Western Power

2009/10 – 2011/12 Regulatory Reset

Quantitative Risk Assessment of CAPEX and OPEX Expenditures

Part 1 – Strategy Development
May 2008

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1 EXECUTIVE SUMMARY

Western Power has engaged Evans & Peck to develop a strategy dealing with the asymmetric quantitative risks associated with estimation and delivery of Transmission and Distribution Capital expenditure (Capex) and Operations expenditure (Opex) over the 2009/10 to 2011/12 regulatory period. Put simply, history shows that in almost all industries, there is a greater probability that a project will exceed its budget than come in under budget. This is particularly true of long lead projects estimated at the concept phase as is characteristic of many of Western Power's projects. Based on our analysis of a number of indicators, Western Power's budget to out-turn cost ratios are in line with those found in other network service providers.

This strategy document is intended to provide a basis for gaining management agreement on the approach to be taken by Western Power in preparing their regulatory submission to the Economic Regulation Authority (ERA)., and to provide a focus for activities leading up to that submission. Following submission of an initial draft, a series of workshops and discussion with Western Power management followed. This has been supplemented by extensive analysis by both Western Power and Evans & Peck. This report is the first of two reports, and focuses on strategy considerations and strategy development. Part 2 focuses on analytical outcomes.

The regulatory precedent for some risk allowance in Capex projects (and to some extent programs) is clear. The Australian Energy Regulator (AER) has approved allowances for Powerlink and SP AusNet and Electranet. There have been no allowances for Opex. Evans & Peck has been involved in all of these cases (on behalf of the network service provider) and is also currently assisting Transgrid and Transend in a similar regard.

Establishment of these allowances has not been straightforward. The key issues that continue to concern the AER are:

- The judgemental nature of the determination of the risk ranges, particularly those determined in a workshop environment, and the ability to complete specific analysis to specific projects / programs
- The overlap between explicit risk allowances under this mechanism, and the inclusion of "Business as Usual" risk notionally incorporated in the Weighted Average Cost of Capital
- Potential overlap between explicit risk allowances, and allowances already incorporated in the estimating process
- Risks should be manageable without incurring additional costs
- need to realistically assess opportunities, as well as risks.
- The unreasonable transfer of risks to customers.

These are well publicised, and highly likely to be a key focus of the ERA. To be successful in gaining regulatory acceptance of a risk adjustment, Western Power must address these issues. Whilst the AER has approved risk allowances, they have clearly indicated the need for network providers to quantitatively justify their approach. This is not an easy task across the portfolio of projects and programs currently facing Western Power. In addition, there are constraints on both time and resources. Our focus in the development of this strategy has therefore been to focus on those areas where defensible quantified risk assessments can be developed utilising existing resources and skills within Western Power.

Western Power is under a different regulatory regime to Network Service Providers under AER jurisdiction. Importantly, there is an "Investment Adjustment Mechanism" (IAM) which enables an ex-poste adjustment to recognise changes in the cost of providing system augmentation works resulting from changes in growth rates, customer connections and / or construction costs. It also recognises some Force Majeure type impacts. This is quite different to the ex-ante revenue cap approach applied by the AER with no adjustment mechanisms. Whilst subject to efficiency and prudency tests, this mechanism changes the comparative risk profile of Western Power in relation to capital works covered by the IAM. However, it does not apply to replacement / refurbishment / reliability and other non growth related expenditures, nor does it apply to Opex.

The recommended strategy can be summarised as:

- Western Power should use the precedent in recent AER rulings to justify a risk based approach to the ERA.
- The primary focus in Opex should be on developing unit costs which fully reflect risks actually experienced by Western Power in performing comparatively repetitive tasks over a long period of time.
- No explicit allowances should be made for contingent risks such as Force Majeure initiated events
- Application of the risk factor to IAM projects gives the highest probability of appropriate cash flows and reduces the likelihood of the need for subsequent price adjustments. The underlying risk implicit in these projects should be outlined to the ERA.
- To the maximum extent possible, existing estimating packages and experienced internal estimating skills be utilised to quantify risks.
- The focus for detailed analysis be as outlined in the following table:

Expenditure Category	Risk Approach
Distribution Opex	No explicit risk adjustment – focus on justification of level of activity
Transmission Opex	No explicit risk adjustment - focus on justification of level of activity
Distribution Programs / Projects	Differentiate between growth related programs subject to IAM and non growth related programs not eligible for IAM consideration. Develop high level risk model for each major program utilising Excel / @Risk software tools.
Transmission Programs /Projects	Differentiate between growth related programs subject to IAM and non growth related programs not eligible for IAM consideration. Utilise existing risk adjustment capability inherent in “Success Estimator” to assess risk at individual project / program level. Externally to Success Estimator, adjust results to be more in line with probability distributions more commonly accepted by AER.

2 INTRODUCTION

Western Power is developing their regulatory submission to the Economic Regulation Authority in relation to their 2009/10 to 2011/12 revenue determination. In early 2008, Western Power engaged Evans & Peck to assist in the formulation of a strategy to take forward in this submission in relation to the quantification of financial risk associated with the delivery of the transmission and distribution Capex budgets.

The delivery of major capital and operating works programs involves complex transactions with considerable uncertainty. While risk management measures can reduce risk, they cannot and do not fully remove risk.

The long duration of Western Power's works programs from scope and cost estimation through to completion, combined with the exposure to outside influences, means that at any point in time up until all costs have been expended, the forecast cost at completion will be a range, rather than a single number. This uncertainty is directly related to the risk profile of each project or program, which is related to the way that risk is managed on that project or program.

In statistical terms, future cost is *stochastic* in nature, not *deterministic.* There are three primary areas of uncertainty relating to projects and programs:

- The need for them and their scope
- Their timing
- Their cost

Recent decisions by the Australian Energy Regulator (AER) in relation to Powerlink, SP AusNet and Electranet have made some explicit allowances in the CAPEX building blocks recognising that even with prudent estimating practices, outturn costs are likely to exceed budget to the asymmetric nature of risk associated with delivering a portfolio of Capex projects. Evans & Peck assisted Powerlink, Electranet and SP AusNet in relation to their application to the AER, and is currently also assisting Transgrid and Transend. To date, there have been no explicit risk allowances in Opex programs.

