SP AUSNET REVENUE RESET

Advice on revised revenue proposal

Prepared for

AUSTRALIAN ENERGY REGULATOR

PB Quality System:

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EXECUTIVE SUMMARY

The Australian Energy Regulator, in accordance with its responsibilities under the National Electricity Rules is required to conduct an assessment of the appropriate revenue determination to be applied to the prescribed transmission services provided by SP AusNet[1] (SPA) from 1 April 2008 and VENCorp from 1 July 2008. The previous revenue cap reviews for SPI PowerNet and VENCorp (both 2003-2007/08) were conducted by the Australian Competition and Consumer Commission (ACCC). The AER assumed responsibility for the regulation of transmission revenues in the National Electricity Market from the ACCC on 1 July 2005.

PB has been engaged by the AER to conduct a review of SPA in support of the AER undertaking these revenue determination assessments in March 2007 and presented a consolidated report to the AER in August 2007. The review by PB included an assessment of the historic (ex-post) and forecast (ex-ante) expenditure proposals for both capital expenditure (capex) and operational expenditure (opex) – as submitted to the AER by SP – as well as the proposed transmission service standards.

In August 2007, the AER published its draft decision relating to SPA's transmission determination for the period 2008/09 - 2013/14. PB's assessment was one of the inputs to the AER's decision-making process. In response to the draft decision, SPA submitted a revised proposal in October 2007.

Following receipt of SPA's revised proposal, the AER has requested further comment from PB on specific issues raised by SPA, particularly those issues which formed part of PB's original (detailed) review. This report addresses these issues across three areas – forecast capex, controllable (and other) opex and the service target performance incentive scheme – and aims to inform the AER's final decision on SPA's transmission revenue determination.

FORECAST CAPEX

With respect to SPA's forecast capex allowance, the AER has sought advice from PB regarding six aspects of SPA's revised revenue proposal.

Major project cost estimate contingencies

In its draft decision, the AER accepted PB's recommendation to exclude the contingencies included in SPA's major project cost estimates, effectively reducing SPA's forecast capex allowance by $24.6m (real, 07/08).

In response to this decision, SPA engaged Evans & Peck to identify risks associated with its major project cost estimates. In PB's view, the methodology used is based upon a well established, robust and systematic framework that explicitly highlights both risks and opportunities inherent in the detailed bottom-up estimates and also those that are unplanned and could materially influence the out-turn costs of the selected projects. SPA states that the Evans & Peck modelling indicates that the contingency allowance sought by it was a conservative estimate and should be re-instated.

PB has reviewed the inputs, methodology and outputs of the Evans & Peck studies. In PB's view the nature of the inputs and the interpretation of results has overstated the degree of risk to which SPA is exposed. In particular, PB considers the asymmetry assumed for the inherent risks has not been supported by evidence and that given the experience and detailed nature of the SPA's estimating process, the rate and quantity risks identified have already been mitigated through other means.

Notwithstanding this finding, PB concur with Evans & Peck that there are some unplanned risks – amongst other things, related to latent site conditions and matters outside the control of SPA – that have not been adequately captured by SPA's estimates. On this basis PB considers a contingency allowance of $9.5m is reasonable, efficient and prudent given the identified unplanned risks.

[1] Formerly SPI PowerNet.

Minor works – response capability for unforeseen works

SPA originally included a non-prescriptive allowance of $5.5m (real 07/08) to cover minor capital works not included in its project (and program) bottom-up capex forecast. As informed through PB's assessment, and drawing on its own experience, the AER has determined to exclude the minor works allowance as part of its draft decision.

SPA engaged Evans & Peck to review the unforeseen events undertaken by SPA in the current period with a view to supporting the quantity and need for the minor works allowance. Evan's and Peck identified that the nature of the vast majority (in excess of 75%) of the capex unforeseen but undertaken by SPA over the current period has already been included in its bottom-up project and program forecast. In PB's view no additional information has been presented to support a change in our original findings regarding the minor works allowance. PB maintains that there is sufficient discretion within the overall replacement program to accommodate any minor, unforeseen, expenditure without significant change to SPA's risk exposure.

Refurbishment of Hazelwood power station switchyard

In its draft decision, the AER accepted PB's advice that SPA had not demonstrated that the inclusion of costs for the replacement of some primary plant at Hazelwood power station switchyard reflected an appropriate level of prudence and efficiency, as no clear technical or economic need for these sub-components of a project were presented. The AER made a downward adjustment of $4m relative to SPA's proposed capex of $35.7m.

SPA subsequently provided new information pertaining to the condition and asset failure risks of the excluded items and an economic analysis to substantiate the efficiency and merits of combining the replacements with the circuit breakers.

While PB considers that there are a number of subjective assumptions included in SPA's economic assessment that overstate the benefits of the integrated replacement project, PB is satisfied that the inclusion of the all assets for replacement is an efficient and prudent outcome, and that the $4m be re-instated.

Redevelopment of Richmond terminal station

Based on PB's recommendation, and the AER determined that deferral of the replacement of the 220/66 kV transformers and the 66 kV switchyard was the most prudent and efficient alternative regarding SPA's proposed redevelopment of Richmond terminal station, reflected in a downward adjustment of $51.7m from the proposed allowance of $89.7m, as articulated in SPA's original proposal.

Following the draft determination, SPA presented four sets of new information relating to its proposed works at Richmond concerning the civil integrity of the 66 kV switchyard, the asset failure risks of the 220/66 kV transformers, an economic cost benefit assessment and new information on the project costs.

On the basis of the new and previous evidence presented, PB has now concluded that the integrated redevelopment of Richmond Terminal Station within the next regulatory period is prudent and efficient. PB has reviewed an updated and increased project cost estimate and materially different expenditure profile proposed by SPA and recommend that an allowance of $91.1m be included for Richmond towards the end of the regulatory period.

Transformer replacement program

As informed through PB's detailed project review, the AER determined that replacement of transformers at Bendigo, Dederang and one unit within the metropolitan area are not prudent and efficient capex projects. Amongst other adjustments, in total the AER made a downward adjustment of $22.4m to the original SPA proposal of $28.8m for the purposes of targeted transformer replacements.

With respect to the Bendigo transformer, SPA has presented additional and updated information and an economic analysis comparing a refurbishment option with the replacement option. In PB's view the economic assessment was neither robust nor conclusive. In recognition of the critical role played by this transformer in supplying the Bendigo region, PB suggests that an efficient and prudent alternative to replacing the transformers at Bendigo is the refurbishment of the two most degraded units at a cost of $1m.

With respect to the Dederang transformer, SPA refers to an economic evaluation that supports the units replacement. In PB's view this evaluation has not adequately captured the level of capex proposed by SPA and has overstated the consequential costs of failure. With support of a revised economic analysis, PB maintains that the deferral of the transformer replacement appears to be an efficient and prudent course of action.

With respect to the ASEA 150 MVA transformers, SPA has presented limited additional/updated information, which has not affected PB's previous findings regarding deferral of the replacement of one of the two ASEA transformers. Furthermore, given that the redevelopment of Richmond terminal station will release an ASEA transformer that is less than 10 years old, PB recommends that capex for the second ASEA transformer previously deemed efficient and prudent should be excluded from SPA's forecast allowance. This would result in a further downward adjustment of $4.5m.

CT replacement program

As an outcome of PB's detailed review of SPA's proposed CT replacement program and the Richmond terminal station redevelopment, PB recommended a reduction from 73 sets to 41 sets of CT's as part of the targeted program, plus the deferral of the 66 kV switchyard redevelopment at Richmond – implicitly deferring the replacement of an additional 20 sets of 66 kV CT's at this site. The AER excluded an allowance of $9.09m (37%) for the targeted CT replacement program.

SPA's revised proposal raised technical concerns regarding the increasing CT failure risk should CT replacements be deferred and it presented detailed economical arguments to support the prudence and efficiency of its original proposal.

In respect of the economic arguments presented, PB considers that the results overstate the risk and consequence of failure since they primarily rely on the consequential cost approximated for a single historical incident that is not appropriately representative of the majority of CT's that have been targeted for deferral – namely those with a life expectancy of 8-10 years in 2008. On the basis of the economic arguments presented and the balance of information, PB recommends the AER attenuate its excluded allowance to $8.3m (34%).

PB notes that in addition to replacing CT's under the targeted replacement program, we have also recommended the replacement of CT's associated with the Richmond 66 kV switchyard within the next regulatory period, thereby further reducing the overall asset failure risk associated with CT's within SPA's network.

CONTROLLABLE (AND OTHER) OPEX

With respect to its forecast controllable (and other) opex allowance, the AER has sought advice from PB regarding four aspects of SPA's revised revenue proposal.

NW contract

In its draft decision, the AER proposed revised calculations to estimate the savings from the new North West contract from those proposed by PB. SPA has extended the AER model to include all costs, not just labour and maintenance costs, and also the average regulatory account data over the last three years. PB believes that the use of all costs in the model produces a reasonable outcome. SPA predicts a total saving of $2m over the next six year regulatory period.

SPA has stated that *"For the purposes of this revised Revenue Proposal, therefore, SP AusNet would be prepared to accept PB's estimate of the cost savings arising from the new contract."* PB believes our original recommendation of a likely saving of $2.8m provides a reasonable estimation of the likely savings which will accrue from the introduction of the new NW Contract.

Management services contract

PB believes that SPA has not provided sufficient supporting information to determine if the services provided by the Singapore based staff are a fundamental component of the management and governance of SPA, and are essential in addition to the services and governance provided by the Board and Australian based management team. In the absence of this information PB does not believe that the costs associated with the Singapore based staff are *"costs that a prudent operator in the circumstances of the relevant Transmission Network Service Provider would require to achieve the operating expenditure objectives".*

PB therefore recommends that the management company actual opex costs be reduced by the SPI Management Fee of $1,440,495 resulting in a revised total of $6,280,716, and that these actual costs be the recommended service fee charged to the regulated transmission business for the 2006/07 financial year.

SPA's revised proposal contains two Appendices that provide additional information in relation to corporate costs. PB has examined this information and can confirm the findings of our original review, namely that while maintenance and operating expenditures do not appear to have risen as a result of the merger or the formation of the Management Company, it does not appear that any of the expected economies of scale (or scope) savings have been incorporated into the forecasts for these expenditures for the next regulatory period.

We recommend that the total recurrent and non-recurrent expenditures be reduced by $1.813m in 2006/07 and that this amount be escalated by the labour escalator for future years, namely 2.83%, as these savings comprise mainly labour savings.

Self insurance

In our original review we considered the proposed incident frequency rate for strain towers to be too high compared to historical incident data and recommended a reduction in the failure rate resulting in a reduced recommended self insurance risk premium of $18,399. PB continues to recommend this reduction in the premium for strain tower damage but recommends that the self insurance premium for conductor damage be included in the total self insurance risk premium.

PB also recommends a self insurance premium for both power and current transformers of $732,700 per annum. This figure is based on revised historical incident data provided by SPA, which details increases in the number of failures that have occurred.

PB recommends that the original SAHA recommendation for the self insurance risk premium for circuit breakers be accepted. We have based our revised recommendation on the detailed list of circuit breaker incidents reports over a ten year period provided by SPA to SAHA and included in Appendix "N" of the SPA Revised Proposal. This list contains 37 incident reports from 1997 to 2007 as opposed to the three incidents included in the original SAHA report on self insurance. PB has calculated the self insurance risk premium for circuit breaker failure based on an annual failure rate of 0.72% to be $847,440.

Revised opex requirement

PB has adjusted the SPA revised opex model to incorporate its recommendations in relation to the management services contract, opex merger effects and self insurance premiums. Our revised recommendations are detailed in Table E1 and result in a total downwards adjustment over the next 6-year regulatory period of $22.086m reducing SPA's revised opex from $443.824m to $411.738m.

Table E1 – Revised opex expenditures incorporating PB revised recommendations

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	69.016	70.332	72.174	72.967	74.313	75.022	433.824
Proposed variation	(3.460)	(3.545)	(3.633)	(3.723)	(3.815)	(3.910)	(22.086)
PB recommendation	65.556	66.787	68.541	69.244	70.498	71.112	411.738

Source: PB analysis

Availability Incentive Scheme Rebate Payments

PB considers it appropriate for the AER to allow only the forecast value of the rebate payments in the next regulatory period. SPA has re-estimated the value of the rebate payments as $3.51m per annum (2007/08).

PB examined the components that make up SPA's estimate of the likely rebate value and concluded as follows:

- the opex component should not be inflated by 12% to mirror the increased opex program but should be based on average historical rebate payments. This approach is consistent with the AER's approach for its service target performance incentive scheme
- the fault and forced outages component, based on average historical rebate payments, is accepted
- the SPA capex component has been over-estimated and should be reduced
- the major plant failure component did not take into account the reduction in failure risk over the current and next regulatory period and should be reduced.

PB recommends an allowance for rebate payments of $2.74m per annum.

SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

In its revised revenue proposal, SPA accepted the AER's draft decision on the service target performance incentive scheme for the parameters 'loss of supply events' and 'average outage duration' and most of the decision relating to the 'circuit availability' parameters[2].

SPA has not accepted the AER's decision to reject additional exclusions from the scheme for events relating to planned maintenance of the Brunswick to Richmond underground cable joints; customer works involving line up-ratings, busbar up-ratings or interconnector upgrades; and the proposed revision of the standard third party exclusion.

PB found that the values for the circuit availability parameters previously recommended were based on an incorrect allocation of outage hours to peak and intermediate periods. The values calculated by SPA in its revised proposal are correct. An allowance for customer works requiring the up-rating of lines or interconnector upgrades has also been made to reflect the AER's decision not to accept exclusions for these works. Revised targets and other values for the nine parameters of SPA's service target performance incentive scheme are provided in Section 4.6 of this report.

[2] An error was made in recalculating the 'circuit availability' parameters in the original assessment.

These changes affect the circuit availability parameters only. The values for loss of supply and outage duration parameters remain unchanged from PB's previous recommendations.

PB examined the additional exclusions sought by SPA and conclude as follows:

- PB agrees with SPA that the exclusion for outages of shunt reactors granted for peak periods should also apply to intermediate periods
- PB does not recommend that additional exclusions be allowed for outages associated with the Brunswick to Richmond cable joint replacements. PB considers that it is not unreasonable to expect a TNSP to carry the risk that equipment requires more or less planned maintenance than envisaged at the time of purchase, provided that the incentive is not lost due to the likelihood that the cap/collar might be breached. PB notes that including the works in the incentive mechanism retains the incentive to undertake the work efficiently
- PB does not recommend that exclusions for customer works involving line up-ratings, busbar up-ratings or interconnector upgrades should be made, given that an adequate allowance can be made in setting targets.

PB does not recommend that the standard third party exclusion be changed at this time.

1. INTRODUCTION

In this section of the report we provide some background to the review, together with an overview of the requirements and describe the PB approach to the work. We also set out details of the structure of this report.

1.1 BACKGROUND TO THE REVIEW

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (“Rules”)[3], is required to conduct an assessment of the appropriate revenue determination to be applied to the prescribed transmission services provided by SP AusNet (formerly SPI PowerNet) from 1 April 2008 and VENCorp from 1 July 2008.

PB has been engaged by the AER to conduct a review of SP AusNet in support of the AER undertaking these revenue determination assessments in March 2007 and presented a consolidated report to the AER in August 2007. The review by PB included an assessment of the historic (ex-post) and forecast (ex-ante) expenditure proposals for both capital expenditure (capex) and operational expenditure (opex) – as submitted to the AER by SPA, as well as the proposed transmission service standards.

In August 2007, the AER published it draft decision relating to SPA’s transmission determination for the period 2008/09 - 2013/14. PB’s assessment was one of the inputs to the AER’s decision-making process. In response to the draft decision, SPA submitted a revised proposal in October 2007. The AER has sought advice from PB on those matters contested by SPA.

Following receipt of SPA’s revised proposal, the AER has requested further comment from PB on specific issues contested by SPA – particularly those issues which formed part of PB’s original (detailed) review. This report addresses these issues across three areas – forecast capex, controllable (and other) opex and the service target performance incentive scheme, and aims to inform the AER’s final decision on SPA’s transmission revenue determination.

1.2 PROJECT OBJECTIVE AND APPROACH

PB has adopted the following methodology regarding this engagement:

- a review of the relevant revisions submitted by SPA with particular attention to the new or additional information that has been presented in the areas of dispute
- further consideration of the basis for our original position on specific issues, how the AER’s draft determination varies from that position, and whether the new or additional information impacts the AER’s position
- attendance at meetings between the AER and SPA to discuss the new material and raise any points of clarification
- preparation of a written response formalising our considerations of the revised proposal, followed by the inclusion of comments to allow the report to be finalised.

PB has undertaken this further with due regard to the regulatory principles and objectives outlined in the AER’s terms of reference and in a manner consistent with our original engagement. In particular, we have provided an independent view on whether the revised expenditure proposals reflect efficient costs – i.e. those which a prudent transmission business, operating in the circumstances of SP AusNet, would require to meet the objectives.

[3] The National Electricity Rules, Chapter 6A.

Where PB considers that the revised expenditure proposals do not meet the efficiency and prudence criteria, PB has provided an alternative, quantified, forecast of expenditure that, we believe, does satisfy the criteria.

