CONSULTATION PAPER

BRUNSWICK TERMINAL STATION

12 May 2008

Disclaimer

The purpose of this document is to seek proposals from customers, Interested Parties, Registered Participants and solution providers to address the limitations of the current transmission network supplying the Melbourne Central Business District and surrounding suburbs. This document is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity. This document has been prepared using information provided by, and reports prepared by, a number of third parties.

Whilst care was taken in the preparation of the information contained in this paper, and it is provided in good faith, CitiPower accepts no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it.

This Consultation Paper has been prepared for the purpose of consulting with Registered Participants, Interested Parties and customers regarding a potential network augmentation, Eligible Major Network Project or non-network solution to improving future supply to the Melbourne CBD. CitiPower's network planning processes are currently governed by Victorian regulation. However, this Consultation Paper is designed to meet the requirements of the National Electricity Rules (NER), as electricity distribution is in the process of being phased into the national regulatory framework.

The Consultation Paper has been prepared with consideration for pertinent information provided by a number of third parties. It contains assumptions that, by their nature, may or may not prove to be correct. CitiPower advises that anyone proposing to use this information should verify its reliability, accuracy and completeness before committing to any course of action. CitiPower makes no warranties or representations as to reliability, accuracy and completeness of this information and CitiPower specifically disclaims any liability or responsibility for any errors or omissions in this Consultation Paper or in third party information referred to herein.

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1 Introduction and Summary

CitiPower is facing constraints at three 220kV terminal stations that supply the Melbourne CBD, namely West Melbourne Terminal Stations (WMTS 66kV and WMTS 22kV) and Richmond Terminal Station (RTS 66kV). In order to address these constraints, CitiPower is proposing to upgrade the terminal station at Brunswick to a 66kV station.

Before investing any new large transmission asset, CitiPower is required to apply the regulatory test and consult with Registered Participants, NEMMCO and other interested parties. This document represents CitiPower's application notice in relation to the proposed investment.

CitiPower has considered two options that address the emerging constraints; the upgrade of the Brunswick Terminal Station (BTS) (the 'proposed option') and the re-development of the Bouverie Street/Bouverie-Queensberry (BSBQ) zone substation ('alternate option 1'). As per the requirements of the market benefits limb of the regulatory test, CitiPower has calculated the net economic benefit of the proposed option relative to each alternate option under a range of reasonable scenarios which include sensitivity testing with regard to capital costs, operating and maintenance costs and the discount rate.

Our analysis suggests that the proposed option provides the greatest net economic benefit in the majority of reasonable scenarios as shown in the table below. Under all scenarios considered, the net economic benefit under the proposed option is greater than that under alternate option 1.

Summary of Results

Scenario	Net Economic Benefit ($2008 mill)	
	Proposed Option	**Alternate Option 1**
Base Case	$1,100	$1,066
Capex Sensitivity		
Upper Bound (BC + 20%)	$1,080	$1,039
Lower Bound (BC - 20%)	$1,120	$1,093
Opex Sensitivity		
Upper Bound (BC + 50%)	$1,094	$1,058
Lower Bound (BC - 50%)	$1,106	$1,074
Discount Rate Sensitivity		
Upper Bound (10%)	$765	$733
Lower Bound (6.6%)	$1,480	$1,445

The remainder of this application notice is set out as follows:

- section 2 sets out the requirements that must be met by an entity proposing to invest in a new large transmission asset, namely the requirement to apply the regulatory test and the consultation process in relation to this;
- section 3 describes the rationale for the proposed augmentation;
- section 4 sets out the various options that CitiPower could feasibly adopt to address the emerging network constraints;
- section 5 sets out the range of reasonable scenarios considered for the purpose of the regulatory test; and
- section 6 sets out the results of the regulatory test analysis.

2 Requirements for Investment in a New Large Transmission Asset

Any entity proposing to undertake a new large transmission network asset investment must satisfy the regulatory test and consult with various parties. This section briefly sets out the requirements of the regulatory test and the process for consultation.

2.1 The Regulatory Test

Clause 5.6.6 of the National Electricity Rules (NER) requires the regulatory test to be applied by any entity proposing to undertake a new large transmission network asset investment.

The regulatory test is a form of cost-benefit analysis for assessing alternative investment options. The test comprises two distinct limbs:

- the 'reliability limb', which is intended for use in assessing network investments to be undertaken to meet minimum network performance requirements, and is set out in clause (1)(a) of the test; and
- the 'market benefits limb', for use in assessing other network investments, set out in clause (1)(b).

The proposed upgrade will be assessed under the market benefits limb of the regulatory test, which is set out in clause (1)(b), as follows:[1]

> *(1) "An option satisfies the* regulatory test *if:*
>
> > *(b) in all other cases – the option maximises the expected* net economic benefit *of all those who produce, consume and transport electricity in the national electricity market compared to the likely* alternative option/s *in a majority of* reasonable scenarios*.* Net economic benefit *equals the* market benefit *less* costs*."*

The net economic benefits were calculated based on the value of customer reliability (VCR), as outlined in section 2.3 of the 2007 Transmission Connection Planning Report, produced jointly by the Victorian distribution businesses.

2.2 Consultation Process

Under Clause 5.6.6 of the NER, a person who proposes to establish a new large transmission network asset must consult all Registered Participants, NEMMCO and interested parties about the proposed investment. Specifically, the applicant must make available to all Registered Participants and NEMMCO a notice which sets out:

- a detailed description of the proposed asset, the reasons for proposing to establish the asset and all other reasonable network and non-network alternatives to address the identified constraint or inability to meet the network performance requirements;
- all relevant technical details concerning the proposed asset;

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[1] Clause 3 of the Regulatory Test Version 3 as published in Australian Energy regulator (AER), Final Decision: Regulatory Test version 3 & Application Guidelines, November 2007.

- the construction timetable and commissioning date for the asset;
- an analysis and ranking of the proposed asset and all reasonable alternatives; and
- a detailed analysis of why the applicant considers that the asset satisfies the regulatory test and, where the applicant considers that the asset satisfies the regulatory test as a reliability augmentation, analysis of why the applicant considers that the asset is a reliability augmentation.

The above information is contained in the following sections of this application notice.