In developing this strategy, we need to recognise that:

- Limited time exists to fully develop a detailed quantitative risk assessment of every distribution and transmission Capex project and Opex program in Western Power's portfolio
- Whilst by no means guaranteed, it is likely that the ERA will be influenced by the approach taken by the AER
- Western Power is seeking to significantly increase expenditure in a number of areas, and in the lead up to the regulatory submission, significant internal resources will be devoted to justifying, scoping and estimating these projects

and programs. By necessity, this will take precedence over the resources available for detailed quantitative risk analysis.

In light of these three factors, Evans & Peck therefore believes a somewhat pragmatic approach is required, building heavily on the precedent created by Powerlink, SPI AusNet and Electranet, but drawing heavily on what information is available within Western Power to demonstrate similarity of circumstances.

It is also important to recognise that Western Power is subject to an "Investment Adjustment Mechanism" (IAM) which allows some ex-poste adjustment of funding relating to growth related projects. The impact of "force Majeure" type events may also result in an adjustment. This differentiates Western Power from network service providers operating under AER jurisdiction. Evans & Peck is of the view that this does not remove the need to recognise the likely risks in completing projects. If cash flows are to be in line with expenditure, and the need for catch-up price shocks mitigated, risk adjusted capital budgets should be put in place at the beginning of the regulatory program.

3 BACKGROUND TO QUANTITAIVE ASSESSMENT OF RISKS

The long duration and exposure of projects / programs to outside influences means that at any point in time up until all costs have been expended, the forecast cost will be a range, rather than a single number. The uncertainty is directly related to the risk profile of a project / program.

The risk profile will depend on the measures that are in place to manage risk, including optimising the ability to capitalise on opportunities. Therefore, to measure the potential overall cost of a project or program, it is necessary to understand:

- the potential risks and opportunities;
- how these are managed;
- potential financial exposure (i.e. residual risk) after risk management; and
- the potential cost implications of the residual risk.

3.1 WHY USE RISK ANALYSIS

Traditionally portfolio managers have made best estimates of future project and program costs, and applied a contingency to each to allow for unforeseen cost increases. Applying contingencies at a project / program level can give rise to an excessive contingency amount at a portfolio level.

The US Department of Energy recognises the need to address the uncertainty associated with estimates, with an entire directive devoted to contingency, which it defines as:

"costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope. The amount of the contingency will depend

on the status of design, procurement, and construction; and the complexity and uncertainties of the component parts of the project."

While contingency allowances and risk analysis have the same end goal – to provide an accurate allowance for costs likely to be incurred – risk analysis is a more sophisticated and accurate tool which recognises both risks <u>and</u> opportunities.

3.2 QUALITATIVE RISK ASSESSMENT

The first step in quantifying the cost impact is to assess the risks and risk management measures that exist on the project or program. This is called qualitative risk assessment. The basic process involves identifying the risks and opportunities, assessing them generally in terms of likelihood and consequence, identifying the treatment measures that are in place for the risks and opportunities, and where necessary, developing and implementing appropriate risk treatment measures. Such an approach is usually used early in the development of a portfolio of projects and programs, and is used to guide organisational decisions on whether or not to include projects and programs and their timing.

Our starting point builds on the assumption that Western Power has completed this analysis, and the portfolio of projects / programs that they are taking forward over the regulatory period represents those that would be required by a prudent and efficient network service provider to meet expected growth, reliability, safety, environmental and any other drivers appropriate to their business.

3.3 QUANTITATIVE RISK ASSESSMENT

The outputs of the qualitative process become the inputs to the quantitative process as illustrated in Figure 3.1 below.

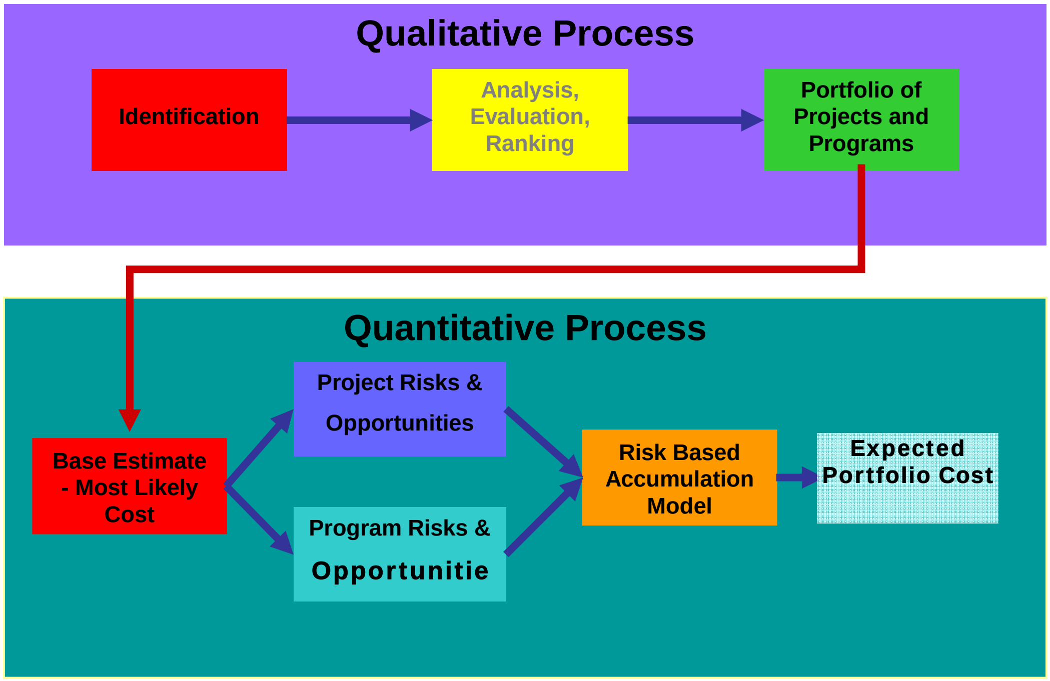

Figure 3.1 Relationship between Qualitative and Quantitative Risk Assessment

In applying quantitative risk analysis, there are two potential sources of cost uncertainty – inherent risk and contingent risk.