PB has given due regard to the following information in undertaking this review:

a. AER Draft Decision – SP AusNet transmission determination 2008-09 – 2013-14 (31 August 2007)

b. PB Strategic Consulting – SP AusNet Revenue Reset: An independent review prepared for the Australian Energy Regulator (16 August 2007)

c. SP AusNet – Electricity Transmission Revised Proposal 2008-09 – 2013-14 (12 October 2007), and supporting information provided with that revised proposal

d. The AER's First Proposed Service Target Performance Incentive Scheme

1.3 REPORT STRUCTURE

In Section 2 of this report we address the issues associated with forecast (ex-ante) capex. Controllable (and other) opex is discussed in Section 3 and in Section 4 we set out our thoughts and recommendations on the service target performance incentive scheme. Our findings and recommendations are summarised in the Executive Summary of this report.

2. FORECAST CAPEX

In this section of the report we respond the issues raised by SPA with regard to its ex-ante (forecast) capex.

2.1 MAJOR PROJECT COST ESTIMATE CONTINGENCIES

SPA originally included a contingency allowance in nine station rebuild/refurbishment projects to account for the preliminary stage of cost estimates and for unforeseen costs that arise during projects with a complex nature. The contingency and base cost of each project is outlined in Table 2-1. In arriving at these contingency proposals, SPA has advised that it has used its previous experience, good engineering practice and expert understanding of its asset base.

Table 2-1 – Major project contingencies proposed by SPA

Expenditure $m (real 07/08)	Base cost	Contingency		Total
		value	%	
Brooklyn	49,022	2,832	5.8	51,855
Glenrowan	19,824	1,500	7.6	21,324
Geelong	26,011	2,485	9.6	28,496
Hazelwood Power	34,911	1,698	4.9	36,608
Hazelwood Terminal	18,022	1,387	7.7	19,410
Keilor	36,192	3,424	9.5	39,616
Richmond	87,100	5,920	6.8	93,020
Ringwood	27,783	1,594	5.7	29,376
Thomastown	39,980	3,747	9.4	43,727
TOTAL	338,845	24,587	7.3	363,432

Source: PB analysis and original SPA revenue proposal

In its draft decision, the AER accepted PB's recommendation to exclude the contingency for major projects, effectively reducing SPA's forecast capex allowance by $24.6m (real, 07/08).

In response to the AER's concerns regarding the application and quantification of these contingencies, SPA engaged E&P to identify risks associated with the capex project program and estimating process adopted by SPA and to quantify the degree of risk using a detailed bottom-up approach.

SPA has only included a contingency allowance for the major station rebuilds and refurbishment part of its forecast capex program. PB is therefore of the view that SPA has effectively acknowledged that it is prepared to accept all inherent and unplanned risks associated with the balance of its forecast capex program (as estimated using the unit rate models). While noting and concurring with Evans & Peck ("E&P") that the risk posed by those projects estimated through SPA's unit rate models is lower than that for the station rebuilds (given that in PB's opinion a higher degree of risk has already been captured in the base estimates), PB has not sought to review the treatment and quantification of such risks by E&P.

Notwithstanding the retrospective application of the E&P model, in PB's view the approach adopted by E&P is based upon a well established, robust and systematic framework that represents a suitable mechanism for assessing project cost risks. Notably, PB is satisfied that the approach documents and itemises the risks that are intended to be managed through the inclusion of a contingency allowance. However, PB is also of the view that the nature of the inputs and the interpretation of the outputs have lead to an overstatement of the degree of risk to which SPA is/would be exposed.

The inputs to the E&P risk model can be described in two broad categories:

- inherent risks associated with variation in the quantities and rates of each individual line item in the detailed cost estimates (for example, the number of hours required in project management of the construction element of the works and the hourly rate, the number of transformers and the delivered cost, or the volume and rate for excavation works, etc)
- unplanned risks that have not been captured in the detailed project estimates, and are usually the result of unforeseen events, or third party intervention relevant to the project (for example, outage restrictions, delays in delivery of the project or wet weather, inadequate initial scope/design, environmental hazards, etc).

PB observes that the input for each inherent risk is represented as a minimum and a maximum variance (expressed as a percentage) around the most likely quantity and rate – as shown in the following table:

Table 2-2 – Example of input assumptions for each line item of cost estimate

Line Item	Quantity	Rate	Base Estimate	Rate variance %			Quantity variance %		
				Min	Most likely	Max	Min	Most likely	Max
Modify/extend existing earth grid	32	2,558	81,862	75	100	300	80	100	130

Source: Evans & Peck report, Page 22

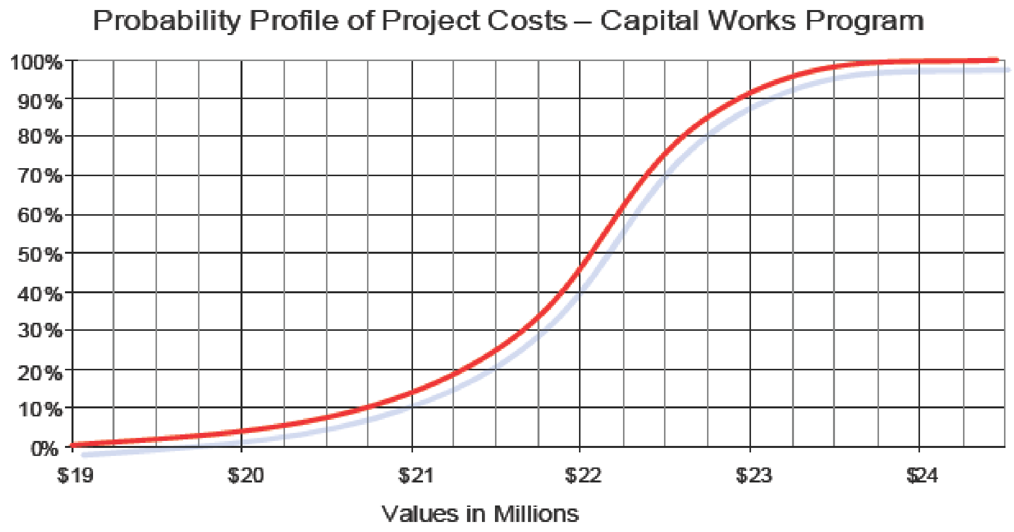
PB understands that all the minimum and maximum values are assigned to a consistent and predefined statistical confidence bound (e.g. a 90% confidence interval) – such that the minimum and maximum values have an equal likelihood of occurrence, and therefore the selection of the variance magnitude defines the extent of risk associated with either the rate or the quantity.

The wider the range of variance, and the greater the asymmetry around the base estimate, the greater is the cost variance risk for a given line item. Using the line item in Table 2-2 as an example, the theoretical range of cost extends from a minimum value of $49.1k, through the most likely figure of $81.8k to a theoretical maximum of $319.3k. Each project cost within this broad range will be assigned a probability of occurrence in accordance with a defined distribution. The outcome of these particular input assumptions is an asymmetric risk profile weighted above the base estimate towards the maximum cost.

A similar approach is adopted for the identified unplanned risks, except in addition to the range of cost implications, an overall likelihood of the occurrence is also made.

The overall risk model (capturing both inherent and unplanned risks) then considers the value and probability weighted influence of each line item using a Monte Carlo based probabilistic model that randomly processes multiple combinations of the line items. Given sufficient iterations, it produces a statistically accurate and weighted project cost distribution curve, as presented by E&P and reproduced in Figure 2-1. The "P50" project cost represents the most likely cost of the project and the shape of the curve reflects the extent of risk, for the defined inputs.

Figure 2-1 – Example of probability profile of project costs



Source: Evans & Peck report, Page 1

Importantly, PB notes that if each and every rate and quantity variance input to the model were assumed to be symmetrical around the base estimate, then the P50 project cost should equal the base estimate – with an equal likelihood that the project outturn cost will be either lower or higher than the original estimate. Effectively, the application and interpretation of the project cost risk model should be heavily focussed on the nature of the symmetry of the input variances, and these assumptions should be well supported by historical evidence.

The approach adopted by E&P to arrive at the input assumptions to the model included the facilitation of workshops with SPA staff to combine the experience of both E&P and SPA in developing the maximum and minimum variation for each line item. Detailed inherent risk models were prepared for projects at Brooklyn, Keilor (500 kV) and Richmond and the aggregated and summarised findings from these models were extended to the remaining station rebuilds. Separate unplanned risk models were developed for each project.

PB has undertaken a simple review of the degree of asymmetry across both the rate and quantity variances and the materiality of the risks and identified the input assumptions associated with the risks outlined in Table 2-3 are materially influencing the size of the contingency proposed.

Table 2-3 – Examples of major risks mitigated by adoption of contingency

Inherent	Unplanned
Project establishment primary design effort	Inadequate initial design requiring additional scope
Project management of site commissioning effort	Delays in internal design approvals
Project management of site construction effort	Scope creep post awarding the contract
Procurement and delivery of primary plant, namely 500 kV circuit breakers, current transformers and voltage transformers	Modified work practices
Earthworks	Site theft and vandalism
Cable trenching	Asset failure during construction
Drainage and pits	Noise mitigation
Project consumables	Removal of contaminated soil
SCIMS engineering support	Delays in planning approvals

Source: PB analysis

Furthermore, in reviewing the input assumptions to the inherent risk model for the Keilor 500 kV project in detail, the Table 2-4 summarises the characteristics identified regarding the minimum and maximum variances assumed.

Table 2-4 – Nature of inherent risk input assumptions for Keilor

Expenditure $m (nominal)	Quantity risk % of line items	Rate risk % of line items
Symmetrical risk (around 100%) – therefore having no influence on the risk exposure	52%	5%
Symmetrical risk (around 125%) – therefore upwardly biasing the degree of risk	6%	24%
Asymmetrical risk (Max > Min) – therefore upwardly biasing the degree of risk	42%	71%
Asymmetrical risk (Max < Min) - therefore downwardly biasing the degree of risk	0%	0%
No risk (Max = Min = 100 for both variances) – therefore assuming the base estimate is accurate	0%	0%
TOTAL	565 line items	565 line items

Source: PB analysis

Table 2-4 indicates the degree of upwardly biased asymmetry incorporated into the risk model input assumptions. Table 2-4 could be extended to indicate the nature of the risks across categories of both labour and materials to provide further insight into each of these areas.

Principally, PB's assertion that the E&P model output overstates the project cost risk to SPA is supported by the following observations:

- the high level of itemised detail included in the station rebuild and refurbishment cost base estimates capturing SPA's best and latest information, and PB's original finding that the base estimates were an efficient reflection of costs in 2007/08. In PB's view, SPA's original cost estimates are well considered, and draw from expert knowledge of the stations being refurbished, plus recent experience in similar types of projects
- the strong degree of upward asymmetry in both the quantity and rate variance of individual line items in the inherent risk model – there are no line items for which the input assumptions assume there maybe a greater likelihood of reducing rather than increasing. Adopting the inherent risk model assumptions suggests that SPA can not categorically confirm the rate and quantity of *any* line item in its detailed estimates for the period 2007/08
- the lack of any supporting evidence to verify the nature of the asymmetric input assumptions – as an example PB believes that SPA should be able to estimate both the quantity of hours and the 2007/08 rate required for the project establishment primary design engineering with a lower variance than 90%-200% and 80%-150%, respectively
- the potential extension of some site specific inherent risks through to other projects by the application of the detailed findings to other projects at an aggregated level
- the potential double counting of some risks in both the inherent and unplanned models (such as the scope creep and project management of site commissioning effort)
- the lack of recognition of other risk mitigation techniques employed by SPA, in particular the treatment of both quantity and rate risks through the use of labour and material escalators, and the long term procurement and design contracts held by SPA
- other risk mitigating approaches adopted by SPA including liquidated damage provisions and insurance arrangements, which have not been clearly and appropriately documented and addressed
- while it is evident that there have been no explicit and generic contingencies built into the reference estimates, there is virtually no discussion on the contents of the base rates and whether they are appropriate to apply to projects in the next regulatory period, that is, the extent that these estimates reflect recently updated, efficient, prudent and symmetrically based risk costs for the defined scope of works
- the repetitive nature of the works and degree of standardisation in design that should reflect in considerable efficiencies across like tasks (e.g. there is no evidence to suggest that SPA has decreased the risk variances to account for the expectation that the 24th circuit breaker to be replaced at Hazelwood should be simpler to replace than the 1st or second)
- the recommendation of P80 figures which, while described as suitable level for a budget requirement estimate, is clearly not a reasonable position given the efficiency based incentive mechanisms within the regulatory framework where a P50, or most likely, outturn cost is the most appropriate position to take.

In reviewing the characteristics of the inputs, the methodology and the probability distribution plots of the potential outturn costs for SPA's major projects – as presented by E&P through the use of inherent and unplanned risks – PB believes that there is evidence that *some* of the risks identified warrant the inclusion of a degree of contingency allowance.

Specifically, and as supported by the observations outlined above, PB maintains that the inherent risks presented pose an equal degree of opportunity and risk to SPA given the process used by SPA in arriving at its base estimates. However, with respect to the unplanned risks, PB accepts that while being overstated there is some merit in the including a contingency, especially given the individual and itemised approach adopted for each project.

Without access to the detailed E&P models to test the sensitivity to specific assumptions, PB has adopted a pragmatic approach and recommends the inclusion of an allowance for some of the unplanned risks only, as outlined in Table 2-5, and informed through a detailed review of some of the projects documented unplanned risks.

Table 2-5 – Major project contingencies recommended by PB

Expenditure $m (real 07/08)	Base cost[1]	Original contingency		Proposed contingency	
		value	%	value	%
Brooklyn	49,022	2,832	5.8	2,166	4.4
Glenrowan	19,824	1,500	7.6	445	2.2
Geelong	26,011	2,485	9.6	466	1.8
Hazelwood Power	34,911	1,698	4.9	1,578	4.5
Hazelwood Terminal	18,022	1,387	7.7	281	1.6
Keilor	36,192	3,424	9.5	805	2.2
Richmond	87,100	5,920	6.8	2,394	2.7
Ringwood	27,783	1,594	5.7	559	2.0
Thomastown	39,980	3,747	9.4	828	2.1
TOTAL	338,845	24,587	7.3	9,521	2.8

Note 1: it is recognised that the scope of work in some projects has changed compared with the original proposal, however PB's recommendations account for this given the changes are implicit in the E&Ps work.

Source: PB analysis

The proposed contingencies have been determined by summating the weighted unplanned risks for each project (as described in the E&P Appendices 2-11), and then reducing these at a project level by a factor of 40%. The reduction reflects the outcome of a bottom-up review by PB of three projects (as detailed in Appendix B) where PB has excluded a number of unplanned risk line items on the basis that:

- many of the identified risk items can be controlled and managed by SPA using good project management practices, specifically PB has excluded allowances for cost risks caused by delays in funding approval, planning approval, internal design approval, award of the contract, delivery of local and overseas items
- there are a number of specific line items that are overlapping and mitigated by other means, specifically PB has excluded allowance for scope creep, labour shortages and loss of key personnel, (sub)contractor insolvency, theft and vandalism at sites, failure of new equipment to meet specifications, accelerated construction needs, and the management of contractor claims.

As a one-off adjustment, PB has also reduced a weighted allowance (from $1.9m to $0.6m) included by SPA for the cost risk associated with noise mitigation at the Brooklyn site which may be required subject to the industrial area being re-zoned to accommodate residential requirements. In PB's view the cost allowance is excessive given that the need for noise mitigation is not clearly established (i.e. nine old transformers are being replaced by five new ones which will have modern design and can be more suitably located compared with the existing units) and that low cost pre-fabricated concrete noise barriers can be used to effectively serve this purpose.

As part of its bottom-up review of the three projects, PB has accepted a number of unplanned risks identified by E&P and SPA that are outside of SPA's direct control including; unexpected planning approval conditions, restrictions on construction access, changes in statutory law, inadequate initial scope, incorrect design or sequencing of works, rescheduling of outages, latent ground conditions, damage to equipment during construction, safety incident delays, extra-ordinary delays, oil or other contamination, industrial disputes, etc

Table 2-6 presents the summarised findings of PB's review of the major project contingency allowance.

Table 2-6 – PB revised allowance for major project contingencies

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Revised proposal	3.5	4.2	3.6	3.8	5.5	4.25	24.8
Proposed variation	(2.2)	(2.6)	(2.2)	(2.3)	(3.4)	(2.6)	(15.3)
PB recommendation	1.3	1.6	1.4	1.5	2.1	1.6	9.5

Source: PB analysis

2.2 MINOR WORKS – RESPONSE CAPABILITY FOR UNFORESEEN WORKS

SPA originally included a non-prescriptive allowance of $5.5m (real 07/08) to cover minor capital works not included in its project and program specific bottom-up capex forecast.

As informed through PB's assessment, and in drawing on its own experience, the AER has determined to exclude the minor works allowance as part of its draft decision, effectively reducing SPA's forecast capex allowance by $5.5m (real, 07/08).

As an extension of its work considering the risk based inclusion of contingencies, SPA engaged E&P to develop a risk based allowance for minor unforeseen works, as informed by SPA's experience through the current period.

