Further, it is our understanding that SPIP has no legal liability for asbestos related claims incurred before 1994. Hence any potential liability in relation to asbestos exposure for SPIP will only be in relation to exposure post 1994. For its own workers accidentally exposed to asbestos, SPIP's workers compensation insurance should cover the liability.

In the event that a third party is exposed to asbestos as a result of a sudden or accidental occurrence and seeks recovery from SPIP then SPIP's public liability policy should offer insurance coverage. However, SPIP would still be required to pay the excess associated with this coverage. The excess in the current policy is $100,000.

Currently, the average claim cost for asbestos related diseases are approximately $100,000 for asbestosis, $150,000 for lung cancer from asbestos exposure and $250,000 for mesothelioma. Hence, if a claim was successfully made against SPIP it is reasonable to expect that SPIP would be required to pay the excess of $100,000. This conclusion does not consider the possibility that SPIP may pass some of its liability on to other third parties (eg: building contractors.)

Given that it is unlikely that SPIP would have a claim made against it, it is our view that for the current regulatory price review the risk is minimal hence no risk premium allowance has been adopted.

8.3 Environmental Issues

SPIP have responsibilities in terms of managing environmental impacts. Policies and procedures are set out in SPIP's environmental manual. SPIP recover expected costs in relation to managing environmental issues through its normal O&M costs.

However, there is also the risk that expected costs would not be adequate due to the hardening attitude towards environmental issues. For example, EPA may toughen their stance on long-term issues (without specific changes in legislation) or noise abatement claims may increase. While this may pose a risk to SPIP we believe that SPIP should seek to recover these additional costs through an appropriate allowance in OPEX or CAPEX. While some increases could occur within a five year reset period it is difficult to attach a realistic risk premium estimate to this as no data is available to perform any quantification. In any event SPIP should look to recover costs over the longer term. This could involve the postponement of work until after the current regulatory period.

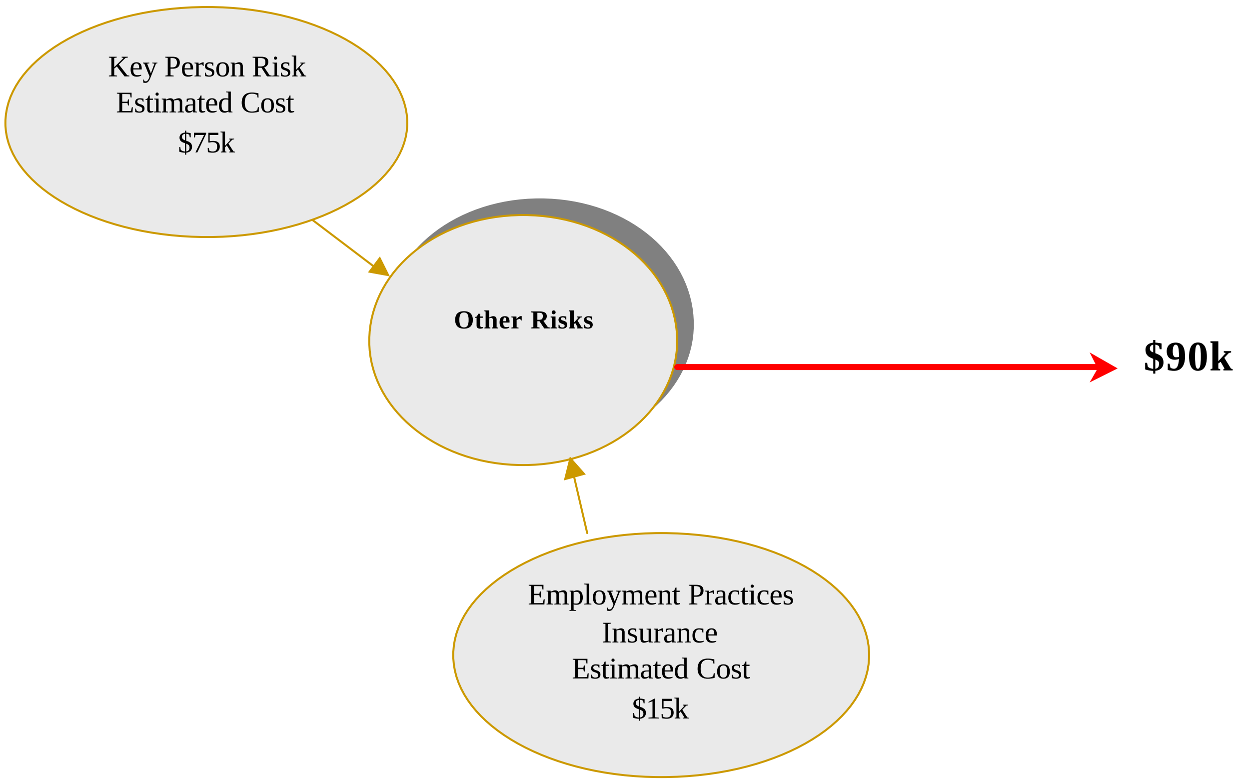
It is our understanding that specific legislation changes that will impact on SPIP's environmental management costs can be dealt with directly through the regulatory reset process.

8.4 EMF Related Issues

SPIP is currently insured against EMF liability claims but is exposed to claim costs within the $100,000 policy deductible. The calculation of the risk premium estimate for this deductible is detailed in a separate report titled "Valuation of Non-Insured Risks - Confidential Documentation".

9 Other Risks

Figure 9.1 – Other Risks



9.1 Key Person Insurance

SPIP requires a highly skilled and experienced workforce. In particular it requires a number of experts in the field of electrical engineering. Also, being a provider of essential services in a complex market environment, SPIP requires a highly competent and experienced management team.

SPIP currently self-insures the risks of business disruption costs arising from the sudden departure or death of its "key" employees.

This type of insurance policy is available from the market and provides for funds to reimburse a company for loss of income upon death or disability of a senior executive, key persons or directors. The policies will also provide for the costs of acquiring a suitable replacement.

SPIP has identified eight employees who are regarded as key people to the extent that their sudden departure would adversely affect the financial position of the Company due to the following reasons:

- Their replacement in the short-term is not likely due to the level of expertise or experience required;
- Their replacement is likely to be from overseas due to the limited availability of specialised expertise locally;
- It is expected that considerable additional expenses would be incurred in respect of recruitment, relocation and settlement costs; and
- Loss of income would follow from the disruption to the Company's core business and the time required for the replacement to understand the Company's processes and strategies.

In estimating the financial impact on SPIP, we have separated the costs into three components:

- Standard Replacement Cost – estimate of the average cost of replacing an employee locally;
- Additional Replacement Cost – additional costs involved with recruiting from abroad from senior executives or candidates within a very specialised area of expertise; and
- Business Disruption Cost.

In our view, the Standard Replacement Cost should not be included in this report as this cost would be captured by the administrative and operations and maintenance (O&M) allowance within the cost-of-service framework. Therefore the appropriate risk premium applies only in respect of the Additional Replacement Cost and Business Disruption Cost faced by SPIP.

Estimation of Additional Replacement Cost and Business Disruption Cost are based on an estimate of the costs involved using past experience where possible, and after discussions with SPIP Officers (including the Human Resource department).

The rates of resignation, mortality in service and disablement used in the latest Actuarial Review of the Victorian Energy Industry Superannuation Fund (to which employees of SPIP are members), as at 30 June 1998 by William M. Mercer, have been adopted in order to derive the average probability of "leaving service" for each of the key employees. This fund applies for executive and management staff and hence its use is appropriate for this context.

The following Table 9.1 gives a summary of our analysis:

Table 9.1 – Summary of Results

Job Description	Additional Replacement Costs ($'000)	Business Disruption Costs ($'000)	Probability of Leaving Service	Risk Premium ($'000)
Executive Manager	65-75	500-600	0.0166	9.4-11.2
Executive Manager	65-75	500-600	0.0730	41.2-49.3
Senior Engineer	45-55	100-120	0.0207	3.0-3.6
Senior Engineer	45-55	100-120	0.0226	3.3-4.0
Senior Engineer	45-55	100-120	0.0226	3.3-4.0
Senior Engineer	45-55	100-120	0.0296	4.3-5.2
Senior Engineer	30-35	100-120	0.0296	3.8-4.6
				68-82

The annual risk premium is calculated as follows:

[Additional Replacement Cost + Business Disruption Cost] x Probability of Leaving Service

We have adopted a risk premium estimate in respect of SPIP's exposure to key person risk of $75,000 p.a.

9.2 Employment Practices Insurance

Employment Practices Liability insurance is intended to protect both SPIP and its employees from actions arising out of any wrongful acts in relation to employment practice claims. This insurance cover includes damages, judgements, settlements, costs and defence costs for actions alleging wrongful acts such as harassment (sexual or otherwise), unlawful discrimination, breach of privacy, victimisation and misrepresentation or defamation.

SPIP have obtained indicative insurance quotations in respect of Employment Practices liability insurance. An indicative insurance premium for a sum insured of $5 million and deductible of $25,000 of all losses is $15,000 per annum. This quote was obtained in August 2001. At that time insurance premiums were already rising and more recent events (in particular the September 11 tragedy) have had a major impact on insurance premiums. We therefore make a conservative adjustment of 10% to allow for this general hardening of the insurance market. We have thus adopted a risk premium estimate of $20,000 pa. Due to the small deductible we make no further allowance for claims within the deductible.

The insurance is expected to cost $15,000 p.a.

10 Reliances

In completing this review we have relied on documents and information provided to us by SPIP and other third parties for the purpose of our review. These source documents are referred to in the appendix to this report. It should be noted that if any of this information is inaccurate or incomplete, this report may have to be revised.

Part III Appendices

A Catastrophic Risks Faced by SPIP

Introduction

SPI PowerNet's assets can be subject to losses arising from catastrophic environmental events. We have identified bushfires, earthquakes, windstorms and hailstorms as potential catastrophic environmental events. This section of the report examines the approach adopted to assess and quantify the probability of catastrophic environmental events.

A Comment on Catastrophic Event Return Periods

Catastrophic events are events that typically have a return period of 1/100 to 1/1000, however as catastrophic events have such low probabilities it is often difficult to derive probability estimates and meaningful expected losses. Blong (1995) identifies PML (Probable Maximum Loss) events as 1/100 to 1/1000 year events. An indication of typical return periods for catastrophic events insured by Australia's leading insurers by premium income may be inferred from a survey conducted by Andrews et al (1995). In a survey of Australia's leading insurers, insurers *were asked to nominate the return period beyond which events are ignored for PML purposes.* The results are presented in Table A.1

Table A.1 - Maximum Return Periods for Insurers

Return Period	Number of Insurers
200 years	2
500 years	4
1000 years	2
Unknown	1

A.1 Catastrophic Bushfire Loss

Victorian Bushfire Experience

Catastrophic bushfires provide a significant exposure to SPI PowerNet. SPI PowerNet's assets have the potential to cause fires where lines or conductors drop to the ground and cause a fire. Historically, Victoria has proven to be the most bushfire prone of Australian states. Even though Victoria accounts for only 3% of Australian landmass, as much as half the economic damage caused by bushfires over the last 150 years in Australia has occurred in Victoria. Examples of devastating bushfires in Victoria include

?? *"Black Thursday"* fires of 1851 when fires covered as much as a quarter of Victoria,
?? *"Black Friday"* fires of 1939 where seventy one lives were lost and vast areas of land were destroyed,
?? *"Ash Wednesday"* fires in 1983 where as much as $250 million worth of damage was done

Annually there are approximately 600 bushfires that occur in Victorian parks and forests, 20-30% of which are a result of lightning strike and remainder due to human activity. A report[1] by the Fire Management Branch of the Department of Natural Resources and Environment identifies public utilities as the cause of approximately 2% of bushfires in Victoria in the past 20 years. The report classifies public utility fires as fires arising from power transmission (transmission and distribution) and trains. Table A.2 presents number of fires associated with fire cause each year. Despite the low probability of public utilities starting bushfires, such fires account for approximately 14% of area burnt.

[1] Research report no. 49: Analysis of fire causes on or threatening public land in Victoria 1976/77-1995/96, Chris Davies, October 1997

Table A.2 – Number of Bushfires

Fire cause	Number of fires 1976/77-1995/96	Percentage of total fires
Lightning Strikes	3024	25.9%
Deliberate Lighting	2499	21.4%
Escapes - burning	2098	18.0%
Escapes -campfire,BBQ	1109	9.5%
Departmental burns	232	2.0%
Public Utilities	224	1.9%
Machines	296	2.5%
Pipes/Cigarettes/Matches	913	7.8%
Miscellaneous	596	5.1%
Unspecified	685	5.9%

Table A3 Area Burnt by Bushfires

Fire cause	Area burnt (ha) 1976/77-1995/96	Percentage of area burnt
Lightning Strikes	1,061,928	46.0%
Deliberate Lighting	312,983	13.5%
Escapes - burning	155,977	6.8%
Escapes -campfire,BBQ	29,333	1.3%
Departmental burns	105,478	4.6%
Public Utilities	325,121	14.1%
Machines	51,030	2.2%
Pipes/Cigarettes/Matches	8,872	0.4%
Miscellaneous	200,188	8.7%
Unspecified	59,473	2.6%

If 50% of Public utility fires are caused by electricity transmission or distribution, this suggests around 6 bushfires per year from these assets. The nature of transmission assets compared to distribution assets suggest the latter is more likely to cause bushfires. Assuming that transmission causes 10% of electricity asset fires, an approximate incident rate for SPIP assets is 0.5 per year.

SPIP's Bushfire Experience

SPIP has no recorded bushfire claims experience. With respect to SPIP's experience in a 12-year period, there were 5 incidents of a conductor falling to the ground and 3 incidents where a ground wire has fallen. None of these incidents have started a fire.

Assessment of Catastrophic Bushfire Risk

It is quite possible to envisage catastrophic fires, which results in total devastation to very large areas. In order to quantify the probability of such a catastrophic bushfire arising from SPIP's power transmission assets we have adopted the probabilities as shown in Table A.4.

Table A.4 – Probability of SPIP's Assets Causing a Major Bushfire

		Description	Probability Adopted
Probability of Catastrophic Bushfire arising from SPIP's assets	=	Probability of Public Utility Bushfire	2%[2]
		X	
		Probability of Power Assets Causing Bushfire	50%[3]
		X	
		Probability of SPIP transmission lines being the power assets	10%[4]
		X	
		Probability of Catastrophic Bushfire	10%[5]
		Total	0.01%

This suggests a return period of 1 in 10,000 years. For the purposes of this report we have adopted an assumption of a return period for catastrophic bushfires of 1 in 1000.

A.2 Catastrophic Earthquake Risk

Australian Earthquake Risk

SPIP's assets are subject to the risk of devastation by a catastrophic earthquake. Compared to countries located close to active tectonic zones Australia has a small earthquake hazard. However, while earthquake hazard in Australia is small it is significant as demonstrated by the Newcastle earthquake. The Queensland University Advanced Centre for Earthquake Studies makes the following assessment,

[2] See Table A.2

[3] Assume 50% is also caused by trains

[4] Five distribution companies cause 90% of fires.

[5] N.P. Cheney (Bushfire: Their threat to life and property, 1990) states, "*recent disaster fires have occurred where the regional frequency of large fires has been lower at 10-20 years*". With respect to Victoria they state, "*When all fire data is taken into account, it appears 20% of seasons are potentially severe, 40 % are moderate to serious and 40% are relatively mild.*"

"Australia is seismically active and earthquakes pose a substantial risk as demonstrated by the deadly magnitude 5.6 Newcastle earthquake of 1989. When compared to plate margin regions such as California or Japan, the rate of activity is lower, but relative to other intraplate regions, Australia's earthquake activity is moderate to high."

Earthquake hazards are typically expressed as the probable ground motion that may be recorded at a given locality with a particular frequency. Figures A.1 and A.2 show the distribution of Australia's earthquake risk and hazard respectively.

Figure A.1- Earthquake Risk Map

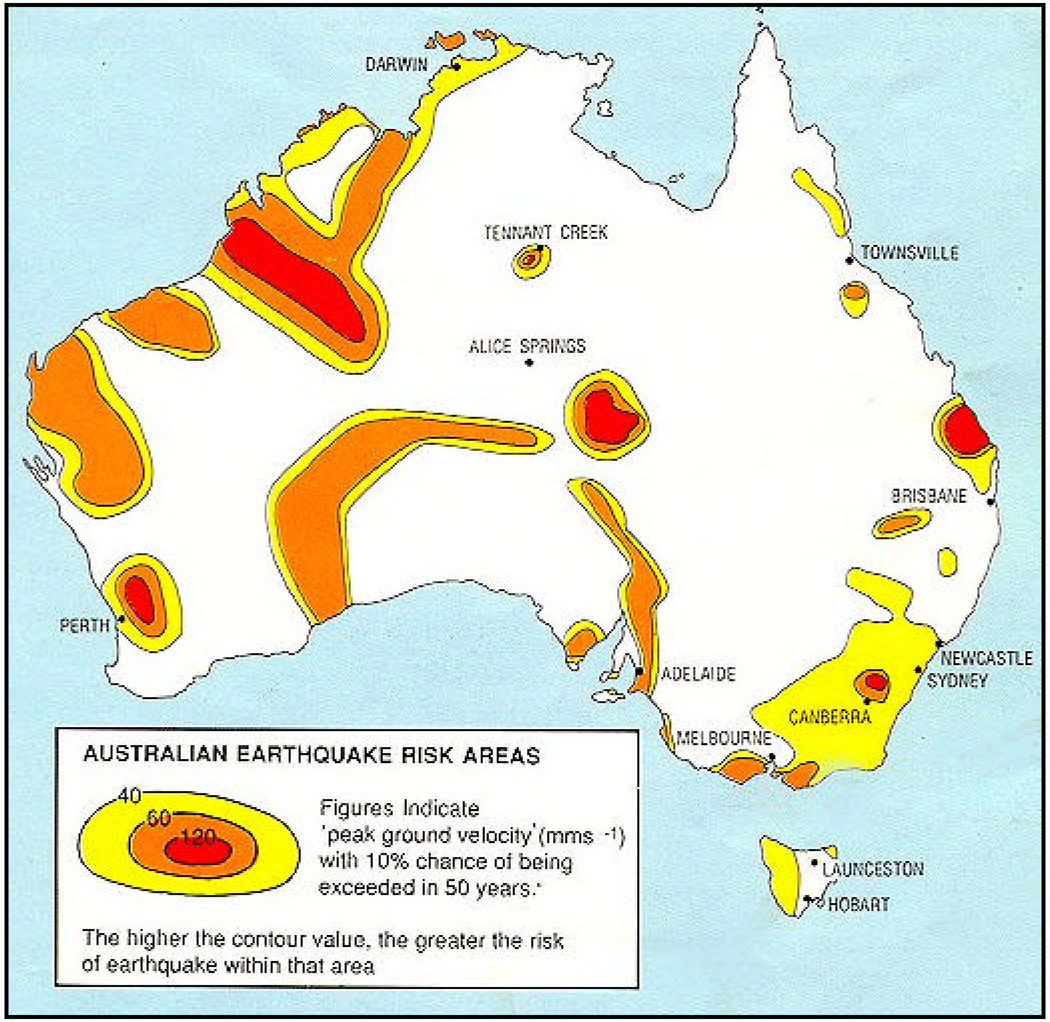
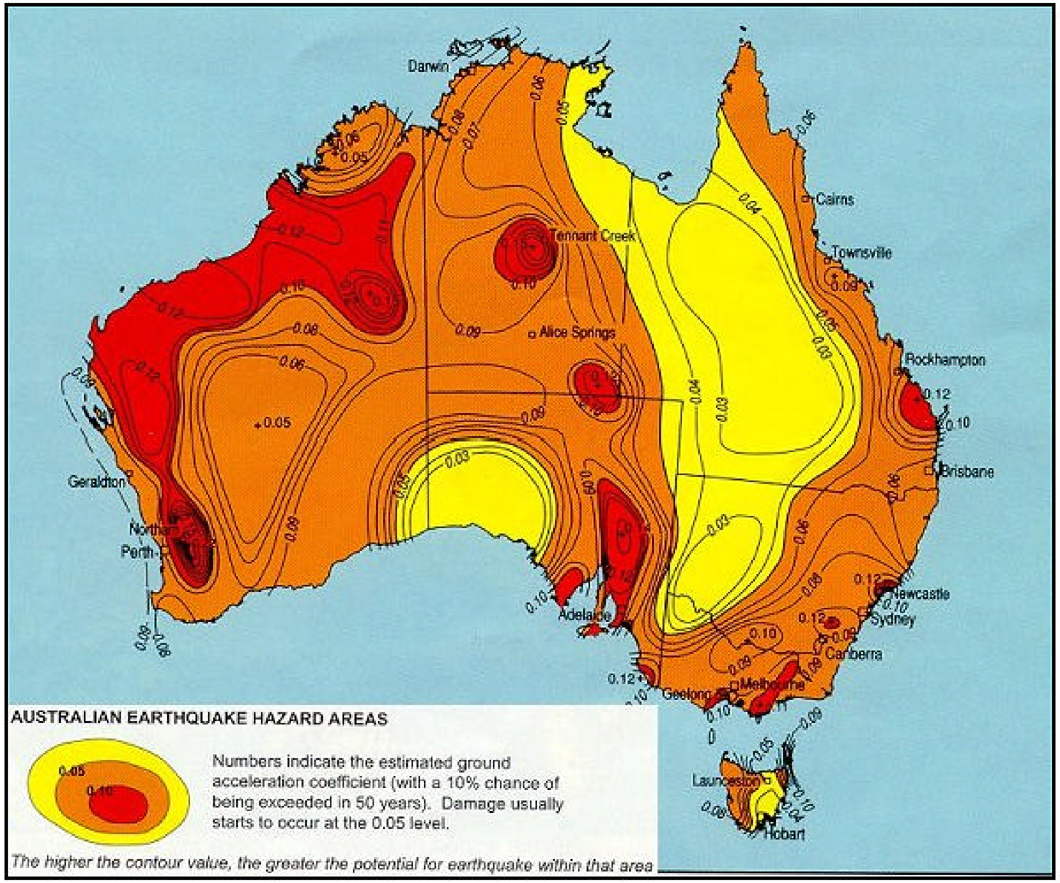


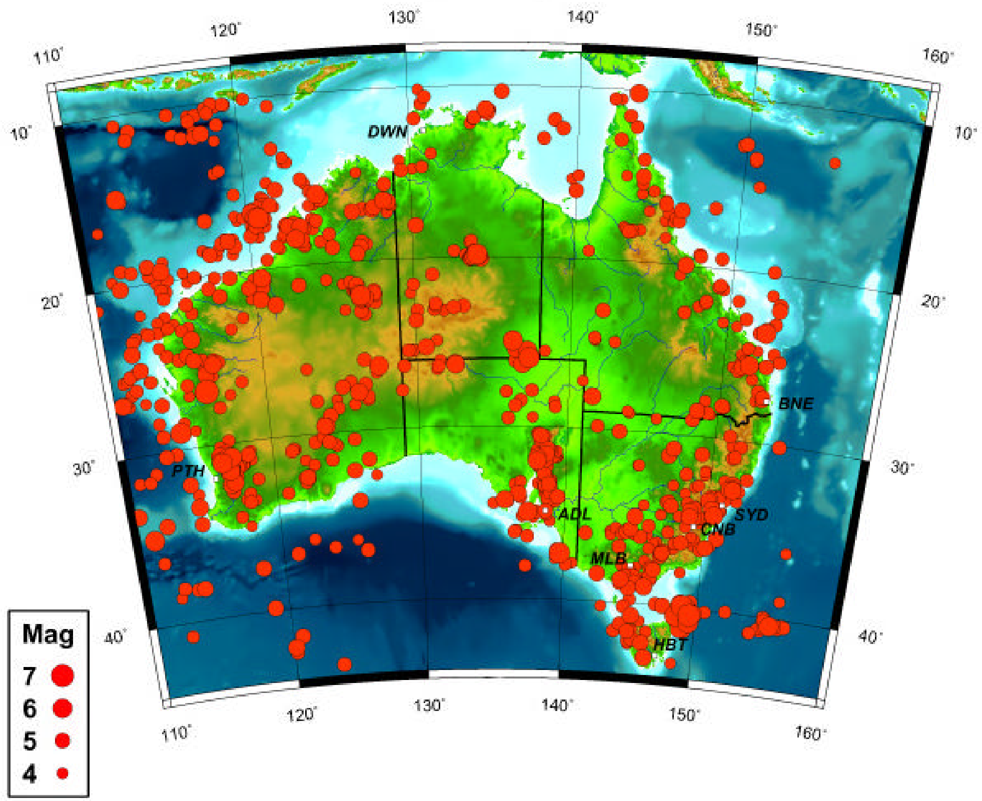
Figure A.2 - Earthquake Hazard Map



Victorian Earthquake Risk

From figures A.1 and A.2 it is evident that parts of Victoria are subject to earthquake risks comparable to Newcastle. Further evidence illustrating the risk of earthquake in Victoria is shown in Figure A.3. Figure A.3 shows earthquakes that have occurred with Richter magnitudes greater than 3.5 and suggests the higher seismicity and hazard regions are along eastern Australia.

Figure A.3 - Australia Earthquake map



Assessment of Catastrophic Earthquake risk

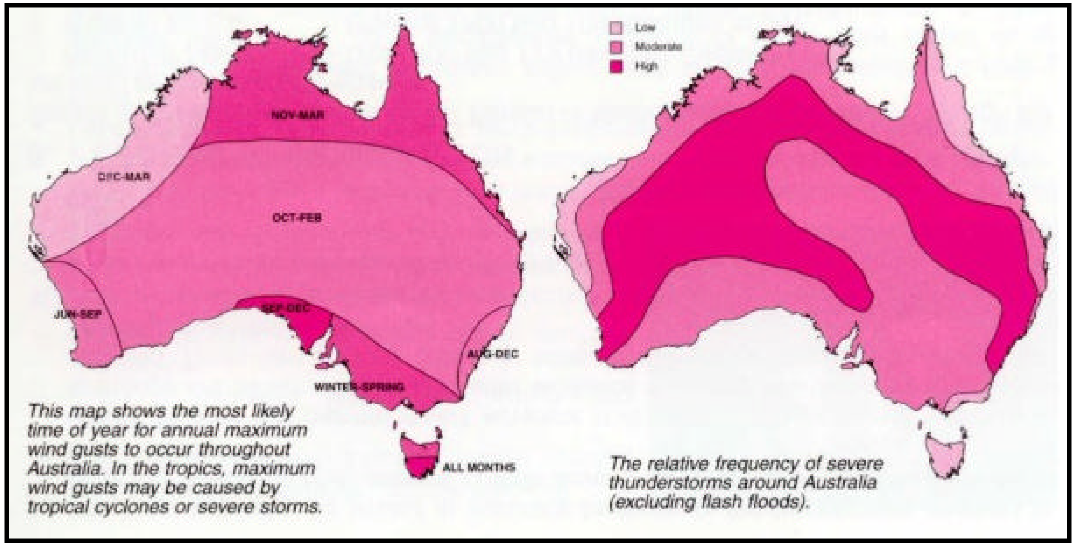
Quantification of earthquake risk is at best an imprecise science. Blong (PML Events-one coming to a place near you, real soon now! 1995) with reference to earthquake return periods states, *"In many cases it is impossible to make rational estimates of return periods"*. The difficulty of making return period estimates is further compounded by limited data, Australia earthquake data is based on 150 years of historic record and instrumental data of a few decades.

In order to quantify the impact of a catastrophic earthquake on SPIP's power transmission assets we have adopted a probability of 1 in 1000. This is based on a qualitative assessment of the likelihood of an earthquake in Victoria and, in particular for SPIP, Gippsland. We have also reduced this probability by allowing for the requirement that the epicentre would need to be located close to SPIP's assets.

A.3 Catastrophic Weather Event

Catastrophic windstorms have the potential to cause major damage to SPIP's transmission assets. Severe hailstorms may also cause major damage to SPIP's motor fleet (which it self-insures). Figure A.4 shows the frequency of severe weather events in Australia.

Figure A.4



Based on discussion with the Bureau of Meteorology we have been informed that annually there are 27 days on which a severe event can occur in Victoria. Current Australian design standards specify *the ultimate limit state wind speed and serviceability limit state wind speeds as having 5% probabilities of being exceed in a 50-year and 1 year period respectively.* Hence we have assigned that there is a 1: 1000 probability that an event occurs in which ultimate limit state design speeds are exceed and there is large scale structural failure of Transmission towers.

We have not assessed the potential for severe hailstorms in Victoria as we believe this will not have any material impact on SPIP's as they only have a motor fleet of 116 vehicles which are stationed at various locations around Victoria.

B Adjustment to Central Estimate

When establishing insurance premiums in a commercial environment an insurance company will make allowance for

- the expected claims cost, including allowance for catastrophes
- inflation and anticipated investment returns on the timing difference between the receipt of premium and the payment of claims
- acquisition costs such as brokerage
- the administration cost of running the insurance business, including the cost of handling claims
- a profit margin to provide a return to its shareholders commensurate with the risk of the business.

The first of these elements, the expected claims cost, is the same as the central estimate concept explained previously. The bulk of this report is dedicated to the assessment of the central estimate (risk premium) for the SPIP non-insured assets.

In addition to recovering the cost of the risk premium we believe it is also appropriate for SPIP to recover a number of other elements of the hypothetical commercial insurance premium, as discussed below.

Having taken on the responsibility for managing and paying the claims associated with self-insured liabilities it is appropriate to recover the associated administrative costs. The major component of these costs arises from staff salaries but they also include costs of training, seeking recoveries from third parties, monitoring experience and maintaining appropriate risk management systems.

We have assumed that all of these costs are adequately reflected in the Operation and Maintenance costs, but additional recoveries should be sought should this assumption be false or the O&M allowance inadequate. Insurance company costs in this area would typically lie in the range of 5% to 10% of the risk premium, with the higher rates appropriate for smaller insurers and those with more complex classes of insurance.

Shareholders of insurers seek returns on their investments which adequately reflect the risk of the business. The greater the perceived riskiness, the greater the required return and the greater the profit margin sought.