CitiPower must provide a summary of this application notice to NEMMCO who must publish it on its website within three business days of receipt. Within thirty business days of publication on NEMMCO's website, interested parties may make a written submission to CitiPower on any matter in the application notice and may request a meeting.

CitiPower must consider all submissions received within a further thirty business days and use its best endeavours to hold a meeting with interested parties who request such a meeting within a further twenty one business days if:

- after having considered all submissions received, CitiPower considers that it is necessary or desirable to hold a meeting; or
- a meeting is requested by two or more interested parties.

CitiPower must prepare a final report to be made available to all Registered Participants, NEMMCO and interested parties who respond to this application notice. The final report must set out the matters detailed in Clause 5.6.6(c) of the NER, summarise the submissions received from interested parties and CitiPower's response to each submission. CitiPower must provide NEMMCO a summary of the final report which will be published on NEMMCO's website within three business days of its receipt.

3 Rationale for the Augmentation

The proposed upgrade to the 220/22kV terminal station at Brunswick is required to relieve constraints at West Melbourne terminal stations WMTS 66kV and WMTS 22kV that supply the northern and western inner central business district and surrounding areas. It will also help to alleviate constraints at the heavily loaded Richmond Terminal Station.

3.1 Capacity Constraints at WMTS 66kV

WMTS 66kV is a summer critical station consisting of four 150 MVA 220/66kV transformers. The terminal station provides major supply to the western Central Business District, including Docklands areas as well as the inner suburbs of Northcote and Brunswick West in the north, and Kensington, Flemington, Footscray and Yarraville in the west.

WMTS 66kV operates one of its four transformers on "Normal Open Auto-close" duty (ie, on hot stand-by with a facility for automatically closing upon a forced outage for any one of the three normal-running transformers) in order to control the 66kV fault level within the safety station fault rating limit. This effectively means that the N rating for the terminal station is restricted to its lower N-1 rating (ie, equal to the capacity of the three transformers)[2] . SP AusNet has indicated their intention to refurbish the terminal station in the price reset period 2014-2019. Following completion of the refurbishment at WMTS, it is expected that the N rating restriction will be removed.

There will not be sufficient capacity at the WMTS 66kV station to supply all demand at the 50th percentile temperature under both N and N-1 conditions (ie, the capacity of the three normal-running transformers would not be sufficient to satisfy demand) from 2010 onwards until the WMTS has been refurbished by SP AusNet. Assuming that the WMTS refurbishment can be completed as early as 2016, the present value of the estimated value of energy at risk for the next 45 years (ie to 2052) is $1.43 billion as outlined in Appendix A, Table A.2. This high value is due predominantly to unserved energy with all plant in service in the period up to 2017.

3.2 Capacity Constraints at WMTS 22kV

WMTS 22kV is also a summer critical station consisting of two 165 MVA 220/22kV transformers. The terminal station provides supply to the West Melbourne area including Melbourne Docks, Docklands Area, North Melbourne (including railway substation), Parkville and Carlton and the northern and western inner Central Business District and surrounding areas.

From 2011 onward there will not be sufficient capacity at the WMTS 22kV station to supply all demand at the 50th percentile temperature if there were an outage of one transformer during the summer period. However, the probability of such an outage occurring is relatively low at around 0.217 per cent. The present value of the estimated value of energy at risk for the next 45 years (ie, to 2052) is $73 million as outlined in Appendix A, Table A.3.

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[2] Note that the strategy for installing the fourth transformer on "Normal Open Auto-close" duty in 2002 also involved taking action at an appropriate time in the near future to remove the station loading restriction by increasing N to the normal four-transformer capacity level (about 700 MVA).

3.3 Capacity Constraints at RTS 66kV

RTS 66kV is a summer critical station consisting of four 150MVA 220/66kV transformers. The terminal station provides supply to the Eastern Central Business District and wide-spread inner suburban areas in the east and south-east of Melbourne, including Fitzroy, Collingwood, Abbotsford, Richmond, North Richmond, Hawthorn, Camberwell, Gardiner, Toorak, Armadale, South Yarra, St Kilda, Elwood and Balaclava.

There is currently insufficient capacity at the RTS 66kV station to supply all demand at the 50th percentile temperature if there were an outage of one of the transformers during the summer period. However, the probability of such an outage occurring is relatively low at around 0.217 per cent. The present value of the estimated value of energy at risk for the next 45 years (ie, to 2052) is $685 million as outlined in Appendix A, Table A.4.

3.4 Brunswick Terminal Station Upgrade

In order to reinforce security of supply to the northern and inner Central Business District areas, and to provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood, CitiPower proposes to upgrade the BTS with 66kV connection point of supply.

The upgraded BTS 66kV would gradually offload WMTS 66kV and WMTS 22kV and provide a new 66kV point of connection for the Central Business District supply, thereby reducing the reliance on the WMTS 66kV. The upgraded BTS 66kV could also offload the heavily loaded 66kV terminal station at Richmond by permanently picking up supply of three zone substations which it currently supplies[3]. This would defer, but not eliminate, the requirement to establish a new terminal station in the inner suburban area.

3.5 Distribution System Constraints

To understand the wider background to the proposed upgrade, reference is made to the 2007 CitiPower Distribution System Planning Report (DSPR), accessible on the CitiPower internet site, www.citipower.com.au.

The 2007 DSPR details capacity constraints on the following subtransmission lines emanating from terminal stations WMTS 66kV, WMTS 22kV and RTS 66kV.

- WMTS 66kV – Victoria Market (VM) zone substation
- WMTS 22kV – BSBQ zone substation
- RTS – Flinders Ramsden (FR) zone substation

[3] The 2007 Transmission Connection Planning Report suggests that the constraints at RTS 66kV could also be alleviated with the transfer of supply to Malvern Terminal Station (MTS 66kV). This option would require a third transformer at MTS 66kV and associated switchyard works together with 66kV line works by 2012/13. Without the load transfer to MTS, the third transformer at MTS 66kV would not be required for at least the next 15 years. Given that even without the transfer of load from RTS 66kV, a third transformer would be required at BTS 66kV to cater for load growth in the CBD by around 2016, the proposed option will be preferred to this option under all scenarios considered. We therefore have not considered the transfer of load from RTS 66kV to MTS 66kV as an alternate option for the purpose of the regulatory test.