The risks identified to support the minor works allowance are associated with the following:

- failure of an asset requiring immediate replacement
- upgrade of the risk-based replacement criteria
- change in legislation
- impact of extreme events such as fire, flood storm.

PB considers each of these risks are sufficiently managed by other means, including SPA's refinement of its asset failure risk models, its spares holdings and policies, its non-recurrent opex allowances, and its insurance arrangements and therefore we consider that a material capex allowance to cover these risks is neither prudent or efficient.

E&P also extended the review of unforeseen events undertaken by SPA in the current period, where the value of such works has been increased (without any explanation) from $46.9m to $51.8m.

E&P identified that of the $51.8m expended in the current period, $5.1m was for work which could not reasonably have been forecast and $12.4m related to the total value of work delivered in the current reset period for which no provision has been made within the forthcoming period – reflecting a considerable improvement in the SPA scoping and forecasting processes.

This outcome re-iterates PB's previous finding that the vast majority of unforeseen minor capex that SPA has experienced is already captured in its bottom-up project and program forecast capex and its continuous improvement initiatives. In PB's view no additional information has been presented to support a change in our original findings regarding the minor works allowance. PB maintains that there is sufficient discretion within the overall replacement program to accommodate any minor, unforeseen, expenditure without significant change to SPA's risk exposure.

Table 2-7 presents the summarised findings of PB's review of the allowance for unforeseen minor works.

Table 2-7 – PB revised allowance for unforeseen minor works

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Revised proposal	0.92	0.92	0.92	0.92	0.92	0.92	5.5
Proposed variation	(0.92)	(0.92)	(0.92)	(0.92)	(0.92)	(0.92)	(5.5)
PB recommendation	-	-	-	-	-	-	-

Source: PB analysis

2.3 REFURBISHMENT OF HAZELWOOD POWER STATION SWITCHYARD

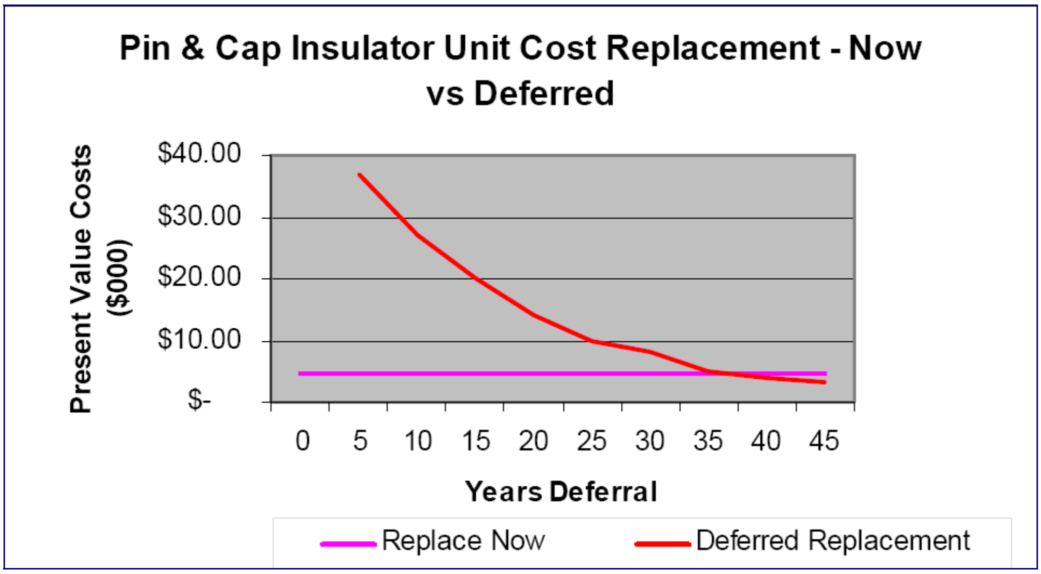
As informed through PB's assessment, and drawing on its own experience, in its draft decision, the AER considers that SPA has not demonstrated that the inclusion of costs for the replacement of pin and cap insulators, line side disconnectors, surge arrestors and capacitive voltage transformers at Hazelwood power station switchyard reflect an appropriate level of prudence and efficiency. This position is based on the absence of a clear technical or economic need for these sub-components of a project based primarily on the replacement of circuit breakers. Given this finding, in its draft determination the AER made a downward adjustment of $4m relative to SPA's proposed capex of $35.7m.

SPA's revised proposal has included new information pertaining to the condition and asset failure risks of the excluded items, together with an economic analysis to support the efficiency and merits of combining the replacements with the circuit breakers. Furthermore, SPA has revisited its estimate of the control building and sought an addition $0.7m for this purpose, bringing its revised proposal to $36.4m (real 07/08).

Replacement of the pin and cap insulators

SPA has advised that the service age of the isolator sets exceeds 40 years and they have a long established history of cracking due to moisture ingress. Furthermore, SPA has estimated that the break-even point at which the present value of costs of the deferral option are less than the incremental replacement costs of the circuit breakers is around 40 years – thereby economically justifying the option to replace now. SPA's analysis is shown in Figure 2-2.

Figure 2-2 – Economical analysis for pin and cap insulators



Source: SPA revised proposal

Replacement of the line side disconnectors

SPA has advised that the service age of more than 80% of the line side disconnector sets exceeds 40 years and that they have a long established history of defects associated with corrosion of poor quality aluminium. Over 50 defects have been identified at Hazelwood in the last 10 years. Furthermore, SPA has estimated that the break even point at which the present value of costs of the deferral option are less than the costs of the incremental replacement with the circuit breakers, is around 25 years – thereby economically justifying the replace now option. Removal and replacement of the line side isolators also plays a key role in ensuring health and safety during the circuit breaker replacement program and ensures an efficient construction program.

Replacement of the spark gaps for surge arrestors

SPA has advised that the existing spark gap devices are fitted to the line side isolators, identified previously to be efficiently replaced in conjunction with the circuit breaker works. While SPA has not presented an economic case to justify their inclusion in the scope of works, the superior lightning protection capabilities have been highlighted in comparison with the obsolete spark gaps.

Replacement of the capacitive voltage transformers

SPA has advised that the service age of the more than 80% of the capacitive voltage transformers exceeds 40 years. Furthermore, SPA has estimated that the break even point at which the present value of costs of the deferral option are less than the costs of the incremental replacement with the circuit breakers is around 20 years – thereby economically justifying the replace now option.

PB's review of the additional information presented by SPA has focussed on the economic analysis as summarised in Table 2-8.

Table 2-8 – Economic evaluation presented by SPA

Asset	Cost to replace with CB works	Cost to replace as an independent and deferred project	Defer vs. replacement 'breakeven'	Implied service life
Pin and Cap insulators	$4,500/set	$54,600/set	40 years	75-80 years
Disconnectors	$55,000/set	$255,000/set	25 years	60-65 years
CVT's	$13,000/set	$44,800/set	20 years	55-60 years

Source: SPA revised revenue proposal.

SPA advises that:

- the 'cost to replace with CB works' assumes no incremental project overheads and reflects supply of materials only
- the 'cost to replace as an independent and deferred project' assumes the replacement of a single device only, as opposed to multiple asset replacements at the same time within this asset class
- the present value calculations have been based on a 6.6% discount factor
- no assumptions have been included regarding the increased operational costs or asset failure risks as part of the deferral option.

PB considers that there are a number of subjective assumptions included in SPA's economic assessment that overstate the break-even period[4]. Nevertheless, accounting for some sensitivity analysis concerning the replacement costs and possibilities of capturing economies of scale, PB is satisfied that the break-even period will be greater than 10 years and therefore that the inclusion of all assets for replacement as part of the wider project is an efficient and prudent outcome. Notably, PB accepts that the costs to replace the individual assets as described by SPA in Table 2-8 appear on the high side of the expected range, but reasonable for the defined scope if adopted as piecemeal projects.

Regarding the variation proposed by SPA for the control room, PB has reviewed the itemised cost presented by SPA to support inclusion of a total amount of $1.4m. PB notes that the estimate includes a 10% ($119k) contingency, a $75k allowance for landscaping, an unsubstantiated increase in delivery and installation of the prefabricated building of $230k, and finance charges of $53k. In PB's opinion each of these items are inefficient and after their exclusion the estimate reduces to $925k. PB also notes that it is not apparent whether the quotation used to inform the updated cost has been competitively sourced.

PB also observes that the building specification is for a floor area of 335m^2 and includes full air-conditioning and VESDA fire protection systems PB confirms that the specification of its benchmark control room valued at $300k comprises a 250m^2 building constructed on a re-enforced concrete slab with 3.5m high timber framed walls clad with Hardipanel, a gable roof clad with colorsteel, and both a smoke detection and security system. The increased floor space specified in the SPA estimate is a significant factor in the difference between the PB benchmark and the allowance sought by SPA.

4 Particularly the difference between the material costs presented and those in the original cost estimate, the ratio of the material costs to the labour costs, the exclusion of any project overheads or labour in the replace with CB's option, and the possibility that all of the assets within each of the three categories could be replaced at the same time – rather than as individual assets where it has been assumed there are no economies of scale or site based efficiencies captured.

Given the new information presented, PB maintains that SPA's original proposal reflects a reasonable and efficient benchmarked allowance for the control room at Hazelwood, therefore we recommend the total project cost of $35.7m be included in the ex-ante capex allowance.

Table 2-9 presents the summarised findings of PB's review of the Hazelwood power station switchyard project capex.

Table 2-9 – PB revised allowance for Hazelwood

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Revised proposal[1]	4.9	11.7	8.6	3.4	5.6	1.5	35.7
Proposed variation	-	-	-	-	-	-	-
PB recommendation	4.9	11.7	8.6	3.4	5.6	1.5	35.7

Note 1, excludes the revised control building costs of $0.7m discussed in section 4.7 of "HWPS CB Replacement Support Paper 12Oct07.pdf"

Source: PB analysis, and Table 5.9.3 of SPA Revised Proposal (pg 112)

2.4 REDEVELOPMENT OF RICHMOND TERMINAL STATION

PB recommended, and the AER has determined in its draft decision, that deferral of the replacement of the 220/66 kV transformers and the 66 kV switchyard was the most prudent and efficient alternative regarding SPA's proposed redevelopment of Richmond Terminal Station. This (draft) decision was reflected in a downward adjustment of $51.7m from the proposed allowance of $89.7m – as per SPA's original proposal. As part of its revised revenue proposal, SPA has presented four material and influential sets of new information relating to its proposed works at Richmond. These are as follows:

- information on the civil integrity of the pile structure supporting the 66 kV switchyard and the associated costly remedial measures, as supported by an independent draft report prepared by GHD
- information relating the relative asset failure risk and plant condition of the 220/66 kV transformers proposed for replacement
- an economic cost-benefit assessment highlighting the lowest cost option is the integrated station redevelopment given the complexities of the site construction, as supported by an independent technical and economical evaluation by Connell Wagner
- information on the design arrangement of the indoor 220 kV GIS switchgear, and a revised cost estimate based on a detailed bottom-up assessment that increases the project costs within the next regulatory period from $89.7m to $113.3m (real 07/08), inclusive of contingency allowances.

Civil integrity of the 66 kV switchyard

SPA engaged GHD in September 2007 to investigate the steel piles and the pavement within the 66 kV switchyard. The key findings highlighted that there was significant steel loss (beyond the design life contained within current Australian Standards) as a result of corrosion to the two piles tested, and that given the state of the pavement as affected by subsidence and poor drainage that the site would be inadequate for the safe operation of maintenance vehicles with wheel loads up to 5 tonnes.

GHD recommended that remedial works be undertaken to address each of these issues. The cost of these works summated to around $750,000. SPA has highlighted that the remedial work proposed by GHD is impractical given the operational nature of the 66 kV switchyard and will likely represent a significant hazard to the secure operation of the switchyard and in practice be materially more expensive.

Notwithstanding the draft nature of the advice presented by GHD, PB concurs that the corrosion of the steel piles beneath the 66 kV switchyard, along with the subsidence at the site constitute considerable risks to SPA that must be managed.

Transformer asset failure risks

SPA has presented additional and updated information to demonstrate that the asset failure risk posed by the B1 transformer at Richmond supports its replacement within the next regulatory period. Further, SPA has indicated that the B1 transformer has the highest risk of failure and the most accelerated deterioration of any of the transformers in its asset base and therefore takes the highest priority for replacement. This is supported by measured Furan levels within oil samples. SPA has also advised that that the capex refurbishment allowance include as part of another project will not materially influence the expect life of the unit. SPA has also assessed that the cost of including the transformer replacements as part of an integrated project provide a least cost development option – this is discussed further below.

PB also notes that SPA has not elaborated on its intentions for the ongoing use of the B3, 150 MVA transformer that was first placed in service in 1999.

Economic cost-benefit assessment

As part of the Connell Wagner report, discounted cash flow analysis is presented in Appendix D comparing SPA's original, integrated project option against PB's recommended deferral option.

Based on a two year deferral of the 220/66 kV transformers and the 66 kV switchyard redevelopment, and under the assumption that there is an additional $10.5m capital required in order to ensure the technical feasibility of the deferral option, it was found that the present value of project costs was lowest for the integrated option (i.e. $71.9m versus $74.7m). The report went on to identify that for the same conditions but with a four year deferral, the deferred expenditure option became marginally preferable (i.e. $71.9m versus $71.2m). The report concluded however, that on strict economic grounds the integrated redevelopment option was preferable.

Of particular note, the deferral of only two years was supported by the increased risk of asset failure in the 66 kV yard due to structural failure of the steel piles, plus CitiPower's observations that it was imperative to cater for additional transformation capacity at Richmond beyond 2016 as the magnitude of energy-at-risk is likely to significantly increase (even after the expected load transfers to Brunswick).

As part of the review of the economic assessment, PB highlights the following matters regarding the approach adopted for the deferred investment option:

- the inclusion of $2.3m for an additional circuit breaker to switch the fourth transformer is subjective on the basis that without this circuit breaker the transformer can still be connected to the 220 kV bus work – while this option is less favourable, this arrangement could be feasible and should have been explicitly considered
- SPA and Connell Wagner have appeared only to consider a (comparatively) expensive option involving the use of 220 kV cables to connect the new 220 kV switchyard to the existing transformers, PB considers that there may be alternative, more efficient options involving the relocation of the existing transformers and that these should also be explicitly considered
- there also appear to be sub-options involving the staged replacement of the transformers (with combined 225 MVA and 150 MVA options) as 66 kV split bus options and auto-close schemes have been adopted as part of the integrated development

- from the energy at risk figures presented by CitiPower, it appears that a loading level equivalent to that accepted in 2011 occurs well beyond 2016, indicating that the timing for economic augmentation of transformer capacity is not likely to be around 2016 given the continuation of planning standards similar to those at present.

Each of these items suggest that subject to detailed assessment the deferral option may actually present the most cost effective solution regarding the redevelopment of Richmond Terminal Station.

The key consideration then becomes the risk posed by the integrity of steel piles and the general civil and subsidence issues of the 66 kV switchyard. As a minimum, inclusion of an allowance for the remediation of these issues in the cash flow analysis would be necessary.

On the balance of the new and previous evidence presented, PB has concluded that the integrated redevelopment of Richmond Terminal Station within the next regulatory period is a reasonable, prudent and efficient project. The key factors informing PB's view that the inclusion of the 220/66 kV transformers and 66 kV switchyard is now acceptable are:

- the condition of the 66 kV civil structures and unmanageable risk presented by not allowing key maintenance vehicles into the yard
- the condition of the 150 MVA B1 transformer, and the likely outcome that its replacement should ideally be a 225 MVA unit, to ensure capacity for future augmentation
- the inconclusive economic assessment that indicates both the integrated development option and the deferred replacement option are reasonable
- the nominal reduction in asset failure risk and ongoing operation and maintenance costs associated with the 66 kV replacement (which have not been accounted for in the economic assessment).

PB notes that the inclusion of the 220/66 kV transformer replacements (and that the project outcome now releases a 10 year old 150 MVA transformer for use elsewhere) and the allowance for the 66 kV switchyard (including an improvement in risk profile for both the CB and CT asset classes) should be considered in conjunction with the AER's other reviews.

Revised cost estimate and design of the 220 kV switchyard

Regarding the design of the 220 kV switchyard and the number of circuit breakers used, the revised proposal by SPA includes three 'breaker-and-a-half' switch-bays for the 220 kV yard as opposed to the original design that allowed for four bays[5]. PB concurs that the three bay arrangement (using nine circuit breakers in total) is a reasonable and efficient design arrangement for Richmond.

In despite the reduction in the number of switch-bays, SPA has presented an increased capital cost estimate for the Richmond redevelopment (i.e. an increase of $13.3m, or 15%, from $89.7m to $103.0m) in accordance with the Connell Wagner supporting report. PB has undertaken a review of the differences in the estimates and has identified that overall the project scope remains substantially the same. Major variations in cost include an increase of $3.4m which is reflective of the entire project scope being undertaken in the 2007/08-2013/14 regulatory period[6], an increased use of expensive 220 kV cable, more expensive 66 kV fault limiting reactors and significant increases in 66 kV protection equipment and SCIMS costs. In addition to these changes there has been a general review of the entire project costs with some aspects increasing in price while others decreased.