While the commercial profit motive is not appropriate in this case, there is a case for seeking to “recoup” costs at a level which exceeds the risk premium. This is because the nature of the self-insured risks is such that the loss experience in any relatively short period is highly uncertain. As shown elsewhere in this report, key components of the SPIP self-insured risks involve low frequency, high severity events. In statistical terms, the claims cost distribution is highly skew. So while we have placed an expected value (central estimate) on non-insured claims, there is clearly a lower bound of zero cost (no claims at all), with an upper bound of many many millions of dollars.

For example in the event that SPIP is found liable for the costs of a large bushfire, it is responsible for the first $5 million of any claim. While this is considered to be a low probability event, there are obvious cash flow implications in the year in which it “hits”. More severe financial implications are associated with catastrophic events affecting large numbers of transmission towers as currently the full costs of these claims are borne by SPIP (the risk is not insured).

A business which chooses to self-insure insurable risks is exposed to greater earnings uncertainty than a company which insures those risks. If the WACC determined for SPIP’s regulated revenue reset does not make appropriate allowance for the extra earnings uncertainty associated with self-insured risks then a ‘contingency margin’ adjustment to the central estimates calculated would be appropriate. The impact on SPIP’s business of variations in earnings from the central estimate is unlikely to be symmetric. Typically the costs of dealing with worse than expected uninsured losses will outweigh the benefits of better than expected experience. This contingency margin would be used to cover the costs associated with extra earnings uncertainty. These costs include:

- Business disruption costs following the occurrence of low likelihood uninsured losses
- Cost of raising short-term funding to meet unexpected shortfalls
- Negative reaction of potential investors to a perceived increase in risk following higher than expected uninsured losses

We suggest that the ACCC consider allowing regulated transmission businesses to build up a volatility and catastrophe reserve by accumulating the contingency margins assessed for each uninsured risk. The reserve would be used to meet the costs of worse than expected uninsured losses. While theoretically a volatility and catastrophe reserve would be determined statistically, it would not normally be possible to assess the appropriate reserve level with the limited claims experience of an individual business. Therefore the contingency margin approach is recommended as a practical alternative.

However, for the purpose of this report we have not included any adjustment to the central estimate in our calculation of the risk premium estimate.

C Insurance Market Hardening

The insurance market and commercial insurance in particular goes through cycles where the market is soft (“cheaper”) or hard (“expensive”). At different times of the cycle the cost of insurance can vary considerably. Further, the terms under which insurance is offered may also change. This includes changes to levels of deductibles/excesses, changes to exclusions and changes to policy wordings. A company’s own claims history will also impact on the premiums sought by insurers and a bad claims history may prompt a substantial rise in premium.

The insurance market goes through cycles as a result of:

- The available capacity in the market (supply/demand); and
- The availability and terms of reinsurance programs; and
- The recent worldwide claims history (including catastrophe experience); and
- The current investment markets (in particular the bond market); and
- The current profitability of market segments.

Market Capacity

As capacity is added or withdrawn from the market, there is an adjustment to the supply available for insurance segments. Generally, capacity will be withdrawn due to insurers seeing a certain segment as unprofitable or from insurers failing (eg: HIH) or placing their portfolio into run-off. This reduction in supply provides other participants with opportunities to increase premiums. When premiums increase to a level where substantial underwriting profits are being generated then this will encourage new players to enter/re-enter the market segment.

Effect of Reinsurance

The premium a direct insurer is required to pay to cover its re-insurance program will also directly impact the premiums charged to the end user. The reinsurance market will be affected by similar factors as the direct insurance market (for example, capacity availability, recent claims history and investment markets)

Claims History

When claim frequencies or average sizes deteriorate then the insurance market needs to reassess the risk estimate allowance in its premiums. This is particularly important in products that have low likelihood of occurrence but large and volatile claims costs (eg: catastrophe insurance). When pricing risk an allowance is made for these low frequency high cost events for these risks but a worse then expected claims history would lead to a re-evaluation of this impact. Similarly where claims history is better than expected, then a reduction in premiums can be expected.

Investment Markets

When pricing, insurers make an allowance for investment returns. At times of strong investment performance, insurers may accept underwriting losses for investment profits. As investment returns tighten, insurers may reassess their underwriting positions and re-price to ensure underwriting profits.

Profitability of Market Segments

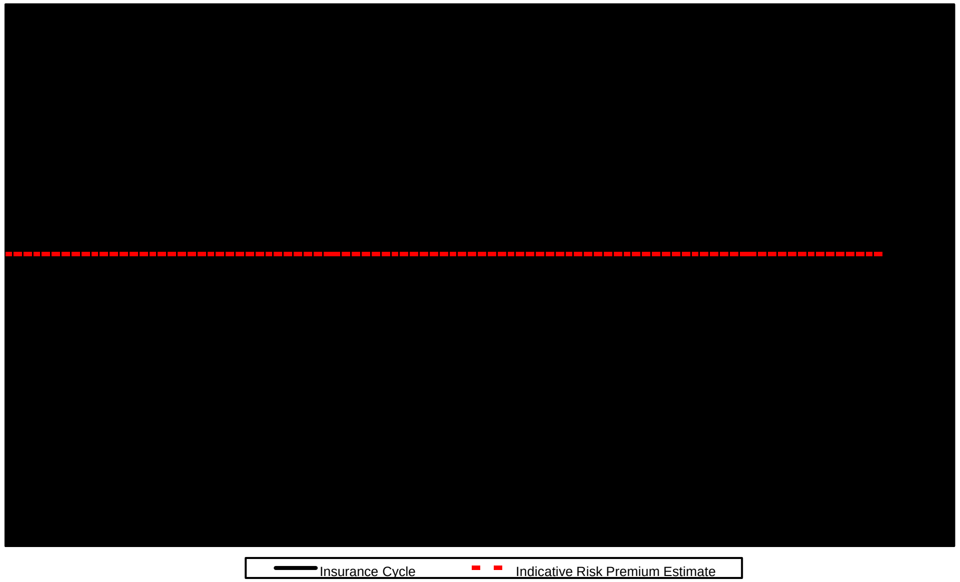
As outlined above, there are a number of reasons why certain market segments become unprofitable. In these instances, insurers will look to re-price to ensure profitability. At times prices may be kept artificially low to ensure market share retention. However, this cannot be a long-term strategy and over time the market will look to increase premiums on unprofitable segments (or capacity is withdrawn).

Impact of Timing

When the insurance industry acts to improve its financial performance by raising prices and tightening conditions, insurers' gains can be eroded initially by the impact of past claims and the need to build adequate reserves for future claims. Therefore it takes time for the higher prices to translate into underwriting profits. This leads to a long upward climb to the insurance cycle.

Figure A.1 summarises the cyclical nature of the insurance market. The straight line shows an indicative risk premium estimate at the average level. At different times of the insurance cycle, insurance can be seen as being good value (worth taking out) or as bad value (worth self-insuring).

Figure C.1



A further impact on the insurance premiums is where claim size and/or claim frequencies worsen overtime. This is particularly the case in liability and professional indemnity insurance where court cases, new technology advances and generally more public awareness of its rights, can lead to steps in the total claim cost due to a higher number of claimants or higher payments per claim. Referred to as superimposed inflation it is generally accepted that this will average at between 3% to 6% p.a.

C.1 Market Expectations prior to September 11

Prior to the terrorist attacks of September 11 the insurance market was already hardening across all commercial segments, from a low in early 2000. The key lines of insurance affecting SPIP's business are public liability, professional indemnity, fire and industrial special risks (ISR) and commercial motor vehicle. The expected increases were different for each insurance market segment and rates varied considerably by insurer.

Table A.1 summarises the average increase in rates expected for 2001-2003 *prior to September 11*. The HIH collapse had already impacted on 2001 premium increases, particularly in the areas where HIH was a key player (public liability and professional indemnity.)

Table C.1

	Estimated Average Real Premium Increase [1]		
Market Segment	2001	2002	2003
	%	%	%
Public Liability	18	16	10
Professional Indemnity	23	18	14
ISR	16	17	8
Commercial Motor Vehicle	10	6	5
Workers' Compensation	9	4	3

1. Source - Deloitte JP Morgan 2001 General Insurance Industry Survey

C.2 Impact of September 11 on the Insurance Cycle

It will be some time before the full effects of September 11 on the insurance industry can be assessed. The immediate response from underwriters and reinsurers has been to increase premiums and reduce the level of insurance cover provided by increasing policy deductibles and excluding certain risks (e.g. terrorism). The level of premium increase has varied significantly between insured risks and rate increases well in excess of 100% have not been unusual.

This dramatic shift in insurance pricing represents a step change in the normal insurance cycle. The reasons for this pricing shock can be attributed to the following key factors:

- Loss of insurance capacity following the reduction in insurers' capital;
- Increased reinsurance costs following the loss of capacity in the reinsurance market – this will have a flow-on effect on direct insurance rates; and
- Reappraisal of risk by insurers to allow for larger losses from catastrophe events and accumulations of risk than had previously been allowed for.

C.3 Outlook for insurance premiums after September 11

The future path of insurance premium rates after September 11 is uncertain. The factors affecting the likelihood of further premium increase or premiums stabilising at current levels compared to the likelihood of premiums falling from current levels are discussed in the following paragraphs:

Rising / Stabilising Premiums

Factors impacting the likelihood of further premium increases, or premiums stabilising at their new higher levels, include:

- There has been a reappraisal of risk by insurers and reinsurers following the September 11 events. This represents a fundamental change in the assessment of the risks faced by insurers and therefore is unlikely to be given away even in a 'soft' market;
- It takes some time for high prices to flow through to an increase in insurers' and reinsurers' capital. This delay in rebuilding capital will continue to limit insurance and reinsurance capacity; and

- Consolidation and a closer focus on capital management should enable the insurance industry to maintain increased rates.

Falling Premiums

The prospect of insurance premiums falling from current levels is possible if:

- The premium increases announced in the months immediately after the events of September 11 overshoot the ‘reasonable’ level of increase required to meet the increased risks of writing insurance business; and
- Excessive premium increases attract substantial amounts of new capital into the insurance market forcing premium levels down and leading to a resumption of a typical insurance cycle.

The outcome for insurance premium rates over the regulatory reset period (2003-2007) is very difficult to assess at this point. The September 11 events will have a major long-term impact on the insurance market but it will be some time before the impact can be accurately assessed. Therefore we have not made any allowance in this report for a change in SPIP’s insurance premiums over the regulatory reset period.

D List of Documents

- Davies C, October 1997, Analysis of fire causes on or threatening public land in Victoria 1976/77- 1995/96, Research report no. 48, Fire management branch,
- Swiss Re, Random occurrence or predictable disaster? New models in earthquake probability assessment,
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- Andrews T, Carless R Vaccaro and Goodwin M, 1995, Catastrophe PML Estimation, 1995 General Insurance Seminar,
- Queensland University Advanced Centre for Earthquake Studies (QUAKES) -http://www.quakes.uq.edu.au
- Bureau of meteorology, Australia - http://www.bom.gov.au
- Newcastle city council - http://www.ncc.nsw.gov.au
- Network Support Agreement between Victorian Energy Networks Corporation and SPI PowerNet for Network Reactive Support 2001/02 to 2003/04.
- Deloitte JP Morgan General Insurance Interim Survey
- We have also relied on information and data provided directly by SPIP, including
- Tower data, tower damage incidents and tower replacement costs
- Motor Fleet Information
- Transformer and Circuit Breaker Data
- Liability Claim Information

Trowbridge Consulting's

Confidential Documentation relating to the *Valuation of Non-insured Risks*

has been deliberately omitted from this Appendix

Appendix C

SKM roll-forward valuation report

SPI PowerNet Pty Ltd

1994 Roll-Forward Valuation

Independent Check

April 2002

SINCLAIR KNIGHT MERZ

Sinclair Knight Merz Pty Limited
ACN 001 024 095
ABN 37 001 024 095
590 Orrong Road
Armadale VIC 3143
PO Box 2500
Malvern VIC 3144
Australia
Telephone: +61 3 9248 3100
Facsimile: +61 3 9500 1180

Contents

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Project Manager: Eddie Tang
Name of Organisation: SPI PowerNet Pty Ltd
Name of Project: Roll-forward valuation
Name of Document: 1994 Roll-forward valuation – Independent check
Document Version: 0
Project Number: BU1320

1. Scope of Work

SPI PowerNet has constructed a financial model that assesses the Regulatory Asset Base (RAB) value as at 1 Jan 2003 by:

a) determining the sunk asset value as at 1 Jan 2001, taking into consideration:
   - the roll forward of the 1994 RAB to 1 Jan 2001;
   - the assets omitted from the 1994 RAB; and
   - the new assets installed between 1994 and 1 Jan 2001

b) rolling the sunk asset value forward to 1 Jan 2003 to form the RAB value as at 1 Jan 2003;
c) re-optimising the network;
d) rolling in non-contestable excluded services; and
e) including the new assets installed between Jan 2001 and Dec 2002.

Sinclair Knight Merz Pty Ltd (SKM) was commissioned by SPI PowerNet to conduct an independent check that SPI PowerNet's calculations are in accordance with the methodology outlined in the SPI PowerNet Revenue Cap Application.

2. Methodology in Conducting an Independent Check

In determining the sunk asset value on 1 Jan 2001, SKM examined SPI PowerNet's methodology in valuing the omitted assets. This is described in Section 3. A simplified high level financial model was then constructed by SKM to independently estimate the sunk assets value. This value was compared with the result determined by SPI PowerNet. This is described in Section 4.

SKM then examined SPI PowerNet's methodology for incorporating the conclusions of the optimisation study. This study was conducted for the regulatory period Jan 2003 to March 2008. The review of the methodology is described in Section 5.

A review of the non-contestable excluded assets to be rolled into the RAB is included in Section 6.

Finally, as a check on the opening RAB value for the new regulatory period the high level model was rolled forward to Jan 2003, after incorporating values arising from the optimisation finding and non-contestable excluded services. The results of this check are described in Section 7.

3. Valuation of Omitted Assets

The breakdown of SPI PowerNet's assessment of the omitted assets as on 1 Jan 2001 is summarised in Table 3.1.

Table 3.1 Breakdown of Omitted asset

Item	**$ x M**
Easements	231.8
Future terminal station sites	25.2
System spares	10.1
Communication assets	28.8
66kV transmission lines	11.2
Total (2001 value)	**307.2**

The following sections examine how these values have been derived.

3.1 Easement Valuation

SPI PowerNet has valued easements based on:

- the CPI indexed land compensation cost; plus
- the transaction cost (indexed) as estimated in the 1997 A.T. Cocks (now Urbis) report.

The easements were acquired between 1905 and 1994 and SPI PowerNet's database has historical records of the compensation costs for some 98% of the easements. The historic compensation costs have been indexed to 1 Jan 2001 by using the CPI – Long Term Price Series published by Australian Bureau of Statistics. A spreadsheet prepared by SPI PowerNet assessing the indexed compensation cost at $79.7M has been examined. The spreadsheet has been found to be in line with the above methodology.

In 1997, A. T. Cocks prepared a valuation of the 8,000 (approx.) easements held by SPI PowerNet over private land. The value of land under easement was estimated as $366.5M (1997 value). Instead of this value, SPI PowerNet has used the indexed actual compensation cost (ie $79.7M). SPI PowerNet has, however, used cost estimates for easement acquisition from the A.T. Cocks report. They are:

Solatium	$ 34.7M
Owner's cost (fee etc)	$ 22.6M
SPI PowerNet cost	$ 81.7M
Total	$139.0M (1997 value)

The transaction cost indexed to 1 Jan 2001[1] is therefore $152.1M, making the total of the easement value to $231.8M.

[1] Using ABS CPI All Groups, Weighted Average of Eight Capital Cities.

3.2 Future Terminal Station Sites

In July 2001, Urbis estimated the land value for both the existing and future terminal stations as $169.2M (as at 1 January 2001). After deducting the land values relating to the existing terminal stations, which have already been included in the 1994 RAB, the land related to the future terminal stations and the radio station sites, was valued at $25.2M

SPI PowerNet has applied this $25.2M as the omitted value of the future terminal station land sites.

3.3 System Spares

It is not feasible to examine the breakdown of the system spares, valued at $10.1M within the time frame available. SPI PowerNet advised that the value had been based on the book value.

For comparison, in the 1994 SKM Valuation report, the system spares were valued at $12.7M.

3.4 Communication Assets

SPI PowerNet has based the value of communication assets on their estimate of Replacement Cost as at December 2000. These assets consist of various sub-systems, each with different service lives ranging from 15 to 70 years.

SKM has prepared a spreadsheet to determine the depreciated value of the communication assets based on SPI PowerNet's estimate of Replacement Cost. Using appropriate technical lives SKM's estimate is in-line with SPI PowerNet's own estimate of $28.8M.

3.5 66kV Transmission Lines

These SPI PowerNet assets were not been included in the 1994 RAB. In 2001, SKM estimated their depreciated replacement cost at $11.2M. This is the value used by SPI PowerNet.

4. Sunk Asset Value - 1 Jan 2001

SPI PowerNet has prepared a detailed financial model to determine the sunk asset value as at 1 Jan 2001, which takes into consideration:

- the roll forward of the 1994 RAB;
- the new asset installed in between 1994 and 2000; and
- the omitted assets shown in Section 3.

While close inspection of the financial model indicates that it derives the sunk asset value correctly, SKM constructed a simplified model to independently check SPI PowerNet's result.

In SKM's model, the system assets, which were called "Transmission assets" in the SKM 1994 Valuation Report with a value of $1,364.5M, are depreciated according to the regulatory lives. The asset values are then indexed to a 2001 value of $1,316.2M according to the actual CPI rates over the period 1 July 1994 to 1 January 2001.

The impacts of system capex and retired assets between 1994 and 2000 are then separately assessed and depreciated according to the regulatory lives. The net effect of the changes is estimated to be an additional $69.9M (2001 value).

A spot check of the 1998 breakdown of the capex assets has been conducted, and this is in line with the aggregated values of the SPI PowerNet financial model.

Non-system assets were not assessed by SKM (non-material). Indeed 1994 non-system assets have largely reached zero depreciated value as of 2001.

The non-system and omitted asset values are then included to derive an estimated 2001 sunk asset value of $1,713.1M. Table 4.1 summarises the results of the SKM simplified model.

Table 4.1 SKM's estimate of 2001 sunk asset

								$ x M
1994 RAB, (1994 value)								1,390.6
Less Non-system assets (1994 value)								-26.1
Less 1994-2000 depreciation, substation assets (1994 value)								-146.1
Less 1994-2000 depreciation, overhead line assets (1994 value)								-103.7
Subtotal								1,114.7
Indexed to Jan 2001 value								**1,316.2**
	Jul-94	Jul-95	Jul-96	Jul-97	Jan-98	Jan-99	Jan-00	
Capex, system	11.2	11.9	12.1	6.2	13.6	0.5	15.1	
Land acquisition			0.01	0.12				
Equipment retirement				-0.08	-0.67	-0.49		
Capex depreciatn, Dec 00	-1.5	-1.4	-1.0	-0.5	-0.8	-0.0	-0.2	
Indexed to Dec 00	11.2	11.7	12.1	6.3	13.2	0.0	15.4	
Subtotal (2001 value)								**69.9**
Non system assets (2001 value)								19.7
Omitted assets								307.2
SKM's estimate of sunk assets, 2001								**1,713.1**

This result is very similar to SPI PowerNet's own estimate of $1,714.1M, which demonstrates that SPI PowerNet's result is reasonable. SKM's simplified model assumes that both the new assets and the equipment retirements took effect in the middle of each period concerned, and are therefore depreciated and indexed accordingly; while SPI PowerNet's model reflects the actual date. SPI PowerNet's model should therefore be more accurate in this instance.

5. Optimisation

SKM completed a separate assessment of optimisations appropriate for SPI PowerNet's regulated shared network assets for the regulatory period from Jan 2003 to March 2008. The optimisations are different from those of the 1994 SKM Valuation report that was used for the regulatory period prior to Jan 2003, with some assets being optimised back in.

SPI PowerNet has assessed the impact of the altered optimisations on the RAB.

5.1 Methodology for valuing assets optimised back into the RAB

SPI PowerNet's methodology involves the assessment of a Revised Optimised Depreciated Replacement Cost (ODRC) based on:

a) Calculating the difference between the 2003 RAB based on a continuation of past optimisations compared with the presently recommended optimisations;
b) The back-calculation of the corresponding 1994 RAB difference (by adding the differential depreciation over the intervening 8.5 years to the difference calculated in a) above); and
c) Rolling forward the result of b) for the subsequent 8.5 years based on the nominal vanilla WACC.

The Revised ODRC is included only if the sum of:

- The increase in the ODRC value from the new optimisation escalated by the WACC;
- the present value of re-building the optimised assets after their retirement; plus
- roll forward of the RAB based on the past optimisation.

DOES NOT EXCEED

- the replacement cost (2003 value) of the re-optimised network.

The replacement cost is used if it is the lower value.

5.2 Comparison of Optimisations

SPI PowerNet's assessment of the changes arising from this re-optimisation is an additional $271.8M ODRC in 2003 value, compared to the value if the current optimised network is rolled forward.

Over 80% of this additional amount is contributed by the following two circuits which are now optimised back into the RAB. They are:

- Moorabool-Heywood-Portland 500kV line (was previously optimised to 330kV line); and
- Hazelwood-Rowville 500kV line (was optimised out).

There are other minor network assets that were in the 1994 regulatory asset base but are now optimised out. Their Depreciated Replacement Cost of $6.0M (2003 value) has been excluded from the RAB.

5.3 SPI PowerNet Assumptions

In deriving the result arising from the change in optimisation, SPI PowerNet has made the following assumptions:

- The amount of depreciation and return on previously optimised assets to be recouped applies for the period between Jul 1994 and Dec 2002.
- As the latest published CPI[2] is 135.4 for Dec 2001, for rolling forward, SPI PowerNet assumes the rate will increase a further 2.2% to Dec 2002.
- SPI PowerNet has constructed a real vanilla Weighted Average Cost of Capital (WACC) for the period 1 Jul 1994 to 31 Dec 2002 and applied actual inflation for the period (thus generating a nominal vanilla WACC). The resulting escalation factor of 2.197 is used when calculating the rate of return to be recouped for the period between Jul 1994 and Dec 2002. The real vanilla WACC is based on the same parameters used to determine the return on capital underlying the Tariff Order revenue cap.

5.4 Findings

SKM has examined SPI PowerNet's breakdown of the increase of the ODRC arising from the re-optimisation, and is satisfied that it adheres to the SPI PowerNet methodology outlined in Section 5.1.

[2] Using ABS CPI All Groups, Weighted Average of Eight Capital Cities.

6. Non contestable services

There are a number of other assets providing non-contestable services that are currently outside the revenue cap but which are to be incorporated into the 2003 RAB. They are services relating to the Victorian Network Switching Centre (VNSC) and some connection and shared network projects, and are valued by SPI PowerNet as $7.4M and $36.1M respectively.

SPI PowerNet advised that the values are based on the contract values of the respective services.

SKM has examined the breakdown of values of the non contestable services and is satisfied with the methodology in rolling forward the values to 2003.

7. Regulated Asset Base Value – 1 Jan 2003

The SPI PowerNet financial model assessment as at 1 Jan 2003 RAB is $2,089.7M.

This has been cross-checked with the SKM simplified model result. The CPI in Dec 2002 used in both models is assumed to be 138.4 or an annual inflation rate of 2.2% from Dec 2001.

In SKM's model, the system assets, which were called "Transmission Assets" in the SKM 1994 Valuation Report with a value of $1,364.5M, are depreciated according to regulatory lives. The asset values are then indexed to a 2003 value of $1,293.9M according to the actual and forecast CPI.

The omitted assets ($307.2M), the system capex and retired assets between 1994 and 2000 ($69.9M), as shown in Table 4.1, are then depreciated and indexed to Jan 2003. Their 2003 values are $317.1M and $70.3M respectively.

The impact of system capex and retired assets between 2001 and 2002 are then separately assessed and depreciated according to the regulatory lives. The net effect of the changes is estimated to be an additional $70.1M (2003 value).

Together with the Non-system assets ($22.1M), optimisation changes ($271.8M), non-contestable excluded assets ($36.1M) and VNSC assets ($7.4M), the estimated 2003 RAB value is $2,088.8M. Table 7.1 summarises the results of the simplified model.

Table 7.1 SKM's estimate of 2003 RAB value

	Jan-01	Mar-02	**$ x M**
1994 RAB, (1994 value)			1,390.6
Less Non-system asset (1994 value)			-26.1
Less 1994-2002 depreciation, substation asset (1994 value)			-189.3
Less 1994-2002 depreciation, overhead line asset (1994 value)			-135.6
Subtotal			1,039.6
Indexed to Jan 2003 value			**1,293.9**
Omitted asset (2001 value)			307.2
Indexed to Jan 2003 value (1)			**317.1**
1994-2000 new system and retired assets (2001 value)			69.9
Indexed to Jan 2003 value			**70.3**
New asset, system	26.9	50.9	
Equipment retirement	2.9	4.7	
New asset depreciatn, Dec 02	0.9	0.5	
Indexed to Dec 02	24.0	46.1	
Subtotal (2003 value)			**70.1**
Non system asset (2003 value)			22.1
Optimisation changes			271.8
Excluded service asset			36.1
VNSC asset			7.4
SKM's estimate of RAB (2003 value)			**2,088.8**

(1) No indexation on System spare as part of the Omitted asset

This result is very similar to SPI PowerNet's own estimate of $2,089.7M, which demonstrates that SPI PowerNet's result is reasonable. SKM's simplified model assumes that both the system capex and the retired assets took effect in the middle of each period concerned, and are therefore depreciated and indexed accordingly; while SPI PowerNet's model reflects the actual date. SPI PowerNet's own valuation should therefore be more accurate in this instance

8. Conclusion

SKM has completed an independent check of SPI PowerNet’s roll forward valuation of the 1994 RAB to both Jan 2001 and Jan 2003, based generally on the input data provided by SPI PowerNet.

SKM is satisfied that the calculation methodology is in line with the approach described in Chapter 7 - Regulatory Asset Base Valuation of the Revenue Cap Application to be submitted to the ACCC.

SKM is satisfied with the execution of the methodology through SPI PowerNet's financial model as checked with the high level simplified model.

Appendix A References

The following documents have been used in conducting an independent check of the SPI PowerNet's valuation result.

1. SPI PowerNet's report "Revenue Cap Application" dated Apr 2002, Chapter 7 on Regulatory asset base valuation.

2. SPI PowerNet's roll forward financial model.

3. Urbis' report "Valuation of SPI PowerNet Land Holding", dated July 2001.

4. A. T. Cocks' report "Replacement Cost Estimates: PowerNet Easements", dated Dec 1997.

5. SPI PowerNet's spreadsheet on the breakdown of communication assets.

6. SPI PowerNet's spreadsheet on easement land compensation costs.

7. SPI PowerNet's spreadsheet on assessing the re-optimisation of system assets.

8. SPI PowerNet's spreadsheets on the breakdown of assets associated with excluded connection and shared network projects.

9. SPI PowerNet's spreadsheets on the breakdown of excluded assets of the Victorian Network Switching Centre.

10. SPI PowerNet's spreadsheet on the breakdown of 1998 Capex.

11. SKM report "Valuation of Victorian ESI Transmission and Distribution Assets" dated Sep 1994.

12. SKM report "Optimisation assessment for the SPI PowerNet Network", dated Apr 2002.

13. Valuation of SPI PowerNet's 66kV transmission asset from SKM's report "Valuation of Transmission Assets", dated November 2001.

Appendix D

SKM optimisation report

SPI PowerNet Pty Ltd

Optimisation Assessment for the SPI PowerNet Network

April 2002

SINCLAIR KNIGHT MERZ

Sinclair Knight Merz Pty Limited
ACN 001 024 095
ABN 37 001 024 095
590 Orrong Road
Armadale VIC 3143
PO Box 2500
Malvern VIC 3144
Australia
Telephone: +61 3 9248 3100
Facsimile: +61 3 9248 3440

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Executive Summary

Sinclair Knight Merz was engaged by SPI PowerNet to undertake an independent assessment of optimisations appropriate for SPI PowerNet's regulated shared network assets for the regulatory period from January 2003 to December 2007.

A detailed optimisation assessment for this network was last undertaken in 1994, at which time the maximum demand for Victoria was 6158MW. The maximum demand projected for 2002/2003 is 9011MW.

A detailed optimisation methodology has been prepared considering the practice of previous optimisations, and a number of published guidelines. This methodology clarifies the criteria and process in a number of areas. It has then been applied in a consistent and methodical evaluation of all of the SPI PowerNet shared network assets.

A summary of the optimisations is as follows:

- The two Yallourn to Rowville low rated double circuit 220 kV lines are optimised to a single double circuit 220 kV line with high rating.
- The Hazelwood to Rowville low rated double circuit 220 kV line is optimised to a high rated single circuit 220 kV line.
- The Yallourn to Hazelwood low rated double circuit 220 kV line is optimised to a high rated single circuit 220 kV line.
- The Rowville to South Morang 500kV circuit (currently operating at 220 kV) is optimised to a single circuit 220kV medium rated line.
- The Keilor to Thomastown medium rated 220 kV double circuit line is optimised to a high rated single circuit 220 kV line.
- The Keilor to Geelong double circuit 220kV line and single circuit 220kV line all with low rating are optimised to one double circuit 220 kV line with medium rating.
- The East Rowville to Tyabb double circuit 220kV line has two circuits rated at 800MVA each. Both circuits are optimised to 400MVA circuits.
- A breaker-and-a-half bay (3 circuit-breakers) of the 500kV switchgear at South Morang Terminal Station is optimised to a double circuit-breaker bay.

1. Introduction

Sinclair Knight Merz was engaged by SPI PowerNet to undertake an independent assessment of optimisations appropriate for SPI PowerNet's regulated shared network assets for the regulatory period from January 2003 to December 2007.

As part of this assignment a detailed optimisation methodology has been prepared considering the practice of previous optimisations. This methodology clarifies the criteria and process in a number of areas.

Sinclair Knight Merz engaged ROLIB Pty Ltd to undertake detailed system analysis work.