4 Investment Options

The market benefits limb of the regulatory test requires the assessment of a proposed investment option relative to a number of alternative options, where the term 'alternative option is defined as:[4]

> *(a) "a genuine alternative to the option being assessed, in that it:*
>
> > *(i) delivers similar outcomes to those delivered by the option being assessed; and*
> >
> > *(ii) would become operational in a similar timeframe to the option being assessed;*
>
> *(b) a practicable alternative to the option being assessed in that it is technically feasible.*

In determining whether an alternative option is likely, a network service provider must consider a range of matters, including whether the alternative option has a genuine proponent and whether it is commercially feasible.[5] The AER notes that the absence of a proponent will not in itself exclude a project from being a likely alternative option for the purpose of the regulatory test.[6]

This section outlines both the proposed and alternative options for addressing capacity constraints at West Melbourne terminal stations WMTS 66kV and WMTS 22kV.

Note that Clause 2 of the regulatory test provides that only direct costs may be included in the analysis, ie, construction costs, operating and maintenance costs and the cost of complying with laws, regulations and applicable administrative requirements. In this section only the capital costs related to each investment option, and the benefits in terms of the value of lost load to those customers served by the relevant terminal stations, have been identified. The associated operating and maintenance costs are discussed in section 5.4.

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[4] Clause 16 of the Regulatory Test.

[5] Clause (17)(b) and (17)(c) of the Regulatory Test. The extent to which an alternative option is commercially feasible is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide the alternative option.

[6] Clause (17)(b) of the Regulatory Test.

4.1 Proposed Option

At present, 50 per cent of the Central Business District load is supplied by the WMTS 66kV and the WMTS 22kV terminal stations. As noted earlier, these stations are expected to exceed N-1 capacity by around 2009/10 and 2010/11 respectively.

The preferred option to address the emerging constraints is to upgrade the current terminal station at Brunswick (BTS) to a 220/66kV station. BTS is currently a 220/22kV terminal station that supplies areas including Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds.

The upgrade will involve the following shared and transmission connection assets at BTS:

- two new 220/66kV transformers; and
- one 50MVA or 66kV capacitor bank.

It will also involve the following distribution works for Bouverie-Queensberry (BQ) supply:

- installation of two 66kV 120MVA cables from BTS to BQ;
- protection works for both ends of 66kV cables between BTS and BQ;
- installation of nine 66kV CBs and isolators in double bus configuration;
- installation of two 66/11kV 60MVA transformers and 11kV switchgear and secondary works;
- civil works for switch bay floors; and
- BQ station refurbishment.

This equipment is planned to be installed and works completed by 2012 and will alleviate the constraints in the CBD.

Figure 4.1 below illustrates how the upgrades fit into the larger network. A breakdown of the timing and capital costs of the planned works is set out in Table 4.1 below.

Figure 4.1
Brunswick Capacity Upgrade

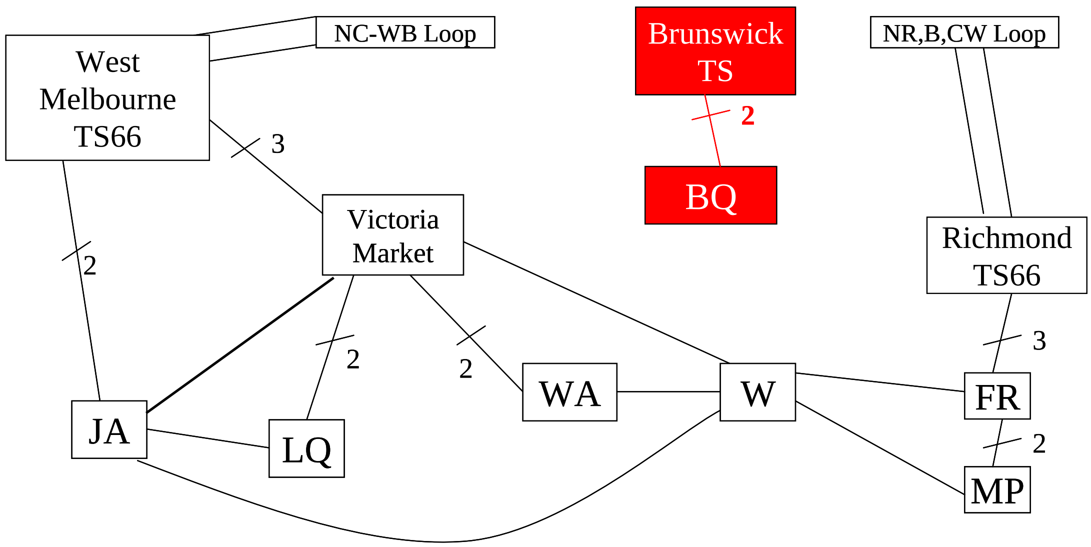

Table 4.1 Brunswick Upgrade Cost Breakdown

Works	Unit Cost ($2008 mill)	Qty	Total Cost ($2008 mill)	Year
Shared & Transmission Connection Assets (BTS)			**$62.847**	
Install 2 x 220/66kV 225 MVA transformers	$61.491	1	$61.491	2010
Install 1 x 50MVAr 66kV Capacitor bank	$1.356	1	$1.262	2010
Demand Related Distribution Works			**$40.848**	
Install 2 x 66kV 120MVA cables from BTS to BQ	$4.158	5.33	$22.161	2010
Protection works for both ends of 66kV cables (BTS-BQ)	$0.228	2	$0.455	2010
Install 9 x 66kV CBs + isolators in Double bus configuration	$0.791	9	$7.117	2010
Install 2 x 66/11kV 60MVA transformers + 11kV switchgear & secondary works	$6.390	1	$6.390	2010
Civil works for switch bay floors (per 66kV transformer)	$1.150	3	$3.449	2010
Station Refurbishment costs for BQ	$1.276	1	$1.276	2010
TOTAL			**$103.696**	

Source: SKM, *CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report, 22 August 2006, Table K.2, page 66, updated from $2006 to $2008 as per SKM Technical Note from Keith Frearson, dated 8 February 2008. Email titled 'Stage 1 and Stage 2 Costs: BTS 66kV connection SLD revision – Option 2A', from Glen D'Costa, Customer Solutions Consultant, SP-Ausnet to Victor Law, CitiPower/Powercor.*

The upgrade of the Brunswick Terminal Station will deliver benefits through a reduction in the expected value of unserved energy not only at WMTS 66kV and WMTS 22kV, but also at RTS 66kV. The present value of these benefits to the year 2052 is estimated to be $1.20 billion as outlined in Appendix B, Table B.1.