5 Appendix 1 – Cost Estimate.pdf

6 SPA's original proposal included a cost estimate of $93m but an allowance for only $89.7m in the regulatory period, where PB understands that the difference is associated with work expected to be incurred after 31 March 2013.

The outcome of PB's review of the revised costs has focused on three key areas:

- The diversions of the existing two lines and one cable to the new indoor 220 kV switch-room - the cost for this work has increased by over 13 times primarily because of the use of underground cable. PB is not satisfied of either the need or efficiency of this change in approach and recommends the proposed allowance of $7.2m for this purpose be excluded.
- The increase in costs of the 66 kV fault limiting reactors - the Connell Wagner report describes the adoption and application of a temporary fast bus reclosure scheme[7] to allow the three new 220/66 kV transformers to service the four existing 66 kV bus sections prior to the procurement and installation of the reactors. In PB's view, and given the medium term intentions to augment and install a fourth transformer at this site, we consider the bus reclosure scheme is a suitable ongoing substitute for the reactors especially in light of the fact the reactors would only be required should one of the brand new and highly reliable transformers fail. PB recommends the proposed allowance of $1.7m for the reactors be excluded on the grounds that the economic merits of this expenditure have not been justified, based on the technical benefits indentified for the period the reactors would be necessary.
- An allowance of $3.6m for 220 kV cabling between the new 220 kV indoor switchgear and the three new transformers - from the engineering drawings included in the Connell Wagner report it is evident that the transformers are located directly beneath the 220 kV switchgear and the need for significant runs of cable is not required. PB recommends the proposed allowance of $3.6m for the cable be reduce to $0.6m, as this reflects an appropriate nominal allowance for the short runs of cable required in the GIS building.

In addition to the increase in project cost, the incurred expenditure profile for the redevelopment of Richmond has varied significantly. Originally, SPA proposed the $89.7m would be required across the final three years 2011/12-2013/14 in the proportions of 8%, 50% and 42%, respectively. The revised figure of $103m also sees a significant amount advanced to the early part of the six year period 2007/08-2013/14 in the proportions of 9%, 7%, 0%, 3%, 50% and 31%, respectively. SPA advised that the basis for the advanced expenditure is to allow the 22 kV switchyard redevelopment to be deferred and co-ordinated with the balance of work at Richmond. Given SPA's desire to include the 22 kV switchgear in the proposed GIS building along with the subsequent 220 kV plant, the result of the changed approach has lead to the advancement of $16.7m from 2012/13-2013/14 to 2008/9-2009/10.

In reviewing the options analysis undertaken by SPA for the 22 kV works[8], it is apparent that remediation of the 22 kV yard was feasible and would allow deferral of the bulk of the 22 kV redevelopment. In PB's view, it is likely that when accounting for the advanced expenditure of $16.7m to enable the 22 kV works to be integrated into the proposed GIS building, then the efficient outcome is expected to be some form of remedial work in the 22 kV yard, followed by a fully integrated redevelopment of the 220 kV, 66 kV and 22 kV switchyards at the end of the next regulatory period. On this basis, PB recommends that SPA's original expenditure profile be maintained, where all costs (including the GIS building) for the 220 kV switchyard works, the 220/66 kV transformer replacements and the 66 kV yard works are incurred in 2011/12-2013/14. This matter would need to be considered in conjunction with SPA's proposal to carry over $5.6m from the current to the next regulatory period for the 22 kV redevelopment.

PB's overall recommendation is to exclude amounts of $7.2, $1.7m and $3.0m from the proposed $103m for each of the three key areas identified above, and to proportion the balance of the expenditure across the final three years, consistent with SPA's original proposal. Table 2-10 presents the summarised findings of PB's review of the Richmond terminal station project capex.

7 Section 2.6, page 7

8 Page 6, CB2_RTS Redevelopment of 22 kV Switchyard V3.pdf

Table 2-10 – PB revised allowance for Richmond Terminal Station

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Revised proposal	9.7	7.0	-	2.8	51.9	31.6	103.0
Proposed variation	(9.7)	(7.0)	-	4.5	(6.4)	6.7	(11.9)
PB recommendation	-	-	-	7.3	45.5	38.3	91.1

Source: PB analysis

2.5 TRANSFORMER REPLACEMENT PROGRAM

As informed through PB's detailed project review, the AER determined that replacement of transformers at Bendigo, Dederang and one unit within the metropolitan area were not prudent and efficient capex projects. It also imposed a like-for-like replacement of the transformer at Yallourn, however it did make an allowance for the replacement of one metropolitan transformer. In total, the AER made a downward adjustment of $22.4m to the original SPA proposal of $28.8m.

SPA has updated its transformer risk model to include parameters that are understood by SPA specialist engineers but which were not explicitly documented in the earlier version of the transformer condition ranking model. Specifically the updated model now explicitly captures the condition of the oil and the bushings and the tap changers and the tank and wiring systems as well as the core and windings. At a high level, it is apparent that the revised transformer condition rankings have significantly increased towards the pre-defined reference level dictated by the oldest and worst condition unit within SPA's transformer asset base - where the number of tanks ranked at a position of 41 or higher has increased by almost 150% from 39 to 97. PB has not observed any transformers that have reduced in ranking score, implying that the four new components in the model are material and should have been included from the onset. Effectively, it now appears that the quantified risk presented by the transformer fleet is significantly worse than originally advised by SPA – indicating an even more pronounced need to invest in transformer replacements. PB considers the significant change in the quantified condition model output requires detailed review to verify the reasonableness of the inputs and new approach adopted.

As informed through the updated models, and along with additional supplementary information such as economic assessments to verify the prudence and efficiency of its proposed investment, SPA has revised its proposal requesting the AER re-instate all of its original transformer replacement allowance.

PB previously reviewed SPA's proposals for the Bendigo, Dederang and metropolitan transformers, and has considered the further information presented by SPA. Our findings are presented in the following sections.

Bendigo 125 MVA 230/66.7/22 kV transformer

SPA has presented additional and updated information to indicate a change in the relative condition of the six transformer tanks comprising the Bendigo transformer, and specifically how the condition is impacted by the poor state of some elements that may be refurbished, including the on-line-tap-changing equipment.

Table 2-11 – Updated transformer condition ranking score

Unit	Previous score	Updated score
2A, serial 3717505	20	42
2A, serial 3717507	20	42
2A, serial 3717508	35	49
2B, serial 3717502	29	46
2B, serial 3717503	29	46
2B, serial 3717504	39	51

Source: PB analysis and SPA revised submission (pg 28, "Transformer Replacement Program - Revised Proposal.pdf")

The significant change evident in the updated condition ranking scores is reflective of the inclusion in the model of the issues associated with oil leaks of the main tank and bushings, and the aged and obsolete tap-changer mechanisms. SPA has indicated that given the reasonable and typical internal condition of the windings, these units are suitable candidates for refurbishment to address the poor condition elements.

Specifically, SPA has presented the results of an economic analysis comparing the refurbishment, replacement and do nothing option that incorporates an assessment of capital outlay, ongoing opex and ongoing transmission power losses. The results of this assessment conclude that the replacement option in 2012 is the preferred alternative, with a minimised NPV of $6.2m compared with $6.9m and $7.2m for the do nothing and refurbishment options, respectively. In PB's view the economic assessment is neither robust nor conclusive and includes some obvious errors[9]. Without making a number of material assumptions, the assessment does not support SPA's preferred alternative. PB considers that, amongst other staged options, a targeted refurbishment option (addressing the two most severely degraded units) is a feasible alternative and should form part of the overall assessment.

PB's acknowledges the critical role the transformers play in supplying the region of Bendigo. PB notes, however, that the other transformer at Bendigo is brand new and the probability of it failing at the same time that the existing unit fails is very low (albeit with a very severe consequence).

On the basis of the critical role the transformers play and the risk presented by the two highest ranked Bendigo tanks[10], and using the economic evaluation presented as a guide, PB recommends an efficient and prudent alternative to replacing the transformers at Bendigo is the refurbishment of the two most degraded units, which can be economically and practically facilitated by the available units recently replaced at Terang. In accordance with the economic assessment presented by SPA, PB recommends a nominal amount of $1m (reflecting approximately 2/6 of the $2.6m allowance identified by SPA) should be included in SPA's transformer replacement allowance for this purpose.

PB also maintains that the intention of SPA to install two 150 MVA transformers at Bendigo by 2011/12 constitutes an augmentation that has not been supported by the local distributor, nor included as part of the economic analysis.

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9 Including the reduction of transmission losses in the replace option prior to replacement occurring, capital costs for the replacement that are slightly lower than the allowance included in SPA's proposal, the timing of the subsequent replacement inherent in the refurbish option, and the lack of clarity regarding the determination of the PV used in the final comparison.

10 Both with a ranking of over 35 years in the original model, whereas the other four tanks are less than 29, and now upgraded to relative scores of 51 and 49

Dederang H1 225 MVA 330/220 kV transformer

SPA has presented additional and updated information to indicate that the relative condition of these units have increased from ranking 46, 44 and 34 to position 50, 49 and 46. SPA has also reiterated that the consequence of failure of these units is very severe given their critical role in supporting Victoria's import capability from NSW. PB concurs with this but still maintains that the risk, represented by the likelihood of the failure and the consequence is somewhat mitigated by the emergency spares that are present at Dederang and readily available to be placed in service by the transfer rack and special transport carriage designed for this purpose.

PB is unaware of the extent to which the SPA transformer risk model (which assigns a resultant increase in risk of 160% should the replacement be deferred) captures the principle of reduced consequences given the local spares. While not necessarily mitigating the risk of explosive failure, the spares certainly mitigate the risk of ongoing outage of the unit and constraints on import capability.

While PB is concerned about the increase in condition ranking of the Dederang H1 tanks in SPA's detailed model (which is recognition of the fact they have been in service since the early 1960's), in our view SPA has not yet substantiated that its replacement within the next regulatory period is prudent or efficient compared with a deferred replacement option.

As part of its revised submission, SPA refers to a supporting economic evaluation with various options to substantiate its preferred approach. The pertinent details of this assessment are summarised in Table 2-12.

Table 2-12 – Single phase transformer replacement

Unit	Do Nothing	Replace	Refurbish
SPA NPV	$5,203k	$5,024k	$5,942k
PB NPV[1]	$5,178k	$4,819k	$6,013k
Capex	$3,331k in 2018 on failure $3,798k in 2019 to replace	$3,798k in 2008 to replace	$2,900k in 2008 to refurb $3,798k in 2023 to replace
O&M	$4k escalated at 2.8%pa, then $2.5k escalated at 2.8% after replacement	$2.5k escalated at 2.8%	$4k escalated at 2.8%pa, then $2.5k escalated at 2.8% after replacement
Losses	$126k pa for original unit, and $63k pa for new unit		

Note 1, PB has corrected a number of errors (such as the value and timing of changes to the O+M and losses within each option) to more accurately reflect the intention of SPA's original assessment.

Source: PB analysis, SPA revised submission (pg 28, "Transformer Replacement Program - Revised Proposal.pdf")

PB identified three key aspects of this assessment:

- SPA is proposing to invest $9.7m to replace the three single phase transformers, and including this level of capex (as opposed to only $3.8m for a single phase) captures significant additional benefits of deferring the investment where the NPV of the do nothing option becomes $8.1m compared with the replacement option of $10.7m.
- In PB's opinion, the $3.3m allowance representing the consequences of failure overstates such costs given the local and dedicated spare at Dederang and the underlying assumptions. A more reasonable assumption is $1.9m which excludes a

number of inappropriate inclusions[11]. This adjustment also reverses the economic assessment outcomes since the do nothing option has an NPV of $4,422k compared with the replacement option of $4,819k.

- SPA's assessment does not identify or consider any materially increased risk of failure. Without any discussion on this matter, PB maintains that the deferred investment option is practical and that this can be approached without any significant increase in asset failure risk. With appropriate condition monitoring and maintenance of the unit itself and its protection systems, SPA could optimise the deferred replacement option without accepting an increased risk of an explosive failure outcome. Deferring the replacement does not specifically endorse a run to failure outcome, and as SPA gather increased information regarding the condition of the unit as time progresses, the unit can be replaced with the spare should the need arise – and at that time consider the option of a full replacement.

Regarding the augmentation component of this project identified by PB, and on the basis that the existing H1 transformer has a forced cooling rating of 225 MVA and that the proposed replacement transformer has a rating of 340 MVA, PB also maintains that the replacement constitutes some degree of augmentation. SPA acknowledges[12] that the H1 and spare (former H2) transformer tanks limit the throughput capability of the station and that the replacement does provide an opportunity for including an augmentation component[13]. PB reiterates that there may be opportunities to include an augmentation benefit in any economic analysis on the basis that VENCorp has foreshadowed a need for such a project.

Given PB's review of SPA's revised proposal concerning Dederang, PB maintains the deferral of the transformer replacement is an efficient and prudent outcome.

ASEA 150 MVA 220/66 kV transformers

The information presented by SPA as part of its revised proposal has focussed on the combined effect of deferring seven transformers as part of the targeted transformer program and the station redevelopment, and the relative increase in asset failure risk compared with 2008 levels. SPA has advised that the overall asset failure risk will increase by 10%[14] should the deferrals occur.

PB accepts this outcome however highlights that has been informed through a substantially revised risk model, where it was evident from the original model output that there was a significant degree of diminishing returns as the number of transforms to be replaced was increased[15].

Based on the present condition of the ASEA transformers, SPA has prioritised its replacement needs as Richmond B1, Thomastown B3, West Melbourne B3, Geelong B2, Heatherton B1 and Heatherton B2.

SPA has presented limited additional and updated information, which does not affect PB's previous findings regarding the deferral of the replacement of one of the two ASEA transformers proposed for replacement by SPA. PB's original advice to the AER regarding the

11 Excludes premium for urgent manufacture and delivery of replacement, transport of spare to site, and dismantling and transport of failed unit back to storage for re-establishment of spare. PB's reduction also attenuates the assumed impact on maintenance costs down from five years (not 6 as described) to three years to align with the extensive testing program undertaken.

12 Page 25, Transformer Replacement Program - Revised Proposal.pdf, SPA 17/09/07.

13 Page 10, Transformer replacement program.pdf, SPA 16/04/07.

14 Reflective of a net increase of overall risk of 5% rather than a net decrease in risk of 5% compared with 2008 levels.

15 The original model output indicated a reduction in overall risk of 20% when replacing 18 tanks and only a further reduction of around 10 percent with an additional 15 tanks.

need to replace one of the ASEA transformers was focussed on the condition of the West Melbourne B3 unit[16]. While the need to replace this unit is still evident and our advice still stands, PB further considers that in recognition of its recommendation that the replacement of the four Richmond 220/66 kV transformers is appropriate within the next regulatory period, and that this redevelopment will release the B4 transformer (which is less than 10 years old), the B4 unit will be a suitable specimen to replace the West Melbourne B3 unit.

On this basis, PB extends its original findings such that the capex allowance for the second ASEA transformer should also be excluded from SPA's forecast allowance given the West Melbourne transformer can be replaced using an alternative means. This would result in a downwards capex adjustment of $4.5m. PB notes that this matter should be considered in conjunction with the AER's findings regarding the Thomastown B3 unit. Should the AER decide to re-instate an allowance for the Thomastown B3 unit into SPA's allowance, then the outstanding units remaining in SPA's priority list are the Heatherton transformers. As informed through SPA's presentation of oil test results (marginally breaching the 'excessive aging rate' level) and the associated condition ranking values (ranked equally at 51), and that these units are already identified for replacement in the early part of the regulatory period beyond 2013/14, then PB considers that the incremental asset failure risk between advanced replacement of one unit and the station redevelopment would not economically warrant inclusion of an allowance for the advanced replacement. PB also considers the consequence of failure of a Heatherton unit will be mitigated by the availability of the metropolitan spare transformer or even the Richmond B2 unit which has a condition ranking of 45 and will be released through the station redevelopment.

Table 2-13 presents the summarised findings of PB's review of the transformer replacement capex.

Table 2-13 – PB revised allowance for transformer replacements

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Revised proposal	3.5	5.4	2.0	5.5	7.9	4.5	28.8
Proposed variation	(3.5)	(5.4)	(1.0)	(3.6)	(7.9)	(4.5)	(24.9)
PB recommendation	-	-	1.0	1.9	-	-	2.9

Source: PB analysis

2.6 CT REPLACEMENT PROGRAM

As an outcome of PB's detailed review of SPA's proposed CT replacement program and the Richmond terminal station redevelopment, PB recommended a reduction from 73 sets to 41 sets of CT's as part of the targeted program, plus the deferral of the 66 kV switchyard redevelopment at Richmond, implicitly deferring the replacement of 20 sets of 66 kV CT's at this site.

In its draft determination, the AER was not satisfied that a capex allowance for 24 of the 73 sets of CT's proposed by SPA for targeted replacement reasonably reflected prudent and efficient capex. It excluded an allowance of $9.09m for the CT's summarised in Table 2-14, which includes seven 500 kV units and seventeen 220/275/330 kV units.

16 On the basis that the Richmond B1 unit was to be refurbished and its replacement occur within the next regulatory period.