This report provides a review of the capability of SPI PowerNet's shared network assets against the optimisation principles, including the planning criteria. It then considers optimisations to remove any over-design or over-capacity and to adjust plant configuration where the system capability can be achieved in a more cost-effective manner.

Connection assets, that is, the assets used for entry to and exit from the network by generators and consumers, are not considered as part of the scope of this assessment. They are the subject of direct negotiation between SPI PowerNet and the connected parties.

2. Optimisation Methodology

The optimisation methodology, including planning criteria and optimisation principles to be applied for this optimisation study, is presented in Appendix A.

The key points are summarised below:

- An "N-1" criterion is generally applied. However, for the critical inner Melbourne Metropolitan area and the Latrobe Valley to Melbourne transmission, an "N-2" criterion is applied.

- If a network work element is not needed to provide the specified transmission capability during the regulatory period, then it is optimised out. If the transmission capability of the element exceeds the network requirements at the planning horizon, then the transmission element is generally optimised downwards to this requirement.

- Where the lesser of the actual or required transmission capacity can be achieved in a more cost-effective manner, the network elements are replaced with optimised assets in the optimised system.

Load forecasts used in the analysis are based on those published by NEMMCO. The demand forecasts selected are based on ten percent probability of excedence using the medium economic growth scenario.

The methodology requires consideration of loadings up to 2017 (10 years after the end of the regulatory period). Forecasts up to 2017 were estimated by extrapolating the NEMMCO forecasts. As the summer period is most critical due to the higher demands and lower transmission line ratings, analysis of summer loading conditions was used in determining the optimised system. Summer demand forecasts used for the analysis are presented in Table 2-1.

Table 2-1 Summer Demand Forecast for Victoria

Year	MW
2002/03	9,011
2003/04	9,283
2004/05	9,557
2005/06	9,830
2006/07	10,090
2007/08	10,327
2008/09	10,536
2009/10	10,743
2010/11	11,146
2011/12	11,446
2012/13	11,753
2013/14	12,069
2014/15	12,394
2015/16	12,727
2016/17	13,069

Load forecasts for specific supply points have been obtained from the VENCorp report “Terminal Station Demand Forecasts 2000/2001 - 2010/2011”. Again, load estimates beyond this time have been extrapolated.

Network data for the analysis was prepared by NEMMCO and VENCorp and provided by SPI PowerNet. Analysis was carried out using the PSS/E power system analysis package.

The transmission line circuit ratings applied in the assessment are the actual ratings of the transmission lines. In some cases lower operational ratings may currently apply due to the rating of secondary and termination equipment that can be readily up-rated as system loading levels increase.

The methodology refers to 30 minute capability of the system following a contingency. This implies the use of 30 minute plant ratings in the assessment. For overhead lines it is normal practice in Victoria to adjust the line ratings with ambient temperature. Rather than increase line ratings to reflect short term capability then reduce them to reflect the higher ambient temperature that is likely to occur at the times of high system loading, the 35 ºC line ratings have been applied. For transformers, short term ratings advised by SPI PowerNet have been used.

Load flow analysis and contingency analysis has been used to assess maximum transformer and transmission line loadings. A consistent and methodical assessment of all of the SPI PowerNet shared network has then been performed, with optimisations being proposed for various network elements. The performance of the optimised system was then compared to that of the actual system. This performance was subsequently checked using stability analysis.

The optimisation assessment was undertaken on an area by area basis, as follows:

- Latrobe Valley to Melbourne transmission
- Melbourne and Geelong Area transmission
- State Grid transmission (Ballarat, Terang, Horsham, Redcliffs, Shepparton etc)
- Hydro Area transmission
- Supply to Portland and Interconnection with South Australia

The optimisation assessment considered the following interconnections in accordance with the optimisation methodology, in particular Appendix A Section A.4.2 (b).

- Victoria – NSW/Snowy
- Victoria – South Australia via Heywood
- Victoria – South Australia: Murraylink
- Victoria – Tasmania: Basslink.

In general, the additional generation capacity required to meet the forecast demand has been based on scaling up generation at existing locations to meet generation requirements. This is described in Appendix A Section A.4.2 (b).

Proposed network optimisations may provide a different level of reactive support, or a different amount of annual losses estimated for the optimised element. In these instances the net effect is noted for consideration in calculating the cost differential for the optimisation.

3. Optimisations

The optimisations proposed in this section are selected as a result of a methodical assessment of the SPI PowerNet shared network assets, applying the methodology included in Appendix A.

Unless otherwise stated, all optimisations are applicable at January 2003.

3.1 Latrobe Valley to Melbourne 220kV Transmission

There is a relatively close match between the Latrobe Valley to Melbourne 220kV transmission and the maximum output of Yallourn W power station.

There are effectively six 220kV circuits, each with a low summer rating of 307MVA. Three circuits at 800MVA would provide sufficient capacity.

3.1.1 Yallourn to Rowville – 2 x 220kV Double Circuit Lines

The two low rating double circuit 220 kV lines (2 x 2 x 307MVA) between the Yallourn switchyard and Rowville are optimised to a single double circuit 220 kV line with high rating (2 x 800MVA). To compensate for increased reactive losses for this optimisation and the optimised Hazelwood to Rowville transmission (see below), an additional 166 MVAr shunt capacitor bank should be included at Rowville in the optimised system.

The associated effects for terminal stations and estimated losses are as follows:

- ROTS: Delete circuit-breaker bays (for two line circuits) and add circuit-breaker bay (for shunt capacitor bank).
- YPS: Delete circuit-breaker bays (for two line circuits).
- There is a reduction in losses for the optimised system, estimated at 4 GWh p.a.

3.1.2 Hazelwood to Rowville – 220kV Double Circuit Line

This low rated double circuit 220 kV line (2 x 307MVA) is optimised to a high rated single circuit 220 kV line (1 x 800MVA).

The associated effects for terminal stations and estimated losses are as follows:

- ROTS: Delete circuit-breaker bay (for one line circuit).
- HWPS: Delete circuit-breaker bay (for one line circuit).
- There is a reduction in losses for the optimised system, estimated at 2 GWh p.a.

3.1.3 Yallourn to Hazelwood – 220kV Double Circuit Line

This low rated double circuit 220 kV line (2 x 307MVA) is optimised to a high rated single circuit 220 kV line (1 x 800MVA). Thus, when the 500kV and 220kV transmission systems from the Latrobe Valley to Melbourne are configured in “radial” (high generation) mode, there are effectively three 220kV circuits rated at 800MVA.

The associated effects for terminal stations and estimated losses are as follows:

- YPS: Delete circuit-breaker bay (for one line circuit).
- HWPS: Delete circuit-breaker bay (for one line circuit).
- There is negligible change in losses for the optimised system.

3.2 Latrobe Valley to Melbourne 500kV Transmission

Most of the Latrobe Valley generation is connected into the 500kV transmission system. All significant additional Latrobe Valley generation is also expected to be connected into the 500kV transmission system to facilitate power transfer to Melbourne.

There are presently four 500kV transmission lines between the Latrobe Valley and Melbourne, one of which is currently operating at 220kV. This 4h 500kV line was intended for operation between Hazelwood and South Morang terminal stations. It is routed via Rowville, and at present is operated as a 220kV line between Hazelwood and Rowville, and a 220kV line between Rowville and Thomastown via South Morang (only the Thomastown to South Morang portion has 220kV construction).

3.2.1 4th 500 kV Line, Between Hazelwood and Rowville

This 500kV circuit is currently operating at 220 kV. Application of the planning criteria in the optimisation methodology already requires this circuit be operated at 500kV to satisfy the criteria.

No optimisation has been proposed.

3.2.2 4th 500 kV Line Between Rowville and South Morang

This 500kV circuit is also currently operating at 220 kV. This circuit is optimised to a single circuit line (450MVA) between Rowville and South Morang, with the existing 220kV portion between South Morang and Thomastown remaining in the optimised network. Thus, the element continues to provide a 220kV circuit from Rowville to Thomastown.

There is an increase in losses for the optimised system, estimated at 1.9 GWh per annum.

3.3 Melbourne and Geelong Area Transmission

3.3.1 Keilor to Thomastown 220kV Double Circuit Line

The two Keilor to Thomastown 220kV circuits provide sharing of 500/220kV and 330/220kV transformation in the metropolitan area. Assuming a balance of transformer augmentation across the metropolitan area, it is unlikely the transfer requirement would exceed 800MVA through to the planning horizon.

Thus, this medium rated 220 kV double circuit line (2 x 600MVA approximate) is optimised to a high rated single circuit 220 kV line (1 x 800MVA).

The associated effects for terminal stations and estimated losses are as follows:

- KTS: Delete circuit-breaker bay (for one line circuit).
- TTS: Delete circuit-breaker bay (for one line circuit).
- There is an increase in losses for the optimised system, estimated at 1.5 GWh p.a.

3.3.2 Keilor to Geelong 220kV Lines

One double circuit line and one single circuit line all with low rating (3 x 270MVA) are optimised to one double circuit 220 kV line with medium rating (2 x 600MVA).

The associated effects for terminal stations and estimated losses are as follows:

- KTS: Delete circuit-breaker bay (for one line circuit).
- GTS: Delete one circuit-breaker bay (for one line circuit).
- There is a decrease in losses for the optimised system, estimated at 1.3 GWh p.a.

3.3.3 East Rowville to Tyabb 220kV Double Circuit Line

This double circuit 220kV line has both circuits rated at 800MVA. Both of these 800MVA circuits should be optimised to 400MVA circuits. There is an increase in losses for the optimised system, estimated at 2.5 GWh p.a.

3.4 State Grid Transmission

The state grid transmission refers to Ballarat, Terang, Horsham, Redcliffs, Kerang, Bendigo, Shepparton and Glenrowan.

Note that Murraylink is connected at Redcliffs, and thus has some impact on this system.

3.4.1 Dederang – Glenrowan – Shepparton 220kV Lines

Currently there is one single circuit line with low rating (1 x 270MVA) and one double circuit line with medium rating (2 x 450MVA) on this easement. The low rating single circuit line is connected in parallel with one of the medium rating circuits, effectively forming two circuits on the easement. Future work to separate the circuits to provide three circuits is imminent, as described in the VENCorp 2001 Statement of Opportunities.

A possible optimisation would be an 800MVA double circuit line from DDTS to GNTS and from GNTS to SHTS. However, in order to provide the same voltage performance, 34% series compensation is required in each 220kV circuit. The cost of this proposed optimisation is however more than the cost of the actual system.

Thus, no optimisation is proposed.

3.5 Hydro Area Transmission

The hydro area transmission refers to Eildon, Mt Beauty, Dartmouth and Kiewa.

It is noted that operation of the Dederang–Mount Beauty–Eildon–Thomastown 220kV transmission can effect capability of the Victoria–NSW–Snowy interconnection, and that an upgrade of the Victoria-NSW-Snowy interconnection has now been approved.

No optimisations have been proposed for assets within this area.

3.6 Transmission from Moorabool to Heywood and Portland

The transmission from Moorabool to Portland was constructed at a voltage of 500 kV in the expectation of a higher level of demand at Portland than initially experienced.

Since 1994 the loading on the transmission line from Moorabool to Heywood has increased. Figure 3.1 presents load duration curves for the period 1994 to 2000.

Figure 3.1 Moorabool-Heywood Line Load Duration Curve

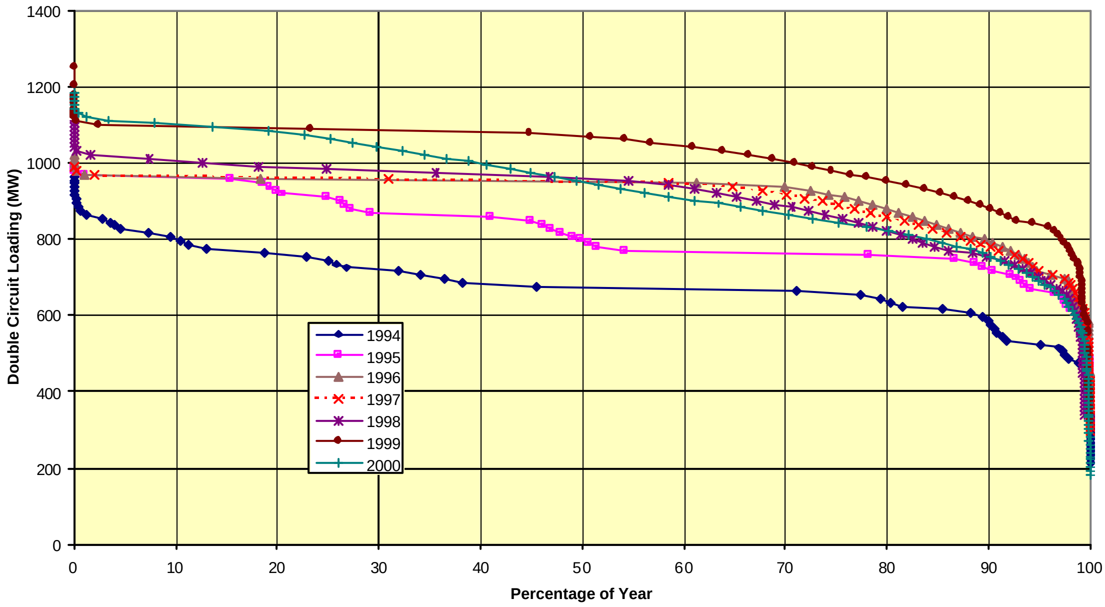
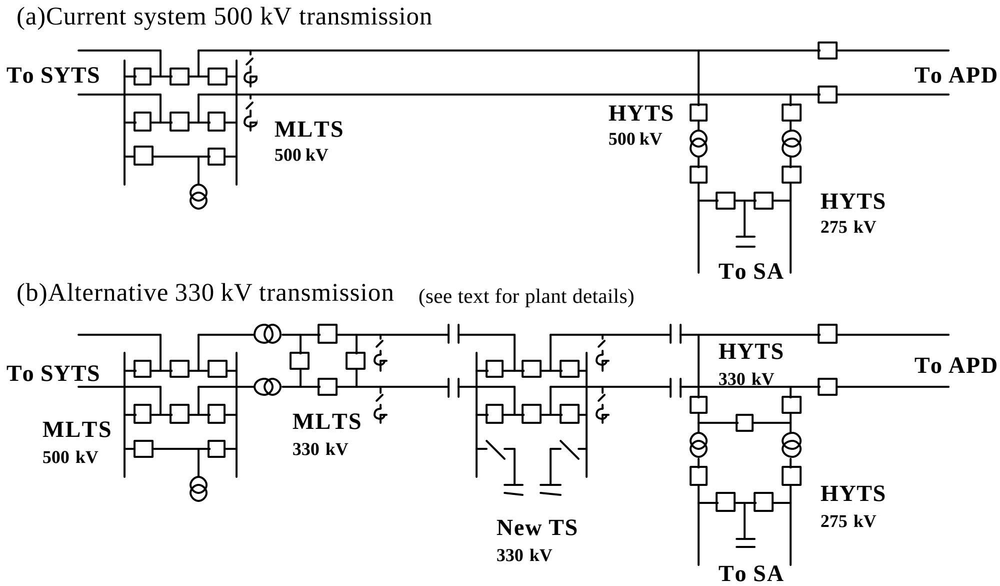


Figure 3.2 Moorabool to Heywood and Portland Transmission



A system arrangement based on a double circuit 330kV line has been considered as a possible optimisation, as presented in Figure 3.2 (b). The arrangement includes

- A 330kV switchyard at Moorabool with 2 x 1200MVA 500/330kV transformers;
- A 330kV switchyard between Moorabool and Heywood with 2 x 150MVAr shunt capacitor banks;
- A double circuit 330 kV line from Moorabool to the new terminal station, from the new terminal station to Heywood, and from Heywood to Portland with a summer rating of 1200 MVA per circuit;
- Shunt reactors (20 MVAr) on the 330 kV circuits at Moorabool and at the new terminal station on the 330 kV circuits to Heywood;
- 50 % series compensation at the new terminal station on the 330 kV circuits from Moorabool, and 50% series compensation at Heywood on the 330 kV circuits from to the new terminal station; and
- 330kV switchyard and transformers at Heywood, with a 330kV bus tie.

This proposed optimisation has transient stability limitations below present levels of power transfer. Hence, since the arrangement proposed above is at the practical limit of what can be achieved with 2 x 330kV lines with compensation, this optimisation arrangement is considered unsuitable and is not examined further.

The capacity of interconnectors is addressed in the optimisation methodology, Appendix A Section A.4.2 (b). This states that interconnector capacities shall be increased in proportion to load growth where there is a credible incremental interconnector upgrade path. The present export limit from Victoria to South Australia on this interconnector is 500MW. The load growth from 2002 is estimated to be 30% for a 10 year period and 50% for a 15 year period, which when translated to the interconnector export limit results in 650MW and 750MW respectively. The Moorabool to Heywood 500kV line already has the capacity to handle such increases. An incremental upgrade path is available on the 275kV portion of the interconnector (within Victoria and South Australia) to achieve such export limit increases.

Other issues relevant for establishing a rating appropriate for the Moorabool to Heywood transmission element at the planning horizon are described below.

- Southern Link (as described in the NEMMCO 2001 Statement of Opportunities) has the potential to increase loading on the Moorabool to Heywood transmission element by 65MW.
- No Portland Smelter load additions or further major industrial load in the Portland area have been added.
- Additional generation, particularly wind farms, may be developed in the Portland and Mt Gambier areas. Some of these schemes may have the potential to limit export from Victoria to South Australia (depending on their connection point) due to capacity limitations of the South Australian 275kV transmission system. It is understood that none of these projects are committed. Clearly, the output of wind farms will depend on prevailing weather conditions and cannot necessarily be relied upon at times of peak demand.
- Any increase in the export limit which requires capital works would presumably be categorised as a “regulated interconnector” and hence be the subject of Regulatory Test assessment by the ACCC.

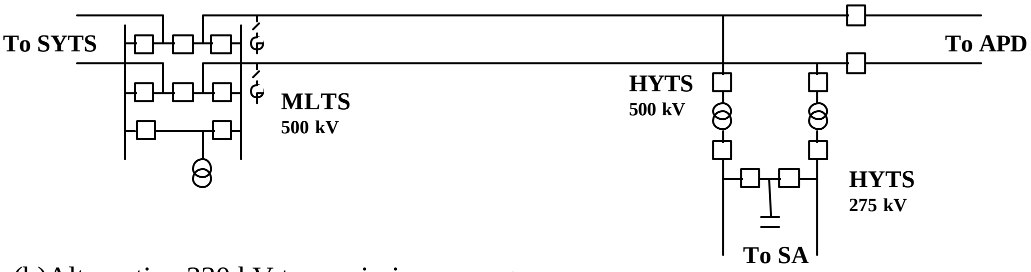
A 3 x 330kV transmission line optimisation has been considered for the Moorabool to Heywood transmission element. Such a configuration is required for 330kV in order to deliver the present level of power transfer. The ratings of elements in the optimised arrangement have be selected to provide for anticipated flows at the planning horizon, in line with the optimisation methodology. A power transfer capability of 1250MW to 1350MW has been selected. It is noted again that the existing 500kV system already has this capacity.

The optimisation proposed is presented in Figure 3.3 (b). Key features are as follows:

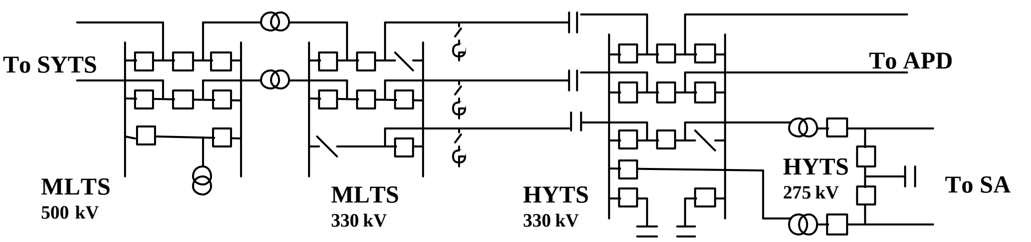
- At Moorabool, two 500/330 kV transformers are added (each with a continuous rating of 1350 MVA), plus a 330 kV switchyard with a 1½ breaker configuration.
- Three 330 kV circuits run from Moorabool to Heywood (a double circuit line plus a single circuit line). A double circuit 330 kV line of the same capacity is included from Heywood to the Portland Smelter (APD). The resistance of these circuits has an impact on stability and a low loss conductor such as twin pawpaw is recommended.
- The three circuits between Moorabool and Heywood have 50 % series compensation, and shunt reactors of about 20 MVAr on each 330 kV circuit.
- The Heywood 500 kV switchyard is changed to 330 kV and additional switchgear is provided to connect the three circuits from Moorabool into the two circuits to APD and the two 330/275 kV transformers at Heywood. Two 330 kV switched capacitor banks of 200 MVAr each are provided.
- The additional losses for the optimised system is estimated at 93 GWh p.a.

Figure 3.3 Moorabool to Heywood and Portland Transmission

(a)Current system 500 kV transmission



(b)Alternative 330 kV transmission (see text for plant details)



The cost of this proposed optimisation is more than the cost of the actual system. Thus, no optimisation is proposed for the transmission system from Moorabool to Heywood and Portland.

3.7 Other Considerations

3.7.1 Shared Network Transformers

All shared network transformers are required in 2002/2003 to satisfy the planning criteria. All will reach or exceed their ratings within the planning period under consideration. Thus, no optimisations are proposed.

3.7.2 Reactive Compensation Plant

All reactive compensation plant on the system has been assessed as required.

The level of capacitor banks required on the system is reviewed annually by VENCorp and installations are increased as necessary to maintain adequate system voltage control and stability. This is undertaken via separate contractual arrangements. This practice is expected to continue throughout the planning period under consideration.

The quantity of dynamic reactive compensation currently on the network must be retained in order to maintain voltage, transient and oscillatory stability, and to maintain system voltage fluctuations within limits.

3.7.3 Terminal Station Optimisations

The optimisations proposed in preceding sections of this report have in some instances highlighted reductions in terminal stations switchbays associated with the optimisations of transmission line circuits.

An optimisation is proposed at South Morang Terminal Station, consisting of optimising a breaker-and-a-half bay (3 circuit-breakers) of 500kV switchgear to a double-circuit bay.

No other terminal station optimisations associated with terminal station configuration changes are proposed.

It is noted that the complex switching arrangements at Rowville Terminal Station 220kV and Thomastown Terminal Station 220kV provide facility for fault level control.

Appendix A Optimisation Methodology

A.1 Overview of Valuation and Optimisation

A.1.1 Asset Based Valuation

The cornerstone of asset based valuation is the Optimised Depreciated Replacement Cost (ODRC) of the assets.

> ODRC measures the minimum cost of replacing or repeating the service potential embodied in the network with modern equivalent assets in the most efficient way possible from an engineering perspective, given the service requirements, the age and condition of the existing assets and replacement in the normal course of business.
>
> The adjustment of the gross replacement cost of the modern equivalent assets for over design, over capacity and redundant assets its termed 'optimisation'. [1]

A.1.2 Incremental (Brownfield) Approach to Optimisation

Optimisation is a notional exercise. The objective is to determine the optimised transmission system that gives 'industry best practice' levels of service, or the same level of service as the existing system, whichever is the lower.

"Brownfield" optimisation follows an incremental approach and not a greenfields approach. With incremental optimisation the existing network is reviewed and configurations, ratings and designs assessed to identify excess redundancy, over-capacity and over-design. It is based on there being no changes to points of supply (generating stations), location of loads, transmission line or cable routes, easements or substation sites. However, existing substations or lines can be amended in layout, or rating, or design, or deleted as appropriate. With greenfields optimisation the entire network would be completely redesigned and all lines and substations re-engineered and potentially relocated.

Incremental optimisation places a limiting constraint on the extent of optimisation. It recognises that there will always be some degree of sub-optimality and reflects to some extent the historical development of the network. It takes a position between a pure economic (greenfield) approach that would lead to significant optimisations and a historical approach (and acceptance of staged construction of assets where economically justified) that would result in virtually no optimisation.

An incremental optimisation methodology has in general been followed for previous electricity asset valuations, thus establishing a precedence for this methodology. Incremental optimisation is considered pragmatic, and has been adopted for this optimisation assessment.

[1] Policy Guidelines for Valuation of Network Assets of Electricity Network Businesses, NSW Treasury Technical Paper, December 1995.

A.2 Optimisation Process

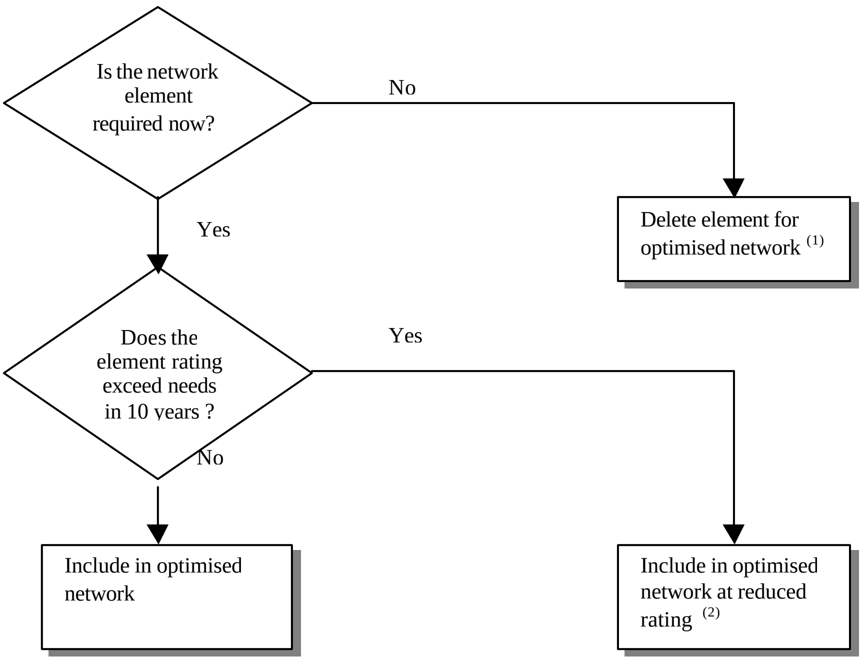
A.2.1 Scope of Optimisation Process

There are two aspects to the optimisation process:

- Optimisation of the network configuration (network security, level of redundancy, statutory requirements for certain assets)
- Optimisation of the assets (over design, over capacity)

Figure A.1 shows the decision paths for the optimisation process. It equally applies whether one "starts from scratch" or considers assets that were optimised out in previous valuations.

Figure A.1 Decision Paths for Optimisation Process
(Also applies to elements of the network previously optimised out)



Note (1) : Deletion of an element may involve reinforcing or amending other parts of the network. The reduction in value of the optimised network should be net of any additional works required for other parts of the network.

(2) : Where the rating of the asset is inadequate the optimisation methodology does not provide for uprating in the optimised network.

With reference to Figure 2.1, for the context of this assessment "now" shall refer to 1 January 2003 to coincide with the start of the next 5 year regulatory period. The assessment will also identify those asset that may become "required" in the period 1 January 2003 to 31 December 2007.

A.2.2 Basic Steps

The basic steps in the optimisation process are:

a) Review the network planning criteria to determine if they are in accordance with "good electricity industry practice". Any optimisation carried out on the network configuration or assets must meet current good practice planning criteria.

b) Review the design criteria for network assets to determine if they are in accordance with good practice for the location and application of those assets. If the design criteria result in the assets being over-designed compared to good practice they would be optimised down.

c) Review operating criteria, practices and performance as required to ensure that operating constraints are considered as part of the optimisation process.

d) Review the forecast load, generation and interconnector flows for the nominated planning horizon. The period must also take into consideration that most transmission assets can only be installed in relatively large blocks.

e) Review asset ratings.

f) Carry out steady state and dynamic network studies to ensure that the optimised network and its configuration meets required levels of service and quality standards, and the requirements of the National Electricity Code (NEC) and the Reliability Panel.

A.3 Planning Criteria Issues

A.3.1 Network Security and Planning Criteria

Current Practice for Optimisation
The transmission network provides bulk supply of energy between major generation and load centres. While the network is very reliable the consequences of any outages may be very severe both in terms of the amount of load that is lost and the duration of the interruption.

Consequently the transmission network must be designed with some redundancy. Generally this requires that there is sufficient capability built in to the network to allow for the unexpected outage of any plant item under extreme conditions, without resulting in immediate overloads on other elements. The consequences of such overloads could be very severe since they may ultimately lead to cascade tripping of transmission elements and loss of system integrity.

Optimisation current practice is to use deterministic network security criteria for establishing the configuration of the optimised network and cyclic or overload ratings for the assessment of asset utilisation. Both the NSW Treasury guidelines (December

1995) and the New Zealand Ministry of Commerce Handbook for Optimised Deprival Valuation of Electricity Line Businesses (1999) refer to deterministic criteria.

Generally transmission networks in Australia are planned so that there is no loss of supply and normal service levels and quality of supply are maintained for any single contingency event (n-1 security). A single contingency event is the unplanned disconnection of an element of the network from the network. Following a single contingency, load shedding is not required to bring flows within plant ratings, but some rescheduling of generation, interconnection flows or system configuration may be necessary within 30 minutes, during which short term plant ratings may be relied upon. Some load shedding may however be required to secure the power system from a subsequent (second) contingency event.

For large or critical loads or parts of the network where load flows are high, higher levels of redundancy may be appropriate (n-2 security). For smaller loads located some distance from the main transmission network it may not be economic to provide n-1 security.

VENCorp Probabilistic Approach
VENCorp no longer applies a deterministic planning basis in considering the impact of transmission outages on supply reliability (that is, customer load shedding). A probabilistic planning approach is now applied in the assessment of augmentations for the Victorian transmission network, with transmission investment decisions based on a probabilistic analysis of energy at risk. That analysis includes consideration of the probability weighted impacts on supply reliability of unlikely, high cost events such as single and multiple outages of generation or rotating reactive compensation plant, and unexpectedly high levels of demand.

This approach takes into account the fact that the level of supply reliability is uncertain because it is subject to variations in load (due to forecasting inaccuracies and weather impacts), and performance and availability of generating plant. A pool simulation model is used to determine the hourly generation dispatch for a large number of scenarios to capture the range of variation. Critical transmission line loadings are then determined on an hour by hour basis and compared with the ten minute network capability. This allows the risks associated with the transmission system to be identified.