4.2 Alternate Option 1

The emerging constraints may also be addressed through the re-development of the Bouverie Street/Queensberry (BSBQ) zone substation.

This consists of developing a 220/66kV terminal station at the BSBQ substation site, through the installation of two 220/66kV 225MVA transformers, 12 66kV GIS CBs, a 50MVAr 66kV capacitor bank, five 220kV GIS CBs, control room facilities and associated refurbishment. In addition, a new 220kV cable would connect BTS with Richmond Terminal Station (RTS) via

BSBQ. CitiPower note that this cable would be developed at some time in the future as part of the shared transmission network.[7]

Finally, three 66/11kV 30MVA transformers, 11kV CBs and secondary works would complete the upgrade of BSBQ.

Table 4.2 below sets out the timing and costs of the BSBQ development.

The re-development of the Bouverie Street/Queensberry (BSBQ) zone substation will deliver benefits through a reduction in the expected value of unserved energy at WMTS 66kV, WMTS 22kV and RTS 66kV. These benefits are the same as that achieved under the proposed option ($1.20 billion to the year 2052), as outlined in Appendix B, Table B.1.

[7] SKM estimates that the redevelopment of the BSBQ site brings this investment forward by 20 years. As a result, our cost-benefit analysis only includes the costs of bringing this investment forward by 20 years. See SKM, *CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report*, 22 August 2006, page 32.

Table 4.2 BSBQ Redevelopment Cost Breakdown

Works	**Unit Cost ($2008 mill)**	**Qty**	**Total Cost ($2008 mill)**	**Year**
Shared & Transmission Connection Assets (BSBQ)			$127.144	
Total station costs (electrical works only as per BTS quote)	$61.491	1	$61.491	
Install new BTS-RTS 220kV cable running via BSBQ	$4.105	12	$49.257	2010
Station Refurbishment (220kV + transformer civils+220kV& 66kV switch bay floors)	$16.395	1	$16.395	2010
Demand Related Distribution Works			$11.894	
Civil works for 66kV switch bay floor (per 66kV transformer)	$1.150	3	$3.449	2010
Install 1 x 50MVAr 66kV Capacitor bank	$1.356	1	$1.356	2010
Install 3 x 66kV 60MVA cables from BSBQ TS to Sub BSBQ	$4.158	0.05	$0.208	2010
Protection works for both ends of BSBQ TS Sub BSBQ 66kV cables	$0.228	3	$0.683	2010
Install 3 x 66/11kV 30MVA transformers +11kV CBs & secondary works	$5.623	1	$5.623	2010
Station Refurbishment (11kV)	$0.575	1	$0.575	2010
TOTAL			**$139.038**	

Source: *SKM, CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report, 22 August 2006, Table K.1, page 65, updated from $2006 to $2008 as per SKM Technical Note from Keith Frearson, dated 8 February 2008.*

4.3 Alternate Option 2

Alternate option 2 involves the construction of an embedded generator which would help defer the need for augmentation. A summary of the level of embedded generation that would temporarily alleviate the constraints at each terminal station required for the period 2008 to 2016 is set out in Table 4.3 below.

Table 4.3 Embedded Generation Required to Alleviate Constraints (MVA), 2008 – 2016

Terminal Station	2008	2009	2010	2011	2012	2013	2014	2015	2016
WMTS 66kV									
50% POE	-	-	14	32	53	73	94	116	138
10% POE	-	19	57	76	98	120	143	165	189
WMTS 22kV									
50% POE	-	-	-	-	1	7	12	17	23
10% POE	-	-	1	7	12	18	24	29	35
RTS 66kV									
50% POE	69	82	95	107	120	133	146	158	171
10% POE	129	142	157	171	185	199	213	226	240

Source: *Data provided by CitiPower staff.*

CitiPower is not currently aware of any proponents of embedded generation that would be capable of alleviating the constraints identified above and has therefore not conducted an assessment of costing this option. CitiPower notes that embedded generation would be required at specific locations as set out in CitiPower's Distribution Planning Review.[8] CitiPower invites discussion with proponents of embedded generation within these areas, to the extent they would be capable of satisfying the demand requirements identified in Table 4.3 above.

A number of other options were considered, however CitiPower determined that these were either not genuine or practicable alternatives to the option being assessed in line with the requirements of the regulatory test. These options are discussed further in Appendix C.

[8] CitiPower, Distribution System Planning Report 2007 at http://www.citipower.com.au/docs/pdf/Electricity%20Networks/CitiPower%20Network/CitiPower%202007%20Distribution%20System%20Planning%20Report.pdf

5 Range of Reasonable Scenarios

Under the market benefits limb of the regulatory test, an investment option will satisfy the test if it maximises the net present value of the market benefit, compared with a number of alternative options in a majority of reasonable scenarios. For the purpose of the test, reasonable scenarios are defined as those incorporating reasonable forecasts of demand and operating costs, market development scenarios and sensitivity testing:[9]

"Reasonable scenarios means scenarios incorporating:

(a) reasonable forecasts of:

(i) Electricity demand (modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);

(ii) The efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed, anticipated *and* modelled *projects, including demand side and generation projects;*

(iii) the avoidable costs of committed, anticipated *and* modelled *projects including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred**;***

(iv) the cost of providing sufficient ancillary services to meet the forecast demand; and

(v) the capital and operating costs of other regulated network and market network service *projects that are augmentations consistent with the forecast demand and generation scenarios;*

(b) scenarios defined as market development scenarios; and

(c) sensitivity testing."

The rationale for assessing the costs of alternative options across a number of reasonable scenarios is to test the robustness of the results. Where the analysis relies on forecasts or uncertain assumptions, the outcome should be tested against variations in these forecasts or assumptions.