Inherent (or planned) risks and opportunities represent the uncertainty in the pricing of the known scope of work, and are due to uncertainty in the scope of work, quantities or unit cost rates for items in the base estimate. This is especially so where assumptions have been made in regard the scope, size or type of material required for the Project / Program. Inherent risks include:

- uncertainty in the scope of work;
- uncertainty, or potential variations, in quantities and unit rates/metrics proposed in the base estimate;
- variance in construction method;

Contingent risks are risk events that may occur during the life of the Project / Program, or across the portfolio, that may differ from what has been assumed in the original pricing. Contingent risks include:

- occurrence of an unplanned or unforeseen event such as a catastrophic natural event or a major safety incident;
- change to planned assumptions;
- stakeholder issues (operators, community);
- delayed access to site;

- Industrial Relations issues external to the Project / Program.

As a general rule, the AER has rejected the inclusion of contingent risks in the revenue allowances made to transmission operators. Given that Western Power has a specific mechanisms relating to force Majeure type events, we do not believe that is appropriate to consider such events in this analysis.

At the time regulatory submissions are prepared, many projects and programs can be 5 to 7 years from implementation, and have only been scoped to a concept or pre – feasibility stage. From a regulatory perspective, we are primarily interested in the plethora of risks and opportunities, irrespective of their category, that result in a change in the outturn cost of a project or program from that budgeted and included in the regulatory submission.

Our approach draws heavily on the knowledge and experiences of estimators and project / program managers familiar with the factors that result in cost savings and overruns, and the extent of these changes from initial scoping and budgeting.

3.4 RISK ANALYSIS

The analysis of a project / program risk profile to develop a model for portfolio costs involves using statistical techniques and computational power. The most effective and well recognised of these techniques is Monte Carlo simulation, where very large numbers of potential combinations of risk and opportunity outcomes are randomly sampled within a defined probability distribution.

For a portfolio of capital works, Monte Carlo simulation involves:

- including the range of potential cost outcomes for each item based around the Project / Program cost estimates;
- simulating potential combinations of the costs of all of these to develop a likely range of costs for the overall Project / Program portfolio.

Fundamental to the justification of an estimating risk allowance is the recognition that cost risks are often asymmetric in nature – i.e. there is a greater probability that the cost of a project or program will exceed its most likely cost estimate by a large amount is greater than the probability that the project will come in under budget by a similar amount..

Cost estimates are often expressed as +/- 10%, +/- 15% +/-20% or similar. Implicitly this implies that there is an equal chance of the project / program coming in at the higher or lower band. Explicitly, such an assumption may be expressed in the form shown in Figure 3.2 below.

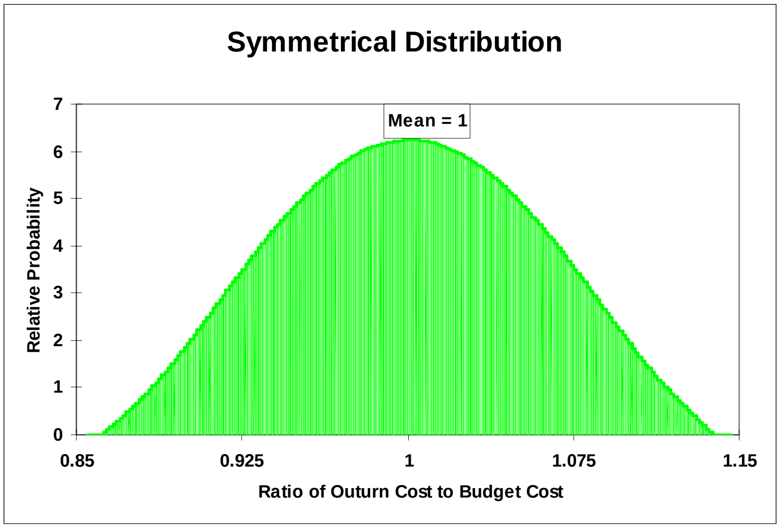

Figure 3.2 Symmetrical Risk Profile

Since there is an equal probability of a cost overrun or underrun, over a large number of projects or program tasks, it is expected that the average outcome would be in line with budget, even though individual jobs may vary.

In reality however, the cost risks associate with real projects and programs are asymmetric. For example, the outturn cost may range between 85% and 150% of budget. This is shown graphically in Figure 3.3 below.

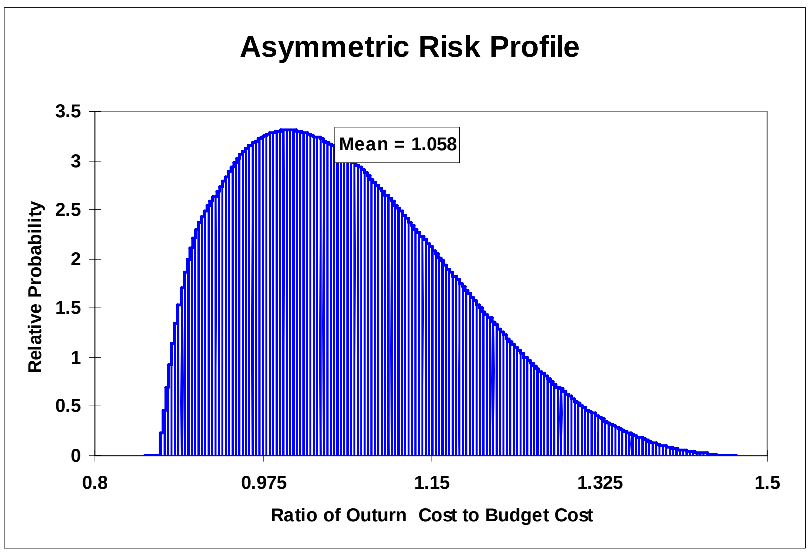

Figure 3.3 Asymmetrical Risk Profile

Across a portfolio of projects and programs, there is invariably a mix of risk profiles. When combined into a portfolio, it is most unlikely that all projects or programs will simultaneously have their best outcome, or their worst outcome. The result across the portfolio is a largely symmetrical range of possible outcomes, but with a shift in the overall expected outcome. This is shown in figure 3.4 below.