Conclusions
The deterministic approach for network planning is simpler, facilitates independent assessment of the network, and is current practice for optimisation.

Thus, it is concluded that for the purposes of optimisation the deterministic approach is satisfactory. In general, the n-1 security criteria should be applied. For very large loads, critical loads or segments of the transmission network where load flows are high, the security of the network post the first contingency event should be taken into account. In some cases, particularly if the proposed optimisation is material, it may be necessary to carry out a more detailed assessment of the optimisation. We would expect that, in general, this would be a subjective assessment, based on discussions with network planners and a review of the appropriate network planning studies.

The network planning criteria that is proposed in Section 4 of this report provide simple criteria for the assessment of asset utilisation and for establishing reduced rating as appropriate in the optimised network. Criteria are based on cyclic or short term plant ratings.

A qualitative assessment will be provided on the impact of using a probabilistic planning criteria in lieu of deterministic criteria.

A.3.2 Planning Horizons

Network Configuration
Optimisation of the network configuration ensures that the network does not have excessive redundancy and that the network configuration is the most efficient given present and projected load, generation and interconnection flow patterns.

System planning must consider the time lag in the planning, design and construction of assets. However for optimisation, this is irrelevant. Plant should only be considered part of the regulatory asset base (and thus a candidate for optimisation out or down) once it has been introduced into service. Correspondingly, asset values should include an allowance for interest during construction.

Asset Utilisation
Transmission assets can only be installed in relatively large blocks. Their ratings therefore generally provide for load growth over the long term, say 10 years. This must be recognised in the assessment of asset utilisation by using load data that reflects long term forecasts.

The NSW Treasury Guidelines suggest a planning horizon of 10 to 15 years for optimisation. The New Zealand Ministry of Commerce Handbook adopts a 10 year planning horizon for transmission and subtransmission networks optimisation. Further, it is noted that the National Electricity Code requires Transmission Network Service Providers to provide 10 year forecasts.

Thus, it is proposed that the planning horizon for data used in the assessment of asset utilisation should be 10 years.

This optimisation assessment will evaluate the impact of optimisation for SPI PowerNet's five year regulatory period from 1 January 2003 to 31 December 2007. For plant that may be selected for optimisation out or down in 2003, an assessment will also be made if this plant (or an increased plant rating) is required at some time during the five year reset period, and if so at what stage.

A.3.3 Reinstatement of Assets Optimised out in Previous Valuation

Previous optimisations could have resulted in an asset either being deleted from the optimised network or having its rating/capacity reduced in the optimised network.

In deciding whether assets optimised out previously should now be included in the optimised network or its rating/capacity restored, the decision path set out in Section 2.1 is appropriate. It is noted that the decision process is the same regardless of whether optimisation is considered to be "undertaken from scratch" or whether assets previously optimised out or down should now be included or "optimised back or up".

The replacement value of the reinstated asset will be calculated at the current Modern Equivalent Asset (MEA) rate. The current MEA rate should be based on the original

MEA rate adjusted for inflation on the same basis used to roll forward the value of the asset base.

A.4 Optimisation Principles

A.4.1 General Principles

The underlying principle for developing the optimised network is:

> How would the network be configured today by a Transmission Network Service Provider (TNSP) following modern 'good practice' network design or what would a competitor do if the competitor replicated the service provided?

This principle requires that future loads be taken into account when assessing utilisation of assets. It also means that where two single circuit transmission lines connect two nodes on the network a double circuit transmission line in the optimised network should generally replace them. This would not necessarily apply for supply to major or critical loads or for primary parts of the network where there are large load transfers between generators and major load centres.

Optimisation of a transmission network will be carried out in accordance with the following principles.

a) The optimised network will be based on the location of existing generators, loads, interconnectors and existing transmission line routes.

b) The optimised network will be specified to meet existing loads and expected future patterns of load growth and generation.

c) The optimised network should have import / export capacities for interconnectors increased in proportion to load growth (where incremental upgrade is feasible). Where practical, interconnector capacity shall be assessed on a scenario basis using credible interconnector upgrades and additions.

d) The requirements of the National Electricity Code and the Reliability Panel in relation to security and reliability will be satisfied by optimised network.

e) Optimisations must not result in improvements in the network from the existing service levels and quality standards. If a network or an asset is not adequate to meet good practice levels of service it cannot be optimised up to that level.

f) Present voltage levels utilised in the network will be assessed. It is expected that only voltage levels that are used at present in a particular network will be used in the optimisation, unless it is considered the introduction of the highest voltage would have been more appropriate at a reduced voltage.

g) All TNSPs for reasons for economy in design, construction, maintenance and spares have adopted a standard range of conductor sizes for lines and cables and ratings for substation equipment. The optimisation of the network will recognise the TNSP's existing standards.

h) The determination of normal, cyclic and emergency ratings of conductors and plant must be in accordance with standards or codes or practices applicable to the asset concerned.

i) Optimisation should focus on aspects that are likely to materially affect the ODRC valuation; some aspects might require considerable effort for little effect on the valuation. It should be recognised that optimisation need not be all encompassing, but should cover only those aspects that have or are likely to have a material affect on the valuation.

j) Optimisation is constrained by the principle that any optimisation should be practical from a technical, operational, environmental and community acceptance point of view. It in no way infers that the network owner should make the change to the network or assets although in some circumstances it may do so.

k) Shared network assets and land which are required to be held by SPI PowerNet for statutory reasons should not be the subject of optimisation.

A.4.2 Application of Principles for SPI PowerNet

a) Application of the general principles above for the optimisation of the PowerNet transmission assets will be as follows:

b) Load, generation and interconnection flow scenarios
   - Projected loads as set out in the VENCorp Electricity Annual Planning Review. The maximum demand summer or winter (whichever is the most critical) at the 10% probability of exceedance, medium economic growth scenario shall be used. For later years the load projections shall be extrapolated as required. Distribution of load growth shall be in accordance with individual terminal station load growth forecasts.
   - Interconnection constraints/flows as set out in the NEMMCO Statement of Opportunities shall be used as a starting point. Where practical, interconnector capacity shall be assessed on a scenario basis using credible interconnector upgrades and additions (Basslink, VIC/SA existing and additional, VIC/NSW). Otherwise, interconnector capacities shall be increased in proportion to load growth, where there is a credible incremental interconnector upgrade path.
   - Generator capacity based on scaling up generation at existing locations to meet generation capacity requirements.

c) Security Criteria
   - Service levels and quality of supply maintained for single credible contingency events (n-1 security), transmission or generation.
   - For large loads or critical loads or for segments of the network where there are large flows, network security post the first credible contingency event should be considered (refer Section 3.1.1).
   - For small remote loads ‘n’ security is appropriate where ‘n-1’ security is uneconomic.

The security criteria are interpreted as follows:

- Transmission from Moorabool to Portland: 'n-1'
- Transmission to regional Victoria: 'n-1'
- Transmission from Latrobe Valley to Melbourne: 'n-2'.
- (Refer Section 3.1 and above. After the first contingency, load shedding is not needed and system security is maintained. After the second contingency, load shedding is not required to bring flows within plant ratings, but some rescheduling of generation, interconnection flows or system configuration may be necessary within 30 minutes, during which short term plant ratings may be relied upon. Some load shedding may however be required to secure the power system from a subsequent (third) contingency event.)
- Transmission to the CBD (Richmond, West Melbourne): 'n-2'. (As above.)

d) Network Voltage Levels
   - Existing voltage levels are 500kV, 330kV, 275kV, 220kV and 66kV.

e) Equipment Ratings
   - Normal and short term ratings as advised by SPI PowerNet

f) Shared Network Assets
   - The optimisation process will only considered shared network assets. Connection assets are not considered.

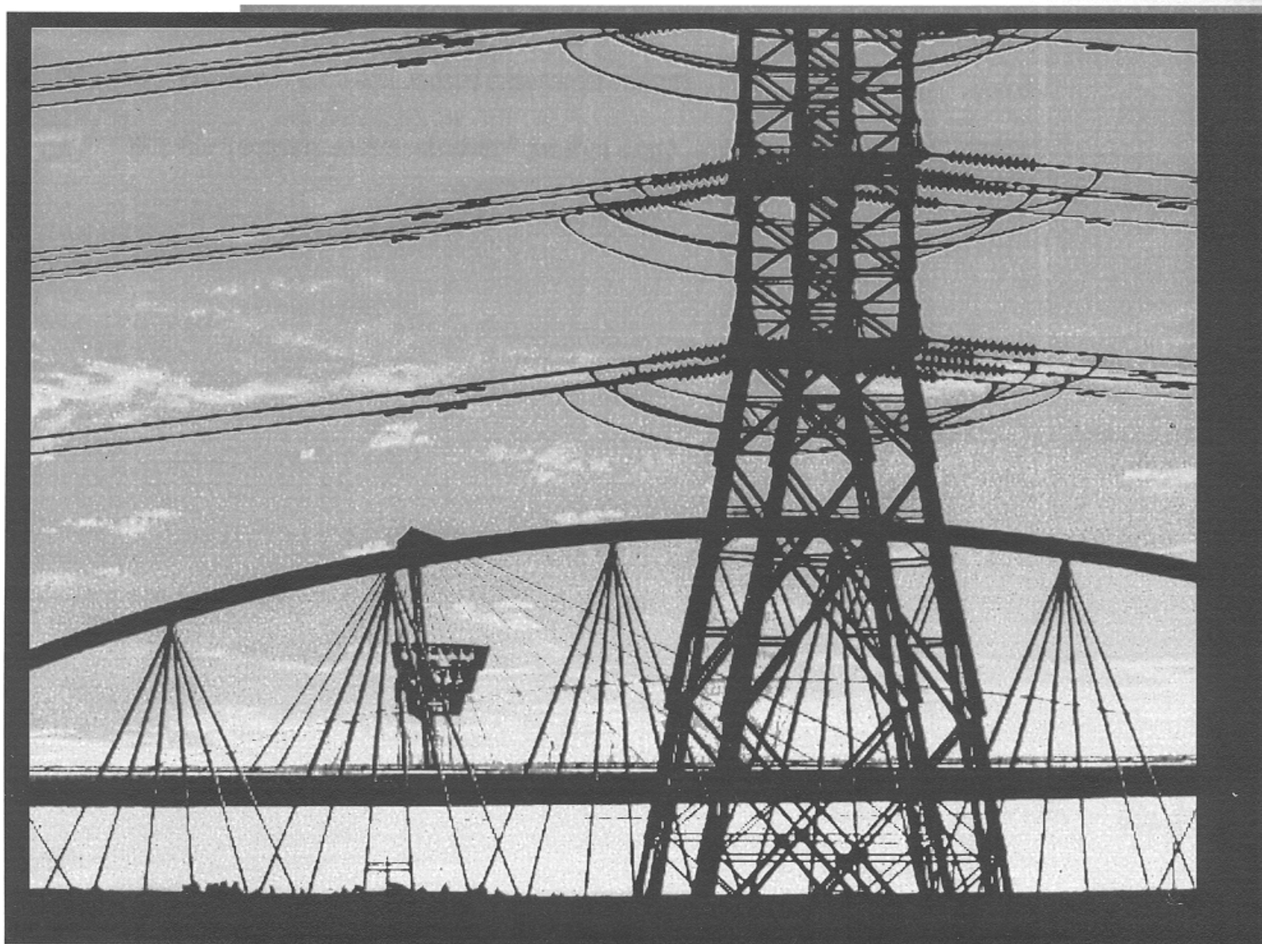
Appendix E

A.T. Cocks (urbis) report on easement value

REPLACEMENT COST ESTIMATES

POWERNET EASEMENTS

GPU PowerNet



DECEMBER 1997

A T COCKS CONSULTING

PROPERTY ADVISERS · MANAGEMENT CONSULTANTS
MELBOURNE · SYDNEY

A.T. Cocks and Partners Pty. Ltd. ACN 005 658 293
Milton House, 25 Flinders Lane, Melbourne VIC 3000
Telephone 03 9654 8555 Facsimile 03 9654 8989
Email postmaster@atcocks.com.au

Associated Office
Digby Swale and Associates, Perth W.A.

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EXECUTIVE SUMMARY

- ***Instructions***

  We have been instructed by GPU PowerNet to prepare estimates of the cost of acquiring, at today's costs, the 8,000 easements over privately held land within the GPU power line network. This cost is to include all costs likely to be incurred in that hypothetical acquisition project.

  The costs will include all items of compensation payable to land owners under the Land Acquisition and Compensation Act (1986), and costs likely to be incurred by the Authority in managing and implementing the acquisition program.

- ***Methodology***

  It is not practical to inspect all of the 8,000 easements and we have therefore used a combination of map information, aerial photographs and PowerNet records to obtain an understanding of the land covered by the easement network.

  The land value, valuation, and compensation inputs have been determined by consultation with valuers having expertise in specific locations, government authorities with compulsory acquisition experience and the extensive experience of AT Cocks Consulting which has recognised specialist expertise in the compulsory acquisition field.

- ***Limitations***

  These cost estimates apply only to the easement network over privately held land and do not include GPU PowerNet's easements over Crown land, or land owned by Government and semi-Government authorities.

  It is also important to note that the acquisition cost estimates include only the easement rights and do not include properties owned by PowerNet, such as terminal stations, along the network.

- ***Summary Breakdown of Cost Estimates***

Value of land under easements	$366.5 million
Value of Injurious Affect	$109.3 million
Value of land acquired under LAC Act (Sub-Total)	$475.8 million
Solatium	$34.7 million
Owner's costs (fees etc.)	$22.6 million
Sub-Total Owner's costs	$533.1 million
Authority's fees and direct costs	$46.5 million.
Authority's costs for management of acquisition project	$35.2 million
Sub-Total Authority's costs	$81.7 million
Total cost (Owner's plus Authority's)	$614.8 million

1. INSTRUCTIONS

We have been instructed by GPU PowerNet (PowerNet) to prepare estimates of the current replacement cost of the PowerNet easement network over privately owned land.

The replacement cost estimates are to include all costs that would be incurred by PowerNet if it were required to acquire, at today's date, all of the easement rights over privately owned land. Broadly, these costs include compensation that would be payable to the land owners, reimbursement of land owners expenses in the compulsory acquisition process, the Authority's (PowerNet's) expenses in the compulsory acquisition process and the Authority's management of the acquisition program.

2. UNDERLYING PRINCIPLES

Since the easement network and the easement rights already exist, the question of their current replacement costs must be considered in the context of a hypothetical situation where all of the easement rights are assumed not to exist, but that the property status and conditions along the network are as they exist today.

The easement network was acquired over a long period of time, however the cost assessment exercise has been based on the assumption that the entire network of easements would be acquired in bulk at todays date.

Since public works programs involving the acquisition of interests over a large number of properties generally cannot proceed without the power of compulsory acquisition we have assumed that PowerNet would be a recognised Authority with the power of compulsory acquisition under the Land Acquisition and Compensation Act.

3. BRIEF DESCRIPTION

The easements accommodate a transmission line network which extends around Victoria, within the Melbourne metropolitan area and, to a minor degree, crosses into New South Wales for short distances. The network is approximately 4,000 kilometres long, covers around 21,000 hectares of private land, and includes approximately 8,000 registered easements over 7,500 properties.

Broadly speaking the easement rights provide PowerNet with the right to construct towers in designated locations, extend transmission wires over the easement area, have access rights to the easement area for maintenance and works and to restrict the use and development of the easement affected land.

Appendix 1 is a map of Victoria with the network highlighted.

4. COMPULSORY ACQUISITION

Given that the easement network requires a sequence of uninterrupted easement rights over a large number of properties it is highly unlikely that those rights could be acquired in full without the use of the power of compulsory acquisition. Compulsory acquisition is the strategy normally used by Government and semi-Government authorities to acquire land, or interests in land, for public works and infrastructure projects where there are large numbers of properties involved.

The procedures, processes and assessments of compensation for compulsory acquisition are governed in Victoria by the Land Acquisition and Compensation Act 1986. In making our assessments of the easement replacement costs we have had close regard to that Act, and have assessed the compensation and cost recovery entitlements of the property owners in accordance with the provisions of that Act.

Briefly, the Act provides that compensation is payable to the owner of land which is subject to a compulsory acquisition for the following:

- ***Market value of the land***
  This would include, in this instance, the value of the interest acquired over the easement land, the reduction in the market value of the easement land in the hands of the owner, and the reduction in value of the balance of the owner's land as a result of the easement and the transmission line works on the easement land. The latter is usually referred to as Injurious Affect.

- ***Loss attributable to disturbance***
  This means any pecuniary loss which arises as a result the fact that the claimant's interest in the land has been divested or diminished, and can include allowance for loss of use during the construction period.

- ***Loss attributable to severance***
  This means the amount of the reduction in the market value of the balance of the owner's land as a result of it being severed from the acquired land. This is not usually a big issue in transmission line easements.

- ***Special Value***
  This means any pecuniary advantage which the owner enjoys through ownership of the land in addition to its market value.

- ***Solatium***
  This is an amount up to a maximum of 10% of the market value of the land (including Injurious Affect), to compensate the owner for intangible and non-pecuniary disadvantages resulting from the acquisition.

- ***Fees***
  The owners are entitled to recover reasonable fees for legal, valuation and other professional assistance in settling their claim for compensation.

5. METHODOLOGY

Since the amount of compensation that must be paid to land owners for easement acquisitions varies greatly from property to property depending on the individual impact of the power line easement and transmission lines on the highest and best use of each property, the most accurate means of assessing that cost would be to individually inspect each property to correctly assess the impact. Since that is not a practical option we have developed methodologies which will produce the most reliable estimates possible, within the constraints of cost and time practicality.

The land and easement information required to formulate the cost estimates is fairly diverse and was found not to exist in a form which is easily adaptable to this task. We have therefore had to adjust our methodologies for the various cost items to make optimum use of the information that is available. In some instances this has resulted in methodologies which are less than ideal, but in our opinion there have been no superior, practical alternatives.

The attached calculation spreadsheets show calculations broken down to various easement segments, and it will be noted that the names for the easement segments vary for different cost categories. This has arisen because the various sources of information used have different easement segment names and it has not been possible, in the course of this exercise, to reconcile those differences accurately. We have identified three sources where the easement segments have different names:

- The segment names used in the easement register.

- The easement names used on the current PowerNet maps.

- The easement names used by Natural Resource Systems (an arm of the Department of Natural Resources and Environment) in their survey database.

We believe these differences in terminology have arisen because the easement segment names have changed over time as the network has been expanded and this has resulted in differences between old and new records.

If reconciliation of all costs for each easement sector is desirable, this could be achieved by clearly defining the extent of each sector, following which we could provide some adjusted calculations.

5.1 Owner's Costs

Our methodology in assessing the various items of acquisition costs to the owners is described below. Our calculations are shown in the spreadsheets attached at Appendix 3.

- ***Land Area***
  The land area within each easement segment has been calculated by Natural Resource Systems which has an extensive database of the PowerNet easements survey information, and the computer software and expertise to calculate the land areas within the easements accurately.

  These land area calculations form the basis of our land value calculations. This process has not been without its difficulties because the NRS survey database is not complete in some locations and the current status of the land is not accurately shown in some cases. This has meant that, whilst the calculations themselves are accurate, the results have needed to be adjusted in some circumstances to remove anomalies.

  The NRS report is a bulky document and copies will be available separately to this Report. A result summary is attached at Appendix 2.

- ***Underlying Land Values***
  The underlying land values for all sectors of the network have been determined partly from AT Cocks Consulting's own expertise and knowledge in land valuation matters, and partly from a Victoria wide consultation with experienced property valuers having expertise in their particular locations. The survey dealt specifically with the easement route through each valuer's location of expertise.

  This has resulted in a fairly comprehensive picture of the underlying land values along the easement routes. The land values determined by this process have been applied on a detailed basis along each easement route depending on the quality of the land, location, highest and best use and level of surrounding development.

- ***Easement Percentage***

  Acquisitions for transmission line easements normally take into account that the easements “take up” a percentage of the land’s underlying value, because they restrict the use of the area of the land covered by the easement, convey future rights over the land to the authority, and affect the use of the adjoining land.

  The best means of determining the proportion of the land value which should be attributable to the easement would be to analyse sales of equal properties, with and without the easement, to determine the market value difference. Whilst this is recognised as the best method in theory it is almost universally acknowledged that in practice it is extremely difficult to come up with conclusive analysis of the valuation impact by this means. The problem is further compounded in the current exercise because there is a diverse range of property types and uses involved.

  In our opinion, the best guide to the proportion of land value attributable to easements is by reference to expert valuers familiar with this area of valuation practice. In reaching our conclusions on this item we have relied on our own expertise in this field, (being a specialist in the area of compulsory acquisition), have had regard to the views sought from other valuers and have researched expert articles on this subject. Our conclusions are also closely aligned with the compensation outcome for the Geelong to Portland transmission line acquisition project which was the last major project in this field in Victoria. That easement line covered primarily rural land and the predominant allowance for land value percentage was 35%.

  We have adopted an easement value of 35% of the underlying value for rural properties, 45% for most urban properties, and factors ranging from 20% to 50% for special circumstances.

  Analysis of the overall results shows an average for the total network of 39.9%.

- ***Solatium***

  Solatium is an amount payable under Land Acquisition and Compensation Act, up to a maximum of 10% of the market value of the land, for non-pecuniary losses from a compulsory acquisition.

  In the context of our calculations this allowance applies to the Easement Land Value and to the total Injurious Affect. Solatium applies to both of these items because under the Land Acquisition and Compensation Act the value of the land acquired is calculated on a "before and after basis" which means, in the context of these easements, that Market Value includes the land beneath the easements as well as the impact on the adjoining land held by the same owner.

There are no hard and fast rules for the rate granted for Solatium because it is mostly determined by the circumstances of each case, however it is largely driven by the degree of the owner's attachment to the land. This means that large corporations or professional property investors would generally receive Solatium at the bottom end of the range, and owner occupiers with a long period of residence at the property would receive Solatium at the upper end of the range.

Having regard to the fact that transmission line easements tend to result in relatively low total amounts of compensation per owner, and having regard also to the increasing apprehension in the community on electro-magnetic fields we have adopted Solatium rates of 8% in urban areas, where the principle dwelling is likely to be close to the lines, and 5% in rural areas.

- ***Injurious Affect***

  Injurious Affect refers to the adverse impact on the non-easement affected balance of a property which results from either the presence of the easement or the construction and presence of the transmission lines. This term covers a broad range of impacts which are categorised in the Act under the headings of Disturbance, and Special Value. In general terms it refers to the degree to which the market value of the property is reduced as a result of the presence of the easement and the works on the easement land.

  Injurious Affect is by far the most difficult of the cost items to assess accurately. The difficulty arises because the impact on a property's market value is extremely variable and can vary from one property to the next by large amounts depending on the position of current improvements, the activity on the land, zoning boundaries and numerous other factors. Since there are no common, recurrent sets of circumstances in compulsory acquisitions for transmission line easements there are, not surprisingly, no evolved guidelines for valuers in assessing their value impact. We have therefore relied to a considerable degree on our own expertise in the compulsory acquisition field, have consulted other valuers active in that field, and have had regard to some of the broad rules of thumb that have been applied in the past.

  Generally, it is acknowledged that Injurious Affect is at its least in rural areas, where the use of the land is not greatly inhibited by the easement and crucial residential improvements are usually not close to the transmission lines. Conversely Injurious Affect tends to be at its highest in dense urban areas where the transmission line is close to residential dwellings, the loss of visual amenity is a potent market factor and the loss of even a small proportion of the use rights over land can result in significant financial disadvantage to the owner.

As shown in the calculations, this item is calculated on two separate components namely; Injurious Affect to the balance of the land in each property, and Injurious Affect to crucial improvements (mostly houses).

The rate of Injurious Affect to the land has been calculated by assessing the probable average size of each holding, the probable total value of each holding and the likely extent of market value loss claimable by the owner. The rates applied vary widely depending on whether it is a rural or urban location, the type of land use, the proximity and density of improvements and the levels of land value in each easement sector. Generally the allowance varies from 5% to 30% of the value of the balance of the property.

In undertaking the assessments of Injurious Affect without property inspections we have been conscious of the need for property specific information and have used a wide range of information to obtain the best possible picture of the conditions on the ground. This information includes:

- Topographic plans demonstrating land type, natural features and structural improvements on the ground.

- Satellite photographs and aerial photographs showing land use types Powernet's survey database.

- Street directory detailed mapping and Zoning maps in developed urban areas.

That level of research was applied along the entire easement network in various combinations.

A more accurate outcome would, in our opinion, only be possible with a vastly more detailed examination of the individual properties along the easement routes.

The Injurious Affect to improvements close to the easement route is exceptionally difficult to assess because current accurate mapping information on buildings improvements does not exist for much of the network. We have therefore used a combination of topographic maps in rural areas and street directories with easement survey information in urban areas to estimate the likely number of critical improvements affected by the transmission lines. To this number we have applied and assessed market value reductions depending on the size of the transmission line, location and level of market values in each location.

- ***Fixed Costs***
  Fixed costs recoverable by the owner of a property subject to a compulsory acquisition include out of pocket expenses for professional assistance in managing the compulsory acquisition process and in assessing and settling their claim for compensation. In most instances this is limited to valuation and legal fees, however it can occasionally include a variety of other expert costs, particularly with disputed claims. We have assessed these costs, on an probable average basis, by reference to the current levels of valuation fees for this kind of work and through enquiries with legal firms who are familiar with this area of practice. We have also made an allowance for the much higher costs associated with the minority of claims that proceed to protracted dispute or litigation.

  These costs tend to be lower in rural areas than urban areas, primarily because the proximity of dwellings is less of an issue and because professional costs generally are lower. We have provided different costs for each of these categories in our calculations.

5.2 Acquisition Costs – Authority's Costs

In the course of compulsory acquisitions an acquiring authority will incur four major areas of cost:

- Valuation fees and fees for other technical costs.
- The costs of surveying the easement over the property and documentation.
- Legal costs and conveyancing.
- Compulsory acquisition management. The compulsory acquisition of interests over land is reasonably complex and stringent in the procedures and that must be followed. This requires considerable administration, and also demands considerable management of the negotiation and compensation resolution process.

We have estimated these costs using a combination of information including discussions with VicRoads, who are the most active compulsory acquisition authority in Victoria, our own experience and involvement in compulsory acquisitions, and discussions of cost estimates with legal, valuation and surveying firms familiar with this area of practice. We have adopted the following average costs:

Fees for legal, valuation, documentation, Notices and disputes	$5,000
Surveying of Easement boundaries and Titles	$1,200
Administration and Management of compulsory acquisitions	$4,700
	$10,900

6. CALCULATIONS

A copy of our summarised calculations are attached. The first set deals primarily with land value and the value of the land taken up by the easement. It shows the land area as estimated by Natural Resource Systems, the estimated underlying market value of the land, the percentage of the land value taken by the easement, and an allowance for Solatium on the land value component.

The second set shows the number of properties covered by easements in each easement sector, the estimated Injurious Affect to each property for the land component, the estimated Injurious Affect for improvements, a Solatium allowance on the Injurious Affect and the claimant's estimated costs for professional fees and out of pocket expenses.

It should be noted that the costs shown in this set are primarily driven by the number of properties affected by the easements in each easement sector. Where there have been two easement acquisitions over one property (eg. easement widening) we have assessed the costs only once, on the assumption that both easements would be acquired as one in this hypothetical exercise.

The third net shows a breakdown of the Authority's compulsory acquisition costs broken down into the three major categories. This is then multiplied by the number of properties estimated for the network.

7. LIMITATIONS

7.1 Land Not Included

Our instructions are to assess the replacement cost of the easement network over privately owned land. Accordingly, our calculations do not include the following lands:

- Terminal station sites which are owned outright by PowerNet.

- Crown land, roads, and land owned by or controlled by Government and semi-Government authorities. We are instructed that these are to be excluded from our calculations on the assumption that the easement rights over the land would be transferred to PowerNet in bulk and at no cost.

7.2 Compensation Estimates

Without a detailed inspection of each property and feedback from the owner or occupier on the impacts of the easement on the current use it is difficult to provide an accurate prediction of the compensation cost. Some elements of our cost estimates are therefore, of necessity, broad estimates. This difficulty is compounded by increasing community awareness over recent years of the presence of electro magnetic fields. Whilst current scientific knowledge suggests that there is not a great need for concern there have not been sufficient transmission line easement acquisitions in recent years, or conclusive property market sales activity, to draw any firm conclusions on what impact this concern is likely to have on the market value of properties in close proximity to transmission lines. In the absence of definitive valuation conclusions on this issue we have made estimates of what we believe would be the likely valuation influence.

7.3 Acquisition Project Benchmarks

As an overall check on our total cost estimates we would have preferred to draw comparisons with the cost of comparable major compulsory acquisition projects to ensure that our assumptions are reasonable, however, we are not aware of any major compulsory acquisition projects which could be compared meaningful to the hypothetical acquisition of the entire easement network.

To the extent that they can be compared to this project, we have had regard to the cost estimates by VicRoads for the 100 acquisitions of incomplete PowerNet easement acquisitions, which is due to be undertaken shortly, and also to the cost experiences of bulk property acquisition projects for other purposes. The usefulness of these projects as a cost benchmark is restricted to the claimant’s fees costs and the Authority’s acquisition costs and in both of those areas our conclusions are broadly in line with the costs in those projects.

8. SUMMARY OF COST ESTIMATES

A summary and breakdown of the cost estimates follows:

8.1 Cost Estimate Totals

-	Land values plus Solatium	$394,242,156
-	Injurious Affect to land plus Solatium and Owner’s costs	$138,847,672
-	Sub-Total Owners	$533,089,828
-	Authority’s costs 7,499 acquisitions	$81,739,100
		$614,828,928

8.2 Breakdown of Cost Components

Value of land under easements	$366,475,516
Value of Injurious Affect	$109,349,000
Value of land acquired under Land Acquisition and Compensation Act	$475,824.516
Solatium	$34,678,380
Owner’s costs (fees etc.)	$22,586,932
Authority’s fees and direct costs	$46,493,800
Authority’s costs for management of acquisition project	$35,245,300
Authority costs – Total	$81,739,100
Total	$614,828,928

We are obliged to advise that this report is only for the use of the party to whom it is addressed, and no responsibility or liability is accepted to any third party for the whole or any part of its contents.