Given that the regulatory test considers only direct costs and benefits, market development scenarios are relevant only to the extent that they impact the nature, timing and level of such costs and benefits. In light of this, only scenarios that impact the present value of direct costs and benefits have been considered.

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9 See Clause 4 of the Regulatory Test.

5.1 Demand

Under Clause 4 of the regulatory test, the analysis needs to consider reasonable forecasts of electricity demand (modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity).

Estimates of the 50th percentile summer maximum demand for each of WMTS 22kV, WMTS 66kV and RTS 66kV are outlined in table 5.1 below.

Table 5.1 Summer Maximum Demand Forecast (MVA), 2007 - 2016

Terminal Station	2008	2009	2010	2011	2012	2013	2014	2015	2016
WMTS 66kV	481.4	504.4	540.2	558.4	578.7	599.4	620.5	642.0	664.0
WMTS 22kV	105.5	111.6	119.7	125.3	130.5	135.7	141.0	146.4	151.8
RTS 66kV	560.4	572.7	585.8	598.5	611.3	624.0	636.8	649.3	661.9

Source: *Transmission Planning Connection Report 2007, produced jointly by the Victorian Electricity Distribution Businesses*

To project peak demand beyond 2016 CitiPower employs an assumption of a uniform 2.5 per cent growth in electricity peak demand within the Melbourne CBD network.

Given the importance of demand and demand growth assumptions on the calculation of customer benefits, CitiPower would ordinarily undertake sensitivity tests at ±10 per cent of estimated demand growth rate. However, given the size of the benefits that accrue under both the proposed and alternate option 1 ($1.10 billion and $1.07 billion respectively as outlined in Appendix D, under the base case in Tables D.1 and D.2 respectively), we have not done so. We note that a 10 per cent reduction in estimated demand growth rate would not reduce the present value of the benefits below the cost of either the proposed or alternate option 1.

5.2 Generation and Transmission Developments

The purpose of this regulatory test is to assess the most beneficial option for additional services at the terminal station level. As a result, different assumptions of generation development, other than embedded generation, have no impact on this assessment.

5.3 Demand Management Options

Peak demand at WMTS 66kV, WMTS 22kV and RTS 66kV would need to be reduced significantly to defer the proposed upgrade to the Brunswick terminal station. The size of the required reduction in peak demand is set out in Table 5.2 below.

Table 5.2 Reduction in Peak Demand Required to Alleviate Constraints (MVA), 2008 – 2016

Terminal Station	2008	2009	2010	2011	2012	2013	2014	2015	2016
WMTS 66kV									
50% POE	-	-	14	32	53	73	94	116	138
10% POE	-	19	57	76	98	120	143	165	189
WMTS 22kV									
50% POE	-	-	-	-	1	7	12	17	23
10% POE	-	-	1	7	12	18	24	29	35
RTS 66kV									
50% POE	69	82	95	107	120	133	146	158	171
10% POE	129	142	157	171	185	199	213	226	240

Source: Data provided by CitiPower staff.

CitiPower welcomes comments from potential proponents of demand management initiatives that would achieve demand reductions in the order of the above.

5.4 Sensitivity Testing

For the purpose of this analysis sensitivity testing has been applied to the following variables:

- Capital costs;
- Operating and Maintenance Costs; and
- Discount rate

5.4.1 Capital Costs

The capital costs associated with both the proposed and alternate option 1 were assessed by Sinclair Knight Mertz (SKM) in the context of CitiPower's Review of CBD Security of Supply and Planning Standards.[10] These costs have since been updated to reflect increases in the cost of various items over time and are set out in sections 4.1 and 4.2. There is always uncertainty regarding the quantum of capital costs of a project. Therefore sensitivity tests at ±10 per cent of the estimates have been applied.

All the costs included in this report are denoted in 2008 dollars as per the capital costs outlined in the SKM update and the estimated value of annual unserved energy as set out in the 2007 Transmission Connection Planning report.

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[10] SKM, *CitiPower Review of CBD Security of Supply and Planning Standards: Updated Final Report*, 22 August 2006, p.65 – 66.

5.4.2 Operating and Maintenance Costs

For the purpose of the analysis it is assumed that the operating and maintenance costs associated with all network augmentations to be 1 per cent of the capital cost. Since this is a generic estimate that may not reflect actual costs, sensitivity analysis was undertaken with operating costs at ±50 per cent of this estimate.

All operating and maintenance costs are assumed to be incurred, on average, in the middle of the financial year.

In order to estimate the value of operating expenditure cash flows after year 10 of the analysis, the terminal values have been calculated as annuities, starting in the 11th year and continuing until the end of the life of each asset. It is estimated the lives of the relevant assets are 45 years.

5.4.3 Discount Rate

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to convert the future cash payments and receipts into present value terms. The choice of discount rate will impact the estimated present value of costs and may impact the ranking of alternative options.

The regulatory test requires that the modelling be conducted using a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector, and that the rate used be appropriate to the cash flows being discounted.[11] We have adopted a real pre-tax discount rate of 8 per cent for the purpose of our analysis. This is consistent with the discount rate applied by VENCorp in three recent assessments of new transmission investments.[12]

The regulatory test requires that sensitivity analysis using alternative discount rates be carried out, and that the lower boundary should be the regulated cost of capital.[13] CitiPower's real pre-tax regulatory weighted average cost of capital is 6.6 per cent.[14]

Accordingly, for the purpose of this analysis a real discount rates of 6.6 per cent and 10 per cent for sensitivity testing was applied.

5.5 Summary of Reasonable Scenarios

The range of reasonable scenarios considered for the purpose of our analysis is set out in table 5.3 below.

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[11] Clause 10 of the Regulatory Test.

[12] VENCorp, *New Large Transmission Network Asset: Additional 500/220kV Transformation to Support West Metropolitan Melbourne and Geelong Area Load Growth*, September 2005, p27; VENCorp, *New Large Network Asset: Additional 500/220kV Transformation to Support Melbourne Metropolitan Load Growth*, July 2005, p48; and VENCorp, *Consultation Notice Small Network Augmentation Rowville to Richmond Transfer Capacity Upgrade*, March 2005, p13.

[13] Clause 15(c) of the Regulatory Test.

[14] Using the ESC Final Decision 2005 WACC parameters converted to an "Officer" real pre-tax WACC.