Table 2-14 – Excluded CT's

Location	Life Expectancy of 8 years	Life Expectancy of 9 years	Life Expectancy of 10 years
West Melbourne (WMTS)			2
South Morang (SMTS)		2	2
Springvale (SVTS)	1		1
Dederang (DDTS)	5	1	
Heywood (HYTS)			4
Rowville (ROTS)			2
Hazelwood PS (HWPS)			1
Wodonga (WOTS)			2
Tyabb (TBTS)			1
TOTAL	6	3	15

Source: AER draft determination, page 290

As part of the AER's extension of PB's findings across the balance of the capex program, it also made downward capex adjustments to defer the refurbishment of a number of 66 kV switchyards, implicitly deferring the replacement of further sets of 66 kV CT's at Brooklyn, Glenrowan, Geelong, Horsham, Keilor and Thomastown.

SPA has advised that the combined impacts of these adjustments are neither prudent nor efficient on the basis that a clear need has been identified to replace high-risk CT's and that the original CT replacement program provided the least cost option. It has supported this economic argument with various forms of least cost analysis. Furthermore, it argued that the resultant risk profile across the CT asset base would revert to the unacceptable levels experienced during 2003.

Specifically, SPA has advised that should the draft determination findings be held, then[17]:

- field workers will be constantly exposed to the hazards of at least one CT failure per annum through the period 2008-2014
- Victorian electricity consumers will continue to be exposed to loss of supply risks costing an expected $ 6.3m per annum
- CT failure risks would not be reduced, nor would risk levels be maintained near 2008 levels (as claimed), but would rise by approximately 7%
- SPA will be unable to comply with the Occupational Health and Safety Act of Victoria or the safety exposure levels of IEC 1508. SP AusNet's stated objective of significantly reducing CT failure risks cannot be met.

In response to these matters, PB notes that SPA has failed to explicitly quantify any material reduction in either the annual CT failure rates or the exposed loss of supply risks based on its original capex proposal, or why it must now significantly reduce its CT failure risks in order to comply with the described Act and IEC standard as opposed to maintain them at similar to existing levels. SPA has not elaborated on the standard it will eventually accept.

[17] Page 6, CT Replacements 2008-2014 Capital Works Revised Proposal.pdf, SPA, 10/10/2007

Notwithstanding these observations, PB does acknowledge that given the combined adjustments contained in the AER's draft determination, the overall CT failure risk would result in a return closer to 2003 risk levels.

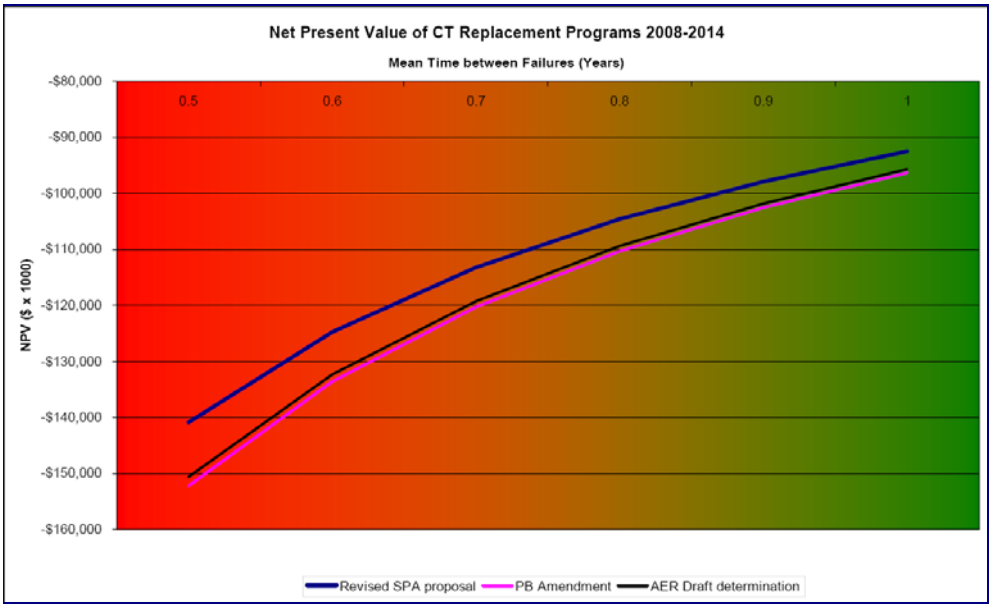
SPA also considers that the AER's and PB recommendations were flawed because:

- the impact of reducing the number of CTs to be replaced in station refurbishment and circuit breaker replacement projects was not factored into estimates of CT failure risk
- the non-linear relationship between remaining life and probability of CT failure was not adequately considered when deferring replacement of CTs with less than 4 years remaining life at 2014

SPA also states that the recommendations made by PB and the AER regarding current transformer replacement do not reflect efficient levels of expenditure since:

- the Net Present Value of the program of works recommended by PB is consistently lower than that of the SPA proposal across the relevant range of CT failure frequencies, as shown in Figure 2-3

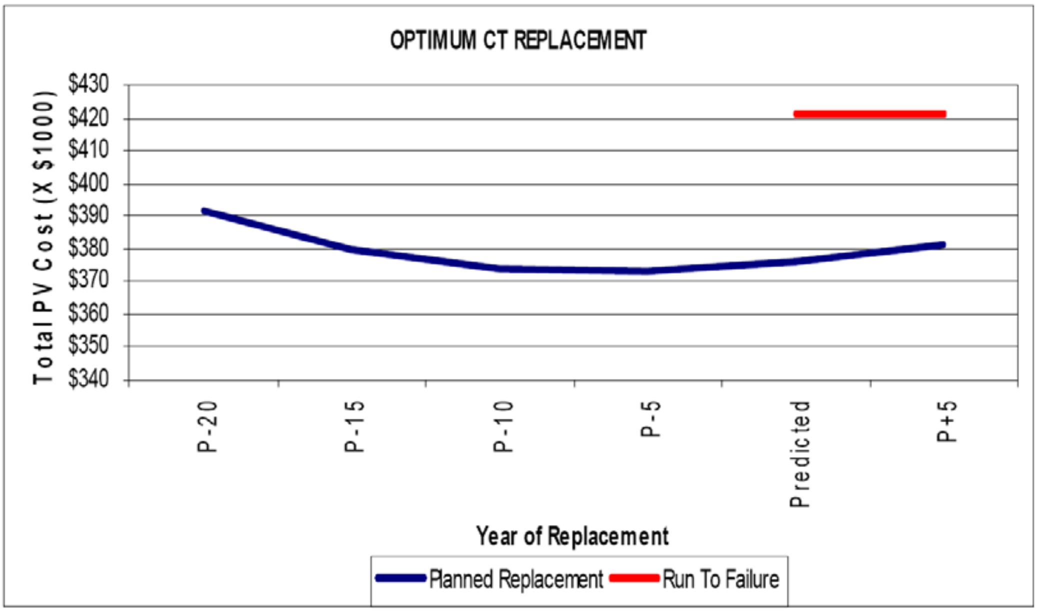
Figure 2-3 – Economic analysis for overall CT replacements proposals



Source: SPA revised proposal, Page 8 of CT Replacements 2008-2014 Capital Works Revised Proposal.pdf

- the costs of replacement in the aftermath of an explosive CT failure clearly outweigh the costs of planned replacement, and this factor has not been properly taken into account
- the optimum economic window for planned replacement of CTs is between 5 and 10 years prior to their predicted end of life, as shown in Figure 2-4

Figure 2-4 – Economic analysis for optimised timing of CT replacements



Source: SPA revised proposal, Page 19 of CT Replacements 2008-2014 Capital Works Revised Proposal.pdf

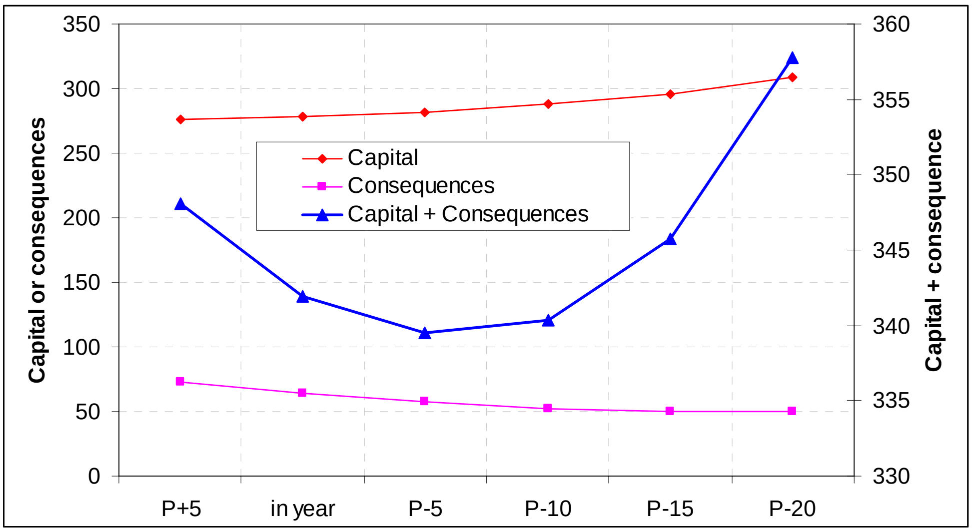
- deferring the replacement of CTs with remaining life less than 5 years is not economic as rising failure risk costs exceed the benefit of deferring capital expenditure for short periods.

As part of our review of the detailed documentation submitted by SPA in support of the above economic evaluations, PB makes the following observations regarding the approach and assumptions adopted by SPA:

- The underlying methodology adopted by SPA to arrive at the optimal timing of CT replacements based on its predicted life expectancy model is sound (as it is informed through an assessment of life cycle costs over a 75 year outlook period capturing capex, opex and safety and community costs as dictated by asset age and failure rates).
- Notwithstanding any discretionary safety margins implicit in SPA's life expectancy model[18], PB concurs that a pre-emptive replacement approach presents a far more economical and prudent outcome than an explosive run-to-failure scenario (as supported in the comparison of the Total Present Value Cost of $373k compared with $421k in Figure 2-4).
- PB also acknowledges that as informed purely from the economical basis of Figure 2-4, replacement of generic CT's based on the modelled parameters appears optimal five years prior to predicted failure ($373.3k). However, it is also noted that the variation in the Total PV Cost varies by only $3k (<0.9%) between the investment at the time of the predicted life and replacement 10 years earlier, however, the economical outcome is highly sensitive to input assumptions, particular the capital cost and the consequential costs as described in Figure 2-5 where it is seen that capital costs reduce at investment closer to the predicted life occurs but where consequential costs reduce.

18 Evidenced by the material difference between the run to failure PV cost of $421k compared with that of the $381 PV cost of pre-emptive replacement 5 years after the predicted life expectancy, and that as part of its revised CT failure model (2007 CT RISK MODEL.xls), SPA will be accepting the risk that around 55 CT's will have a life expectancy of less than zero and as low as -18 years as of 2014 even after its proposed replacement program and station redevelopment projects.

Figure 2-5 – Breakdown of economic analysis for optimised timing of CT replacements

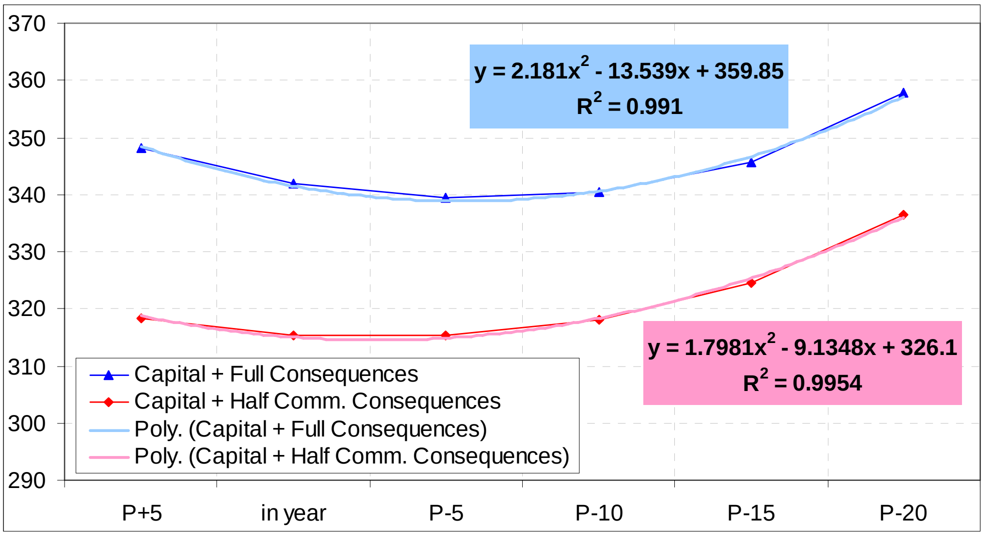


Source: PB analysis

- The input assumptions have been informed from previous SPA experience of CT failures and generalised at a high level to reflect generic outcomes, which has the influence of smearing consequential costs experienced for specific incidents across the balance of the CT replacement portfolio.
- Safety costs associated with the risk of a site fatality have been determined on a reasonable basis from both a likelihood and consequence perspective.
- The reactive opex and capex costs associated with a plant failure have been informed from five historic events across a range of voltages – as there is considerable variation in these costs (i.e. for 500 kV plant vs. 66 kV plant), PB considers a more appropriate model would be based on specific voltage levels and targeted more appropriately to the CT's excluded by the AER's draft decision.
- Community costs in the model have been informed by the same set of five historic events, and capture both loss of supply and network constraint outcomes. The average community cost is however heavily biased by a 220 kV incident at Terang (TGTS) in 2006 where supply was lost to 50,000 homes. PB notes that the Terang 220 kV switchyard design and the specific outcome of this historic event are not directly representative of the majority of Victorian terminal stations and those being targeted for CT replacements[19].
- With the exception of Springvale (SVTS) and Tyabb (TBTS), an explosive CT failure at most stations with targeted CT replacements excluded by the AER is not likely to lead to loss of supply. Rather the event is more likely to lead to network constraints, which based on historical evidence will result in a community cost of only 5% of that involving loss of supply. As the consequential costs reduce, the benefit of deferred replacement becomes more apparent to the point where it could be reasonably argued that the optimum economic timing can reduce to 0 - 5 years. Figure 2-6 shows the reduction in optimal timing when the community costs implicit in the consequential costs assumed by SPA to occur for all CT failures is halved.

19 The station is only supplied by two 220 kV lines, such that outage of both will lead to widespread loss of supply – the majority of other station have more than two lines and therefore a greater degree of diversity of supply and less likelihood of being prone to the consequences of a single explosive failure taking out all incoming lines.

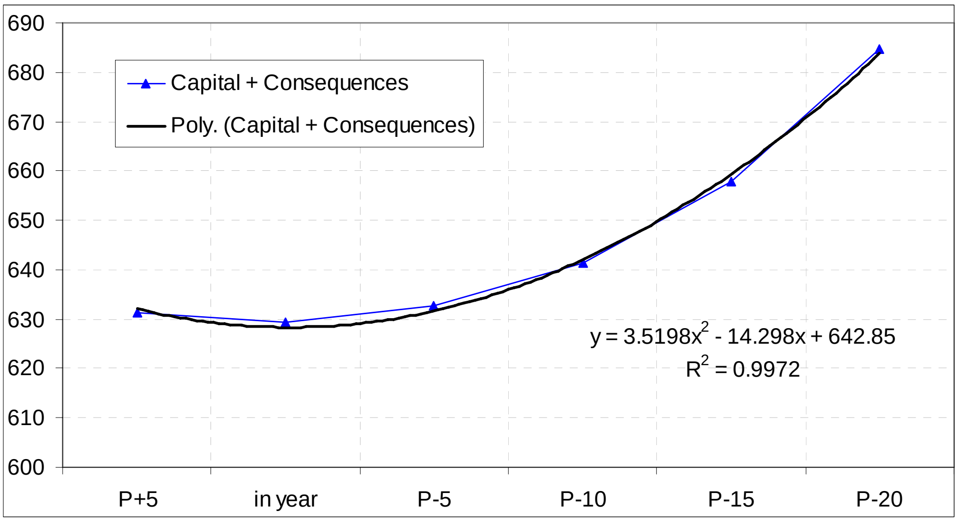
Figure 2-6 – Economic analysis for optimised timing of CT replacements with reduced community costs



Source: PB analysis

- In undertaking sensitivity analysis, PB has concluded that for a 500 kV CT replacement which has a capital cost of $565k (compared with a 220 kV CT of $275k as used in the generalised model) the optimum timing for pre-emptive replacements is at the predicted life expiry given the increased benefits of deferring larger investments. This is seen in Figure 2-7, and is applicable in the case of seven of the twenty-four CT's deferred as part of the AER's draft determination and supports the decision to defer these into the next regulatory period.