Appendix 1

For map of PowerNet lines over Victoria – refer to Figure 1 in main Application document

Appendix 2

AREA STATEMENT IN HA OF FREEHOLD LAND OVER EACH POWERLINE

NEWLINE NAME	HA
BALLARAT-GEELONG	290.9
BALLARAT-HORSHAM	612.7
BALLARAT-TERANG	383.0
BENDIGO-BALLARAT	287.8
BENDIGO-KERANG	532.1
BROOKLYN-YARRAVILLE	32.3
COLDSTREAM-TEMPLESTOWE	130.8
DARTMOUTH-MT. BEAUTY	161.0
DEDERANG-SHEPPARTON	847.9
DEDERANG-SHEPPARTON	240.1
DEDERANG-STH. MORANG	1889.7
DONCASTER-TEMPLESTOWE	24.8
EASTROWVILLE-TYABB	309.9
GEELONG-KEILOR2	865.7
GEELONG-POINT HENRY	233.5
GEELONG-TERANG	536.1
HAZELWOOD	692.3
HAZELWOOD-CRANBOURNE	1117.8
HAZELWOOD-STH.MORANG	1588.2
HEYWOOD-STH.AUST	357.0
HORSHAM-REDCLIFFS	796.1
JINDERA-DEDERANG	279.5
KEILOR-BROOKLYN	75.3
KEILOR-GEELONG	244.8
KEILOR-RICHMOND	56.4
KERANG-REDCLIFFS	719.3
KIEWA-DEDERANG	135.9
LOYYANG-BAIRNSDALE	220.0
LYNDHURST-MORDIALLOC-DANDENONG	55.6
MOORABOOL-PORTLAND	1525.7
MT.BEAUTY-EILDON	128.7
MT.BEAUTY-STH.MORANG	276.8
NEWPORT-FISHERMANSBEND	82.2
NEWPORT-YARRAVILLE	4.8
RICHMOND-STH.MORANG	105.0
ROWVILLE-HEATHERTON	56.8
ROWVILLE-MALVERN-RICHMOND	199.5
SHEPPARTON-BENDIGO	476.4
SNOWY-DEDERANG	864.6
STH.MORANG-KEILOR	727.1
STH.MORANG-TEMPLESTOWE	174.1
TEMPLESTOWE-KEW	28.9
TEMPLESTOWE-RICHMOND	97.5
TEMPLESTOWE-ROWVILLE	161.2
THOMASTOWN-KEILOR	65.0
THOMASTOWN-STH.MORANG	266.7
YALLOURN-ROWVILLE	1865.3

Appendix 3

EASEMENT COSTS PRIVATE PROPERTIES - LAND VALUES - DECEMBER 1997

KEY ASSUMPTIONS

1. Solatium Rate

Rural	5%
Urban	8%

3. Easement/Land Value %

Rural	35%
Fringe	40%
Urban	45%
Special	50%
Minimum	20%

Sector	Land Area (ha/m2)	Land Value Rate	/ha /m2	Total Land Value	Easement %	Easement Land Value	Solatium	Total
Ballarat - Geelong	250.9	$5,000	/ha	$1,254,500	35%	$754,075	$37,700	**$791,775**
	40	$22,500	/ha	$900,000				
	290.9			**$2,154,500**				
Ballarat - Horsham	150	$3,000	/ha	$450,000	35%	$394,056	$19,700	**$413,756**
	150	$1,500	/ha	$225,000				
	212.7	$1,250	/ha	$265,875				
	100	$1,850	/ha	$185,000				
	612.7			**$1,125,875**				
Ballarat - Terang	90	$7,000	/ha	$630,000	35%	$382,988	$19,150	**$402,138**
	40	$3,700	/ha	$148,000				
	253	$1,250	/ha	$316,250				
	383			**$1,094,250**				
Bendigo - Ballarat	40	$8,500	/ha	$340,000	35%	$689,150	$34,460	**$723,610**
	217.8	$5,000	/ha	$1,089,000				
	30	$18,000	/ha	$540,000				
	287.8			**$1,969,000**				
Bendigo - Kerang	40	$1,000	/ha	$40,000	35%	$100,118	$5,010	**$105,128**
	492.1	$500	/ha	$246,050				
	532.1			**$286,050**				
Brooklyn-Yarraville	**323,000**	$30	/m2	**$9,690,000**	20%	$1,938,000	$96,900	**$2,034,900**
Coldstream - Templestowe	**130.8**	$25,000	/ha	**$3,270,000**	40%	$1,308,000	$104,640	**$1,412,640**
Dartmouth - Mt Beauty	**161**	$375	/ha	**$60,375**	20%	$12,075	$600	**$12,675**
Dederang - Shepparton	50	$5,000	/ha	$250,000	35%	$1,265,054	$63,250	**$1,328,304**
	30	$20,000	/ha	$600,000				
	767.9	$3,600	/ha	$2,764,440				
	847.9			**$3,614,440**				
Dederang - Shepparton	60	$5,000	/ha	$300,000	35%	$128,638	$6,430	**$135,068**
	180.1	$375	/ha	$67,538				
	240.1			**$367,538**				
Dederang - South Morang	100	$50,000	/ha	$5,000,000	40%	$3,496,704	$174,840	**$3,671,544**
	550	$5,000	/ha	$2,750,000				
	1239.7	$800	/ha	$991,760				
	1889.7			**$8,741,760**				
Doncaster - Templestowe	**248,000**	$180	/m2	**$44,640,000**	45%	$20,088,000	$1,607,040	**$21,695,040**
East Rowville - Tyabb	**309.9**	$40,000	/ha	**$12,396,000**	40%	$4,958,400	$396,670	**$5,355,070**
Geelong - Keilor2	10	$25,000	/ha	$250,000	40%	$4,573,500	$365,880	**$4,939,380**
	200	$20,000	/ha	$4,000,000				
	574.7	$12,500	/ha	$7,183,750				
	784.7			**$11,433,750**				
Geelong - Pt Henry	30	$45,000	/ha	$1,350,000	35%	$1,897,000	$94,850	**$1,991,850**
	203.5	$20,000	/ha	$4,070,000				
	233.5			**$5,420,000**				
Geelong - Terang	20	$75,000	/ha	$1,500,000	35%	$1,321,040	$66,050	**$1,387,090**
	40	$9,250	/ha	$370,000				
	476.1	$4,000	/ha	$1,904,400				
	536.1			**$3,774,400**				
Hazelwood	**692.3**	$3,500	/ha	**$2,423,050**	35%	$848,068	$42,400	**$890,468**
Hazelwood - Cranbourne	200	$13,000	/ha	$2,600,000	40%	$3,348,480	$167,420	**$3,515,900**
	350	$10,000	/ha	$3,500,000				
	567.8	$4,000	/ha	$2,271,200				
	1117.8			**$8,371,200**				

Sector	Land Area (ha/m2)	Land Value Rate	/ha /m2	Total Land Value	Easement %	Easement Land Value	Solatium	Total
Hazelwood - Sth Morang	160	$35,000	/ha	$5,600,000	40%	$16,510,720	$825,540	**$17,336,260**
	350	$20,000	/ha	$31,764,000				
	200	$2,000	/ha	$400,000				
	878.2	$4,000	/ha	$3,512,800				
	1588.2			**$41,276,800**				
Heywood - S.A.	300	$1,250	/ha	$375,000	35%	$171,150	$8,560	**$179,710**
	57	$2,000	/ha	$114,000				
	357			**$489,000**				
Horsham - Redcliffs	70	$2,500	/ha	$175,000	35%	$177,284	$8,860	**$186,144**
	100	$1,250	/ha	$125,000				
	100	$750	/ha	$75,000				
	526.1	$250	/ha	$131,525				
	796.1			**$506,525**				
Jindera - Dederang	80	$350	/ha	$28,000	35%	$550,200	$27,510	**$577,710**
	75	$10,000	/ha	$750,000				
	100	$5,000	/ha	$500,000				
	24.5	$12,000	/ha	$294,000				
	279.5			**$1,572,000**				
Keilor - Brooklyn	45	$250,000	/ha	$11,250,000	35%	$7,119,000	$569,520	**$7,688,520**
	30.3	$300,000	/ha	$9,090,000				
	75.3			**$20,340,000**				
Keilor - Geelong	30	$20,000	/ha	$600,000	35%	$4,096,750	$327,740	**$4,424,490**
	60	$12,500	/ha	$750,000				
	30	$85,000	/ha	$2,550,000				
	25	$60,000	/ha	$1,500,000				
	20	$250,000	/ha	$5,000,000				
	64.8	$12,500	/ha	$810,000				
	15	$33,000	/ha	$495,000				
	244.8			**$11,705,000**				
Keilor - Richmond	**36.1**	$150,000	/ha	**$5,415,000**	45%	$2,436,750	$194,940	**$2,631,690**
Kerang - Redcliffs	40	$1,000	/ha	$40,000	35%	$88,893	$4,440	**$93,333**
	679.3	$315	/ha	$213,980				
	719.3			**$253,980**				
Kiewa - Dederang	**135.9**	$350	/ha	**$47,565**	35%	$16,648	$830	**$17,478**
Loy Yang - Bairnsdale	180	$1,900	/ha	$342,000	35%	$126,700	$6,340	**$133,040**
	40	$500	/ha	$20,000				
	220			**$362,000**				
Lynd - Mord - Dand	30	$25,000	/ha	$750,000	40%	$1,204,000	$60,200	**$1,264,200**
	15	$80,000	/ha	$1,200,000				
	10.6	$100,000	/ha	$1,060,000				
	55.6			**$3,010,000**				
Moorabool - Portland	75	$25,000	/ha	$1,875,000	35%	$1,472,993	$73,650	**$1,546,643**
	70	$3,750	/ha	$262,500				
	1380.7	$1,500	/ha	$2,071,050				
	1525.7			**$4,208,550**				
Mt Beauty - Eildon	28.7	$5,000	/ha	$143,500	35%	$93,975	$4,700	**$98,675**
	100	$1,250	/ha	$125,000				
	128.7			**$268,500**				
Mt Beauty - Sth Morang	40	$5,000	/ha	$200,000	35%	$199,850	$9,990	**$209,840**
	100	$2,000	/ha	$200,000				
	136.8	$1,250	/ha	$171,000				
	276.8			**$571,000**				
Newport - Fishermans Bend	80,000	$100	/m2	$8,000,000	35%	$7,332,500	$366,630	**$7,699,130**
	70,000	$185	/m2	$12,950,000				
	150,000			**$20,950,000**				
Newport - Yarraville	**48,000**	$100	/m2	$4,800,000	40%	$1,920,000	$96,000	**$2,016,000**
Richmond - Sth Morang	360,000	$10	/m2	$3,600,000	45%	$10,620,000	$849,600	**$11,469,600**
	100,000	$200	/m2	$20,000,000				
	460,000			**$23,600,000**				
Rowville - Heatherton	118,000	$75	/m2	$8,850,000	40%	$12,540,000	$1,003,200	**$13,543,200**
	450,000	$50	/m2	$22,500,000				
	568,000			**$31,350,000**				

Sector	Land Area (ha/m2)	Land Value Rate	/ha /m2	Total Land Value	Easement %	Easement Land Value	Solatium	Total
Rowville - Malvern - Richmond	123,000	$250	/m2	$30,750,000	40%	$175,640,000	$14,051,200	**$189,691,200**
	84,000	$400	/m2	$33,600,000				
	121,000	$230	/m2	$27,830,000				
	13,000	$300	/m2	$3,900,000				
	141,000	$300	/m2	$42,300,000				
	387,000	$315	/m2	$121,905,000				
	3,000	$600	/m2	$1,800,000				
	53,000	$230	/m2	$12,190,000				
	151,000	$140	/m2	$21,140,000				
	55,000	$450	/m2	$24,750,000				
	149,000	$190	/m2	$28,310,000				
	85,000	$325	/m2	$27,625,000				
	630,000	$100	/m2	$63,000,000				
	1,995,000			**$439,100,000**				
Shepparton - Bendigo	35	$20,000	/ha	$700,000	35%	$511,735	$25,600	**$537,335**
	50	$3,500	/ha	$175,000				
	391.4	$1,500	/ha	$587,100				
	476.4			**$1,462,100**				
Snowy - Dederang	**864.6**	$500	/ha	**$432,300**	35%	$151,305	$7,600	**$158,905**
Sth Morang - Keilor	25	$100,000	/ha	$2,500,000	40%	$5,792,600	$463,400	**$6,256,000**
	75	$35,000	/ha	$2,625,000				
	20	$50,000	/ha	$1,000,000				
	557.1	$15,000	/ha	$8,356,500				
	677.1			**$14,481,500**				
Sth Morang - Templestowe	25	$150,000	/ha	$3,750,000	40%	$12,986,500	$1,038,900	**$14,025,400**
	50	$500,000	/ha	$25,000,000				
	99.1	$37,500	/ha	$3,716,250				
	174.1			**$32,466,250**				
Templestowe - Kew	10	$30,000	/ha	$300,000	45%	$730,350	$58,400	**$788,750**
	18.9	$70,000	/ha	$1,323,000				
	28.9			**$1,623,000**				
Templestowe - Richmond	50	$600,000	/ha	$30,000,000	45%	$21,782,250	$1,742,600	**$23,524,850**
	40.9	$450,000	/ha	$18,405,000				
	90.9			**$48,405,000**				
Templestowe - Rowville	111.2	$95,000	/ha	$10,564,000	40%	$13,225,600	$1,058,000	**$14,283,600**
	50	$450,000	/ha	$22,500,000				
	161.2			**$33,064,000**				
Thomastown - Keilor	**65**	$350,000	/ha	**$22,750,000**	40%	$9,100,000	$728,000	**$9,828,000**
Thomastown - Sth Morang	80	$110,000	/ha	$8,800,000	40%	$7,768,000	$621,400	**$8,389,400**
	20	$300,000	/ha	$6,000,000				
	154	$30,000	/ha	$4,620,000				
	254			**$19,420,000**				
Yallourn - Rowville	150	$35,000	/ha	$5,250,000	35%	$4,606,420	$230,300	**$4,836,720**
	150	$1,000	/ha	$150,000				
	450	$5,000	/ha	$2,250,000				
	350	$7,000	/ha	$2,450,000				
	765.3	$4,000	/ha	$3,061,200				
	1865.3			**$13,161,200**				
TOTALS	**20,526**			**917,923,457**		**$366,475,516**	**$27,766,640**	**$394,242,156**

EASEMENT COSTS PRIVATE PROPERTIES - INJURIOUS AFFECT & FIXED COSTS - DECEMBER 1997

KEY ASSUMPTIONS

1. Solatium Rate

Rural	5%
Urban	8%

2. Fixed Costs (Legal/Valuation/Other)

Rural	$2,287
Urban	$5,425

Sector	No. of Ppties	Inj Aff /Ppty	Inj Aff Land	No. of Houses	Inj Aff /Improv	Inj Aff Improv's	Inj Aff Total	Fixed Costs	Solatium	Total
Altona - Brooklyn	**9**	$20,000	**$180,000**	0		$0	**$180,000**	$20,583	$9,000	**$209,583**
Ballarat - Terang	**188**	$6,000	**$1,128,000**	47	$2,000	$94,000	**$1,128,000**	$429,956	$56,400	**$1,614,356**
Bendigo - Ballarat	94 70 **164**	$8,100 $15,000	$761,400 $1,050,000 **$1,811,400**	60	$5,000	$300,000	**$2,111,400**	$375,068	$105,570	**$2,592,038**
Bairnsdale - Latrobe	**48**	$5,000	**$240,000**	10	$3,000	$30,000	**$270,000**	$109,776	$13,500	**$393,276**
Ballarat - Geelong	200 109 **309**	$8,000 $15,000	$1,600,000 $1,635,000 **$3,235,000**	19	$7,500	$142,500	**$3,377,500**	$706,683	$168,875	**$4,253,058**
Ballarat - Horsham	**342**	$3,000	**$1,026,000**	49	$3,000	$147,000	**$1,173,000**	$782,154	$58,650	**$2,013,804**
Bendigo - Kerang	**115**	$2,000	**$230,000**	35	$1,500	$52,500	**$282,500**	$263,005	$14,125	**$559,630**
Brunswick - Richmond	**22**	$10,000	**$220,000**	10	$12,000	$120,000	**$340,000**	$119,350	$27,200	**$486,550**
Bendigo - Shepparton	60 112 25 **197**	$7,000 $5,400 $10,000	$420,000 $604,800 $250,000 **$1,274,800**	40	$3,000	$120,000	**$1,394,800**	$450,539	$69,740	**$1,915,079**
Coldstream - Templestowe	7 86 **93**	$18,000 $20,000	$126,000 $1,720,000 **$1,846,000**	22	$10,000	$220,000	**$2,066,000**	$504,525	$165,280	**$2,735,805**
Cranb - Lynd - Carrum	**20**	$30,000	**$600,000**			$0	**$600,000**	$108,500	$48,000	**$756,500**
Dederang - Sth Morang	135 70 **205**	$7,000 $19,000	$945,000 $1,330,000 **$2,275,000**	50	$5,000	$250,000	**$2,525,000**	$468,835	$126,250	**$3,120,085**
Dartmouth - Mt Beauty	**9**	$2,100	**$18,900**	0		$0	**$18,900**	$20,583	$945	**$40,428**
T'Stowe - Doncaster	39 1 **40**	$28,500 $125,000	$1,111,500 $125,000 **$1,236,500**	34	$15,000	$510,000	**$1,746,500**	$217,000	$139,720	**$2,103,220**
E Geelong - Pt Henry	**27**	$16,000	**$432,000**	20	$5,000	$100,000	**$532,000**	$61,749	$26,600	**$620,349**
Geel - S Geel	**132**	$15,000	**$1,980,000**	59	$4,000	$236,000	**$2,216,000**	$301,884	$110,800	**$2,628,684**
Geelong - Terang	196 29 **225**	$10,000 $15,000	$1,960,000 $435,000 **$2,395,000**	29	$12,000	$348,000	**$2,743,000**	$514,575	$137,150	**$3,394,725**
Hazelwood - Cranbourne	250 46 **296**	$20,000 $60,000	$5,000,000 $2,760,000 **$7,760,000**	104	$12,000	$1,248,000	**$9,008,000**	$676,952	$450,400	**$10,135,352**
Horsham - Redcliffs	110 37 **147**	$6,000 $8,000	$660,000 $296,000 **$956,000**	25	$5,000	$125,000	**$1,081,000**	$336,189	$54,050	**$1,471,239**
Hazelwood - Rowville	50 15 10 18 91 118 **302**	$11,000 $11,000 $18,000 $13,500 $31,500 $15,000	$550,000 $165,000 $180,000 $243,000 $2,866,500 $1,770,000 **$5,774,500**	42 5 7 15 70 115 **254**	$12,750 $6,000 $5,000 $5,000 $4,000 $7,000	$535,500 $30,000 $35,000 $75,000 $280,000 $805,000 **$1,760,500**	**$7,535,000**	$690,674	$376,750	**$8,602,424**
Springvale - Heatherton	35 5 **40**	$5,000 $12,000	$175,000 $60,000 **$235,000**	35	$10,500	$367,500	**$602,500**	$217,000	$48,200	**$867,700**

Sector	No. of Ppties	Inj Aff /Ppty	Inj Aff Land	No. of Houses	Inj Aff /Improv	Inj Aff Improv's	Inj Aff Total	Fixed Costs	Solatium	Total
Heywood - S.A.	**94**	$2,500	**$235,000**	10	$1,000	$10,000	**$245,000**	$214,978	$12,250	**$472,228**
Hazelwood - Sth Morang	185	$14,000	$2,590,000	108	$6,000	$648,000	**$6,883,000**	$761,571	$344,150	**$7,988,721**
	58	$7,500	$435,000	58	$8,000	$464,000				
	90	$20,000	$1,800,000	86	$11,000	$946,000				
	333		**$4,825,000**	**262**		**$2,058,000**				
Jindera - Wodonga - Dederang	30	$3,700	$111,000	30	$5,000	$150,000	**$361,000**	$160,090	$18,050	**$539,140**
	20	$4,500	$90,000							
	20	$500	$10,000							
	70		**$211,000**							
Brunswick - Thomastown	**269**	$16,500	**$4,438,500**	250	$10,000	$2,500,000	**$6,938,500**	$1,459,325	$555,080	**$8,952,905**
Keilor - Geelong	10	$10,500	$105,000	60	$13,000	$780,000	**$1,757,000**	$164,664	$87,850	**$2,009,514**
	10	$30,000	$300,000							
	52	$11,000	$572,000							
	72		**$977,000**							
Keilor - Truganina	**20**	$15,000	**$300,000**	10	$8,000	$80,000	**$380,000**	$45,740	$19,000	**$444,740**
Keilor - Truganina	**121**	$15,000	**$1,815,000**	50	$7,000	$350,000	**$2,165,000**	$276,727	$108,250	**$2,549,977**
Keilor - West Melb	97	$16,500	$1,600,500	85	$12,000	$1,020,000	**$2,690,500**	$547,925	$215,240	**$3,453,665**
	4	$17,500	$70,000							
	101		**$1,670,500**							
Kerang - Redcliffs	**111**	$1,500	**$166,500**	14	$500	$7,000	**$173,500**	$253,857	$8,675	**$436,032**
Kiewa - Shepparton	30	$300	$9,000	40	$2,000	$80,000	**$1,893,700**	$1,001,706	$94,685	**$2,990,091**
	70	$2,000	$140,000	50	$2,000	$100,000				
	179	$4,300	$769,700							
	159	$5,000	$795,000							
	438		**$1,713,700**	**90**		**$180,000**				
Mt Beauty - Eildon +	200	$2,000	$400,000	70	$6,000	$420,000	**$1,122,500**	$734,127	$56,125	**$1,912,752**
	121	$2,500	$302,500							
	321		**$702,500**							
Lyndhurst - Dandenong	**14**	$30,000	**$420,000**				**$420,000**	$75,950	$33,600	**$529,550**
Lyndhurst - Mordialloc	**13**	$30,000	**$390,000**				**$390,000**	$70,525	$31,200	**$491,725**
Lynd - Mord - Dand	**15**	$30,000	**$450,000**				**$450,000**	$81,375	$36,000	**$567,375**
Lower Yarra Xing	**18**	$30,000	**$540,000**				**$540,000**	$97,650	$43,200	**$680,850**
Loy Yang - Hazelwood	**48**	$12,000	**$576,000**	19	$3,500	$66,500	**$642,500**	$109,776	$32,125	**$784,401**
Morwell - Loy Yang	**13**	$12,000	**$156,000**	10	$3,500	$35,000	**$191,000**	$29,731	$9,550	**$230,281**
Malvern - Pakenham ("R" Widening)	**57**	$20,000	**$1,140,000**				**$1,140,000**	$130,359	$57,000	**$1,327,359**
Moorabool - Portland	25	$15,000	$375,000	10	$7,000	$70,000	**$2,251,200**	$647,221	$112,560	**$3,010,981**
	178	$5,400	$961,200	22	$2,500	$55,000				
	50	$7,500	$375,000	15	$3,000	$45,000				
	30	$9,000	$270,000	25	$4,000	$100,000				
	283		**$1,981,200**	**62**		**$270,000**				
T'Stowe - Sth Morang	70	$12,000	$840,000	70	$11,000	$770,000	**$2,532,000**	$547,925	$202,560	**$3,282,485**
	26	$18,000	$468,000	20	$12,000	$240,000				
	3	$70,000	$210,000							
	2	$2,000	$4,000							
	101		**$1,522,000**	**90**		**$1,010,000**				
Wheelers Hill - Yarraville	**181**	$20,000	**$3,620,000**				**$3,620,000**	$981,925	$289,600	**$4,891,525**
Narre W - Cranb - F'ston	80	$9,000	$720,000	60	$6,000	**$360,000**	**$1,639,000**	$667,275	$131,120	**$2,437,395**
	43	$13,000	$559,000							
	123		**$1,279,000**							
Newport - Fishermans Bend	**0**		**$0**			$0	**$0**	$0	$0	**$0**
Rowville - East Burwood	**6**	$9,000	**$54,000**	5	$5,000	$25,000	**$79,000**	$13,722	$3,950	**$96,672**
North Pearcedale - P'dale	**29**	$25,000	**$725,000**				**$725,000**	$157,325	$58,000	**$940,325**
Pearcedale - Tyabb	15	$12,000	$180,000	15	$6,000	$90,000	**$465,000**	$151,900	$37,200	**$654,100**
	13	$15,000	$195,000							
	28		**$375,000**							
"R" Widening	**797**	$5,000	**$3,985,000**				**$3,985,000**	$1,822,739	$199,250	**$6,006,989**
Rowville - Richmond	130	$25,000	$3,250,000	125	$14,000	$1,750,000	**$5,090,000**	$737,800	$407,200	**$6,235,000**
	6	$15,000	$90,000							
	136		**$3,340,000**							

Sector	No. of Ppties	Inj Aff /Ppty	Inj Aff Land	No. of Houses	Inj Aff /Improv	Inj Aff Improv's	Inj Aff Total	Fixed Costs	Solatium	Total
Richmond - Caulfield	**97**	$62,000	**$6,014,000**	97	$20,000	$1,940,000	**$7,954,000**	$526,225	$636,320	**$9,116,545**
Ringwood - Boronia	55	$12,000	$660,000	50	$7,500	$375,000	**$1,615,000**	$482,825	$129,200	**$2,227,025**
	34	$10,000	$340,000	30	$8,000	$240,000				
	89		**$1,000,000**	**80**		**$615,000**				
Snowy - Dederang	**132**	$1,000	**$132,000**	37	$500	$18,500	**$150,500**	$301,884	$7,525	**$459,909**
Sth Morang - Thomastown	150	$8,000	$1,200,000	150	$11,000	$1,650,000	**$2,964,000**	$868,000	$237,120	**$4,069,120**
	9	$6,000	$54,000							
	1	$60,000	$60,000							
	160		**$1,314,000**							
Sth Morang - Somerton - Keilor	20	$5,500	$110,000	18	$6,000	$108,000	**$437,000**	$179,025	$34,960	**$650,985**
	8	$12,500	$100,000							
	2	$55,000	$110,000							
	3	$3,000	$9,000							
	33		**$329,000**							
Rowville - Springvale	29	$9,000	$261,000	29	$8,000	$232,000	**$565,000**	$200,725	$45,200	**$810,925**
	8	$9,000	$72,000							
	37		**$333,000**							
Sth Morang - Syd - Keilor	42	$8,250	$346,500	40	$7,000	$280,000	**$1,428,000**	$477,400	$114,240	**$2,019,640**
	7	$9,500	$66,500							
	3	$65,000	$195,000							
	36	$15,000	$540,000							
	88		**$1,148,000**							
Syd - Truganina - M'bool	25	$30,000	$750,000	30	$13,000	$390,000	**$1,760,000**	$34,305	$88,000	**$1,882,305**
	31	$20,000	$620,000							
	56		**$1,370,000**							
Templestowe - Kew	**30**	$55,000	**$1,650,000**	27	$25,000	$675,000	**$2,325,000**	$162,750	$186,000	**$2,673,750**
Yarraville - Sunshine	15	$6,000	$90,000	10	$4,000	$40,000	**$450,000**	$34,305	$22,500	**$506,805**
	20	$16,000	$320,000							
	35		**$410,000**							
TOTALS	**7,499**		**86,162,000**	**2,737**		**$29,174,500**	**$109,349,000**	**$22,586,932**	**$6,911,740**	**$138,847,672**

AUTHORITY'S COMPULSORY ACQUISITION COSTS - DECEMBER 1997

Total Number of Properties Subject to Compulsory Acquisition	**7,499**

		Average $/Property
(1.)	Disbursements for Legal, Valuation, Consultants, Documentation, Conveyancing, Notices and Disputes	$5,000
(2.)	Surveying of Easement boundaries and Titles	$1,200
(3.)	Administration and Management of Compulsory Acquisitions	$4,700
Total Per Property		**$10,900**

Authority's Total Compulsory Acquisition Costs	**$81,739,100**

Appendix F

Professor Officer report on capital financing and taxation

A Weighted Average Cost of Capital for a Benchmark Australian Electricity Transmission Business

A Report for SPI PowerNet

R.R.Officer

28 February, 2002

Synopsis and Conclusions

In order to determine the required rate of return on the regulated asset base in SPI PowerNet's upcoming revenue cap review, a weighted average cost of capital (WACC) is needed. The appropriate WACC is a post tax nominal estimate of this required return using the "Vanilla" WACC equation.

Differences in the cost of capital or WACC, at any point in time, reflect differences in the risks associated with the cash flows being generated by the assets. In the context of capital market theory, only non-diversifiable or systematic risks are accounted for in the cost of capital estimates. This does not imply that diversifiable or non-systematic risks are not relevant to a valuation decision or the problem of determining revenue caps in a regulatory setting. Such diversifiable risks are, typically, accounted for in the net cash flows being generated by the assets. This paper outlines the procedures for taking account of such risk but it is beyond the mandate of the paper to do the calculations.

Ultimately, it is risk that determines the size of the cost of capital or WACC. The assessment of the cost of capital or the required return on the assets of the entity in this paper will be estimated using the capital asset pricing model (CAPM).

The CAPM has a number of parameters whose value will be estimated from the available evidence to arrive at the appropriate cost of capital. An important parameter is the beta risk; various sources for the estimates of beta or non-diversifiable risks are identified to arrive at an estimate. An examination is made of off-shore company betas, domestic sources for the estimation of beta including those provided by regulators and some separately calculated betas.

The determination of an appropriate beta for the asset class (electricity transmission) is not definitive and must be based on empirical evidence and inevitably subjective judgments about the weight to place on the evidence. The examination leads me to conclude that an ***asset beta of around 0.6*** *is justified and a point estimate of 0.585 would be realistic and consistent with the regulatory precedents on equity beta and the market evidence on debt beta.*

It should be noted that the WACC approach used in this paper means that the vanilla WACC can be estimated directly from the asset beta using the CAPM formula. In many regulatory decisions, this approach is not taken, apparently because the debt margins observed in the capital markets are assumed to relate partly to diversifiable (non-beta) risks. In view of this, the associated asset betas are not always directly comparable to those in this paper.