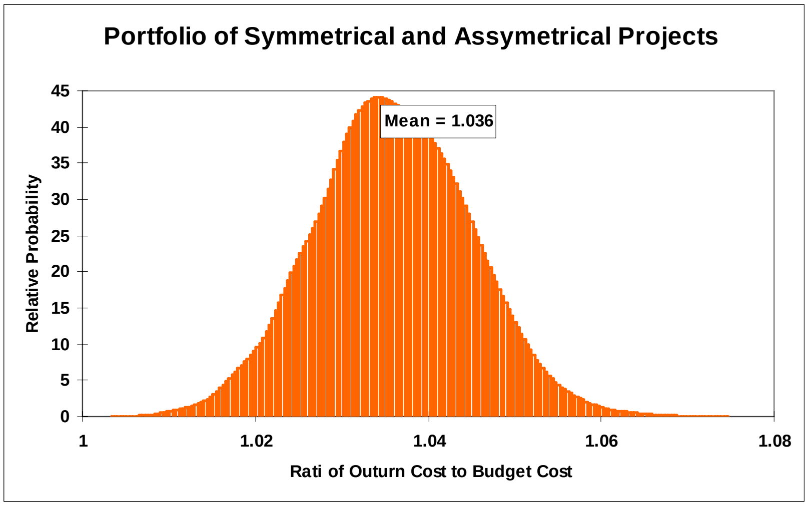

Figure 3.4 – Resultant Distribution for a Portfolio of Projects and Programs

This "shift" in the expected outcome across the portfolio has been recognised by the AER in a number of recent decisions, and provides a key input to the development of Western Power's strategy development.

4 RECENT AER DECISIONS

The AER has now made 3 final determinations relating to the inclusion of an estimating risk allowance in regulatory determinations. These relate to:

- Powerlink
- Electranet
- SP AusNet

4.1 POWERLINK

Powerlink (Queensland) was the first network service provider to apply to the AER for an estimating risk allowance.

The process involved each forecast Capex project being classified as a high, medium or low risk and being applied a risk profile. The three types of projects were assigned risk profiles based on a Pert Distribution. The probability distributions determined were based on the combined judgment of Powerlink and Evans and Peck. The three probability distributions used were low risk project (± 10 per cent), medium risk project (–15 per cent to +20 per cent) and high risk project (–15 per cent to +35 per cent)[1].

Powerlink applied these risk factors to broad activity categories, as shown in Table 4.1

Table 4.1 – Powerlink – Allocations of Risk Categories

High-risk Projects	Medium-risk Projects	Low-risk Projects
Construction of overhead and underground powerlines	Communications projects	Augmentation of Static-VAr Compensators
Replacement of Substations	Information Technology projects	Augmentation of Substation Capacitor Banks
Replacement of Substation Secondary Systems	Establishment of Substations	Augmentation of Substation Transformers
Obtaining easements, and payment of compensation	Security augmentation of Substation Transformers	

The estimated expenditure and risk profile of each project was modeled using a Monte Carlo simulation to determine a risk-adjusted estimate of the forecast Capex requirement. The modeling resulted in a recommendation of a 2.6 per cent increase in the expected cost

[1] AER documentation indicates -20% but in order to parallel the results over a large number of simulations, a value of -15% provides more consistent outcomes with the an overall result of 2.6%. We have used this slightly higher value in this report.

of Powerlink's forecast Capex program. Powerlink applied this factor to all of its base cost estimates.[2]

On the advice of PB Consulting, the AER rejected this application in their Draft Decision. Key concerns were:

- No historic evidence of outturn to budget cost overruns
- Base planning object costs already included some risk
- Likely that listed risks already included in estimates
- Risk factors associated with minor items
- Risk factor unfairly transfers risk form Powerlink to customers

Powerlink, assisted by Evans & Peck, challenged the AER's draft decision. In addition to addressing other issues, Powerlink provided evidence[3] that a historical analysis of outturn to budget ratios on a large number of projects indicated an adjustment of the order of 9.4% was more in keeping with actual performance.

The AER, in its final decision granted a 2.6% cost estimation adjustment on Powerlink's $2.25 million capital budget. Salient points relevant to Western Power's strategy are:

- Powerlink only sought allowance on CAPEX, not OPEX
- Escalation factors were single value series estimates, and not risked
- Variations in growth were captured through a deterministically determined weighted scenarios, rather that probabilistic estimated
- AER allowed a "portfolio" amount, rather than a project specific amount
- AER choose to apply Evans & Peck's initial assessment which was always highlighted as being extremely conservative
- A key determinant in finally awarding allowance was demonstrated historical outturn to budget performance.

[2] Australian Energy Regulator Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12 8 December 2006 P77
http://www.aer.gov.au/content/item.phtml?itemId=707570&nodeId=f733be92d6de34fa8510fbcf65f74e19&fn=Draft%20decision%20(8%20December%202006).pdf

[3] QUEENSLAND TRANSMISSION NETWORK RESPONSE TO AER DRAFT DECISION of 8 December 2006 Appendix B
http://www.aer.gov.au/content/item.phtml?itemId=708646&nodeId=98310d8e17ba8a95bea087cf72aa5df0&fn=Powerlink%20(9%20February%202007).pdf

4.2 ELECTRANET

Electranet proposed[4] to apply a cost estimation risk factor of 5.2 per cent based on the methodology and modeling developed by Evans & Peck. The risk factor is applied only to network projects and used the following process to develop the inputs to the risk model:

- Risk workshop—E&P conducted a risk workshop with Electranet to identify each risk element for both inherent and contingent risk categories and the probability of each risk occurring. The risk associated with the Adelaide CBD project was analysed in detail as a separate project because it comprised 20 per cent of the value of the Capex program. All remaining projects were analysed together.

- Risk profile and consequential costs of the Adelaide CBD project—The Adelaide CBD project risks were identified in detail with each risk item assigned a likelihood of occurrence and allocated a minimum, most likely and maximum consequential dollar value of occurrence.