Figure 2-7 – Economic analysis for optimised timing of 500 kV CT replacements

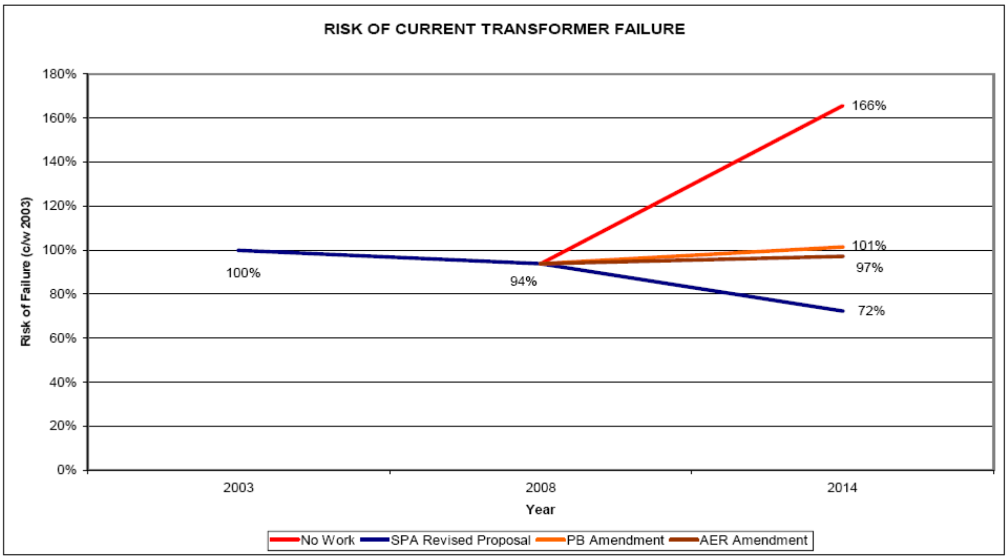


Source: PB analysis

- With respect to the net present value assessment of the overall CT replacement program (Figure 2-3), where the SPA proposal is shown to have a least cost NPV of $92.4k compared with the AER's draft determination of $95.7k (for a mean time between failures of 1 year), PB notes that the results are predicated based on the following key assumptions:

- o the use of a Mean Time Between Failure (MTBF) rate of 1 (or less than 1)
- o the relative and cumulative risk of CT failures which is used as a direct proxy for the likelihood a failure in any given year, as described in Figure 2-8

Figure 2-8 – Economic analysis for optimised timing of 500 kV CT replacements



Source: PB analysis

- o the consequential costs of a CT failure of $8.4m per event
- o the balance of capex being deferred being evenly spread over the first three years of the next regulatory period.

- PB considers each of these matters can be subject to some degree of refinement. As an example, for the PB modelled scenario where the MTBF is assumed to marginally increase to 1.05, where the relative CT failure risk risk in 2014 is correctly reference against the 2003 levels rather than 2008 levels[20], where the community cost component of the consequential costs is reduced by 50%[21], and where the deferred capex in the first three years of the next regulatory period is allocated in proportion to the number of deferred CT's with a life expectancy of 8,9 and 10, respectively[22], then the least cost NPV outcome reverts to support the AER's proposal as the preferred option with a value of $69.4k compared with the SPA proposal of $69.5k. PB notes that the economic assessment is fundamentally dependant on the assumptions regarding the consequential costs of CT failures and the MTBF figure.

20 It is noted from SPA's provision of detailed supporting information to its risk model (2007 CT risk model.xls) that the relative risks are referenced to 2008 levels rather than 2003 levels and that this error overstates the risk of failure in the years beyond 2008 in all scenarios

21 This approach is consistent with that adopted by PB when assessing the optimal life for replacing CT's, where it was observed that the Terang incident that heavily informed the consequential cost of $8.5m was not representative of the CT failure risks posed by those units recommended for deferral

22 This reflects in the deferred capex being proportioned in the ratio of 25%, 12.5% and 62.5% in the years 2014/15-2016/17, respectively

On the balance of both the new and previous information presented by SPA regarding the targeted replacement of CTs, PB is of the opinion that through the use of reasonable and more targeted input assumptions specific to the CT's recommended for deferral, that there is an economical basis to continue recommending CT deferrals. This position is maintained in respect of all CT's except the three units at Springvale and Tyabb, where there is a higher likelihood that the consequential losses could be similar to that which was calculated from the Terang incident in 2006, given the similarity in the number of lines and 220 kV design configuration. On this basis, PB recommends an additional $0.8m be added to the AER's draft determination allowance for SPA's targeted CT replacements in the year 2013/14.

PB's recommendation is underpinned by the following key aspects:

- the economic analysis presented by SPA has been generalised and not sufficiently targeted at the actual CT's proposed for deferral by the AER
- at sites other than Springvale and Tyabb, the consequential losses modelled by SPA appear to be overstated, thereby unreasonably diminishing the value of deferring capex
- SPA has, and will continue, to invest in CT replacements even though some units have a life expectancy of less than 1 year and this is considered an acceptable risk
- as part of our review of the redevelopment of Richmond Terminal Station, PB has recommended the 66kV yard should be rebuilt – affectively further reducing the CT failure risks
- the overall CT MTBF is expected to improve beyond the historically observed level of 1, given SPA's historic and the allowed capex, which strongly prioritises and targets the worst condition units.

With respect to this last point regarding the CT asset failure risk and forecast MTBF, PB notes that the failures predicted by SPA's quantitative model are normalised around the 2003 levels (refer to Figure 2-8) based on a theoretical and absolute failure rate of 3.3 units per annum (or a MTBF of approximately one every 114 days), given the model's population of around 1280 units in 2007. The model appears to be overstating the actual level of risk experienced by SPA, which has only experienced 5 explosive failures since December 2002 over a total population of 1852 units[23] - or about 1 per year. While PB concurs with SPA that the MTBF has reduced significantly given the spate of recent failures[24] over a short period of time, PB considers the absolute model outputs are not directly applicable to describe SPA's CT failure risk or the MTBF of its fleet. Accordingly and appropriately, SPA's application and presentation of the risk model information has been focussed on the models relative rather than absolute failure risks as time progresses. Specifically, in its economic analysis for overall CT replacements (refer to Figure 2-3) SPA has quantified its CT replacement benefits using a relative change in risk for a given MTBF based on 1 failure in 2003. It has also stated that the reduced CT replacement program proposed by the AER will expose field workers to the hazards of at least one CT failure per annum through the period 2008-2014[25]. Given that SPA has targeted its replacement of 203 single phase CT's in the years 2006 and 2007 (including all of the high risk 500kV CT's at Moorabool which attributed two of the explosive failures in 2002 and 2005) and combining this with the balance of the forecast allowance under this program – PB is of the view that the MTBF will be increasing from the existing level around 1 per annum. This is somewhat supported by the observation that there have been no explosive CT failures since October 2006.

23 The (2006) risk model only includes 60% of the total fleet of single phase oil insulated units.

24 From approximately 7 years to around 0.6 years

25 Page 6, CT Replacements 2008-2014 Capital Works Revised Proposal.pdf, SPA, 10/10/2007

PB also acknowledges that the AER should consider the combined impacts of each individual station redevelopment project finding when making its final determination regarding the total number of CT's to be replaced.

Table 2-15 presents the summarised findings of PB's review of the CT replacement capex.

Table 2-15 – PB revised allowance for CT replacements

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
AER draft determination	2.8	2.5	2.4	2.8	2.3	2.5	15.4
Revised proposal	4.8	6.1	5.2	4.2	2.7	1.4	24.5
Proposed variation	(2.0)	(3.6)	(2.8)	(1.4)	(0.4)	1.9	(8.3)
PB recommendation	2.8	2.5	2.4	2.8	2.3	3.3	16.2

Source: PB analysis

3. CONTROLLABLE (AND OTHER) OPEX

In this section of the report we review and, where appropriate, provide revised recommendations on those sections of the SPA revised proposal where the recommendations in the AER Draft Decision have not been implemented by SPA. We have not revisited the adjustments proposed by the AER that were subsequently accepted and implemented by SPA.

Further, our report does not address all the opex issues raised by SPA in its Revised Proposal and our recommendations are confined to the forecast opex associated with the following areas:

- North West contract routine maintenance
- management fees
- merger savings
- self insurance, and
- AIS rebates

3.1 NW MAINTENANCE CONTRACT

PB has reviewed Section 6.10.3 of SPA's revised proposal and in particular the comments relating to the North West Contract.

3.1.1 North West contract – calculation of savings

The AER did not accept PB's recommendations about the savings likely to be realised through the introduction of the new North West (NW) contract. Instead, it sought to calculate the savings from the new contract more directly, based on confidential information supplied by SPA. Accordingly, the draft decision proposed revised calculations to estimate the savings from the new contract.

SPA noted that PB's approach to estimating the savings from the new contract is conceptually weaker than the AER's more direct method. In particular, the PB approach involves a key assumption regarding the Transfield bid, and as such the calculation is vulnerable to this assumption being inaccurate.

PB acknowledges the underlying assumption incorporated into its calculation of expected savings resulting from the introduction of the new NW contract. This assumption, namely that the Transfield tender could be used as a proxy for the base line maintenance and operation costs for the north west area of SPA's network, is based on the premise that the incumbent contractor who has held the contract for many years should have a very good understanding of the quantity of work involved in providing maintenance and operational services to the portion of the SPA network covered by the contract. We believe that it would be reasonable to expect that Transfield would base its new competitive tender on this information.

PB also believes that both final tenders for the contract would be exposed to similar cost pressures going forward. PB believes that in recent times the wage outcomes and conditions for the electricity workers have been relatively similar across all sectors and businesses. In addition there has also been a noticeable move to wage parity between the States. Hence we maintain that the methodology we used to estimate likely savings in our original report provides a reasonable insight into the probable savings that will result for the implementation of the new contract.

PB has reviewed the modelling carried out by the AER to forecast the savings resulting from the introduction of the new NW Contract and acknowledges that calculating the savings more directly by using the model would be preferable. We note, however, that this approach relies on various assumptions being incorporated into the modelling. Additional information has now been provided by SPA since the AER initially constructed its model, and this new data has a significant impact on the model's outputs.

PB has not audited or checked the validity of the additional data provided by SPA which is based on the regulatory accounts from 2004/05 to 2006/07. Accepting the validity of the data, PB believes that the "Alternate Model" based on the additional data which SPA has included in it's NW contract analysis should provide a reasonable estimate of the likely savings that will result from Powercor winning the NW Contract. This model replicates the intent of the AER model but incorporates all costs, not just labour and maintenance costs, and also the average regulatory account data over the last three years. PB believes that the use of all costs in the model produces a reasonable outcome.

The "Alternate Model" output indicates a total saving of $2m over the next six year regulatory period. In comparison the modelling carried out by PB indicates a likely saving of $2.8m.

PB believes that in addition to the slightly lower profit, overhead/support costs and slightly lower allocation to unscheduled works Powercor included in its successful tender, there are other advantages of appointing a distribution business (Powercor) with an overlapping service area as the successful tenderer. These benefits include: established depots with existing stores facilities: reduced travelling times; and the ability to use existing staff for some of the TNSP work. However we have difficulty in accepting that the total savings from the Powercor tender would be greater than $350k to $500k per annum. The savings, if any, on direct labour costs would be minimal and limited to labour productivity improvements; and as the stores are usually supplied only minor savings would be possible on holding/storage costs. We therefore believe that the new NW contract should produce total savings over a six year period in the range of $2m to $3m.

SPA has stated in its Revised Proposal that "*For the purposes of this revised Revenue Proposal, therefore, SP AusNet would be prepared to accept PB's estimate of the cost savings arising from the new contract*". On this basis and for the reasons outlined above PB believes our original recommendation provides a reasonable estimation of the likely savings which will accrue from the introduction of the new NW contract.

Recommendation

PB therefore recommended that the reduction in annual maintenance and operation spend resulting from the new NW contract be factored into the SPA opex model by reducing the proposed spend in the maintenance line item in the 'Routine Maintenance — Recurrent' section of the model for the year 2006/07 by $0.428m. This recommendation is based on the assumption that the Transfield tender provides a reasonable indication of the base costs associated with the provision of maintenance and operation services to the SPA network located in the north west area of Victoria.

3.1.2 North West contract – treatment of savings

The SPA Revised Proposal includes a statement the "*SP AusNet has also reduced its opex forecast for the next regulatory period to take account of the savings that are now expected to be delivered by the new NW contract."* PB has noted that the Revised Opex Model includes adjustments in the Routine Maintenance – Recurrent section indicating that this has been carried out, and the order of magnitude of the reductions indicate that these savings appear to be based on the original PB calculations.

PB believes an important issue is the timing of the introduction of the new NW contract. The new contract commenced on 31 March 2007, however all the tendering, tender analysis, internal approval and appointment of the successful tenderer was carried out during the

2006/07 financial year. Accordingly we believe that the knowledge gained by this process should be incorporated into the base year data so that realistic forecasts of future opex expenditures could be incorporated into the proposal. The business has a reasonable understanding of the expected savings and these were reported to the SPA Board and accordingly we believe that the savings expected from the new contract should be incorporated into the future cost projections.

PB agrees with the statement made in the draft determination that in order to forecast reasonable future costs expected to be incurred by SPA in meeting its operational and maintenance objectives, the cost savings achieved by the introduction of the new NW contract need to be incorporated into the opex modelling. We note that SPA appears to have made the required adjustment to the revised opex model.

3.2 MANAGEMENT SERVICES CONTRACT

Appendix “L” of SPA’s revised proposal details the Manageable Company Cost Analysis and the relationship of these costs to the Service Fee charged by the Management Company to the regulated portion of SPA’s transmission business. PB has reviewed Appendix “L” and has formed a view that the Management Company costs — with the exception of the SPI Management Fee — appear reasonable. PB acknowledges that direct comparisons between transmission companies is not possible due to different structures, company activities, specific state arrangements, and accounting methods. However the order of magnitude of the Service Fee charged by the management Company to the regulated transmission business appears reasonable without the SPI Management Fee included. We believe that as SPA currently manages three transmission and distribution businesses, opportunities exist to achieve economies of scale and scope not normally available to stand alone transmission businesses. Hence, in PB’s opinion the Service Fee charged by the Management Company should be lower than if the SPA transmission business was a stand alone company.

With respect to the SPI Management Fee, PB has reviewed SP AusNet’s 2006 Annual Report and concluded that there appears to be a full Board providing governance to the SPA business as well as a complete Australian based management team led by the Managing Director (Nino Ficca) providing management and governance services to the business. This management team appears to have the ability to provide all the services detailed in Appendix “L” attributed to the Singapore based staff, including:

- accountability;
- planning;
- financial reporting;
- corporate funding (treasury);
- risk management;
- audit; and
- due diligence.

PB, therefore, has some difficulty in understanding from the information provided in Appendix “L”, what additional essential management and corporate governance services are provided by the staff based in Singapore.

PB notes the requirements of the National Electricity Rules:

> *“The AER must accept the forecast of required operating expenditure of a Transmission Network Service Provider that is included in a Revenue Proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects:*
>
> *(1) the efficient costs of achieving the operating expenditure objectives;*

(2) the costs that a prudent operator in the circumstances of the relevant Transmission Network Service Provider would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives."

PB believes that SPA has not provided sufficient supporting information to reasonably conclude that the services provided by the Singapore based staff are a fundamental component of the management and governance of SPA, or that they are essential in addition to the services and governance provided by the Board and Australian based management team. In the absence of this information PB does not believe that the costs associated with the Singapore based staff are justified or *"costs that a prudent operator in the circumstances of the relevant Transmission Network Service Provider would require to achieve the operating expenditure objectives".*

PB therefore recommends that the management company actual opex costs be reduced by the SPI Management Fee of $1,440,495 resulting in a revised total of $6,280,716, and that these actual costs be the recommended service fee charged to the regulated transmission business for the 2006/07 financial year. This recommendation can be actioned by inserting this recommended fee, indexed by 1.06 to convert it to 2007/08 dollars, into cell "I30" of the revised Opex Model.

3.3 OPEX MERGER EFFECTS

SPA's revised proposal contains two Appendices that provide additional information in relation to corporate costs. The first, Appendix "L" titled Management Company Analysis and the second Appendix "K" titled Opex Merger Effects.

Appendix "K" implies that total savings of approx $1.8m have been achieved going forward due to the recent merger of the distribution business and SPA's transmission business. If the non-recurrent asset works are excluded from the analysis, however, the total recurrent routine maintenance cost and corporate costs remain relatively constant from 2004/05 to 2006/07. As these costs account for the majority of operating and maintenance costs, we would expect to see some of the purported merger savings appearing in these expenditures. PB notes that recurrent maintenance and corporate costs comprise approximately 79% of SPA's total operating and maintenance costs.

Non-recurrent expenditure, besides being potentially highly variable, usually contains a high proportion (approximately 75%) of external contractor costs, and SPA's internal costs (approximately $3.5m, 2008/09) are relatively constant. PB has reviewed the non-recurrent maintenance expenditures, including the internal SPA costs, in detail and with the adjustments recommended consider them to be reasonable.

Our conclusion from this review is consistent with the findings of our first review namely that while maintenance and operating expenditures do not appear to have risen as a result of the merger, or the formation of the Management Company, it does not appear that any of the expected economy of scale (or scope) savings have been incorporated into the forecasts for these expenditures for the next regulatory period.