Estimating the required return to the assets also requires using a surrogate for a "risk-free" rate of return. The yield on the 10 year Commonwealth Government Bond is an appropriate surrogate. This is currently 5.945%.

Another important parameter of the CAPM is the estimation of the market risk premium. Evidence is presented to indicate that this is equal to 6% although there is considerable debate as to the value and arguments have been advanced that support both a higher estimate and a lower estimate. However, there is no compelling evidence in my opinion to change the estimate from 6%.

Adopting these estimated values for the parameters of the CAPM implies a ***post-tax nominal WACC of approximately 9.5%*** *(or more accurately 9.455% as at this date) or a real cost of capital of approximately 6.9% (or more accurately 6.890%).*

The asset cost of capital is the WACC. However, to the extent there may be a requirement to separately estimate components of the WACC, given the required return or cost of capital for the assets, implies a required return to equity (R_E) equal to 11.7% with a capital structure of 60% debt and 40% equity, and a required return to debt of 7.2% which reflects a debt margin of 1.85%. The 1.85% debt margin has been justified by examining the rates on corporate debt and the implied beta, assuming that the margin is predominantly due to systematic or non-diversifiable risk. The margin is consistent with what has been adopted by some regulators in hearings to date. Similarly, with the capital structure of 60% debt, this has been the capital structure adopted by most of the regulatory hearings in Australia to date for infrastructure projects and is broadly consistent with the empirical evidence.

Another feature of the mandate for the paper was to estimate the value of imputation tax credits. Taxes that are collected from the entity need adjustment for tax credits in order to accurately depict the company tax attributable to the entity. The basis of the WACC or cost of capital assessments is on an after company tax but before personal tax basis. Therefore, it is important to adjust taxes for any tax credits because these credits implicitly represent a collection of personal tax at the company level. The evidence suggests a value of these credits, on average, is equal to about 50% of their face value. The estimates can be quite variable and there is ongoing research being conducted by the author and a colleague that may cause an update to this estimate. Also there is some recent material that suggest this estimate may be too high.

Table of Contents

1. Introduction

As part of its upcoming revenue reset, SPI PowerNet has to develop and document a benchmark estimate of the Weighted Average Cost of Capital for the Company's regulated activities and a treatment for dividend imputation in the calculation of a tax allowance. To this end, SPI PowerNet commissioned this paper, which presents a review and analysis of current issues and the results from estimation of the various inputs.

Background

SPI PowerNet is the owner of Victoria's high voltage electricity transmission system. Privatised in 1997, the Company was recently sold to Singapore Power International by GPU International. The majority (95%) of the Company's revenue is regulated under a revenue capping arrangement put in place by the Victorian Government prior to privatisation. This arrangement expires on 31 December 2002 and will be replaced by a revenue capping regime administered by the Australian Competition and Consumer Commission (ACCC).

Operating pursuant to chapter 6 of the National Electricity Code, ACCC will set a new revenue cap with a minimum tenure of 5 years. ACCC's current approach to setting revenue caps is described as a post-tax nominal accrual building block. In essence, the revenue cap in year t of the control period is based on (noting that all items represent forecasts made at the time the revenue control is set):

$$R_t = OM_t + WACC * RAB_t + RD_t + (1-\gamma)Tax_t + GP_t \qquad (1)$$

where:

R_t is revenue in year t;

OM_t is operating and maintenance cost in year t;

WACC is the "vanilla" cost of capital;

RAB_t is the value of the Regulated Asset Base in year t – this is rolled forward from an initial valuation on a CPI-indexed basis, ie opening value plus capex plus indexation less deprecation;

RD_t is regulatory depreciation (net of the CPI indexation of the asset base);

γ is the dividend imputation factor representing the proportion of a company's income tax that is eventually offset against its owners' personal income tax;

Tax_t is a company income tax allowance calculated on a cash flow basis; and

GP_t is an incentive payment (glide path) for achieving greater than forecast cost savings in the previous regulatory period.

While this is the basis for setting the revenue caps, they are actually implemented as a CPI-X control. That is, the result of applying the building block approach in each year of the control period is reduced to a present value at the start of the period, then working from the total of these present values, an X factor is derived that delivers the same present value total when the revenue cap is projected forward on a CPI-X basis using a forecast of CPI consistent with other assumptions (most notably WACC).

SPI PowerNet understanding of the methodology for WACC and tax in 2003

SPI PowerNet has indicated that the post-tax nominal approach to determining revenue will most likely be used in the context of the 2003 reset. Consistent with this, the WACC used in the revenue calculation will be of the "vanilla" formulation.

$$WACC = R_e \frac{D}{V} + R_d \frac{E}{V} \qquad (2)$$

where:

R_d is the return on debt;

D/V is the debt to value ratio;

R_e is (post-tax) return on equity; and

E/V is the equity to value ratio.

In concert with this, the tax allowance will be determined (essentially) as:

$$Tax_t = \left(R_t - O_t - TD_t - RAB_t \frac{D}{V} R_d \right) T(1-\gamma) \qquad (3)$$

where:

TD_t is tax depreciation in year t; and

T is the corporate tax rate.

In essence the task of this paper is to provide estimates for the "vanilla" WACC, ie.

$$WACC = R_d \frac{D}{V} + R_e \frac{E}{V}$$

and the value of the imputation tax credits, γ, and to discuss various issues that arise in the context of these estimations.

Organisation of the paper

The paper is organised as follows:

- section 2 sets out a framework (the Capital Asset Pricing Model) for analysing the risks relevant to the cost of capital, presents analysis of market data on equity, debt and asset betas and estimates a consistent set of betas for a benchmark Australian electricity transmission business;
- section 3 provides an analysis of tax and the value of imputation credits;
- section 4 reviews recent evidence on the market risk premium;

- section 5 considers issues relating to the definition and measurement of the risk free rate;
- section 6 discusses the estimation of expected inflation for use in the revenue determination;
- section 7 reviews the evidence on debt margin and gearing; and
- section 8 provides a summary of the estimates and my recommendations.

2. Risk

2.1 Non-Diversifiable (β) and Diversifiable (non-β) Risk

Non-diversifiable Risk

Non-diversifiable risk is also known as:

- systematic risk;
- market risk;
- covariance risk; and
- beta risk.

Because the risk β is non-diversifiable it commands a risk premium, known as the market risk premium (MRP), which is defined as [$E(R_m) - R_f$]. The MRP is the premium a market portfolio of assets or securities (R_m) is expected to earn above the risk-free rate (R_f).

The effect of non-diversifiable risk is captured through such models as the Capital Asset Pricing Model (CAPM)*:*

$$\begin{aligned} R_j &= R_f + \beta_j \left[E(R_m) - R_f \right] \\ &= R_f + \beta_j MRP \end{aligned} \tag{4}$$

where:

R_j is the expected return on asset (security) j or its required return or cost of capital; and

βj is the non-diversifiable risk associated with asset j and because of the MRP this βj component of risk increases the discount rate or cost of capital in an NPV analysis.

The CAPM is the standard approach to estimate the required return (Cost of Capital) of equity (R_E) where unlike debt there is no contractual rate set for the return. The risk occurs as β in the above CAPM and this is non-diversifiable risk for which the capital market pays a market risk premium MRP.

In the case of debt, we typically use the yield on debt to estimate the cost of debt (R_D). Such a yield includes both non-diversifiable risk and diversifiable risk. The latter is usually included when estimating a company's WACC or asset cost of capital, although logically the diversifiable risk should not be included but for major companies it is so low the bias is judged to be not consequential.

The diversifiable risk is typically taken into account in the expected net cash flows that are to be discounted. It is discussed below.

Diversifiable Risk

Diversifiable risk is also known as:

- non-systematic risk;
- non-market risk;
- non β risk;
- idiosyncratic risk;
- residual risk; and
- insurable risk.

Diversifiable risk can be diversified away because it is uncorrelated with other risks or variations in net cash flows and as such it does not command a premium in the sense that non-diversifiable risk commands a premium. However, this does not mean that it has no effect on values or that it can be ignored in a discounted cash flow analysis.

As one of the names for it suggests, the cost of diversifiable risk is akin to an insurance premium, to the extent that insurance represents those events which can be diversified.

The “charge” against cash flows should be the actuarial estimate of the event, i.e. the product of the probability of the event occurring times the effect on net cash flows of the event[1]. Therefore, the standard (textbook) approach to handling risk in a valuation (NPV) problem is to account for non-diversifiable risk in the discount rate and diversifiable risk in the net cash flows.

An Example

Suppose we have a three period investment whose net cash flows are at the left of the column and the expected value is on the right of each column:

Probability		Period 1		Period 2		Period 3	
Event 1	0.3	\$10m	\$3m	\$15m	\$4.5m	\$20m	\$6m
Event 2	0.5	\$40m	\$20m	\$50m	\$25m	\$50m	\$25m
Event 3	0.2	\$60m	\$12m	\$65m	\$13m	\$60m	\$12m
		E(\$35m)		E(\$42.5m)		E(\$43m)	

The expected or actuarial flows for each period are respectively \$35m, \$42.5m and \$43m. The “**normal**” cash flows are \$40m, \$50m and \$50m – these relate to the outcomes of event 2 which represent the median outcome.

Applying a WACC of 10% to the expected net cash flows gives a value of *:*

$$
\begin{aligned}
NPV &= \frac{35}{1.1} + \frac{42.5}{(1.1)^2} + \frac{43}{(1.1)^3} \\
&= 99.25
\end{aligned}
\qquad (5)
$$

---

[1] Another way of saying this is that the all potential costs should be estimated at their (statistical) expected value rather than at their median or typical year value.

So much for the textbook approach for handling risk

The "business approach" is often different. Practitioners often take expected net cash flows to mean "normal" cash flows which is what they expect and not the actuarial expectation. The result is they adjust the discount rate for diversifiable risk as well as non-diversifiable risk.

Consider our previous example, "normal" cash flows per period are:

40, 50, 50

which when discounted by a 18.6% instead of 10% result in the same value for the project, i.e.

$$99.25 = \frac{40}{1.186} + \frac{50}{(1.186)^2} + \frac{50}{(1.186)^3}$$

The 18.6% includes an adjustment for both the non-diversifiable and the diversifiable risk.

The problem with the "business approach" is how to get a measure for the diversifiable risk contribution to the discount rate. It is usually an ad hoc adjustment unless we first solve for the value using the "textbook" approach and then plug in the "normal" net cash flows and solve for the internal rate of return to get an appropriate discount rate that incorporates both diversifiable and non-diversifiable risk.

In the approach I will be using and that which is adopted generally by regulators it is assumed that the WACC only reflects β or non-diversifiable risk. It is assumed that account will be taken of diversifiable risk in the estimates of net cash flows.

2.2 Betas for Electricity and Gas Companies

Australia has relatively few privatized electricity and gas companies. Moreover, nearly all of them have only been privatized in recent years. This means that there is a paucity of data on the risk characteristics of the companies and the industries. In such circumstances it would seem obvious to examine the risk characteristics of comparable companies and industries in countries that have been around for a much longer time, to supplement the limited observations on the Australian companies. However, such an approach is hazardous because of different economic and regulatory conditions in foreign countries. Nonetheless, providing caution is exercised in interpreting the relevance of the offshore results for Australia, some information can be usefully gleaned from such an examination.

The CAPM is the most popular procedure for estimating the required returns for assets or securities (equity) where there is no contractual right for a particular amount of return to the capital providers. The risk that is accounted for in the CAPM is non-diversifiable or beta-risk; it was described in the previous section. A domestic beta, i.e. the covariance risk of an asset or a company with its domestic share market, reflects the relative risk of that asset relative to the domestic market. A beta for an electricity company in the US or UK measures the risk of that company relative to those markets. Further, although such a beta may be indicative of the type of relative risk experienced by an Australian electricity company, certain conditions must apply before one can derive an Australian electricity beta from a US or UK beta.

As long as the component of the return on the Australian market that is uncorrelated with the return on the US market is also uncorrelated with the return on stock i[2], then it follows that:

$$\beta_{i,AUS} = \beta_{US,AUS} \times \beta_{i,US} \tag{6}$$

where:

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[2] In effect, this component of a stock's return is idiosyncratic to the company, it does not related to returns of either markets.

$\beta_{i,Aus}$ is the domestic beta of an Australian company;

$\beta_{US,Aus}$ is the beta of the US index regressed against an Australian index;

$\beta_{i,US}$ is the domestic beta of the US company.

On the basis of data from Datastream the average beta ($\beta_{i,US}$) for US electricity companies is about 0.35. In addition, it is estimated that the beta $\beta_{US,Aus}$ over recent years is about 0.5. This implies an Australian $\beta_{i,Aus}$ of 0.18 – a very low number. A comparable analysis using UK electricity companies gave a $\beta_{i,UK}$ for UK electricity companies of about 0.4, a $\beta_{UK,Aus}$ of 1.19, which, using the relationship defined above, implies a $\beta_{i,Aus}$ of about 0.48 which is also a low but more realistic number.

The problem is that the assumption underlying the relationship between domestic and offshore betas implies that the respective capital markets are fully integrated, such that any idiosyncrasies of the Australian market reduce the β-risk for an offshore investor and accordingly make investment in an Australian electricity company look attractive. Also, measurement errors can make the domestic market look attractive from a β-risk perspective. In the circumstances, I believe it is unwise to simply adopt in the Australian context the β-risks implied by offshore companies at face value. Nonetheless, an examination of the consistency or otherwise of the β-risks amongst the different type of energy companies can be instructive. For this reason, the β-risks for offshore companies are shown below in Table 1.

Table 1
Estimates of Overseas Betas

Industry Name	Source	Number of Firms	Average Equity Beta	Market D/E Ratio	Asset Beta
US					
Electric Util. (Central)	DNYU	28	0.53	118.35%	0.29
Electric Utility (East)	DNYU	34	0.55	83.4%	0.35
Electric Utility (West)	DNYU	17	0.56	150.22%	0.27
Electricity Integrated	QCA	53	0.45 (0.26-0.9)	NA	0.32 (0.22-0.78)
Electricity Distributors	Datastream	12	0.27	NA	NA
Natural Gas (Distrib.)	DNYU	33	0.59	82.35	0.38
Natural Gas(Diversified	DNYU	37	0.72	45.95	0.54
Gas Distribution	Datastream	16	0.33	NA	NA
UK					
Electricity	QCA	4	0.68 (0.48-1.00)	NA	0.52 (0.41-0.72)
Electricity	ORG Bloomberg	5	0.32 (0.18-0.47)	32	0.29 (0.17-0.40)
Electricity	ORG Lond. Bus.S.	5	0.59 (0.51-0.65)	32	0.47 (0.34-0.56)
Electricity	Datastream	6	0.24	NA	NA
NZ					
Electricity	Datastream	4	0.54	NA	NA
Gas	Datastream	1	1.00	NA	NA

DNYU=http://www.stern.nyu.edu/~adamodar/New_Home_Page/datafile/Betas.html)

An examination of the equity β-risks in the table indicate they are all relatively low, significantly lower than the equity β of the average investment, whose β=1.0. The asset betas have been calculated with the assumption of a debt beta of zero and often using a more conventional after tax WACC and not the "Vanilla" WACC assumption.

Betas are notoriously unstable. The beta of an individual company or entity is measured with a considerable amount of error and for this reason it is usually preferable to estimate groups of companies in the same risk or industry class in order to get an estimate of the β-risk appropriate for a company.

One of the features of any regression parameter that is estimated with error is that the parameter tends to mean revert over a number of separate measurements or observations. The mean reversions is caused by the errors on the high side in the next measurement will tend to be less next period and so the estimate will move downwards, and conversely errors on the low side. The net result will be mean reversion for the estimates of the parameter. Moreover, the mean of all companies is by definition, a beta of 1.0 and as a consequence the estimates of the equity betas over time tend to move towards that number. The first to note this was Marshall Blume in a paper in the Journal of Finance in 1975. Subsequent studies have confirmed some degrees of mean reversion for β estimates.

The consequence of this observation is that some of the measuring services such as Bloomberg provide estimates of beta that mean revert. The problem with this approach is that the mean reversion parameter is far from stable and what might be observed one period can be inappropriate for another period. Inevitably, the parameters used to mean revert tend to be ad hoc in these circumstances and hard to justify, particularly where estimates are based on significant numbers of companies or industry groups where the measurement errors are less.

A second problem causing instability in betas is “thin trading”. “Thin trading” causes the beta parameter to be measured with error because the returns or price changes for the entity’s shares being regressed against the market are not contemporanious with the market. An attempt to overcome this problem is to use the Scholes-Williams estimators for beta. Unfortunately, in my experience, the Scholes-Williams estimates of beta tend to be more unstable than those measured under conventional ordinary least squares regression and I do not believe the use of such estimators improves the estimate of β.

As a consequence none of the beta estimates reported in this paper have engaged in either modification.

2.3 Beta Estimates including the Effect of Gearing

The logic of the balance sheet applies to the derivation of asset betas from the betas of debt and equity. For example, the total assets of a company can be divided amongst the financial obligations as broad categories of debt and equity. The cash flows generated by the assets have to service the financial obligations of those providing capital (debt and equity). Further there is "natural conservation of risk" such that the risk of the cash flows generated by the assets have to be shared and totally accounted for amongst the risks attached to the returns of the providers of the capital (debt and equity). Therefore, the balance sheet logic compels the asset beta or the risk associated with the assets, to reflect the weighted average of the risks associated with the financial obligations (debt and equity). In effect, the weighted average cost of capital (WACC) is the cost of capital reflected in the assets and therefore the asset beta must be equal to a weighted sum of the debt and equity betas i.e.

$$\beta_a = \beta_e \frac{E}{V} + \beta_d \frac{D}{V} \tag{7}$$

where:

β_a is the asset beta;

β_e is the equity beta;

β_d is the debt beta; and

E + D = V, the value (V) of the company's assets made up of equity (E) and debt (D).

The use of the WACC in SPI PowerNet's upcoming revenue determination is to allow for a return to the Regulated Asset Base (RAB), reflecting the opportunity cost of capital tied up in that base. In these circumstances, the appropriate WACC is the WACC indicated by the assets (and the corresponding asset beta). In effect, the knowledge of the asset beta would not require a further breakdown into debt and equity betas, and the CAPM could be used, with an asset beta, to determine the appropriate after-tax WACC for applying to the RAB. An after-tax WACC is appropriate because the form of the revenue determination is such that tax is compensated as a separate item, see Equation 1 above.

One of the advantages of using an after-tax definition of the WACC is that the parameter estimates can be taken directly from the capital market. Further, since these estimates are provided on an after-tax basis there is no requirement to modify the WACC equation for tax and the "simple or vanilla" formula of the WACC can be adopted.

It is not only measurement errors that may cause problems with estimation of appropriate betas. The assumptions explicitly or implicitly employed, using the CAPM, in relation to gearing and the beta of debt to estimate the cost of capital can also have a significant effect on the outcome.

Beta estimates are usually restricted to traded securities in deep and well informed capital markets. The trade in securities amongst the world capital markets is dominated by equities issued by companies and debt issued by governments, with some limited amount of corporate debt. This means that the beta estimates have to be derived from the equities of the companies that are operating in the same industry class or reflect the same asset composition of the company whose beta has to be estimated.

One of the variables causing differences in beta estimates for companies in the same industry class with the same assets is the differential gearing on average between companies. The greater the level of gearing, the greater the risk of both debt and equity, however over reasonable ranges, the risk of the total assets does not change. This is because the change in the weighting of capital from equity to debt maintains a constant risk level for the assets as a whole even though the beta measures of both debt and equity will increase.

To estimate the beta of a company from the betas of listed equities requires an adjustment for the gearing differential between the company whose beta is to be estimated and the beta of the companies providing the estimates. Further, insofar as the beta of the assets is made up of a weighted average of the beta of debt and equity, but the debt of companies is infrequently traded, means that some judgement is required in assessing debt betas before an overall asset beta can be estimated. An approach that can be adopted is to "reverse engineer" the CAPM such that with the knowledge of a return on debt, one can get an estimate of the implied beta consistent with this return. This assumes that all the risk compensation for the required return is systematic and not non-systematic; for major companies this is probably a reasonable assumption.

In the various regulatory hearings that are documented later in this paper in Table 7, the estimate of asset betas has been by this process of estimating an equity beta and then assuming a particular level of debt beta in order to derive the asset beta. However, in some of the decisions, the choice of an asset beta appears to have been somewhat subjective in that the equity beta, the level of gearing, and the debt beta are not exactly consistent with the asset beta that has been chosen.[3] The problem is further compounded when the regulatory body breaks the asset beta up into equity and debt in order to use it in a before-tax weighted average cost of capital.

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[3] In fact there is some indication that the wrong re-gearing formula has been used for the Vanilla WACC equation. See Appendix 4 *ACCC - Report on the Assessment of Telstra's Undertaking for the domestic PSTN originating and terminating access services, July 2000.* In this report reference is made to using the "Monkhouse" formula, this formula for re-gearing equity estimates is inconsistent with the Vanilla WACC.

Table 2 below indicates the source of beta estimates and where an estimate has been made of the WACC, two alternative assumptions have been made about the beta of debt. In the first instance following a number of the regulatory bodies a zero beta of debt has been assumed. However, in my opinion this is unrealistic as most companies' debt securities are affected by the state of the market and reflect some market risk and, as a consequence, would be expected to have a positive beta. Private communication by investment bankers (Westpac letter dated 29 November 2001 and UBS Warburg Australia letters dated 19 November and 28 November 2001) to SPI PowerNet indicate that they believe that ten year debt issued by the typical utility company would attract a BBB+ rating. Such debt is currently attracting a debt margin of approximately 185 basis points. (Section 7 discusses this issue further).

An alternative approach to using the estimates provided by underwriters for the debt margin, which gives consistent answers to the estimates based on the underwriters, is to use data from the Reserve Bank of Australia's Monthly Bulletin. For example, Table S49 of the February 2002 issue of the Bulletin indicates a "risk premium" of 82 basis points (bp) for October 2001 of A-rated corporate debt relative to Commonwealth securities of the same maturity (two to four years). This "risk premium" when added to a "maturity premium" of 100 bp, the difference between three year and ten year Commonwealth securities, implies a debt margin of 182 bp. The figures for the end of January, 2002 are respectively, 62 and 60 bp, implying a debt margin of 122 bp.

Adopting the debt margin suggested by the underwriters of 185 basis points implies a beta of 0.31. I believe such a figure is a realistic estimate for the risk of the debt for infrastructure companies that include electricity transmission.

Table 2 below presents estimates of equity and asset betas for various companies provided in the recent decision of the Queensland Competition Authority on Regulation of Electricity Distribution, May 2001. The asset beta of the companies listed averages around 0.62 for the reported asset betas and 0.68 if the debt beta in the WACC is assumed to be 0.31.

Table 2
Beta estimates from Queensland Electricity Distribution Price Review

Firm	Primary Business	Equity Beta	Leverage (%)	Asset Beta*	Asset Beta**
United Energy Ltd	Electricity distribution	0.84	53	0.42	0.56
Pacific Energy Limited	Electricity generation	2.03	29	1.42	1.53
Pacific Hydro Limited	Electricity generation	1.00	45	0.66	0.69
Energy Developments Ltd	Electricity generation	1.17	25	0.92	0.96
Allgas Energy Limited	Gas distribution and retailing	0.50	17	0.47	0.47
Australian Gas Light Ltd	Gas distribution and retailing	0.62	30	0.44	0.53
Envestra Ltd	Gas distribution and retailing	0.48	80	0.00	0.34
Simple Averages		**0.95**	**40**	**0.62**	**0.75**

* Asset beta as reported.
** Asset beta calculated with a debt beta of 0.31.
Source: Queensland Competition Authority, May 2001

Table 3 below sets out the estimates cited by the Victorian Office of the Regulator-General (ORG) in its decision for Electricity Distribution. The results give a consistently lower WACC than the QCA estimates which may simply reflect the time at which the estimates were made and indicate the variability of betas over time. It is worth noting that the ORG used a debt beta of 0.2 for its estimates of the appropriate WACC.

Table 3
Beta estimates from Victorian Electricity Distribution Price Review

Firm	Primary Business	Equity Beta	Leverage (%)	Asset Beta*	Asset Beta**
United Energy Ltd	Electricity distribution	0.46	54	0.32	0.38
AGL	Gas distribution and retailing	0.57	25	0.48	0.51
Envestra	Gas distribution and retailing	0.50	78	0.27	0.35

* Asset beta as reported
** Asset beta calculated with a debt beta of 0.31
Source: Office of Regulator General, Victoria, September 2000

The estimates in Table 4 are taken from Datastream and I believe are based on the Australian Graduate School of Management's latest (September 2001) Risk Measurement Service estimates. The results indicate an asset beta for the group of nearer 0.53 for a debt beta assumption of 0.31. However, for the Industry Group the Datastream estimates suggest a higher asset beta of around 0.7. The difference in the estimates reflects the different gearing levels of the all industry group compared to the sample companies

Table 4
Datastream beta estimates for electricity and gas, May 2001

Firm	Primary Business	Equity Beta	Leverage (%)	Asset Beta*	Asset Beta**
United Energy Ltd	Electricity distribution	1.06	47	0.56	0.71
Pacific Energy Limited	Electricity generation	0.79	37	0.50	0.61
Pacific Hydro Limited	Electricity generation	0.66	37	0.42	0.53
Energy Developments Ltd.	Electricity generation	0.67	54	0.31	0.48
Allgas Energy Limited	Gas distribution and retailing	0.5	15	0.43	0.47
Australian Gas Light Ltd	Gas distribution and retailing	0.77	53	0.36	0.53
Envestra Ltd	Gas distribution and retailing	1.82	94	0.11	0.40
	Simple Averages	0.9	48	0.38	0.53
Industry Group	**Infrastructure & Utilities**	**0.8**	**27**	**0.58**	**0.67**

* Asset beta calculated with debt beta of 0.0
** Asset beta calculated with a debt beta of 0.31
Source: Datastream

Independent estimates of equity betas were made and these are listed in Table 5.

The betas in Table 5 were calculated by regressing monthly total returns (from capital gains or losses plus dividends) against monthly total returns on the All Ordinaries Accumulation Index. The most recent sixty months of data (ending May 2001) was used in this estimate, except where less than sixty months data was available, such as for more recent listings. This was done for all companies in the Infrastructure and Utilities index plus the Infrastructure and Utilities Accumulation Index itself. If less than 36 months data was available then the estimate was not formed as it would statistically be too unreliable.

As a generality, the results give a lower estimate of the equity betas than the Datastream which may reflect the longer time interval over which the estimates were made. Datastream estimates are over 48 months whereas the estimates in Table 5 are over 60 months.

Table 5
Infrastructure and utility betas estimated over a 60 month period

Company	Weight by Market Capitalisation	Listing Code	Equity Beta
Australian Gas Light	25.12%	AGL	0.514
Australian Infrastructure Trust	2.00%	AIX	0.765
AJ Lucas Group	0.27%	AJL	0.459
Energy Developments	7.96%	ENE	1.223
Envestra Ltd	2.60%	ENV	0.367
Environmental Solutions	0.34%	ESI	0.516
Hills Motorway Group	6.00%	HLY	0.290
Macquarie Infrastructure	18.01%	MIG	0.515
Origin Energy	11.18%	ORG	1.036
Pacific Hydro	3.72%	PHY	1.088
Renewable Energy	1.90%	REL	2.241
Transurban group	13.41%	TCL	0.476
United Energy	7.40%	UEL	0.717
Pacific Energy	0.08%	PEA	2.041
Average – weighted by market capitalisation	**100%**		**0.68**

Source: Estimated by the author from ASX data

In Table 6 the companies that are involved in electricity (those highlighted in Table 5) have been separated from those of Table 5 and the WACC estimated based on the equity betas shown in Table 5. The results are weighted by capitalisation. They indicate an increase in the equity beta, although it is slight for the value weighted estimate. Similarly, for the WACC there is a significant difference between the value weighted average WACC for the group compared to the simple average. In normal circumstances the value weighted average would be preferred but the large weight given to AGL means that it has a profound effect on the result and the company may not be as representative of an electricity transmission business as the other companies or indeed the infrastructure industry group as a whole.