- Inherent risk—to calculate the effect of inherent risks in the other projects, EP determined a risk profile for each asset class. Applying this risk profile to each individual project cost estimate derives the risk adjusted cost estimate.

- Contingent risks—To calculate the effect of contingent risks, each risk element was assigned a consequential annual dollar value of occurrence and a likelihood of occurrence based on a minimum, most likely and maximum probability.

Using these inputs, a Monte Carlo simulation was undertaken to develop a likely range of costs for the overall Capex program. The simulation showed that the risks facing the Capex program totalled around $37 million, which is equivalent to 5.2 per cent of the base Capex estimate—that is, the base Capex estimate is increased by a cost estimation risk factor of 5.2 per cent.

Part of Electranet's justification for the 5.2% value was a comparison of the out-turn cost against the budget cost of 29 historical projects that showed that the mean difference between Electranet's historical estimated and out turn project costs is 22% - that is, they had historically <u>underestimated</u> costs by 22%.

Electranet's submission was reviewed for the AER by SKM. SKM concluded:

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[4] Draft decision Electranet transmission determination 2008–09 to 2012–13 9 November 2007 P104

Notwithstanding its concerns about the reliability of some of the inputs and their quantification used in the EP modelling, based on its industry experience SKM considered that a 5.2 per cent cost estimation risk factor is not excessive.[5]

The AER did not endorse SKM's findings in their Draft Decision[6]. Instead, they concluded:

On balance, the AER is satisfied that a 2.6 per cent risk factor will provide Electranet with a total forecast Capex allowance that reasonably reflects the efficient costs a prudent TNSP would require to achieve the Capex objectives.

The grounds for rejecting the 5.2% allowance were as follows:

- Projected risk profiles and costs were based on the outcomes of a risk workshop and not any systematic evaluation of past evidence of actual occurrences or actual cost impact. In the absence of such evidence the risk profiles and costs were considered to be reliant on arbitrary projections;

- Electranet has not attempted to moderate the risk workshop outcomes to take account of new initiatives;

- The process inappropriately transfers typical operational business risks that are normally considered as being within the control of Electranet's management to users; and

- Electranet's risk assessment has only identified two instances of cost saving opportunities and the AER is not satisfied that Electranet has sufficiently identified and accounted for all possible gains from projects that could come under budget.

Assisted by Evans & Peck, Electranet has challenged this reduction in their Revised Revenue Proposal.

"Electranet submits a cost estimation risk factor of 4.6 per cent for inclusion in the AER's final determination. Electranet considers that this risk factor reflects the costs that a prudent TNSP operating under the circumstances of Electranet would require to achieve the Capex objectives comments on the Draft Decision".

In their final decision, the AER reverted to the 2.6% outlined in their draft. Salient points relevant to Western Power's strategy are:

- Electranet only sought allowance on CAPEX, not OPEX
- Escalation factors were single value series estimates, and not risked

[5] Op cit p 102
[6] Op cit p 105

- Variations in growth were captured through a deterministically determined weighted scenarios, rather that probabilistic estimated
- Electranet only included projects, not programs
- AER has endorsed the general principal of a cost estimation allowance, but chose to revert to Evans & Peck's initial Powerlink which resulted in 2.6%
- The AER continues to have concerns over "work shop" analysis forming the basis of the risk quantification.
- Despite historical performance showing a 22% overrun, this was discounted.

4.3 SP-AUSNET

Evans & Peck did not assist SP AusNet in their initial application to the AER in relation to the 2008/09 to 2012/13 determination. SP AusNet had initially proposed a $24.8 million "contingency allowance" relating to the redevelopment of 9 major substations with capital works valued at $359.2 million. SP AusNet's justification[7] was based on:

...the contingency allowed for the station refurbishments is to cover costs that arise when this type of complex refurbishment work is undertaken. The cost estimate only covers the scope of work that could be defined. Naturally issues will arise as the detailed design and installation work is undertaken.

The AER considered the proposed contingency allowance as inappropriate, for the following reasons[8]:

- Lack of strong evidence justifying the need or quantum of the proposed allowances for each individual station rebuild project.
- the proposed average contingency allowance of 7.0% of total project costs is above the level that the AER would expect
- It is likely that base unit costs already address some cost uncertainties given that the cost database is updated on an ongoing basis to reflect actual project outcomes.
- SP AusNet has had five years of experience undertaking complex station rebuild / refurbishment projects and should therefore have a more thorough understanding of the typical project scope
- SP AusNet has included a number of other risk mitigation allowances in its forecast Capex proposal.

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[7] Draft Decision SP AusNet transmission determination 2008-09 to 2013-14 31 August 2007 p94 - http://www.aer.gov.au/content/item.phtml?itemId=714698&nodeId=cf54d675cb859054d44a54db5fd05550&fn=Draft%20Decision%20-%20SP%20AusNet%20transmission%20determination%202008%20-%202014%20(31%20August%202007).pdf

[8] Op cit p95

Whilst recognizing that provision for a contingency allowance is a common budgeting practice, the AER did not consider that SP AusNet had, in this instance, demonstrated that the contingency allowance was justified. In their Draft Decision, the AER removed $21.8m of the $24.8m proposed.

With the assistance of Evans & Peck, SP AusNet challenged this draft decision. A series of risk workshops were held. Whilst the results of these workshops indicated that the initial contingency allowance sought was conservative, with the assistance of PB Strategic Consulting, in the Final Decision, in short the AER concluded[9]:

> *After considering the views of E&P, and on the basis of PB's advice, the AER is not satisfied that SP AusNet's proposed contingency allowance reasonably reflects Capex likely to be incurred by a prudent and efficient TNSP in the circumstances of SP AusNet. The AER, however, accepts in principle that certain unquantifiable risks need to be captured in SP AusNet's forecast Capex allowance for complex station rebuild/refurbishment projects, and has approved a contingency allowance $9.52m (around 2.7%) to reflect this assessment. However, the AER reiterates that the total forecast Capex approved is an allowance only, and is not tied to a fixed, project specific, work program. Within the approved allowance, SP AusNet retains the discretion regarding the allocation and expenditure of Capex, and is expected to be responsive to changing conditions in order to meet the prescribed Capex objectives.*

Salient points relevant to Western Power's strategy are:

- SP AusNet sought contingency allowance on select CAPEX projects, not OPEX
- AER again endorsed the general principal of a risk allowance, but chose to revert to a level commensurate with Evans & Peck's initial Powerlink value (2.7% cf. 2.6%)
- The AER continues to have concerns over "work shop" analysis forming the basis of the risk quantification, but has accepted the general principal.