Table 5.3 Scenarios Considered

Sensitivity	Lower Bound	Base Case	Upper Bound
Capex	- 20%	CitiPower Estimate	+ 20%
Opex	- 50%	CitiPower Estimate	+ 50%
Discount Rate (Real Pre-Tax)	6.6%	8%	10%
Demand	- 10%	CitiPower Estimate	+ 10%

6 NPV Analysis

This section outlines the results of our analysis of all scenarios presented in section 5.5. We note that we have reported our assessment over a ten-year time horizon. This is consistent with the network-planning horizon for transmission networks required under Clause 5.6.2(d) of the NER.

The results of our analysis are set out in table 6.1 below. We first calculate the present value of costs for the base case for both the proposed and alternate option and then present the results for each scenario, involving the base case changed for one variable only (capex, opex or the discount rate). A more detailed analysis is set out in Appendix D.

Table 6.1 Summary of Results

Scenario	**Net Economic Benefit ($2008 mill)**	
	Proposed Option	**Alternate Option 1**
Base Case	$1,100	$1,066
Capex Sensitivity		
Upper Bound (BC + 20%)	$1,080	$1,039
Lower Bound (BC - 20%)	$1,120	$1,093
Opex Sensitivity		
Upper Bound (BC + 50%)	$1,094	$1,058
Lower Bound (BC - 50%)	$1,106	$1,074
Discount Rate Sensitivity		
Upper Bound (10%)	$765	$733
Lower Bound (6.6%)	$1,480	$1,445

As illustrated above, the net present value of the benefits resulting from the proposed option are greater than the alternate option for each of the scenarios considered. Whist the expected benefits are the same, the present value of the cost of the proposed option is lower than that of the alternate option for each of the scenarios considered. On the above basis, we conclude that the proposed option minimises the present value of costs compared with the alternate option in the majority of reasonable scenarios.

Appendix A. Value of Expected Energy at Risk

The value of expected unserved energy in the absence of the proposed augmentation is set out in table A.1 below. Tables A.2 to A.4 provide supporting data for each of WMTS 66kV, WMTS 22kV and RTS 66kV.

Table A.1 Value of Estimated Annual Energy at Risk ($2008 mill), 2008 - 2052

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Terminal Value (2017 – 2052)**
Summer										
WMTS 66kV	$0.0	$0.0	$1.6	$9.5	$35.7	$91.1	$187.1	$340.4	$556.3	$942.3
WMTS 22kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$85.8
RTS 66kV	$0.4	$0.7	$1.0	$1.4	$2.0	$2.7	$3.5	$4.4	$5.5	$895.6
Total	**$0.4**	**$0.7**	**$2.6**	**$11.0**	**$37.7**	**$93.8**	**$190.6**	**$344.9**	**$561.9**	$1,923.7
Winter										
WMTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$495.5
WMTS 22kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$59.3
RTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$446.0
Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	$1,000.9
Grand Total	**$0.4**	**$0.7**	**$2.6**	**$11.0**	**$37.7**	**$93.8**	**$190.6**	**$344.9**	**$561.9**	**$2,924.6**
Present Value of Expected Annual Unserved Energy	**$2,191.5**									

Table A.2 WMTS 66kV Estimated Energy at Risk ($2008), 2008 - 2052

	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Summer										
50th Percentile Summer Max Demand (MVA)	481.4	504.4	540.2	558.4	578.7	599.4	620.5	642.0	664.0	
Summer % Overload	0.0%	0.0%	2.7%	6.2%	10.0%	14.0%	18.0%	22.1%	26.2%	
Annual Hours at Risk	-	-	30	181	678	1,727	3,547	6,454	10,546	
Annual Energy at Risk (MWh)	-	-	5	16	44	138	138	208	285	
Expected Annual Unserved Energy (MWh)	-	-	30	181	678	1,727	3,547	6,454	10,546	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$1.6	$9.5	$35.7	$91.1	$187.1	$340.4	$556.3	$942.3
Winter										
50th Percentile Winter Max Demand (MVA)	359.3	383.5	407.8	422.8	439.1	455.7	472.5	489.7	507.5	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$495.5
Total Value of Expected Annual Unserved Energy ($mill)	**$1,433.5**									

Notes: (1) Based on a value of customer reliability of $52,746 per MWh (2) Based on a value of customer reliability of $45,899 per MWh.

Table A.3 WMTS 22kV Estimated Energy at Risk ($2008), 2008 - 2052

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Terminal Value (2017 – 2052)**
Summer										
50^{th} Percentile Summer Max Demand (MVA)	105.5	111.6	119.7	125.3	130.5	135.7	141.0	146.4	151.8	
Summer % Overload	0.0%	0.0%	0.0%	0.0%	1.1%	5.2%	9.3%	13.5%	17.7%	
Annual Hours at Risk	-	-			0.4	29.2	132	350	709	
Annual Energy at Risk (MWh)	-	-			0.8	14.0	37	69	110	
Expected Annual Unserved Energy (MWh)	-	-			0.0	0.1	0.6	1.5	3.1	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$85.8
Winter										
50^{th} Percentile Winter Max Demand (MVA)	88.2	95.8	101.2	105.8	110.4	115.1	119.8	124.6	129.5	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$59.3
Total Value of Expected Annual Unserved Energy ($mill)	**$72.8**									

Notes: (1) Based on a value of customer reliability of $45,050 per MWh (2) Based on a value of customer reliability of $46,437 per MWh.

Table A.4 RTS 66kV Estimated Energy at Risk ($2008), 2008 - 2052

	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Summer										
50th Percentile Summer Max Demand (MVA)	560.4	572.7	585.8	598.5	611.3	624.0	636.8	649.3	661.9	
Summer % Overload	14.1%	16.6%	19.3%	21.9%	24.5%	27.1%	29.7%	32.2%	34.8%	
Annual Hours at Risk	1,004	1,568	2,364	3,403	4,717	6,318	8,292	10,529	13,087	
Annual Energy at Risk (MWh)	46	63	86	115	143	182	220	256	293	
Expected Annual Unserved Energy (MWh)	9	14	21	30	41	55	72	91	114	
Value of Expected Annual Unserved Energy ($mill)[3]	$0.4	$0.7	$1.0	$1.4	$2.0	$2.7	$3.5	$4.4	$5.5	$895.6
Winter										
50th Percentile Winter Max Demand (MVA)	430.2	440.9	450.4	459.3	468.1	478.0	487.8	497.6	507.7	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$446.0
Total Value of Expected Annual Unserved Energy ($mill)	**$685.2**									

Notes: (1) Based on a value of customer reliability of $48,512 per MWh (2) Based on a value of customer reliability of $47,843 per MWh

Appendix B. Estimated Benefits of the Proposed Option and Alternate Option 1

It is expected that both the proposed and alternate option 1 will result in a reduction in the present value of expected annual unserved energy in the order of $1.20 billion as shown in Table B.1 below. Tables B.2 to B.5 provide supporting data for each of BTS 66kV, WMTS 66kV, WMTS 22kV and RTS 66kV.