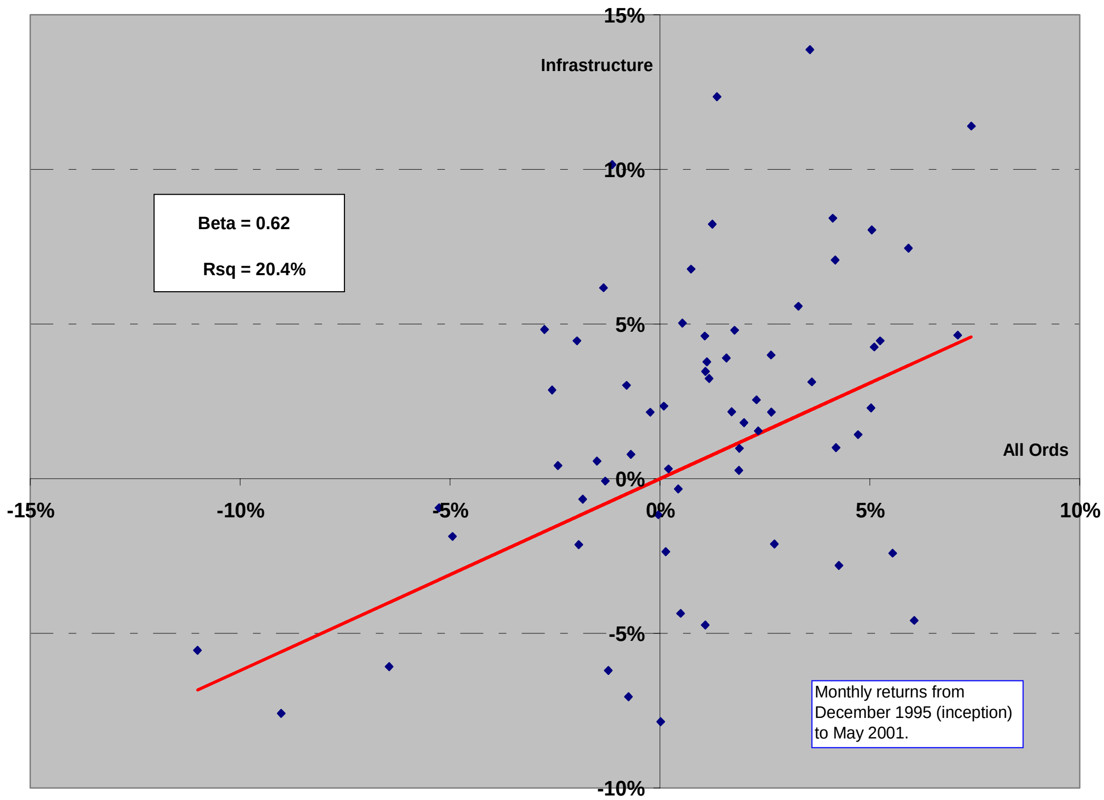
Table 6
Betas for electricity companies estimated over a 60 month period

	Adjusted weight by market capitalisation	Equity Beta	Leverage %	Asset Beta*	Asset Beta**
Australian Gas Light	0.54	0.514	53	0.24	0.41
Energy Developments	0.17	1.227	54	0.57	0.73
Envestra Ltd	0.06	0.367	94	0.02	0.31
Pacific Hydro	0.08	1.088	37	0.69	0.80
United Energy	0.16	0.717	47	0.38	0.53
Pacific Energy	0.00	2.041	37	1.29	1.40
Simple Average		0.99	54	0.53	0.70
Average – weighted by market capitalisation	**1.00**	**0.71**	**54**	**0.34**	**0.51**

* Asset beta calculated with debt beta of 0.0
** Asset beta calculated with a debt beta of 0.31
Source: Estimated by the author from ASX data

An example of the calculations for Tables 5 and 6 betas is demonstrated in the plot which demonstrates the estimation of the beta for the Infrastructure and Utilities index against the All Ordinaries index.

Figure 1
Infrastructure beta vs All Ordinaries



Source: Estimated by the author from ASX data

Table 7 summarises recent regulatory decisions in electricity and gas transmission and distribution. The results are consistent with those already discussed and the β estimates are no more definitive. The asset betas are between 0.4 and 0.6 (as reported) in the decisions but up to 0.72 in the case of the ACCC's decision with respect to the AGL pipeline if a debt beta of 0.31 is used. Overall, an estimate of 0.5 to 0.6 (based on a debt beta of 0.31) appears to be most realistic.

Table 7
Recent regulatory decisions on betas for electricity and gas

Matter	Industry	Equity Beta	Leverage (%)	Asset Beta*	Asset Beta**
ORG, Price Determination	Electricity Distribution	1.00	60	0.40	0.59
ACCC, Snowy Mountains	Electricity Transmission	1.00	60	0.40	0.59
ACCC, NSW & ACT	Electricity Transmission	0.78-1.25	60	0.35-0.50	0.50-0.69
ACCC, Queensland	Electricity Transmission	1.00	60	0.40	0.59
IPART, Elect. DB's	Electricity Distribution	0.77-1.14	60	0.35-0.50	0.49-0.64
QCA, Price Determination	Electricity Distribution	0.71	60	0.45	0.47
ACCC, EAPL	Gas Pipeline	1.16	60	0.5	0.65
ACCC, AGL	Gas Pipeline	1.50	60	0.6	0.79

* Asset beta as reported
** Asset beta calculated with a debt beta of 0.31

It is difficult to find any conclusive evidence for a specific asset beta for electricity transmission. The regulators have opted for a number between 0.4 and 0.6 with most around 0.4 (based on asset betas as reported). Empirical evidence from the industry group Infrastructure would suggest an asset beta of around 0.6 (based on a debt beta assumption of 0.31). A point estimate of 0.585 (combining the regulatory precedent of an equity beta of 1.0 with the market evidence for a debt beta of 0.31) is most realistic in my opinion.

3. Tax and the Value of Imputation Credits

The most appropriate definition for the WACC is after-company tax but before personal tax. Moreover the most suitable of the alternative formulae that are available is the simple or "vanilla" WACC which is also the definition of the WACC that is consistent with the revenue determination formula in the current matter. It is also the equation that has found most acceptance by the various regulatory authorities in Australia. The equation was defined above as Equation 2. One of the advantages of the "vanilla" WACC is that all the tax is accounted for in the cash flows, which in the context of a revenue determination requires separate compensation for tax (see Equation 1 above). This raises the issue of what is the company tax that is appropriate with the definition of the net cash flows and the WACC; it is not the net cash flows multiplied by the statutory tax rate.

The amount of tax paid by a company reflects the tax assessable income which is unlikely to coincide with the net cash flows, and the "effective" tax rate. Under an imputation tax system not all the tax collected from the company is really company tax. To the extent that part or all of the tax collected is redeemable against personal tax liabilities it represents personal tax. The company is collecting that proportion of the tax that is redeemable but it is tax that would otherwise be paid by the shareholder as personal tax. Therefore the "effective" tax rate for the company must take into account that amount of the tax paid by the company that is later redeemed by shareholders as a payment of personal tax. The issue is to assess what proportion of the tax collected from the company is not company tax but a pre-payment of personal tax.

There are two basic methods[4] of estimating the average amount of company tax that is redeemed as imputation tax credits against personal tax:

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[4] There is a third mechanism but it requires warrants to be listed on the shares which severely limits the sample of companies for which an estimate of the value

- through the official tax statistics of the amount of company tax paid that is redeemed and
- dividend drop-off studies.

The most comprehensive study to date, using both methods, is by Hathaway and Officer. The work is currently being up-dated but the results, to date, are broadly consistent with earlier studies by the authors and others.

The introduction of imputation tax in July l987 substantially reduced the previous position of double tax on company earnings; company tax followed by personal tax on dividends. Shareholders now pay personal tax on the gross of dividends and imputation tax (company tax) credits and obtain credit for the company tax paid. There are three milestones in the life of franking credits; they are created when company tax is paid, they are distributed along with dividends and they are redeemed when shareholders claim them against personal tax liabilities. Two issues thus arise; how many credits are issued (access) and how many of these distributed credits are redeemed (utilisation)? The study found that the access factor is 80% and increasing (an increasing amount of company tax is being distributed as credits) and about 60% of distributed credits are being redeemed. Overall, 48% of company tax is actually pre-payment of personal tax.

The study of official tax statistics indicate that a large proportion (48%) of the tax that "masquerades" as company tax is personal tax collected (withheld) at the company level. This means that the effective company tax rate in Australia during the period of the study was much closer to 18% than the statutory rate of 36%.

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of the credits can be assessed. This approach has been adopted in an unpublished paper by Cannavan, Finn and Gray (2000), Department of Commerce, University of Queensland.

A company that pays a dividend, other-things-being-equal, is expected to drop in value by the value of the dividend being paid. By examining the amount of cash dividends and, separately, the amount of imputation credits we are able to assess the implied market value of the credits for the extent that the share price drops as the credit is being paid. The dividend drop-off study showed slightly greater value to the franking credits about 62% which may reflect the sample which was based on listed companies whereas the tax statistics include all companies. The main data set analysed consisted of all closing share prices for the period January 1 1985 to June 30 1995, although only a subset of this data was suitable for analysis.

As a result of these studies and preliminary analysis of an up-dated version of these studies suggest that an estimate of 50% of the "face value" of the imputation tax credits is reasonable for attributing this to personal taxes. Nonetheless, there is considerable variance between individual company estimates of the value of these credits and the 50% is only an average or "benchmark" estimate. Moreover, there is ongoing research to update the period of the analysis and the tax environment has changed with changing legislation and these factors may have some effect on the conclusion as to the average value of franking credits.

For example, in the limited sample of the Cannavan, Finn and Gray study, referred to in footnote 4 above, there is evidence that large companies that have a substantial overseas shareholding have seen the value of the credits dropping to around 25% with some around 0%. Further, the lowering of the capital gains tax rate makes it more attractive for investors to use companies as a tax shield so that companies will be encouraged to retain a greater proportion of earnings instead of paying franked dividends. This will reduce the value of the franking credits, other things being equal.

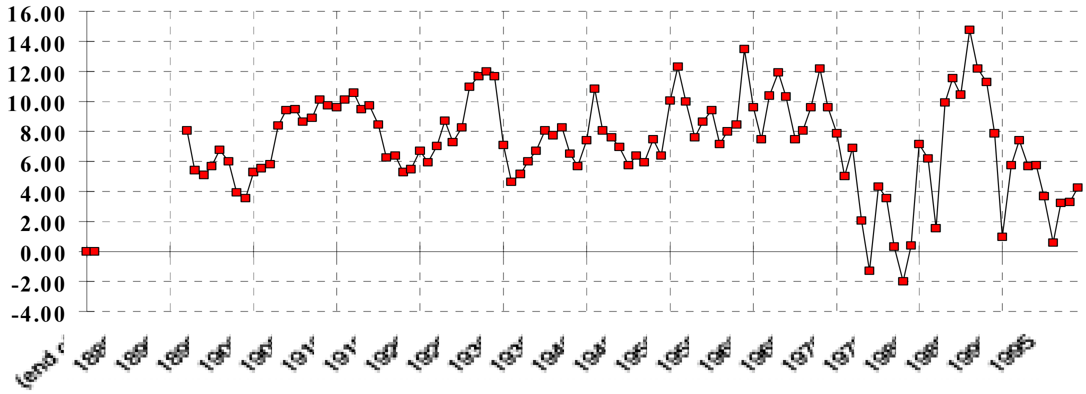
4. Market Risk Premium

The market risk premium (MRP) arises out of the capital asset pricing model (CAPM). The MRP is the stock market's price of risk relative to a risk-free rate of return such as the yield on 10-year Government bonds. The MRP is a real measure of risk as distinct from a nominal measure. The rationale for using historical data as a measure of the ex-ante MRP is that investors' expectations will be framed on the basis of their past experience. Historically, the MRP tends to be mean reverting but there have been 10-year periods when the returns from equities have been below the yield of 10-year bonds.

A figure of 6% is commonly used in Australia and the US by regulators and academics, although some market participants use more recent data and subjective measures to justify using a lower MRP figure. When calculating ex-post MRP figures as a basis for determining the ex-ante MRP, the use of arithmetic average stock returns is favoured over the geometric measure because arithmetic average returns are probably a closer proxy for what are expected by investors on how the expectations are framed by investors. The Australian historical MRP data has been reasonably consistent with that of the US, UK and New Zealand.

The graphs below demonstrate a justification for a MRP of 6%. The ten year moving average has a mean of about 6% although in any ten year period the average could be well below or above this average but this does not mean expectations will be framed on any one ten year period.

Figure 2
Ten year MRP

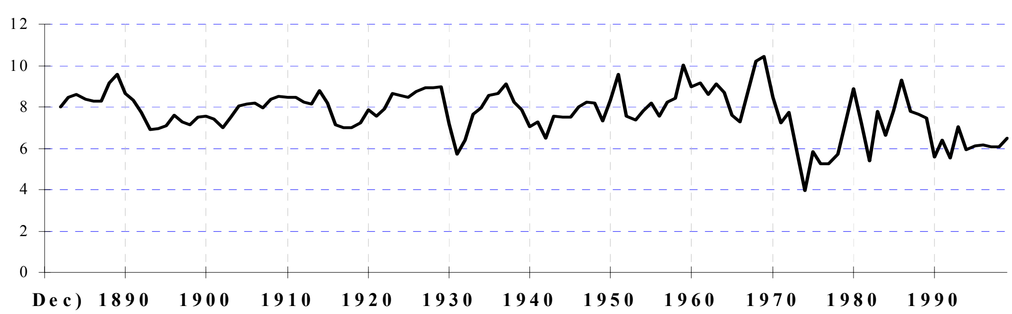


Source: Author's estimates

The Exponential Moving Series is also trending towards 6%, such a series places greater weight on more recent observations, the equation is defined as:

$$SMRP(t) = \alpha.MRP(t) + (1-\alpha).\ SMRP(t-1)$$

Figure 3
Simple exponential smoothing of the MRP, alpha=0.5



Source: Author's estimates

A Jardine Fleming Capital Partners survey of professional market participants' MRP expectations found that on average these participants thought the historic MRP for Australia was 5.87%. Their expectation for the future MRP is about 1% below this figure. However, there was a high co-efficient of variation in these expectations reflecting a significant amount of uncertainty.

Also, a survey of brokers' forecasts of stocks' future earnings related to their current share price showed an implied MRP of about 6% - see the table below:

Table 8
Implied MRP from brokers' forecasts

Company	IRR perpetuity (%)	Start date	Prices at this date ($)	Risk-free rate, Rf (%)	Beta	IRR – Rf (%)	Implied MRP (%)
Seven	8.774	30-06-00	7.09	6.16	.95	2.61	2.48
Sonic Healthcare	11.779	30-06-00	6.88	6.16	1.13	5.62	6.35
Howard Smith	13.107	30-06-00	8.16	6.16	1.16	6.95	8.06
Tabcorp	11.850	30-06-00	9.60	6.16	1	5.69	5.69
Wesfarmers	8.183	30-06-00	13.30	6.16	0.95	2.02	1.92
Woolworths	7.187	30-06-00	6.16	6.16	0.25	1.03	0.26
Westfield Holdings	5.996	30-06-00	11.48	6.16	1.2	-0.16	-0.20
Cable & Wireless	5.459	30-06-00	4.98	6.16	1	-0.70	-0.70
Frucor	20.384	30-06-00	1.71	6.16	1	14.22	14.22
Telstra	7.591	30-06-00	6.78	6.16	1.05	1.43	1.50
BHP	11.280	30-05-00	19.75	6.27	1.2	5.01	6.01
MIM	32.041	30-06-00	0.90	6.16	1.95	25.88	50.47
North Broken Hill	12.005	30-06-00	3.95	6.16	2.25	5.84	13.15
Rio Tinto	18.232	31-12-99	32.72	6.96	1.77	11.27	19.95
Western Mining	10.592	31-12-99	8.40	6.96	1.7	3.63	6.17
Woodside	9.231	31-12-99	11.25	6.96	0.9	2.27	2.04
Qantas	14.913	30-06-00	3.38	6.16	0.23	8.75	2.01
Totals	**399.849**			**221.31**		**178.54**	**216.69**
Averages	**11.42**			**6.32**		**5.10**	**6.19**

Source: JF Capital Partners, Trinity Best Practices Committee.

Finally, The Millennium Book: A Century of Investment Returns, shows in the table below that the Australian results are consistent with countries such as the US, UK and Canada whose capital markets are very similar to Australia. The arithmetic rates are more likely to be reflected in investors' expectations than the geometric rates, which over the period represent 10 year rates, whereas the arithmetic represent annual rates.

Table 9
Market Risk Premium

Equity Premium	Arithmetic Mean (%)	Geometric Mean (%)
Australia	7.6	5.9
Canada	6.1	4.6
Denmark (from 1915)	3.6	2.5
France	7.0	5.0
Germany (ex1922/3)	10.1	6.9
Italy	8.5	5.0
Japan (from 1914)	10.9	6.4
Netherlands	6.8	4.8
Sweden	8.0	5.8
Switzerland (from 1911)	4.3	2.8
USA	7.2	5.3
UK	5.8	4.6

Source: The Millennium Book: A Century of Investment Returns

5. The Risk-Free Rate

There has been some debate about what is the appropriate risk free rate to use in the CAPM. The debate has not concerned the source of the surrogate "risk free" rate which is a Commonwealth Government Issued security. The debate, to the extent that it exists, concerns the duration or term of such a security together with the sampling method used for determining an estimate.

The CAPM is a single period model of no fixed duration and various governments securities from government bills to long term government bonds have been used as a surrogate rate. In the context of CAPM theory there is no reason to pick one duration over another. However, ideally the duration of the CAPM should be the duration of the planning period for which the CAPM is to be used to estimate an expected or required return. This means that if the planning horizon is a long term investment then a long term government bond is the appropriate duration to use.

Further, it has been conventional in Australia to use 10 year Commonwealth Bond Yields as the proxy of the risk free rate as it is a highly liquid security which provides a good reflection of the expected yield on a long term government security. The data bases that have been assembled typically use such a bond as the surrogate risk free rate and, therefore, measures of market risk premium and the like are more readily available where a 10 year Commonwealth bond rate has been used. To the extent that a shorter rate has been used in electricity regulation (refer to Table 10), it has only been by ACCC, to my knowledge, in relation to Snowy Mountains and more recently Powerlink (its Draft Regulatory Principles also foreshadow this treatment). In these two decisions a 5 year rate was used on the grounds that this was consistent with the period of the regulatory decision.

Table 10
Risk-free rate parameters adopted in regulatory decisions

Entity/Author	Industry	Benchmark bond	Estimation factor
QCA (2001)	Electricity distribution	10 year Commonwealth	20-day average
ORG (2000a)	Electricity distribution	10-year inflation indexed Commonwealth	20-day average
ACCC (1999a)	Electricity transmission	5-year Commonwealth	40-day average
ACCC (2000a)	Electricity transmission	10-year Commonwealth	40-day average
IPART (1999c)	Electricity distribution	10-year Commonwealth	20-day average
IPART (1999d)	Electricity distribution	10-year Commonwealth	20-day average
OTTER (1999)	Electricity distribution	10-year Commonwealth	12-month average
OFGEM (1999)	Electricity distribution	(UK) A range, with particular weight on the 10-year Gilt	A range, on the 10 year Gilt
ACCC/ORG (1998)	Gas transmission	10-year Commonwealth	12-month range
ORG (1998b)	Gas distribution	10-year Commonwealth	2-month average
IPART (1999b)	Gas distribution	10-year Commonwealth	20-day average

Source: Queensland Competition Authority, Electricity Distribution Decision, May 2001, page 78

However, even in these circumstances, if the planning period of the company is longer than the periods between regulatory decisions, it is a mistake to use the 5 year rate as distinct from a longer term rate such as the 10 year rate. The longer term will better reflect the investment horizon of the company which is the relevant term and not that of the regulators. A moving 10 year rate should be used if regulatory periods are considerably shorter than the 10 year period. In short, there is no sound justification for the use of a five year rate.

The argument for a term consistent with the regulatory period would be correct if the entity, at the time they purchased the assets, were guaranteed that they would get compensation for the required return based on a five year benchmarked fixed interest security and at the end of the five years, if they choose to walk away from the asset, they would be fully compensated. In these circumstances, from the perspective of the owner of the asset, it is a five year asset even though its economic life might be greater.

Electricity companies are not in this position. When a company commits funds to purchase an asset, it is typically long-term, for infrastructure assets probably considerably longer than the term of the ten year Government Bond that is used for a surrogate risk-free rate that I and others advocate as an appropriate benchmark. When it makes the purchase, it has to consider making the purchase of that asset or the opportunity cost of investing in other assets of comparable risk and duration, or where the risk and duration has adequate compensation for the alternative investments. Even though it knows that the allowed rate of return on the asset will be reset at regular periods, it does not have the luxury of having those rates prescribed to it at the time of the purchase of the asset. Nor does it have the luxury of knowing that it can walk away from the asset if it finds such compensation unsatisfactory. The risk to the infrastructure owner is the risk faced by the purchaser of a long-term asset. The nature of the risk may be affected by the regulatory regime but nonetheless it is still committed to the asset unless it is offered full compensation should they choose to walk away or sell the asset. For these purposes a full compensation implies at least the replacement cost of the asset or its optimal deprival value under the same set of conditions i.e., the same regulatory regime that was expected at the time the asset was purchased.

Another issue that has been contentious is at what point should the redemption yield on a government security be used. Typically regulators have used an average rate running from 12 months down to 20 days. The argument is that these averages remove potential “spikes” which may reflected in the rates due to some short term uncertainty. There is no theoretical justification for using an average of rates. If the only information available is historical rates, then the changes in redemption yields behave as a random walk, which implies that the best forecast of future rates is the last observed rate. By taking an average of the last 20 days or longer simply lessens the information content in the last rate about expected future rates. The only justification for not using the last observed rate is if there was information that suggested that rate was not characteristic of the markets' expectations at the time, then this would open opportunities for arbitrage if such a circumstance existed and was recognised.

6. Expected Inflation.

The expected level of inflation comes into a regulatory decision on prices when an inflation adjustment is required for forecasting net cash flows. It is important in such circumstances that the inflation adjustment made with respect to net cash flows is consistent with the implied rate of inflation embedded in the cost of capital. The CAPM takes account of expected inflation in the risk free rate and, to the extent that this is a 10 year bond, then the embedded inflation is the expected annual geometric mean inflation over the 10 years of the bond. An alternative approach would be to estimate the risk free rate in real terms. In this circumstance a 10 year capital indexed bond rate would be appropriate. The rates then would require simply forecasting net cash flows at current prices and then adjusting for any inflation forecast.

There are basically two methods by which an estimate of inflation can be made.

- The difference between a Commonwealth Government capital index bond and a Commonwealth Government nominal index bond of the same duration, will reflect the expected inflation over the period of the duration.
- There are regular forecasts by economists of expected inflation rates for, typically 12 month periods, which could be used as a measure of expected inflation for the period of the forecast.

I would recommend using the difference between a capital indexed bond and the government bond of the same duration to estimate expected inflation over the period of the chosen duration. This would mean the other parameters of the model including the cost of capital would need to be estimated in real terms in the first instance and then adjusted for the expected inflation over the duration of the regulatory decision. Over a ten year period the current expected annual inflation is approximately 2.5%, on the basis of the difference in yields between indexed bonds and nominal bonds.

7. Debt Margin and Gearing (Leverage)

The difference between the interest rate or yield on debt issued by the entity and the comparable yield on the Commonwealth government issued security of the same term is called the debt margin. This margin will reflect the risk of the entity's debt relative to the Commonwealth debt's security. The risk of the security can be divided up into diversifiable and non-diversifiable risk both of which will reflect the default risk of the entity or borrower.

Clearly, the risk of the entity's debt will be a function of the amount of asset backing to the debt or equivalently the degree of leverage or gearing that the entity has. The greater the debt to value or debt to equity ratio of the entity, other things being equal, the greater the risk and therefore the greater the required return or debt margin. Similarly, the cost of equity will increase as the proportion of debt in the capital structure increases but this does not imply the cost of capital for the entity's assets changes. The change in proportion of equity to debt can offset the relative increase in equity and debt costs such that the WACC or asset cost of capital remains unchanged – this is an illustration of the Modigliani Miller (MM) Proposition that "a company's value is invariant with changes in its capital structure". As a practical proposition the so called MM hypothesis is valid within reasonable ranges of debt/equity for most entities. The consequences are that in setting a debt margin, we are implicitly setting a level of gearing. If the observed equity beta is used together with a debt beta to derive an asset beta the assumptions employed will imply a particular level of gearing.

In the estimates of beta above (section 2.3) a recommended beta for debt was 0.31 which implies a debt margin of 1.85%. However, this implies that the total debt margin is due to non-diversifiable or systematic risk and there is no margin for the diversifiable or idiosyncratic risk of the entity. I believe this is not an unrealistic assumption, in the context of default risk for a major entity, i.e. it is unlikely that the default of a major entity's debt will not be associated with the significant external market conditions. The capital structure implied for this debt margin is between 50 and 60% debt as a proportion of the total assets of the entity.

Table 11 below, taken from the Queensland Competition Authority's Final Determination in the context of electricity distribution, shows that the debt margins used in regulatory decisions are typically around 1 to 1.5 with an average of approximately 1.2. The significant difference between these decisions and the debt margin recommended here is due in large part to the implied assumptions made in the decisions about debt financing together with the state of the debt markets at the time that market data was sampled. Although not always explicit, many decisions appear to have assumed that the relevant benchmark for debt financing is based on the term of the regulatory period. As discussed in section 2.3, the long planning horizon for infrastructure necessitates using a long term financing basis (ie 10 year duration or greater).

Table 11
Cost of debt parameters adopted in regulatory decisions

Entity/Author	Industry	Margin above the risk-free rate (%)
QCA (2001)	Electricity distribution	1.65
ORG (2000a)	Electricity distribution	1.5
ACCC (1999a)	Electricity transmission	1.0
ACCC (2000a)	Electricity transmission	1.0
IPART (1999c)	Electricity distribution	1.0
IPART (1999d)	Electricity distribution	0.8-1.0
OFGEM (1999)	Electricity distribution	1.4 (UK)
ACCC/ORG (1998)	Gas transmission	1.2
ORG (1998b)	Gas distribution	1.2

Source: Queensland Competition Authority, Electricity Distribution Decision, May 2001

The capital structure or proportion of debt to the total assets of the company is referred in the tables above as leverage or gearing. As I have indicated above, the capital structure can have a significant bearing on, not only the debt margin, but also the required return on equity although within "reasonable" bounds it is unlikely to affect the asset cost of capital or the WACC.

Table 12 below indicates that the typical capital structure assumed by regulators has been 60% debt as a proportion of total assets. In theory, within the range of 40% to 70% the asset cost of capital should be stable providing appropriate adjustments are made to debt and equity costs to reflect the change in gearing. However, to the extent that the equity cost of capital is the prime determinant of the asset cost of capital one has to be cognisant of the capital structure of the companies determining the equity cost of capital in selecting an appropriate leverage or gearing. In Table 6, the sample average leverage of the companies listed is 54% when the averages were simple or value weighted.

In the circumstances, it would appear that a leverage of between 50 and 60% is a reasonable benchmark. Given that most regulators have adopted a gearing of 60%, which is consistent with this benchmark, there is little compelling reason to vary from this assumption.

Table 12
Gearing levels adopted in regulatory decisions

Entity/Author	**Industry**	**Debt/ Debt+Equity (%)**
QCA (2001)	Electricity distribution	*60*
ORG (2000a)	Electricity distribution	60
ACCC (2000a)	Electricity transmission	60
IPART (1999c)	Electricity distribution	60
IPART (1999d)	Electricity distribution	60
OTTER (1999)	Electricity distribution	50-70
Ofgem (1999)	Electricity distribution(UK)	50
ACCC/ORG (1998)	Gas transmission	60
ORG (1998b)	Gas distribution	60
IPART (1999b)	Gas distribution	60

Source: Queensland Competition Authority, Electricity Distribution Decision, May 2001

8. Estimations and Recommendations

In the context of the upcoming SPI PowerNet revenue determination, my opinion is that the WACC and dividend imputation factor should be set having regard to the following recommendations.

- The WACC should be formulated as the simple or "vanilla" WACC (see equation 2).
- The WACC only captures the required compensation for bearing non-diversifiable risks. Consequently, compensation for the actuarial value of all diversifiable risks should be included as a separate item in SPI PowerNet's revenue allowance.
- The parameter estimates (MRP, asset beta, equity beta, debt beta/debt margin, gearing and gamma) for the WACC and tax allowances should be as set out in Table 13 below.
- While these parameter estimates are expected to be stable over the period to the end of 2002, the estimates for the risk free rate and inflation are variable in nature. Hence, when the revenue determination is made, the estimates need to be refreshed at that time. The risk free rate should be determined as the Commonwealth Government 10 year nominal index bond on the last day before the determination is made. The inflation estimate should be derived consistent with this with respect to the difference between the Commonwealth Government 10 year nominal index bond and the Commonwealth Government 10 capital index bond.
- As at 28 February 2002 the combination of these parameters and variables yields an estimate of the vanilla WACC for SPI PowerNet of 9.455%.

Table 13
Estimate of WACC and dividend imputation factor

	Estimate
Market Risk Premium (%)	6.0
Asset beta	0.585
Equity beta	1.0
Debt beta	0.31
Debt margin (%)	1.85
Gearing (Debt/Assets, %)	60
Risk free rate (28/2/2002, %)	3.45
Nominal risk free rate (28/2/2002, %)	5.945
Inflation estimate (%)	2.41
Return on debt (%)	7.795
Return on equity (%)	11.945
Vanilla WACC (28/2/2002, %)	9.455
Imputation factor	0.5

Source: Author's estimates and http://www.rba.gov.au/Statistics/indicative.html

Westpac Institutional Bank

Corporate Securities
Level 4, 255 Elizabeth Street
Sydney NSW 2000
Telephone: (612) 9284 9437
Facsimile: (612) 9284 8270
Email: jbrien@westpac.com.au

FACSIMILE

29 November 2001

Mr Jim Lamborn
Treasurer
SPI Powernet
Milton House
25 Flinders Lane
Melbourne VIC 3013

Dear Jim,

We are pleased to provide indicative pricing for a new issue for a generic Australian electricity transmission issuer.

<u>Assumptions:</u>

Rating:	BBB+/A3
Maturity:	10 years
Issuance Margin to 10 year swap:	+1.30 / 1.40% pa
Fees:	0.05% pa
Current 10yr benchmark CGS yield:	5.67%
All-In Margin to 10 year swap:	+1.35 / 1.45% pa

The margin between Commonwealth Bonds and swap has historically traded at an average rate in the 40 to 50 basis point range. Assuming a mid point in this range, the all in yield would be in the range of 7.47% to 7.57%, or a spread of 180 to 190 basis points to the "risk free" Commonwealth bond rate.

This level has been extrapolated from other transmission issuers in the market and longer dated comparable-rated issuance (and taking into account the 'utility' issuer premium as compared to average corporates). Comparisons include:

Issuer	Rating	Maturity	Trading Margin to Swap
Duke	A	09/04	+60
ETSA Utilities	A-	07/05	+66
ETSA Utilities	A-	04/07	+75
Southcorp	BBB+	03/10	+125

Please let me know if I can provide any further information.

Yours sincerely,

Jennifer Brien
Associate Director, Corporate Securities

Official Partner 2000 Australian Olympic Team

www.westpac.com.au

UBS Warburg Australia Ltd
ABN 40 008 582 705
PO Box 4151
Sydney, NSW 2001
Tel. +612-9324-2000

Debt Capital Markets
Fixed Income

Mark Langsworth
Level 25, Governor Phillip Tower
1 Farrer Place
Sydney NSW 2000
Tel. +612-9324-3943
Fax +612-9324-3832
mark.langsworth@ubsw.com

www.ubswarburg.com

Mr Jim Lamborn
Treasurer
SPI PowerNet
25 Flinders Lane
Melbourne VIC 3000

19 November 2001

Subject: 10 Year Funding Levels for BBB+ Utility Companies

Dear Jim

I am pleased to provide you with some information regarding 10 year funding levels for BBB+ rated utility companies in the debt capital markets.