5 RELEVANCE OF AER DECISIONS TO WESTERN POWER

Powerlink, Electranet and SP AusNet are only Transmission Network Service Providers. As such, the lower limit of their supply system is generally the outgoing terminals of terminal stations. Western Power is a hybrid transmission / distribution company. To date, no eastern distributors have submitted applications to the AER[10]. The NSW distributors will be the first, and their submission timetable parallels that of Western Power's submission to

[9] Final decision SP AusNet transmission determination 2008-09 to 2013-14 January 2008 p9 http://www.aer.gov.au/content/item.phtml?itemId=717343&nodeId=685d9eef34df08b1e84bb351079621c8&fn=Final%20decision.pdf

[10] EnergyAustralia, Integral Energy and Country Energy submitted on 30 May 2008. However, their submissions are not public at the time of preparation of this report.

the ERA. Notwithstanding, we are of the view that there are direct parallels between the risks facing Western Power and those already the subject of a determination by the AER.

In order to demonstrate this linkage and assist in the development of a strategy to take forward, we have conducted a one day workshop with Western Power staff to outline the approach adopted with the AER, and to identify parallels with Western Power's transmission and distribution Capex / Opex projects and programs.

As a starting point we have examined the process for estimating risk associated with capital projects, and some historical analysis of outturn costs as a ratio of budget costs.

5.1 ANALYSIS OF SAMPLE COMPLETED PROJECTS

During the workshop, Western Power provided a sample of "close out" analysis sheets on a total of 11 projects ranging from greenfield 132kV line projects to capacitor installations and additional transformers. We have no reason to believe that the samples provides were anything other than a random sample. In order to illustrate the commonality of issues faced by Western Power with other network service providers, and indeed any other organisation completing long lead capital projects or projects of vary scope or commercial exposure, we have plotted the out-turn cost to budget ratio for:

- Materials
- Resource Costs
- Total Project Costs

for each of the 11 projects. These ratios are shown graphically in Figure 5.1 below.

Western Power - Ratio of Out-Turn Cost to Budget

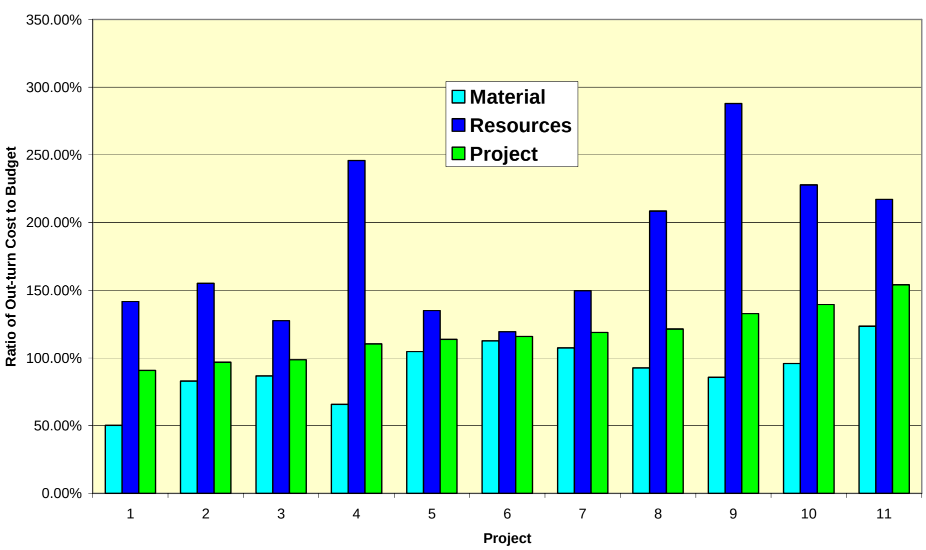

Figure 5.1

It can be seen that as a general rule, material costs are below budget, but resource costs have almost invariably exceeded budget, sometimes by a factor of in excess of 250%.

Because of diversity between material costs and resource costs, projects have come in between 91% and 154%. Lines projects tend to be at the higher end of the spectrum, and brownfield substation projects at the lower end. These values have not been adjusted for cost escalation over the period from budget to delivery, which will tend to reduce the higher extremities (and increase the difference where the project has come in below budget).

These results are by no means atypical of the results Evans & Peck has observed for other network service providers. For example, in their response to the AER's draft decision[11], Powerlink demonstrated the range of outcomes for a total of 119 projects sorted into High, Medium and Low Risk categories. The results for the medium risk category are shown in Figure 5.2. The horizontal axis shows the ratio of outturn to budget costs, and the vertical axis shows the relative frequency of occurrence.

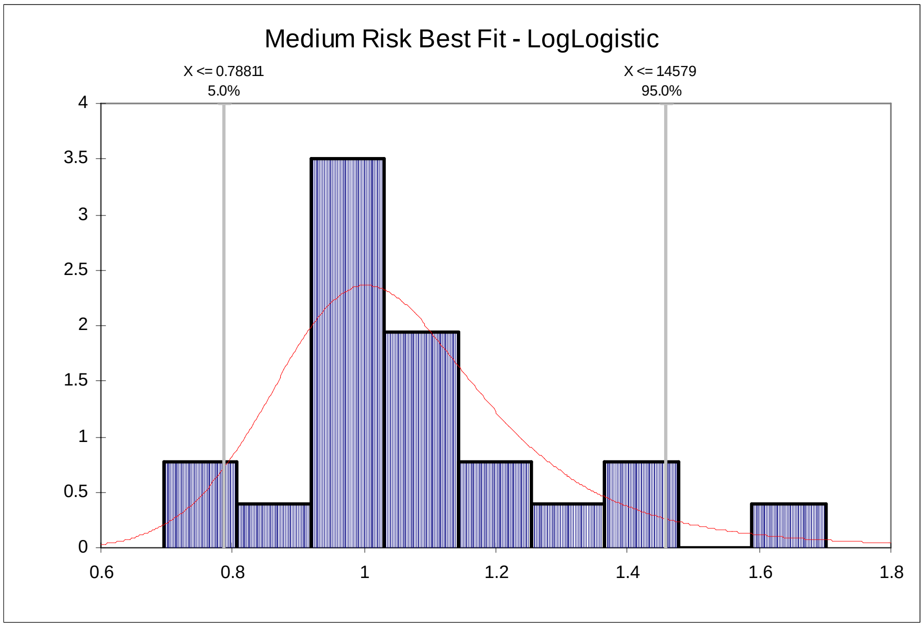

Figure 5.2 – Powerlink Medium Risk Projects – Ratio of Out-turn to Budget Cost *(Source – Powerlink Regulatory Submission)*