PB would expect the merger of the distribution business into SPA to result in economy of scale and scope savings. Such savings include (but are not limited to), the shared use of IT systems such as financial, asset management and SCADA etc: removal of duplicated management/corporate positions such as payroll, finance, IT, treasury, HR and plant/fleet: and removal of duplicated services such as system control, purchasing and stores, etc. If, as SPA contend, the merger savings attributable to the regulated transmission business are $1.813m (2007/08) then PB believes that these savings should be incorporated into the opex forecasts.

As we also believe it is extremely difficult to allocate these total merger savings between the components of recurrent, non-recurrent and corporate costs with any degree of accuracy, we recommend that the total recurrent and non-recurrent expenditures be reduced by $1.813m in 2006/07 and that this amount be escalated by the labour escalator for future years, namely 2.83%, to reflect the fact that these savings comprise mainly labour savings.

3.4 SELF-INSURANCE

PB has reviewed both Section 6.10.7 of SPA's revised proposal and Appendix "N" entitled SAHA Response to Draft Decision on self insurance. Appendix "N" contains considerable additional data and information in relation to the asset failures experienced by SPA as well as age profile data and probability of failure information. This additional data and information has been incorporated into our revised self insurance risk premium recommendations.

3.4.1 Risk of Property Damage to Towers and Lines

In our original report on the risk of property damage to towers and lines we commented as follows:

> *"In assessing the risk of property damage to towers and lines, the incident frequency rate assumed for strain towers seems high when compared to the Victorian experience to date. PB notes that no strain towers have failed over the last 49 years but SAHA has assumed a failure rate of three towers per 100 years for pre-1965 strain towers and 0.7 strain towers per 100 years for post-1965. We are of the view that based on nine recorded incidents since 1958 involving 36 tower failures, none of which included a strain tower an assumed incident frequency rate of 0.01 (one strain tower failure in 100 years) would have been a reasonable assumption for pre-1965 strain towers. The self-insurance risk premium for this reduced incident rate for pre-1965 strain towers assuming on average five towers would be involved in any strain tower failure incident, is $8,900. The impact on the estimation of self-insurance risk premium for a 0.01 incident rate risk for pre-1965 strain tower failure is a reduction of $18,399 and we would recommend the total annual self-insurance premium be reduced by this amount."*

Previously, PB reviewed Section 1, Risks of Property Damage to Towers and Lines, of the SAHA report entitled SPA Self Insurance Risks and only recommended a variation to the self insurance premium for strain towers based on SPA's historical performance of these types of towers. We reviewed the information supplied in relation to conductor damage and did not recommend any variation. We considered the proposed incident frequency rate for strain towers to be too high compared to historical incident data and recommended a reduction in the failure rate resulting in a reduced recommended self insurance risk premium of $18,399. PB continues to recommend this reduction in the premium for strain tower damage but recommends that the self insurance premium for conductor damage be included in the total self insurance risk premium.

3.4.2 Risk of power transformer and current transformer failure

In this section we discuss the risks associated with failure of transformers and CTs.

Power transformers

SPA provided SAHA with additional data and information relating to power transformer failures and the probability of failure of power transformers by age of asset. SAHA incorporated this data and information into its response to the AER's Draft Decision including the calculation of its revised self insurance risk premium for the probability of failure of power transformers.

In our original report on the self insurance risk premium for power transformer failures we commented as follows:

> *"In assessing the power transformer failure risk, SAHA has assumed that the failure rate for power transformers is 1%. While this figure is often used in the power industry, it is not supported by SPA's power transformer failure history. Over the last 6 years SPA has experienced three power transformers failures and this equates to an annual failure rate of 0.21% over the transformer population of 238 transformers. Assuming this failure rate was to double due the ageing transformer population, which is supported by local and international industry experience, the forecast failure rate would rise to 0.42%. Based on this failure rate the power transformer self-insurance premium would be $484,806, a reduction of $669,494. We therefore recommend that the total annual self-insurance premium be reduced by $669,494. "*

In relation to the original power transformer failure data SPA has confirmed that one fault referred to in its previous report was in fact two separate incidents at the same location. In addition another incident has now been included which occurred in March 2007. This new data indicates that there were a total of five incidents over a 6.3 year period, which translates into a historical failure rate of 0.33% for a power transformer population of 238 transformers.

The methodology PB adopted to determine the self-insurance premium for power transformer failure was a simple estimate based on the limited data available. PB notes that the methodology adopted by SAHA in its Response to the Draft Decision on Self Insurance should provide a more robust estimate, but relies heavily on the age profile of the power transformer population to predict likely failure rates. PB believes other issues such as the transformer loading history, transformer design and construction, maintenance history and environmental issues can also have a substantial impact on actual power transformer service lives.

The methodology used in the SAHA response to the draft report to calculate the annual failure rate for power transformers is based on the age profile of the SPA power transformer population and takes into account replacing 51 of the oldest transformers over the next 6 year regulatory period, at the rate of 9 transformers per year except in the final year where only 6 are to be replaced. The 6 annual failure rates are then averaged to obtain an average rate for the 6 year regulatory period. This methodology produces an average failure rate of 0.599%. For a transformer population of 238 transformers, this failure rate correlates to 1.42 failures per annum. Based on an annual incident rate of 1.42, and an average excess per incident of $485,000 the self insurance risk premium would be $688,700.

PB believes that the methodology used by SAHA in its latest report is reasonable for the following reasons:

- the age profile of the SPA power transformer is such that a very large proportion is greater than 30 years of age with 68 being greater than 50 years of age at the commencement of the next regulatory period. This indicates that the risk of failure is likely to increase during the next regulatory period
- the average failure rate calculated by SAHA using the revised SPA information and data is 0.599% which reflects the SPA power transformer population age and is 40% lower than the 1% failure rate incorporated in the original SAHA report which is based on US data. PB believes it is preferable to use data based on the actual assets under investigation due to the difficulty in adjusting and converting international data to reflect local conditions, designs and operating and maintenance procedures
- the revised self insurance risk premium calculated by SAHA, while slightly lower than the self insurance risk premium calculated by PB is of the same order indicating a refinement of the figures rather than a step change. Our power transformer self insurance risk premium based on the revised failure rates and the same average excess per incident is $761,838.

Accordingly, PB recommends that the risk premium for power transformers should be $688,700, noting that this self insurance risk premium incorporates the AER recommendation that 51 power transformers be replaced over the next regulatory period. This premium represents a reduction of $465,600 over the self insurance risk premium for power transformer failure included in the original SPA proposal.

Current transformers (CTs)

SPA reviewed the initial information provided in relation to current transformer failures and advised that it is incomplete and hence has provided additional information incorporating the probability of failure versus the age of the asset, and information relating to additional failures during the current regulatory period.

In our original report we commented on the self insurance risk premium for current transformer failures as follows:

> *"SAHA included the self-insurance premium for the risk of current transformer failures in the self-insurance premium for power transformers. As we have substantially reduced the assumed failure rate of power transformers to 0.42%, we believe that a separate self-insurance premium for current transformer failure risk should be included in the total self-insurance premium. In calculating the self-insurance premium for current transformer failure risk, we have relied on the data supplied by SPA and included in the SAHA report. We have assumed an incident rate for current transformer failures of 1 in 6 years and an average cost in 2007/08 dollars of $185,000. These assumptions result in a self-insurance premium of $30,839.50 for each of the 220 kV and 500 kV current transformers. We therefore recommend that the total annual self-insurance premium be increased by $61,679 for the risks associated with the failure of current transformers."*

SPA has now advised that there were a total of five current transformer incidents recorded in the 5 year period from 2002, as opposed to 2 incidents originally reported for the 2002 to 2006 regulatory period. This additional information has a significant impact on the calculation of the self insurance risk premium for current transformer failure. It translates into a historical failure rate of 0.054% per annum based on the current population of 1852 current transformers. This translates into 1 incident per annum over the last five year period.

In re-calculating its forecasts of annual estimated failure rates, SAHA has used the age profile information provided by SPA and incorporated the AER recommended current transformer replacement program (68 replacements per annum) and the probability of current transformer failure modelling versus age information supplied by SPA. These 6 annual rates were then averaged to determine a theoretical average failure rate for the next regulatory period of 0.143% which correlates to 2.65 failures per annum. Based on an average excess per incident of $200,000 this translates into a self insurance risk premium of $530,000 per annum.

PB notes that the estimated forecast failure rate calculated by SAHA is more than 2.5 times the recent historical failure rate experienced by SPA. This is in the context of SPA replacing 408 current transformers during the next regulatory period in accordance with the AER's recommendation.

PB notes that the data provided by SPA in Figure 3-2 – Probability of Failure of Power Transformers by Age of Asset is comparable to that referenced in the IEEE power engineering journal of April/May 2005 regarding US experience. Similar references have not been provided for the data for Figure 3-4 – Probability of Failure of Current Transformers by Age of Asset. In addition, the age distribution of the CT population is not as skewed towards the 35 year and above age group as occurs for transformers. Hence it is difficult for PB to understand how the annual incident rate will increase by more than 2.5 times in the next regulatory period given the proposed level of CT replacements.

Based on these observations and in the absence of references to the source data relating to the probability of failure of current transformers versus age, PB draws on the detailed assessment it has carried out as part of the information submitted by SPA regarding the capex based CT replacement program (refer to section 2.6 of this report) and recommends that the self insurance risk premium for current transformers be calculated by using the historical failure rate of 1 per annum, coupled with an average opex related excess of $44,000 per incident[26], which would equate to $44,000 per annum in total for the purposes of the self insurance premium for CT failures.

Self insurance premium for power transformers and current transformers

PB recommends that the annual self insurance premium for both power and current transformers be the sum of $688,700 for risk of power transformers failures and $44,000 for the risk of current transformer failures. PB's total recommended annual self insurance premium for both power transformers and current transformers is therefore $732,700, a reduction of $421,600 from the amount included in the original SPA proposal.

3.4.3 Risk of circuit breaker failure

SPA has advised that the information it initially provided in relation to circuit breaker failure history (information on failures for a two year period) was only designed to provide an indication of the costs incurred as a result of circuit breaker failure, not the total number of incidents. To rectify this situation SPA has provided detailed records of all circuit breaker incidents over the ten year period from 23/07/1997 to 15/07/2007. Over this ten year period there have been a total of 37 separate incidents providing very detailed historical record of SPA's circuit breaker incidents.

The historical records indicate an annual failure rate of 0.37% and based on a population of 1002 units translates into an annual incident rate of 3.7. Based on the "reasonableness" test used by PB for current and power transformers, i.e. doubling the historical annual failure rate, results in an annual failure rate of 0.74% for circuit breakers which closely correlates with the CIGRE adopted failure rate for circuit breakers of 0.72%.

PB has reviewed all the additional information provided in the SAHA Response to the Draft Decision on Self Insurance and generally agrees with the comments in relation to the application of the probability of failure curves and the mean time to failure methodology. We see no reason why the circuit breakers in SPA's network should not follow the long term trend established for such items. Accordingly we recommend that the CIGRE annual failure rate of 0.72% for major failure be adopted noting that the CIGRE study excluded aged equipment which are more likely to experience major failure. This is consistent with SPA's intention to spend $10m over the 6-year regulatory period on preventative circuit-breaker refurbishment work to reduce the risk of circuit-breaker failure.

This recommendation results in PB now accepting the original SAHA recommendation for the self insurance risk premium for circuit breakers. We have based our revised recommendation on the detailed list of circuit breaker incidents reports over a ten year period provided by SPA to SAHA and included in Appendix "N" of the SPA Revised Proposal. This list contains 37 incident reports from 1997 to 2007 as opposed to the three incidents included in the original SAHA report on self insurance.

PB has calculated the self insurance risk premium for circuit breaker failure based on an annual failure rate of 0.72% to be $847,440 as detailed in Table 3-1.

26 This is informed through the average clean-up opex figure presented by SPA of $44,000 in the "NPV INPUTS - CT REPLACEMENT PROGRAM.xls' spreadsheet

Table 3-1 – PB recommended risk premium for circuit breakers

CB type	Number of CBs	Annual rate of CB failures %	Estimated exposure $	Estimated risk $
22 kV	114	0.72	25,000	20,520
66 kV	451	0.72	50,000	162,360
220 kV	339	0.72	200,000	488,160
275 kV	6	0.72	250,000	10,800
330 kV	21	0.72	250,000	37,800
500 kV	71	0.72	250,000	127,800
Total	**1002**			**847,440**

Source: PB Analysis

3.4.4 Revised Self Insurance Premium Adjustment

In compiling this revised self insurance premium adjustment, PB has included our recommended adjustment relating to strain towers, our recommended adjustment relating to the risk of a catastrophic event happening to tower transmission lines as a result of earthquakes and our revised recommended adjustment for the risk of failure of power and current transformers. As a result of this revision we no longer recommend any adjustment to the self insurance premium for the risk of failure of circuit breakers. Table 3-2 details our total recommended adjustment to the self insurance premiums compared to the original SPA Proposal.

Table 3-2 – PB revised total self insurance premium

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	2.539	2.539	2.539	2.539	2.539	2.539	15.234
Proposed variation	(0.471)	(0.471)	(0.471)	(0.471)	(0.471)	(0.471)	(2.826)
PB recommendation	2.068	2.068	2.068	2.068	2.068	2.068	12.408

Source: PB analysis

3.5 REVISED OPEX MODEL – RECOMMENDED ADJUSTMENTS

PB has adjusted the SPA revised opex model to incorporate its recommendations in relation to management services contract, opex merger effects and self insurance premiums. Our revised recommendations are detailed in Table 3-3 and result in a total downwards adjustment over the next 6-year regulatory period of $22.086m reducing SPA's revised opex by 5.1% from $443.824m to $411.738m. A copy of the revised opex model incorporating these adjustments highlighted in red is attached to this report as Appendix A.

Table 3-3 – Revised opex expenditures incorporating PB revised recommendations

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	69.016	70.332	72.174	72.967	74.313	75.022	433.824
Proposed variation	(3.460)	(3.545)	(3.633)	(3.723)	(3.815)	(3.910)	(22.086)
PB recommendation	65.556	66.787	68.541	69.244	70.498	71.112	411.738

Source: PB analysis

3.6 AVAILABILITY INCENTIVE SCHEME REBATE PAYMENTS

In its revised revenue proposal (Sections 4.6 and 6.10.10 and supporting spreadsheet models), SPA accepted the AER's draft decision for a reduction in the amount of opex required to meet rebate payments under the Network Agreement between SPA and VENCorp, when network elements are not available for service. It disagreed, however, with the proposed value of $1.4m.

At a subsequent meeting[27], SPA confirmed that the expected value of the rebate payments — initially set at $6m per annum — had not been altered since its implementation in 2002. SPA also noted that it had improved its work scheduling and as a result was paying less rebates than initially estimated. Paying less rebates than estimated results in SPA keeping the difference between the estimated amount ($6m per annum) and the actual rebates paid (an average of $1.4m per annum).

SPA had expected that VENCorp would negotiate to increase the value of the rebates assigned to network elements so as to return the expected value of the rebates to $6m per annum. This did not occur. Hence PB considers it appropriate for the AER to allow only the forecast value of the rebate payments in the next regulatory period. SPA has accepted this approach in principle and has re-estimated the value of the rebate payments as $3.51m per annum (2007/08).

SPA proposed that the amount of forecast rebate payments be determined by examining the components that make up the rebate: opex; fault and forced outages; SPA capex; and major plant failure. PB considers this to be a reasonable approach and notes it is consistent with the original work undertaken by Trowbridge when the scheme was first developed. The rebates associated with each of these components are discussed below.

Opex component – SPA proposed that the opex component be based on the historical average plus 12% to account for expected increases in opex expenditures. PB notes that the AER has previously decided that forecast opex would not be taken into account when setting targets under its service target performance incentive scheme. PB agrees with this approach.

Basing the forecast on historical averages without adjustment provides an equitable means of setting targets. Fluctuations in work volume in one regulatory period are corrected for in future regulatory periods. This also means that efficiency gains made over a regulatory period are 'held' by the business for a period of time in the next regulatory period through the target being set at a higher (average) level than current performance.

Additionally, attempting to identify the impact of step changes in work volume requires a detailed understanding of how the future work program relates to rebate payments, and may require the adjustment of historical data to remove the impact of one off events.

27 Meeting held 25 October 2007 attended by AER, SPA and PB.

PB recommends that the same approach be taken for the availability incentive scheme as for the service target performance incentive scheme, that is, rebates for the opex component should be determined from historical performance without adjustment.

Fault and forced outages component – PB agrees with the SPA proposal that the fault and forced outages component be based on the historical average and confirms that the average has been correctly calculated.

SPA capex component – PB agrees with the SPA proposal that the capex component be based on the forecast capex program. This is consistent with the original basis of the scheme and acknowledges that capital works can vary widely in scale and scope between regulatory periods.

The rebates associated with the capital work program, however, are difficult to determine without an in-depth assessment of the detailed works planning. For example, in the current regulatory period, the station rebuilds undertaken were located in rural areas where lines were typically switched by a single circuit breaker. This arrangement likely led to a large number of circuit elements being directly interrupted by the works. In the future works program, station rebuilds are located in urban areas with circuit elements switched in a breaker and a half arrangement. It is less likely that circuit elements will need to be interrupted as a direct result of the works, but the greater congestion at the urban sites is likely to require circuit elements in proximity to the works to be de-energised for safety reasons. Hence, modelling of the level of rebate payments associated with large projects such as station rebuilds is complex.