Table B.1 Value of and Change in Estimated Annual Energy at Risk with Augmentation ($2008 mill), 2008 - 2052

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Terminal Value (2017 – 2052)**
Summer										
BTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$17.5	$19.8	$22.3	$24.9	$878.9
WMTS 66kV	$0.0	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$15.3
WMTS 22kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$7.1
RTS 66kV	$0.4	$0.7	$1.0	$1.0	$1.4	$0.0	$0.0	$0.0	$0.0	$269.0
Total	**$0.4**	**$0.7**	**$2.6**	**$1.0**	**$1.4**	**$17.5**	**$19.8**	**$22.3**	**$24.9**	**$1,170.3**
Winter										
BTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0	$3.7	$5.6	$7.8	$586.1
WMTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
WMTS 22kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4
RTS 66kV	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$88.3
Total	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$2.0**	**$3.7**	**$5.6**	**$7.8**	**$675.9**
Grand Total	**$0.4**	**$0.7**	**$2.6**	**$1.0**	**$1.4**	**$19.6**	**$23.6**	**$28.0**	**$32.7**	**$1,846.2**
Present Value of Expected Annual Unserved Energy	**$990.8**									
Change in Value of Expected Annual Unserved Energy from "Do Nothing"	**$1,200.7**									

Table B.2 Change in Value of Estimated Energy at Risk for BTS 66kV, ($2008) 2008 - 2052

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Terminal Value (2017 – 2052)**
Summer										
50th Percentile Summer Max Demand (MVA)	-	-	-	216.8	223.1	496.2	509.8	523.8	538.2	
Summer % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	72.3%	77.0%	81.9%	86.9%	
Annual Hours at Risk	-	-	-	-	-	1,186	1,186	1,233	1,287	
Annual Energy at Risk (MWh)	-	-	-	-	-	79,519	90,037	101,112	112,848	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	345	391	439	490	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$0.0	$0.0	$0.0	$17.5	$19.8	$22.3	$24.9	$878.9
Winter										
50th Percentile Winter Max Demand (MVA)	-	-	-	167.3	172.5	382.3	393.4	404.7	416.6	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	15.4%	18.8%	22.2%	25.8%	
Annual Hours at Risk	-	-	-	-	-	1,004	1,004	1,081	1,146	
Annual Energy at Risk (MWh)	-	-	-	-	-	10,084	18,455	27,997	38,528	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	44	80	122	167	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$2.03	$3.72	$5.65	$7.77	$586.1
Total Value of Expected Annual Unserved Energy ($mill)	**$795.0**									
Change in Value of Expected Annual Unserved Energy from "Do Nothing" ($mill)	**-$795.0**									

Notes: (1) Based on a value of customer reliability of $50,794 per MWh (2) Based on a value of customer reliability of $46,496 per MWh.

Table B.3 Change in Value of Estimated Energy at Risk for WMTS 66kV, ($2008) 2008 - 2052

	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Summer										
50th Percentile Summer Max Demand (MVA)	481.4	504.4	540.2	388.8	404.3	292.0	304.5	317.1	329.9	
Summer % Overload	0.0%	0.0%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	30	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	5	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	30	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$15.3
Winter										
50th Percentile Winter Max Demand (MVA)			407.8	294.4	306.8	222.0	231.9	241.8	252.2	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.1
Total Value of Expected Annual Unserved Energy ($mill)	**$9.1**									
Change in Value of Expected Annual Unserved Energy from "Do Nothing" ($mill)	**$1,424.5**									

Notes: (1) Based on a value of customer reliability of $52,746 per MWh (2) Based on a value of customer reliability of $45,899 per MWh.

Table B.4 Change in Value of Estimated Energy at Risk for WMTS 22kV, ($2008) 2008 - 2052

	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Summer										
50th Percentile Summer Max Demand (MVA)	105.5	111.6	119.7	90.6	94.8	86.4	90.2	94.1	98.0	
Summer % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$7.1
Winter										
50th Percentile Winter Max Demand (MVA)	88.2	95.8	101.2	76.5	80.2	73.3	76.7	80.1	83.6	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.4
Total Value of Expected Annual Unserved Energy ($mill)	**$4.3**									
Change in Value of Expected Annual Unserved Energy from “Do Nothing” ($mill)	**$68.5**									

Notes: (1) Based on a value of customer reliability of $45,050 per MWh (2) Based on a value of customer reliability of $46,437 per MWh..

Table B.5 Change in Value of Estimated Energy at Risk for RTS 66kV, ($2008) 2008 - 2052

	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Summer										
50th Percentile Summer Max Demand (MVA)	560.4	572.7	585.8	585.9	598.4	484.6	493.8	502.7	511.5	
Summer % Overload	14.1%	16.6%	19.3%	19.3%	21.9%	0.0%	0.6%	2.4%	4.2%	
Annual Hours at Risk	1,004	1,568	2,364	2,365	3,384	-	2	26	68	
Annual Energy at Risk (MWh)	46	63	86	86	115	-	1	4	6	
Expected Annual Unserved Energy (MWh)	9	14	21	21	29	-	0	0	1	
Value of Expected Annual Unserved Energy ($mill)[1]	$0.4	$0.7	$1.0	$1.0	$1.4	$0.0	$0.0	$0.0	$0.0	$269.0
Winter										
50th Percentile Winter Max Demand (MVA)	430.2	440.9	450.4	449.6	458.2	371.2	378.2	385.3	392.3	
Winter % Overload	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Annual Hours at Risk	-	-	-	-	-	-	-	-	-	
Annual Energy at Risk (MWh)	-	-	-	-	-	-	-	-	-	
Expected Annual Unserved Energy (MWh)	-	-	-	-	-	-	-	-	-	
Value of Expected Annual Unserved Energy ($mill)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$88.3
Total Value of Expected Annual Unserved Energy ($mill)	**$182.5**									
Change in Value of Expected Annual Unserved Energy from "Do Nothing" ($mill)	**$502.7**									

Notes: (1) Based on a value of customer reliability of $48,512 per MWh (2) Based on a value of customer reliability of $47,843 per MWh.