Ranges of outcome for High and Low risk categories may be found in the reference document. Suffice it is to say that Western Power shares common issues.

5.2 DERIVATION OF RISK FACTORS

Due to the developmental nature of the initial risk assessment and the limited time available Powerlink, with the assistance of Evans & Peck, assigned High, Medium and Low risk profiles to various project categories.

[11] Opcit, Appendix B (prepared by Evans & Peck)

Various mathematical distributions can be used to model the variability of individual cost components in a risk based quantitative analysis. The most commonly used distributions are uniform, discrete, triangular or Pert. The uniform distribution is used when the range of possible outcomes each have an equal probability of occurrence. The discrete distribution is used when specific discrete outcomes may occur, and is generally more applicable to some forms of contingent risk than for the inherent risks associated with a known scope of works. The Triangular and Pert distributions are of a similar form, as shown in Figure 5.3 below, but with the Pert distribution giving greater weighting to the best estimate (1.00 in the figure).

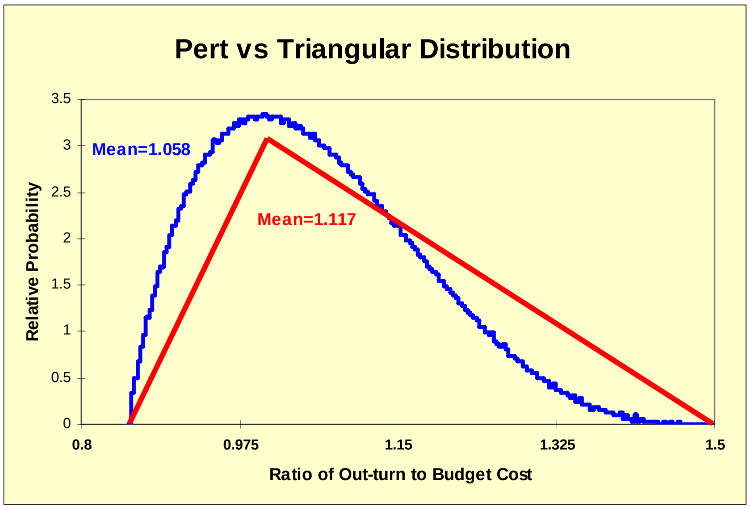

Figure 5.3 – Comparison of Pert Distribution and Triangular Distribution

Evans & Peck generally utilises the "Pert" distribution as the preferred distribution for modelling the range of outcomes for an inherent risk component in a risk based quantitative analysis because:

- It is intuitively easy for clients to understand, being represented by minimum, most likely and maximum values, with the most likely value generally being the best estimate;
- It weights results toward the most likely value, rather than extreme outcomes; and
- The distribution was specifically developed to capture time (and hence cost) overruns on capital type projects.

Whilst Powerlink applied statistical distributions at the project level, subsequent applications by Electranet and SP AusNet (and Transend and Transgrid) have focussed on refining these distributions by examining specific projects at a detailed cost line level in an effort to further develop probability distributions representative of typical project types. These may include:

- Greenfield Transmission Line
- Brownfield Transmission Line
- Greenfield Substation
- Brownfield Substation
- Secondary Systems Replacement
- Land Acquisition

This analysis is conducted in a "workshop" environment, with both estimators and project managers providing input to derive the range of possible outcomes on a line by line basis. A commercial package, such as @RISK, is then utilised to develop the range of outcomes expected at the project level. A "typical" analysis is shown in Figure 5.3 below.

CLIENT: Western Power 2009 to 2014 Capital Works Program PROJECT: (typical of 'Greenfield' substation works)			RISK ANALYSIS Risk applied to Nett Amount							
			Percentages				Values			
	DESCRIPTION	NETT AMOUNT	Min %	ML %	Max %	Dist.	Min	ML	Max	Risk Value
1	**Section 1: Substation, lump sum items**									
1.1	Work at existing Substation (Early spend)	$200	80%	100%	140%	Pert	$ 160	$ 200	$ 280	$ 206.67
1.2	Property acquisition	$500	80%	100%	200%	Pert	$ 400	$ 500	$ 1,000	$ 566.67
1.3	REF preparation and approval	$400	80%	100%	140%	Pert	$ 320	$ 400	$ 560	$ 413.33
1.4	Survey	$200	80%	100%	140%	Pert	$ 160	$ 200	$ 280	$ 206.67
		$ 1,300								**$ 1,393.33**
2	**Section 2: Substation Construction estimate**									
2.1	Contractor establishment	$500	80%	100%	140%	Triang	$ 400	$ 500	$ 700	$ 533.33
2.2	Plant procurement	$5,000	80%	100%	140%	Pert	$ 4,000	$ 5,000	$ 7,000	$ 5,166.67
2.3	Other plant procurement (panels, telecomms, SCADA), incl. labour	$2,000	80%	100%	140%	Pert	$ 1,600	$ 2,000	$ 2,800	$ 2,066.67
2.4	Electrical Works	$1,500	80%	100%	140%	Pert	$ 1,200	$ 1,500	$ 2,100	$ 1,550.00
2.5	Labour for electrical works	$1,700	80%	100%	140%	Pert	$ 1,360	$ 1,700	$ 2,380	$ 1,756.67
2.6	Civil works	$2,400	80%	100%	200%	Pert	$ 1,920	$ 2,400	$ 4,800	$ 2,720.00
2.7	Building works	$1,800	80%	100%	140%	Pert	$ 1,440	$ 1,800	$ 2,520	$ 1,860.00
2.8	Other	$300	80%	100%	140%	Pert	$ 240	$ 300	$ 420	$ 310.00
		$ 15,200								**$ 15,963**
3	**Section 3: Substation, other costs**									
3.1	Project Management (7%)	$10,640					correlated to 3.1 through 3.8			11,174
3.2	Engineering costs (10%)	$1,520					correlated to 3.1 through 3.8			1,596
		$ 12,160								**$ 12,771**
	TOTAL CONSTRUCTION COST EXCL. ESCALATION	**$ 28,660**								**$ 30,127**