Accordingly, PB has examined the proposed value of $1.9m for this component by calculating the historical average rebate per dollar of capex and comparing this with the forecast average. Table 3-4 shows the comparison. PB considers that some increase is likely to occur, given the typically higher rebates associated with circuit elements in urban areas, however, PB found that the forecast average of 0.014 was significantly higher than the historical average of 0.010, indicating that SPA has allocated a significantly higher average level of rebate to each outage hour. This might occur if more outages were assigned to peak and/or intermediate periods than in the past, or if the circuit elements attracted a significantly higher level of rebate. After examining the average levels of rebates for various circuit elements, PB considers the level of increase per dollar of capex unreasonable given that SPA is likely to expand its workforce (directly or through the use of contractors) rather than working the same workforce during peak and intermediate periods.

PB considers that an upper limit for the ratio can be established by taking one standard deviation (calculated from the historical data) above the average, which provides a high estimate of 0.011. Applying this average rebate to the forecast capex as set out in the AER's draft decision[28] gives a forecast annual rebate of $1.26m (2007/08) as shown in Table 3-5, a reduction of 34% from that sought by SPA.

Table 3-4 – Rebate per dollar of capex

Item	2003/04	2004/05	2005/06	2006/07	average	forecast
Capex	57.10	75.50	102.90	107.30	85.70	139.77
Rebate	0.54	0.58	1.06	1.20	0.84	1.90
Rebate per $capex	0.009	0.008	0.010	0.011	0.010	0.014

Source: PB analysis

28 PB recommends that the AER recalculate the SPA capex component of the rebate scheme based on its final decision on capex.

Table 3-5 – Recommended rebate for SPA capex component

Item	Value ($m, 2007/08)
Standard deviation	0.0013
High estimate	0.011
Forecast capex pa	113.17
Estimated rebate pa	1.26

Source: PB analysis

Major plant failure component – SPA proposed that the rebates for major plant failures be maintained at the initially estimated amount of $617,000 (2007/08). SPA has not provided historical data on major plant failures, stating that *"during the present regulatory period the Victorian network has fortunately been relatively free from significant externally influenced disturbances to plant availability".*

PB notes that the categories of major plant failures includes the failure of associated secondary equipment that would be affected by changed risk profiles from work undertaken in the current regulatory period and will be further reduced by the capex program to be undertaken in the next regulatory period. For instance, the risk of a CB failure has reduced by 15% since 2002 and is expected to reduce by 35% by 2013 (refer PB report *SP Ausnet revenue reset*, p. 107).

While it is not possible at this time to undertake a full review of the risk of a major plant failure, PB considers it reasonable to assume that a reduction of 10% should be applied to the major plant failure component to represent the expected reduction in overall risk. This reduction in risk is discussed more fully in section 5.10.6 of PB's previous report on SPA, where PB concluded that SPA's overall risk had increased by 1% between 2003 and 2008 and, on the basis of SPA's propose capex over the 2008/09 to 2013/14 regulatory period, a reduction in overall risk by 2013 is likely to be around 50% in 500%, representing an overall reduction from the 2003 level of 10%.(p. 117).

Summary

Removing the 12% escalator on opex and reducing the major plant failure component by 10% and setting the average rebate at $0.011 per dollar of SPA capex results in forecast rebate payments of $2.74m per annum, as shown in Table 3-6.

Table 3-6 – Forecast rebate payments ($m, 2007/08)

Rebate Component	SPA Proposal	PB recommendation
Total opex	680,115	607,246
Fault and forced	314,993	314,993
SPA capex	1,902,055	1,262,658
Major plant failure	617,273	555,546
Total	3,514,435	2,740,442

Source: PB analysis

4. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

In its revised revenue proposal, SPA accepted the AER's draft decision on the service target performance incentive scheme for the parameters 'loss of supply events' and 'average outage duration' and most of the decision relating to the 'circuit availability' parameters, noting that PB had made an error in recalculating the 'circuit availability' parameters.

SPA did not accept the AER's decision to reject additional exclusions from the scheme for events relating to planned maintenance of the Brunswick to Richmond underground cable joints; customer works involving line up-ratings, busbar up-ratings or interconnector upgrades; and the proposed revision of the standard third party exclusion.

Each of these matters is discussed in this section.

4.1 ALLOCATION OF FORECAST SP AUSNET INITIATED CAPEX OUTAGES TO PEAK, INTERMEDIATE AND OFF PEAK PERIODS

SPA noted that in allocating the outage hours associated with SPA initiated capex to peak, intermediate and off-peak periods, it had mistakenly relied on historical data that included opex and capex. It accepted PB's recommendation that the allocation should be based on capex only. However, PB's recommended allocation contained a spreadsheet error that reduced the allocation to peak and intermediate periods to a half of the true value derived from historical data.

PB confirms that the values recalculated by SPA are correct. They are 3.78% (peak), 12.04% (intermediate) and 84.18% (off-peak). Adopting these values results in lower (less onerous) targets for the circuit availability parameters for peak and intermediate periods. The revised targets (which include the affect of other changes as discussed below) are presented in Table 4 2.

4.2 CALCULATION OF OUTAGES ASSOCIATED WITH EXCLUSIONS

The AER's draft decision rejected SPA's proposal for additional exclusions for customer works associated with line up-ratings, busbar up-ratings and interconnector upgrades. Given the rejection, SPA notes that no outage hours associated with these works have been considered when setting targets for the service target performance incentive scheme.

PB notes that SPA previously stated that no works of these types were forecast for the 2008-13 period. It has now provided a spreadsheet listing ten line up-rating projects and two interconnector projects. No busbar up-rating projects have been specified. To the extent that these projects can be verified, PB agrees that an appropriate allowance should be made when setting incentive targets.

PB compared the 12 projects with VENCorp's latest Annual Planning Report (2007) and notes that two of the line up-rating projects have now been projected to occur in 2015, which is outside of the reset period. The outage hours associated with these projects should be removed from the calculation. The remainder of the projects are confirmed, although PB notes that the timing of the two interconnector projects is dependent of external factors that SPA is unable to control or accurately estimate. In PB's view, it is unlikely that both projects would proceed in the next regulatory period. Given that the timing of these projects is uncertain, however, PB considers it appropriate to include both projects in an initial review of the impact of these projects on incentive targets.

In estimating the outage hours associated with each line up-rating project, SPA assumed an average of 25 days for each thermal upgrade and 1 day for each wind monitoring scheme. Each day was assumed to result in an outage of 24 hours. PB considers that for these types of work, average outage durations of 10 hours per day could be expected. This assumes a normal working day of 8 hours with an additional 2 hours for switching of the network at the start and end of the day. SPA subsequently re-estimated the outage hours associated with all customer works, adopting an average of 12 hours per outage for line up-rating projects.

In revising the outage hours associated with customer works, PB notes that SPA also revised the completion dates of all projects based on current (2007) planning reports. For the two projects that PB identified as being outside of the regulatory period, SPA changed the completion date of one project (MLTS-BATS No.1 220 kV Line Thermal Upgrade to 75 deg C) to 2015 but did not exclude the outage hours from the calculation of targets. The other project identified by PB as being outside of the regulatory period (BATS-BETS 220 kV Line Thermal Upgrade to 75 deg C) had been incorrectly assigned a completion date of 2013 whereas the correct date is 2015[29]. PB removed both projects from the calculation of the incentive targets as they fall outside of the 2008/09-2013/14 regulatory period, however, this resulted in no material change to the targets.

Accordingly, PB recommends that the SPA proposed adjustment with revised outage hours be adopted. Hence, the change in parameter targets due to the inclusion of customer works requiring line up-ratings, busbar up-ratings and interconnector upgrades is as shown in Table 4-1.

Table 4-1 – Change in parameter targets to include forecast line up-ratings, busbar up-ratings and interconnector upgrades

Parameter	SPA initially proposed adjustment	SPA proposed adjustment with revised outage hours
Circuit availability — total	-0.031	-0.012
Circuit availability — peak critical	-0.048	-0.017
Circuit availability — peak non-critical	-0.016	-0.006
Circuit availability — intermediate critical	-0.057	-0.021
Circuit availability — intermediate non-critical	-0.014	-0.005

Source: SPA revised proposal

4.3 RE-ESTIMATION OF OUTAGE HOURS FOR CUSTOMER WORKS

As noted above, SPA's revised proposal had assumed that most outages associated with forecast customer works would be 24 hours in duration. SPA subsequently re-estimated the outage hours associated with these works to better reflect the actual outage hours required. PB has examined the information provided by SPA and has no reason to believe the outage hours assigned to each project are unreasonable. The result is an overall reduction in outage hours from that initially estimated for customer works of 8%.

Table 4-2 shows revised targets that reflect the amended outage hours as forecast by SPA.

4.4 EXCLUSIONS FOR SPECIFIC EVENTS

SPA commented on the AER's decision about additional exclusions for shunt reactors, maintenance work on the Brunswick to Richmond cable underground cable and for customer works involving line up-ratings, busbar up-ratings and interconnector upgrades.

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29 VENCorp, 2007, *Annual Planning Report 2007*, p.81

4.4.1 Shunt reactors

SPA proposes that the AER's decision to exclude shunt reactors from peak circuit availability parameters should also apply to intermediate circuit availability parameters. PB considers this proposal is reasonable as shunt reactors are not required to be in service during periods of high demand for electricity.

PB notes that SPA's original proposal[30] referred only to exclusions during peak periods; however, audit reports by SKM[31] confirm that SPA has excluded outages of shunt reactors during both peak and intermediate periods in its performance reporting. The audit reports note that including outages of shunt reactors would have a material affect on reported performance for the parameters 'circuit availability – peak non-critical' (in 2004 and 2005) and 'circuit availability – intermediate non-critical' (in 2005).

PB recommends that the exclusion be revised to apply to both peak and intermediate periods.

4.4.2 Brunswick to Richmond cable

In its draft decision, the AER states:

> *"The AER does not consider that the Brunswick to Richmond cable exclusion is warranted, and agrees with PB's reasoning for rejecting the exclusion. Even if work on the cable can not be fully completed in the off-peak period, as suggested by PB, and is also undertaken in the intermediate period, the impact on circuit availability parameters is likely to be minimal".*

In its response, SPA states that the inclusion of the outage hours associated with the replacement of 2 joint bays per year has a material impact on the incentive mechanism, representing 5.6% of its revenue at risk (over $1m over the regulatory period).

PB notes that different approaches can be taken with regard to works that are expected to result in outage hours that are substantially different to historical levels:

Exclude the impact: This approach removes the incentive to perform the work efficiently. It may provide a perverse incentive to undertake the work in peak or intermediate periods so as to allow other works that are subject to the incentive mechanism to be performed in off-peak periods when lesser penalties apply. This approach can, however, avoid the incentive mechanism cap/collars being breached and hence exclusions are useful to ensure that the incentive mechanism operates as intended.

Make a specific adjustment to targets: This approach would offset the impact of the increased maintenance but makes target setting more complex because future targets cannot be set on average historical performance alone. To be equitable, future targets would need to be set on historical averages net of the outage hours associated with the events for which the adjustment was made, leading to more complex analysis and data auditing requirements. The AER has decided not to adjust incentive targets in its service target performance incentive scheme to reflect changes in the opex program. Hence, this approach is not consistent with the current service target performance incentive scheme arrangements.

Make no allowance: this approach places the risk that the work is not performed efficiently with the TNSP, where it can be managed. Small penalties incurred in the current period because maintenance works are higher than the historical average are offset by rewards in the next period due to higher targets for a lower than the historical average work requirement. The

30 SPA, 2007, *Calculation of the 2008/09-12013/4 service standards* (ver.4), p.14.

31 SKM, 2007, *Audit of SP AusNet Service Standards Performance Reporting, Performance Results for 2006*, p. 15.

TNSP pays only the time value of money, which provides an incentive to minimise the outage hours associated with the works.

PB considers that it is not unreasonable to expect a TNSP to carry the risk that equipment requires more or less planned maintenance than envisaged at the time of purchase. Provided that the incentive is not lost due to the likelihood that the cap/collar might be breached, PB is of the view that making no allowance is preferable to the other options.

In terms of the likelihood of breaching the collar thresholds, PB notes that SPA has estimated an average of 800 hours to replace each joint bay. This assessment is based on the actual time to replace joints in 2006 and 2007. With two joint bays being replaced each year, SPA has based its assessment of the likely impact on reported performance by assuming 1600 outage hours per annum, representing 5.6% of its revenue at risk. Given this, PB considers the risk of breaching the collar is sufficiently small that the incentive properties of the scheme will not be lost.

Additionally, PB can see no reason why two joint bays cannot be replaced concurrently, which would reduce the total outage hours substantially. PB notes that excluding the joint replacements from the incentive mechanism would remove the incentive for SPA to pursue such initiatives.

4.4.3 Customer works involving line up-ratings, busbar up-ratings and interconnector upgrades

SPA disagreed with the AER's draft decision to disallow an additional exclusion for customer works involving line up-ratings, busbar up-ratings or interconnector upgrades. SPA notes that, while an allowance can be made for known projects, the risk of changes to the forecast works program (as may occur following a customer request) is borne by SPA. It provided an example (SPA revised proposal appendix I) indicating that in SPA's view the risk was material.

PB notes that the example provided by SPA has a high proportion of the work being undertaken in the peak period, with a correspondingly high impact on revenue and hence may not represent a typical case.

PB recommends that the exclusion proposed by SPA not be accepted, for the reasons outlined in PB's previous report. Further, PB notes that excluding line up-ratings, bus up-ratings and interconnector upgrades from the incentive mechanism would provide an incentive for these works to be undertaken in peak periods. This incentive occurs because other works that are subject to the incentive scheme would be likely to be scheduled in the off-peak and intermediate periods in preference to excluded works that do not incur an incentive payment.

PB is of the view that an appropriate allowance can be made for works of these types and recommends that the exclusion not be adopted.

4.5 STANDARD THIRD PARTY EXCLUSIONS

SPA has proposed that the standard exclusion criterion for third party events should be clarified (by a statement in the final decision) to make clear that outages that occur at the same time as a customer's outage request may be excluded. PB is of the view that such outages meet the standard exclusion criterion, which allows outages shown to be caused by "other events" on a 3rd party system to be excluded.

PB is of the view that attempting to clarify the standard exclusion criteria outside of a process that involves all TNSPs may not address the relevant issues. Hence, until a general review is undertaken, PB is of the view that interpretation of the exclusion criterion is best done for each instance where clarification is required.

4.6 CAPS AND COLLARS

In proposing revised targets, SPA also proposed revised caps and collar values for each parameter. Caps were set at one standard deviation of the historical data above the revised targets with collar values set at two standard deviations below the revised target. SPA's revised proposal did not set out its reasons for this approach, although it is consistent with SPA's initial submission.

In recalculating the cap and collar values, PB has adopted the same approach as previously recommended, which is caps and collars at two standard deviations unless this would result in the cap exceeding 100% performance or being so close to 100% performance as to be unreasonable. Setting caps on this basis results in the cap for the 'Circuit Availability – Total' parameter being set at two standard deviations above the revised target. For all other circuit availability parameters, caps are set at one standard deviation above the revised target.

4.7 RECOMMENDED PERFORMANCE INCENTIVE SCHEME

PB recommends that the values for the nine performance parameters as shown in Table 4-2 be included in SPA's service target performance incentive scheme. The values for loss of supply and outage duration parameters remain unchanged from PB's previous recommendations, while the values for the circuit availability parameters have been revised to remove the error in allocation of outage hours to peak and intermediate periods and to include an allowance for customer works requiring line up-ratings or interconnector upgrades.

Table 4-2 – Recommended performance incentive scheme

Parameter	Unit	Max penalty	Start penalty	Target	Start bonus	Max bonus	Weighting (%)
Circuit availability — total	%	98.41	98.73	98.73	98.73	99.05	20
Circuit availability — peak critical	%	98.62	99.39	99.39	99.39	99.78	20
Circuit availability — peak non-critical	%	98.83	99.40	99.40	99.40	99.69	5
Circuit availability — intermediate critical	%	97.29	98.67	98.67	98.67	99.36	2.5
Circuit availability — intermediate non-critical	%	97.57	98.73	98.73	98.73	99.31	2.5
Loss of supply events > 0.05 system mins.	number	9	6	6	6	3	12.5
Loss of supply events > 0.3 system minutes	number	4	1	1	1	0	12.5
Average outage duration — lines (capped 7 days)	minutes	667	382	382	382	98	12.5
Average outage duration — transformers (capped 7 days)	minutes	556	412	412	412	268	12.5

Source: PB analysis

PB notes that the reduction in outage hours resulting from SPA's review of the hours associated with customer works is offset by the inclusion of additional outage hours for line up-ratings, busbar up-ratings and interconnector upgrades. The net change is zero and hence the target for 'Circuit availability – total' remains unchanged. The change in other circuit availability targets reflects the reallocation of outage hours to peak and intermediate periods.

APPENDIX A
REVISED OPEX MODEL – PB ADJUSTMENTS

APPENDIX B
REVIEW OF UNPLANNED CONTINGENCY ALLOWANCES