Appendix C. Options Not Considered to be Genuine or Practicable Alternatives

Other options considered for addressing the emerging constraints included the augmentation of the West Melbourne Terminal Stations (WMTS) and the Richmond Terminal Station (RTS). However, SPI PowerNet did not consider major augmentation of capacity at these stations to be appropriate. These options have therefore not been considered as technically feasible options (and therefore not practicable options) for the purpose of this assessment due to the following:15

- both RTS and WMTS are very old terminal stations, with a significant level of existing plant and equipment. SPI PowerNet considered further major development at either site will result in sub-optimal engineering outcomes and increase both operational and occupational health and safety risks;
- SPI PowerNet considered it necessary to maintain adequate available space for future reactive requirements at all metropolitan stations. SPI PowerNet considered it highly unlikely that there is space for an additional 220kV reactive support at WMTS and RTS with conventional reactive technologies;
- the capacity of both WMTS and RTS as the key CBD supply points is high by world standards. SPI PowerNet considered the undue reliance on a small number of terminal stations to supply critical CDB load not to be a prudent long-term strategy and that increased security would be best achieved by additional diversity with EHV supply points. SPI PowerNet considered that a notional limit of 550MVA should be the planning limit for development terminal station sites, which assumes an installation of 3 x 250MVA transformers or 4 x 150MVA transformers.
- the load level at many of the metropolitan terminal stations is about 500MW and is forecast to grow to more than 600MW over the next ten years. Such a high load level is beyond the firm transportation capacity that can be provided with 4 x 150MVA 220/66kV transformers; and
- additional augmentation to support increased load demand levels at both WMTS and RTS will place increasing pressure on the inner 220kV metropolitan transmission ring networks, necessitating the upgrade of these networks.

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[15] See letter from Charles Popple, General Manager Commercial, SPI PowerNet to Mr Garry Audley, General Manager, CitiPower Pty, dated 28 August 2003.

Appendix D. Detailed Results

D.1. Proposed Option

Scenario	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Base Case										
Capex	$0.00	$0.00	$103.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$13.25
Total Costs	$0.00	$0.00	$104.73	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$13.25
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,100**									
Base Case + Upper Bound Capex										
Capex	$0.00	$0.00	$124.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$15.90
Total Costs	$0.00	$0.00	$125.68	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$15.90
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,080**									
Base Case + Lower Bound Capex										
Capex	$0.00	$0.00	$82.96	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$10.60
Total Costs	$0.00	$0.00	$83.79	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$10.60
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,120**									

Base Case + Upper Bound Opex	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Capex	$0.00	$0.00	$103.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.56	$1.56	$1.56	$1.56	$1.56	$1.56	$1.56	$19.87
Total Costs	$0.00	$0.00	$105.25	$1.56	$1.56	$1.56	$1.56	$1.56	$1.56	$19.87
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,094**									
Base Case + Lower Bound Opex										
Capex	$0.00	$0.00	$103.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$6.62
Total Costs	$0.00	$0.00	$104.21	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$6.62
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,106**									
Base Case + Upper Bound Discount Rate										
Capex	$0.00	$0.00	$103.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$11.10
Total Costs	$0.00	$0.00	$104.73	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$11.10
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$655.76
NPV of Benefits Less Costs	**$765**									
Base Case + Lower Bound Discount Rate										
Capex	$0.00	$0.00	$103.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$15.27
Total Costs	$0.00	$0.00	$104.73	$1.04	$1.04	$1.04	$1.04	$1.04	$1.04	$15.27
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,531.30
NPV of Benefits Less Costs	**$1,480**									

D.2. Alternate Option 1

Scenario	2008	2009	2010	2011	2012	2013	2014	2015	2016	Terminal Value (2017 – 2052)
Base Case										
Capex	$0.00	$0.00	$139.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$17.76
Total Costs	$0.00	$0.00	$140.43	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$17.76
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,066**									
Base Case + Upper Bound Capex										
Capex	$0.00	$0.00	$166.84	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$21.31
Total Costs	$0.00	$0.00	$168.51	$1.67	$1.67	$1.67	$1.67	$1.67	$1.67	$21.31
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,039**									
Base Case + Lower Bound Capex										
Capex	$0.00	$0.00	$111.23	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.11	$1.11	$1.11	$1.11	$1.11	$1.11	$1.11	$14.21
Total Costs	$0.00	$0.00	$112.34	$1.11	$1.11	$1.11	$1.11	$1.11	$1.11	$14.21
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,093**									

Base Case + Upper Bound Opex	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Terminal Value (2017 – 2052)**
Capex	$0.00	$0.00	$139.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$26.64
Total Costs	$0.00	$0.00	$141.12	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$26.64
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,058**									
Base Case + Lower Bound Opex										
Capex	$0.00	$0.00	$139.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$8.88
Total Costs	$0.00	$0.00	$139.73	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$8.88
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,078.37
NPV of Benefits Less Costs	**$1,074**									
Base Case + Upper Bound Discount Rate										
Capex	$0.00	$0.00	$139.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$14.89
Total Costs	$0.00	$0.00	$140.43	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$14.89
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$655.76
NPV of Benefits Less Costs	**$733**									
Base Case + Lower Bound Discount Rate										
Capex	$0.00	$0.00	$139.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Opex	$0.00	$0.00	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$20.48
Total Costs	$0.00	$0.00	$140.43	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	$20.48
Total Benefits	$0.00	$0.00	$0.00	$9.96	$36.30	$74.20	$167.02	$316.97	$529.24	$1,531.30
NPV of Benefits Less Costs	**$1,445**									