As a general comment, corporate credit spreads can be volatile. The margins outlined in this letter are broadly similar to our previous advice to you (refer our letter 25 July 2001). However, since then, credit margins have initially increased (especially as a result of the events of 11 September) and more recently returned to prior to 11 September levels as world events have stabilized.

Australian Domestic Market Comparables

The are no direct comparables for BBB+ rated 10 year debt issued from the utility sector. However there are a number of similarly-rated issues from industrial companies, plus some shorter duration utility issues from which we can extrapolate a BBB+ 10 year utility curve.

1.The most obvious comparable is the Southcorp (rated BBB+) March 2010 issue is currently trading at swap +130. A new 2011 issue (ie. 10 year) for this company would come at around swap + 150.

2. AMCOR, the BBB+ packaging company, issued a 10 year CMBS note (essentially backed by lease rental streams from Amcor Ltd, also rated BBB+) in August at BBSW +150. This paper has not traded since primary, but it would be fair to say that a new issue would be 10-15bp back from this level..

3.This week we are bringing a new 7 year issue for BHP (rated A,) at swap +80 area. A new 10 year issue for BHP would come at around swap +100.

4.Qantas (BBB+) brought a 6 year issue in July at swap +100 that is now swap +150.

Offshore Market Comparables

1. In the Sterling market (good comparison to Australia because of the similar privatisation regime instigated by the UK Government), Wessex Water (BBB+) 2009 issue trading GBP swap 80 (equivalent to AUD swap +90), Innology (BBB+) 2011 at GBP swap + 60 (AUD swap +70)

2. In Euro, Innology (BBB+) 2008 at Euro swap + 110 (AUD swap + 122), Anglian Water (BBB+) 2009 at Euro swap + 105 (AUD swap + 117)

3. In USD, TXU (BBB+) 2009 at USD swap + 140

As a general comment, Australian issuers in the offshore markets would probably trade at a level around 20bps higher than their local counterparts.

Thus in summary, taking a line through all of the data provide by the variety of comparables above, it would be difficult to see a new 10 year issue for a BBB+ rated Australian utility company coming at a level much inside AUD swap + 150bps. Ten year swap spreads (ie the difference between the 10yr Australian Government Bond (AGB) and 10yr swap yields) are currently around 35 basis points implying a spread versus AGB of +185bp for a BBB+ rated Australian utility. Based on current yield curves, this would equate to a yield of around 7.60%.

Please give me a call if you would like additional information, or if you would like to discuss any of the above.

Yours Sincerely

Simon Maidment
Director
Debt Syndicate
UBS Warburg Australia Ltd

UBS Warburg

UBS Warburg Australia Ltd
ABN 40 008 582 705
PO Box 4151
Sydney, NSW 2001
Tel. +612-9324-3000

Fixed Income

Nick Wade
Level 26, Governor Phillip Tower,
1 Farrer Place, Sydney NSW 2000
Tel. +612-9324-2979
Fax +612-9324-2898
nick.wade@ubsw.com

www.ubswarburg.com

Jim Lamborn
Treasurer
SPI PowerNet
Milton House
25 Flinders Lane
Melbourne VIC 3000

November 28, 2001

Credit Rating of Benchmark Electricity Utility

Dear Jim

We have taken the basic parameters provided by you to determine an appropriate rating for a benchmark, regulated utility. This is an approximate rating level to be utilised to determine a cost of debt funding, which will feed into a WACC calculation. Obviously the rating does not take into account specific circumstances and qualitative factors that would be relevant for individual company ratings, but is an indicative level only.

The assumptions provided by you for the exercise are:

- Regulated utility with regulated revenues;
- Gearing level of 60% (debt / debt + equity);
- EBIT interest cover of 2.0x;

Standard & Poor's standard ratios for transmission and distribution companies are as follows:

	'A'	'BBB'
Interest cover	3.25x	2.0x
Gearing	55%	65%

In the determination of a full rating many factors need to be included, both qualitative and quantitative, as well as the above. Typically an assessment will be made as to the strength of the business profile, however in this case we have assumed average. Furthermore, other issues such as diversity of revenues and operations, type and impact of regulation, future strategies, as well other aspects, will be reviewed, which can change the rating level from what the ratios suggest.

However, simply using the above ratios we believe that a standard regulated transmission or distribution business would be rated around 'BBB+'.

If you have any further queries or would like to discuss in more detail, please don't hesitate to contact me.

Sincerely yours

N. Wade

Nick Wade
Director, Credit Research

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Appendix G

Pass-through rules

Pass Through Rules

1 Regulated Pass Through

1.1 Rules form part of revenue cap

These Pass Through Rules form part of the revenue cap set by the Commission to apply to SPI PowerNet for the regulatory control period commencing on 1 January 2003. Any Pass Through Amount approved under these Pass Through Rules forms part of the revenue cap.

1.2 Pass Through Event

Each of the following is a Pass Through Event:

(a) a Change in Taxes Event;

(b) a Service Standards Event;

(c) a Terrorism Event; and

(d) an Insurance Event.

1.3 Entitlement to pass through

If a Pass Through Event occurs, SPI PowerNet is entitled to amend the revenue cap to pass through the financial effect of the Pass Through Event in accordance with the procedures set out in these Pass Through Rules.

1.4 Form of Pass Through Amount

A Pass Through Amount may be expressed in any form which reasonably reflects the factors in clause 2.3, including:

(a) as an increase in the amount of the revenue cap (with SPI PowerNet to determine the corresponding change in customer charges in accordance with the Code);

(b) as a percentage change in one or more customer charges; or

(c) as a change to one or more customer charges.

2 Procedure

2.1 Application for pass through

If SPI PowerNet believes it is or will be entitled to pass through the financial effect of a Pass Through Event, then it may give a notice to the Commission specifying:

(a) details of the relevant Pass Through Event;

(i) the date on which the relevant Pass Through Event took effect or will take effect;

(b) the estimated financial effects of the Pass Through Event on the provision of revenue capped transmission services; and

(c) the Pass Through Amount proposed by SPI PowerNet in respect of the relevant Pass Through Event.

2.2 Approval by the Commission

(a) The Commission will, within 30 business days of the receipt of a statement under clause 2.1 determine whether the Pass Through Event specified in the notice did occur (or will occur) and, if the Commission decides that the Pass Through Event did occur (or will occur), the Commission will decide:

(i) the Pass Through Amount in respect of the relevant Pass Through Event and the form of the Pass Through Amount; and

(ii) the date from, and period over which, the Pass Through Amount may be applied,

and notify SPI PowerNet in writing of the Commission's decision.

(b) If the Commission does not give a notice to SPI PowerNet under clause 2.2(a) within 30 business days of receiving a statement from SPI PowerNet under clause 2.1, then the Commission is taken to have notified SPI PowerNet of its decision that:

(i) the relevant Pass Through Event has occurred (or will occur); and

(ii) the Pass Through Amount and form of the Pass Through Amount are as specified in the statement given by SPI PowerNet under clause 2.1.

2.3 Relevant Factors

In making a decision under clause 2.2, the Commission must seek to ensure that the financial effect on SPI PowerNet associated with the Pass Through Event concerned is economically neutral taking into account:

(a) the relative amounts of revenue capped transmission services supplied to each customer;

(b) the time cost of money for the period over which the Pass Through Amount is to be applied;

(c) the financial effect on SPI PowerNet associated with the provision of revenue capped transmission services attributable to the Pass Through Event and the time at which the financial effect took place or will take place;

(d) in relation to a Change in Taxes Event:

(i) the amount of any reduction in another tax, rate, duty, charge, levy or other like or analogous impost intended to offset in whole or in part the relevant Change in Tax Event and the manner in which and the period of over which that reduction occurs; and

(ii) the amount included in the operating expenses or other cost inputs of SPI PowerNet's revenue cap;

(e) in relation to a Terrorism Event, any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with:

(i) the Terrorism Event; or

(ii) any action taken in controlling, preventing, suppressing or in any way relating to the Terrorism Event;

(f) in relation to an Insurance Event:

(i) the amount of any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with the Insurance Event and including without limitation:

(A) the cost of any material increase in premium paid or payable by SPI PowerNet beyond that provided for in SPI PowerNet's revenue cap;

(B) the cost of any material increase in deductible paid or payable by SPI PowerNet beyond that provided for in SPI PowerNet's revenue cap; and

(C) if an Insurance Event occurs and SPI PowerNet either does not continue the relevant Insurance or continues the Insurance on different terms, losses resulting from any uninsured event or partially uninsured event where that event would have been insured or fully insured by Insurance at the date of the Determination, and

(ii) the economic consequences for SPI PowerNet of a decision to Self Insure.

(g) in relation to a Service Standards Event, the financial effect on SPI PowerNet associated with any increased costs or risks (including in the nature, scope or asymmetry of risks) resulting from the Service Standards Event including, where relevant, an appropriate self-insurance allowance relating to the increased risks.

2.4 Application of Pass Through Amount

If SPI PowerNet has:

(a) received or is taken to have received a notice under clause 2.2 allowing SPI PowerNet to pass through a Pass Through Amount; and

(b) notified its affected customers of:

(i) the Pass Through Amount; and

(ii) the form in, date from and period over which SPI PowerNet will apply the Pass Through Amount,

SPI PowerNet may apply the Pass Through Amount in the form, from the date of and over the period specified or taken to be specified in the notice from the Commission.

3 Definitions

3.1 Definitions

Applicable Law means any legislation, delegated legislation (including regulations), codes, licences or guidelines relating to the provision of one or more revenue capped transmission service, and includes the National Electricity Code and the National Electricity Law.

Authority means any government or regulatory department, body, instrumentality, minister, agency or other authority or any body which is the successor to the administrative responsibilities to that department, body, instrumentality, minister agency or authority, and includes the Essential Services Commission, NEMMCO, NECA and the Commission.

Change in Taxes Event means:

(a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of Relevant Tax);

(b) the imposition of a new Relevant Tax,

to the extent that the change or imposition:

(c) occurs after the date of the Determination; and

(d) results in a change in the amount SPI PowerNet is required to pay or is taken to pay (whether directly, under any contract or as part of the operating expenses or other cost inputs of SPI PowerNet's revenue cap) by way of Relevant Taxes.

Determination means the determination of the Commission setting the revenue cap for SPI PowerNet in relation to the regulatory control period commencing on 1 January 2003.

Insurance means insurance whether under a policy or a cover note or other similar arrangement:

(a) for risks of the sort for which SPI PowerNet was covered at the date of the Determination;

(b) for amounts not less than amounts underwritten in favour of SPI PowerNet at the date of the Determination; and

(c) on terms, including without limitation terms specifying deductibles payable and any applicable exclusions, no less favourable to SPI PowerNet than the terms in place at the date of the Determination.

Insurance Event means where one or more of the following circumstances occurs:

(a) where Insurance in respect of any risk becomes unavailable to SPI PowerNet;

(b) where Insurance in respect of any risk becomes unavailable to SPI PowerNet at reasonable commercial rates;

(c) where Insurance in respect of any risk becomes unavailable to SPI PowerNet on terms which are at least as favourable to SPI PowerNet as those generally available at the date of the Determination;

(d) where the cost of Insurance (including, without limitation, premiums and deductibles) in respect of any risk becomes materially higher than the cost of Insurance at the date of the Determination.

Pass Through Amount means a variation to SPI PowerNet's revenue cap as a result of a Pass Through Event determined in accordance with these Pass Through Rules.

Relevant Tax means any tax, rate, duty, charge, levy or other like or analogous impost that is:

(a) paid, to be paid, or taken to be paid by SPI PowerNet in connection with the provision of transmission services, or:

(b) included in the operating expenses or other cost inputs of SPI PowerNet's revenue cap;

and includes

(c) income tax, fringe benefits tax or capital gains tax;

(d) payroll tax;

(e) fees and charges payable to the Essential Services Commission for licences issued under the Electricity Industry Act 2000;

(f) council rates; and

(g) land tax,

and any tax or levy that replaces any of those taxes or levies.

Self Insure means where SPI PowerNet elects following the occurrence of an Insurance Event to self insure for all or part of a risk of the sort for which SPI PowerNet previously maintained Insurance.

Service Standards Event means a decision made by the Commission, the Essential Services Commission or any other Authority or any introduction of or amendment to an Applicable Law after the date of the Determination that:

(a) has the effect of:

(i) imposing or varying minimum standards on SPI PowerNet relating to revenue capped transmission services that are more onerous than the minimum standards applicable to SPI PowerNet in respect of revenue capped transmission services at the date of the Determination;

(ii) altering the nature or scope of services that comprise the revenue capped transmission services;

(iii) substantially varying the manner in which SPI PowerNet is required to undertake any activity forming part of revenue capped transmission services from date of the Determination; or

(iv) increasing SPI PowerNet's risk in providing the revenue capped transmission services, or

(b) results in SPI PowerNet incurring (or being likely to incur) materially higher costs in providing revenue capped transmission services than it would have incurred but for that event.

Terrorism Event means an act, including but not limited to the use of force or violence and/or the threat thereof, of any person or group(s) of persons, whether acting alone or on behalf of or in connection with any organisation(s) or government(s), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons, including the intention to influence any government and/or to put the public, or any section of the public, in fear.

3.2 References to certain general terms

Unless the contrary intention appears, a reference in these Rules to:

(a) **(variations or replacement)** a document (including these Rules) includes any variation or replacement of it;

(b) **(clauses, annexures and schedules)** a clause, annexure or schedule is a reference to a clause in or annexure or schedule to these Rules;

(c) **(reference to statutes)** a statute, ordinance, code or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them;

(d) **(singular includes plural)** the singular includes the plural and vice versa;

(e) **(person)** the word “person” includes an individual, a firm, a body corporate, a partnership, joint venture, syndicate, an unincorporated body or association, or any Authority;

(f) **(successors)** a particular person includes a reference to the person’s successors, substitutes (including persons taking by novation) and assigns;

(g) **(meaning not limited)** the words “include”, “including”, “for example” or “such as” are not used as, nor are they to be interpreted as, words of limitation, and, when introducing an example, do not limit the meaning of the words to which the example relates to that example or examples of a similar kind;

(h) **(reference to anything)** anything (including any amount) is a reference to the whole and each part of it.

3.3 Headings

Headings (including those in brackets at the beginning of paragraphs) are for convenience only and do not affect the interpretation of these Rules.

Appendix H

Pricing policy for non-contestable augmentations

SPI POWERNET
A subsidiary of Singapore Power International

Policy for interim pricing of new non-contestable transmission services

April 2002

Table of Contents

1 Introduction

New non-contestable transmission services provided by SPI PowerNet that come into effect between reset periods are not included in the revenue cap for that period. These services are generally augmentations and as SPI PowerNet does not plan network augmentations it does not forecast augmentations into its asset base for the purpose of revenue setting.

The Australian Competition and Consumer Commission (ACCC), as regulator under the National Electricity Code (NEC), periodically determines the maximum allowed revenue for provision by SPI PowerNet of revenue capped transmission services, ie all transmission services other than contestable services. Therefore, it is necessary only to price new non-contestable transmission services for the period until they can be included in the next reset of regulated revenue.

SPI PowerNet's intention in this Policy is to provide a methodology which can be used for pricing all new non-contestable transmission services initiated by customers in Victoria until at least 1 January 2008, by which time it will be reviewed by SPI PowerNet as part of SPI PowerNet's 2008 regulated revenue reset. Pricing such services in accordance with this Policy will satisfy SPI PowerNet's obligations under its licence and under the NEC.

The methodology must meet all reasonable needs of SPI PowerNet, its customers and the regulators. Flexibility is necessary so as not to stifle competition between distribution businesses or other connected customers, or be overly restrictive on their ability to manage their businesses; therefore this Policy contains a number of options, and is not binding on SPI PowerNet's customers, who can negotiate different terms with SPI PowerNet if both parties agree.

The Policy details how new non-contestable transmission services will be dealt with under the NEC at the revenue reset next following the services coming into effect.

1.1 Summary of SPI PowerNet's obligations

It is a term of SPI PowerNet's licence, and a provision of the National Electricity Code, that it must if requested by a customer make an offer to connect on "fair and reasonable" terms. SPI PowerNet considers the price of an offer to connect made in accordance with the terms set out in this policy would satisfy, as to price and other specified conditions, SPI PowerNet's obligation under section 5.3.6(c) that an offer to connect must be fair and reasonable.

1.2 Definition of non-contestable services

New non-contestable transmission services are best defined as any new transmission services which are not contestable. A definition of contestable, developed by SPI PowerNet and VENCorp for new shared network services, is attached as Annexure A.

1.3 Contract

All new non-contestable transmission services must be the subject of a contract negotiated between SPI PowerNet and the customer. These contracts will be "take or pay" and based on the general terms and conditions of the appropriate Connection Agreements or Network Agreement or Additional Connection Agreements SPI PowerNet may have with existing customers unless otherwise agreed with the customer.

2 Price for services

2.1 Methodology of pricing

Services will be priced using the same two-step methodology as for pricing revenue-capped services. First, the revenue requirement for each year until the service is rolled into the revenue cap is determined using the post tax nominal methodology:

(CPI indexed WDV) * WACC + O&M + economic depreciation + tax

All components of the equation will be determined in accordance with the relevant sections below.

Second, the (nominal) revenue requirement for each year is converted to a real price. The price charged in a given year will be the real price for that year escalated by the actual CPI experienced over the service period.

2.2 Application fees

Not all proposed services the subject of an enquiry or an application are realised, and unrealised services are often proposed by parties who are not regular participants in the Electricity Services Industry in Victoria. In order to ensure that these costs are efficiently allocated on a "user pays" basis, a fee will be payable by all applicants for new connection services.

SPI PowerNet's experience is that the work generated in processing an application is significant. The fee upon application will range from $2,000 to $10,000 depending on the complexity of the application. Where the actual cost of processing the application exceeds the initial fee, further charges will be rendered to the customer monthly for the balance of the cost based on hours spent on the application and disbursements incurred.

2.3 WACC and taxation

Once the ACCC makes its final determination in relation to SPI PowerNet's regulated revenue for the period 2003 to 2007/08, the WACC used to calculate the price of new non-contestable transmission services will follow the formula so determined. Until that time, WACC on new non-contestable transmission services will be calculated as follows.

WACC will be calculated using the vanilla formula:

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

where:

- R_e is the post-tax nominal return on equity;
- E/V is the proportion of equity funding;
- R_d is the pre-tax nominal cost of debt; and
- D/V is the proportion of debt funding.

The post-tax nominal return on equity will be calculated with reference to the CAPM,

$$R_e = R_f + \beta_e MRP$$

where:

- R_f is the risk free rate;
- β_e is the equity beta; and
- MRP is the market risk premium.

The pre-tax cost of debt will be determined as:

$$R_d = R_f + DM$$

where:

- DM is the debt margin over the risk free rate for raising debt capital.

In applying the vanilla WACC formulation, SPI PowerNet will treat some inputs as parameters and some as variables, the latter to be updated each time a new project is priced. The following table sets out details of how each input is categorised.

Parameters	
Gearing (D/V)	60%
Equity beta (β_e)	1.0
Market risk premium (MRP)	6.0%
Variables	
Risk free rate (R_f)	Yield on 10-year Commonwealth Government bonds
Debt margin (DM)	Margin of the yield on 10-year BBB+ rated corporate bonds for a utility company over the 10 year Commonwealth Government bond

Given the vanilla formulation of the WACC, taxation is treated on a cash flow basis, with the tax treatment of the project explicitly modelled. In so doing, allowance is also made for dividend imputation by netting off an amount for the average market value of tax credits. This is determined through the use of a gamma factor (γ). This factor will be set at 50% until ACCC makes its final determination.

2.4 Operating and maintenance (O&M) costs

In its reset application effective 1 January 2003, SPI PowerNet has sought to apply a marginal costing methodology to cost allocation. That is a change from the Victorian Tariff Order which allocated cost on the basis of assumed growth in excluded services.

Assuming that methodology is accepted by ACCC, O&M costs for new non-contestable transmission services shall be direct, incremental costs only after 1 January 2003. SPI PowerNet will estimate and advise these costs to the customer during development of the contract.

2.5 Term of services and depreciation

VENCorp and connecting parties must be able to control stranding risk on new services and therefore the term for the new service is negotiable. The customer can nominate as the term the usual regulated life of the major asset forming part of the service, or the parties can agree a shorter term.

Depreciation will be CPI adjusted straight-line over the agreed term and, for use in the post-tax nominal methodology, is net of the CPI indexation of the WDV of the assets used to provide the service.

2.6 Retirement of existing assets

There will be instances when, in establishing a service augmentation or new service, existing regulated assets are replaced before the end of their regulatory lives. The following process will apply in that circumstance:

a. SPI PowerNet will as part of the contract negotiations advise the customer of the capital value of the asset to be retired and the projected capital value of the asset as at the next revenue reset.

b. For the period from the date of service to the next revenue reset, the price for the new services will be reduced by an amount equal to the O&M charge on the retired assets.

c. At the date of the next revenue reset, the customer will pay SPI PowerNet the then remaining capital value of the retired assets.

2.7 Capital cost

In order to determine the initial revenue and to provide the ACCC with a value upon which to determine the revenue for each new transmission services contract at the next revenue reset, SPI PowerNet and its customer will agree the capital value of the assets providing the service, or will agree a method for determining that value.

SPI PowerNet will negotiate and agree to determine the opening value of the assets providing the services using either a fixed cost basis, or part fixed / part variable basis.

2.7.1 Fixed cost

Under the fixed price basis SPI PowerNet will provide a firm quotation for the service based on the capital value of the assets providing the service which has been derived from:

a. prices of similar items sourced for recent projects, using an up-to-date estimating data base,
b. prices for equipment or services based on a tender for the project or for recent similar projects,
c. SPI PowerNet's internal labour charges if SPI PowerNet believes it is most appropriate to use internal labour,
d. estimates of hours for design, construction, testing etc based on recent similar projects and more general experience,

Using this basis SPI PowerNet bears the risk of cost overruns, other than costs associated with scope changes and therefore, project contingency provision reflecting specific project uncertainties will be included in the fixed cost.

2.7.2 Fixed and variable cost

For the part fixed / part variable basis SPI PowerNet and the customer will agree which elements in the project costing are to be provided by SPI PowerNet on a firm cost basis, and which will be variable. Typically the supply of major plant items would be provided on a variable basis with the residual SPI PowerNet component of the project provided on a firm basis (other than for costs associated with scope changes). The 'SPI PowerNet component' refers to project design, procurement and management, all other materials not included in the major supply elements and contract administration.

To assist the customer establish a reference overall project cost SPI PowerNet will provide an itemised estimate of the capital value for and the variable component, based on the costing criteria described in section 2.7.1.

The capital value of the assets providing the service will comprise the firm price for the SPI PowerNet component of the project (varied as appropriate), and the actual cost of all the major equipment and components. The customer will bear the risk of cost overruns, except in relation to the SPI PowerNet component.

2.8 Stranded asset risk

Unless otherwise agreed by SPI PowerNet, stranded asset risk / optimisation of assets providing the service will be borne by the customer. For this reason, the take or pay contract for the new service must provide for payment to SPI PowerNet regardless of optimisation or stranding for the whole term of the service.

2.9 Pass-throughs

Any costs which constitute “pass throughs” for the purposes of SPI PowerNet’s regulated services will be passed through to the customer in the same manner and proportion in relation to the new transmission services.

2.10 Credit risk

SPI PowerNet will not be required to carry any greater credit risk for new transmission services than it does for regulated services. If any offer to connect involves a higher credit risk, SPI PowerNet shall be entitled to require bank guarantees or similar sureties from the customer, or apply a margin on WACC for credit risk.

2.11 Extension of term

If the customer requires that the services continue beyond the agreed term, the parties will negotiate in good faith to extend the term or enter into another term. SPI PowerNet will make an offer to the customer to provide the services in accordance with the then current terms of its licence or other regulatory instrument. By way of illustration, “fair and reasonable terms” would take into account, among other considerations, the capital value of the asset in SPI PowerNet’s books at the time, the age and general condition of the asset, and the state of technology at the time.

2.12 Once non-contestable, always non-contestable

The definition of non-contestable will be dynamic as the industry changes and markets develop, and the definition will be reviewed at each SPI PowerNet reset, and may be amended. However, even though a transmission service may under a future definition be regarded as contestable, if at the time the service came into effect it fell within the definition of non-contestable it will continue to be included in SPI PowerNet’s regulated service.

2.13 Payment terms

Payment terms shall be on a monthly basis following commencement of availability of the network or connection services unless otherwise agreed with the customer.

2.14 Fast-tracking of projects

If requested by customers, SPI PowerNet may consider entering into arrangements for “fast-tracking” of projects through advance reservation of long-lead time plant and equipment for a specific project, the terms and conditions of which will include an additional charge for provision of this service, based on stores and supplier holding costs.

3 References

All references to CPI, are references to the CPI All Groups average of eight capital cities, and will be calculated using the index most recently available prior to the relevant date, divided by the index one year previous.

4 Definitions

"Next revenue reset" means the next following reset of SPI PowerNet's regulated revenue at which the new service can effectively be priced by the regulator. Due to the timing of the process of those resets, this may mean that some new services established prior to an ACCC revenue determination will not be included until the following reset.

Annexure A

Criteria for Network Service Contestability
Understanding Agreed Between VENCorp and SPI PowerNet

Agreed Principles

1. A new transmission service could be considered as 3 separate services – build, own, operate. However, the service provider would need to aggregate the services, providing a single overall service to VENCorp. This is because it is most unlikely that Government would grant VENCorp network asset ownership capability.

   This principle does not apply to customers other than VENCorp as ownership constraints do not apply. With respect to connected customers, building, owning and operating of assets delivering new transmission services can be regarded as separate contestable businesses.

2. A dollar threshold will exist for "practical contestability", below which a market would not be attracted by the opportunity. Discussion with investment brokers indicates that the threshold (for net present value of services contract) is around $15 million for shared network services.

   It is acknowledged that the threshold would also take into account the customer's set up cost to run a contestable process (taken to be around $100k).

3. Non-transmission solutions can constitute a competitive market for network augmentations. There must be cost equity between the solutions for this principle to be valid[1].

4. Contestability must be operationally feasible[2]. This means that the contestable service can be separated from other services, such that the contestable service, and other existing services interfacing with the contestable service, can be distinguished as distinct services. The ability to allocate performance liability amongst the service providers must be practically achievable.

   Where the new service is "embedded" within the SPI PowerNet infrastructure, ownership, operation and management of liabilities by a third party is unlikely to be practical.

   Project elements will be non-contestable where they impact on SPI PowerNet's ability to service its existing obligations (generally this would be limited to allocation of the point of interface for the augmentation).

5. Where a new service is classified under the criteria to be non-contestable, then, in the normal course of events, SPI PowerNet would have the right to provide the service, and the customer would have no right to take the service to the market.

[1] The concept of cost equity relates to economic interchangeability of transmission service options with other options to meet the need.

[2] Operational feasibility includes that the service provider would have unfettered access to the assets providing service, and that this should not require the service provider to have intimate knowledge of any SPI PowerNet systems or assets.

6. A service may be deemed to be non-contestable if it is demonstrated that there is no market for provision of the service. A market assessment would be carried out by the customer.

   A market shall be said to exist if there is at least one party other than SPI PowerNet prepared to offer the [aggregated (refer principle 1)] services to the customer.

Examples

(a) Non Contestable

- Upgrading of SPI PowerNet's existing secondary (protection, control) systems:
  - the services are heavily integrated into SPI PowerNet systems;
  - the facilities provide only a sub-service of an integrated node to node transmission availability service provided by SPI PowerNet;
  - it is unlikely that an augmentation would achieve the threshold for contestability;

- Upgrading/re-arranging of SPI PowerNet's existing network configuration switching facilities:
  - the facilities provide only a sub-service of an integrated node to node transmission availability service provided by SPI PowerNet;
  - network re-arrangement in itself does not involve transfer of existing assets from SPI PowerNet's asset register;
  - it is unlikely that an upgrading or re-arrangement would achieve the threshold for contestability;

- Upgrading of SPI PowerNet transmission line by asset adjustment:
  - an upgrade would typically involve replacement of tower components (but not at all towers), regrading of ground profile, re-tension of conductors. There are no distinct assets associated with the augmented service that can be separated from the assets required to provide the existing service;
  - the capital value of the project could, in some cases, satisfy the threshold for contestability;

- upgrade of transmission line by re-conductoring:
  - the conductor is only part of a node to node transmission service. It does not constitute a distinct service to VENCorp (criteria 5 is not satisfied).

- shunt capacitor bank projects:
  - annual requirements are in the range of 100 – 300MVAr. The capital value is less than $5m and does not satisfy the threshold for contestability;
  - the new services would be sufficiently independent of SPI PowerNet systems (apart from switching associated plant) for the capacitor banks to be owned/operated by another party (criteria 5 could be satisfied).

(b) Contestable

- tie transformers at existing or greenfields site:
  - ∗ a tie transformer has already been awarded via a contestable process. This was the ROTS 500/220kV transformer, won by Eastern Energy. Such a project would meet the threshold for contestability;
  - ∗ the new services would be sufficiently independent of SPI PowerNet systems for the capacitor banks to be owned/operated by another party subject to agreement on system/asset interfaces (criteria 5 could be satisfied).

- new transmission line on SPI PowerNet easement, or reconstruction of transmission line (for service augmentation purposes):
  - ∗ the project would meet the threshold for contestability;
  - ∗ the new services would be sufficiently independent of SPI PowerNet systems for criteria 5 to be satisfied.

Appendix I

Information disclosure templates (confidential)

Confidential Information Disclosure Templates (Appendix I)

have been deliberately omitted from these Appendices

SPI POWERNET
A subsidiary of Singapore Power International
ABN 78 079 798 173

Level 17 452 Flinders Street Melbourne, Victoria 3000
Telephone 61 3 8635 7333 Facsimile 61 3 8635 7334
www.spipowernet.com.au