Figure 5.3 – Typical Workshop Analysis – Capital Works Project

The Powerlink approach applied a risk factor on the total cost, rather than derive the factor from a series of individual line items.

In developing Transmission Project capital budgets Western Power utilises a commercial estimating package "Success Estimator". This is an extremely detailed package which builds project estimates on a "bottom up" basis. At each level, Success Estimator has the ability to incorporate a risk distribution for each input parameter. For Capex projects, Western Power clearly has the tools that allow it to parallel the approach adopted by the network service providers who have made application to the AER, or are in the process of making application.

As outlined in Section 4, the AER continues to express concern at the reliability of estimates developed in a workshop environment. Whilst acknowledging this concern and noting the need to improve the process by continual reference to previous experience, Evans & Peck is of the view that such an approach is commonly applied by industry, and provided the right experts participate in the process, experience is drawn into the analysis.

Figure 5.4 shows the range of values typically used by Western Power's estimators when allocating risk profiles to line items in Success Estimator.

Score	Risk rank	Typical range around most likely value
1 - 6	Low	-10% to +10%
7 – 14	Medium	-10% to +35%
15 - 39	High	-15% to +65%
> 40	Extreme	-20% to 100 %

Figure 5.4 Representative Range of Values around Most Likely Value For Various Levels of Risk by Cost Line Item – Success Estimator *(Source – Western Power)*

This range is typical of the range of values that Evans & Peck has observed in risk workshops. Success Estimator incorporates a number of probability distribution forms that can be applied including a normal distribution and a log normal distribution. The normal distribution is symmetrical in shape, and cannot be used to capture the asymmetric risk inherent in many projects. The log-normal distribution is statistically similar to the Pert distribution. Whilst an attempt was made to utilise this distribution in Success Estimator, the form of the log-normal distribution requires the input of the mean and variance of the curve to be applied. Unlike the Pert and Triangular distribution which require the minimum, maximum and most likely, this is not intuitively simple to apply. As a consequence, a decision was made during the development of this strategy to utilise the "triangular" distribution. However, when applied with an expectation of asymmetric risk profiles, it results in a significantly higher expected, P50, P80 and P95 values than the Pert Distribution. Figure 5.5 demonstrates the differences in outcome between a Pert Distribution and a Triangular distribution for a range of minimum, most likely and maximum values, including the values commonly used by Western Power.

Input Distribution			Pert Outcome					Triangular Outcome				
Min	Likely	Max	Expected	P5%	P50%	P80%	P95%	Expected	P5%	P50%	P80%	P95%
0.9	1	1.1	1.000	0.937	1.000	1.035	1.063	1.000	0.932	1.000	1.037	1.068
0.9	1	1.2	1.017	0.934	1.015	1.068	1.114	1.033	0.938	1.027	1.094	1.146
0.9	1	1.35	1.042	0.930	1.030	1.112	1.187	1.083	0.948	1.068	1.177	1.264
0.85	1	1.65	1.083	0.892	1.061	1.199	1.336	1.167	0.930	1.138	1.323	1.488
0.8	1	2	1.133	0.855	1.103	1.311	1.518	1.267	0.911	1.225	1.514	1.750

Figure 5.5 – Pert vs. Triangular Risk Distribution

Figure 5.6 demonstrates the ratio between the Pert outcomes and the Triangular outcomes for the same minimum, most likely and maximum values. Put simply, for asymmetric profiles, the Pert distribution results in an allocation of half the expected risk.

Input Distribution			Ratio of Pert Outcome to Triangular Outcome				
Min	Likely	Max	Expected	P5%	P50%	P80%	P95%
0.9	1	1.1	100%	92%	100%	94%	93%
0.9	1	1.2	50%	106%	56%	72%	78%
0.9	1	1.35	50%	134%	44%	63%	71%
0.85	1	1.65	50%	156%	44%	61%	69%
0.8	1	2	50%	163%	46%	61%	69%

Figure 5.6 – Ratio of Pert Outcomes to Triangular Outcomes

Following the tabling of the initial draft strategy report and discussions with Western Power management, Western Power has been able to complete a risk analysis within success Estimator on all of their transmission projects and programs. The output of this analysis has been the P5, P50, P80 and P95 values for each project, as well as the base estimate. In order to assess what the outcome at the project level may have been had a Pert Distribution been applied, and to establish distributions to use in the development of a "whole of portfolio" model we have adjusted the P50, P80 and P95 values by the following factors:

- P50 48%
- P80 65%
- P95 73%

These values have been allocated based on a visual inspection of Figure 5.6. With three "percentile" points on an output distribution for each project, it is a relatively mechanical task to reconstruct the Pert distribution fro each project using the "Alternate" formulation of the Pert distribution in @RISK[12] software. Instead of being specified by the minimum, most likely and maximum, the distribution is specified by three percentiles (such as P50, P80 and P95) and their respective values. The result of this modelling is contained in Part 2 of E&P's report.

[12] Supplied by Palisade Corporation

Again, following the tabling of our initial draft report and subsequent workshops and discussions with Western Power management, standalone models have been developed for distribution Capex programs in an @RISK / Excel environment. The results of this modelling are also incorporated in Part 2 of our report.

6 APPLICATION OF RISK ALLOWANCES TO OPEX AND CAPEX

The precedent for application of a capital risk allowance to transmission capital projects, and to a lesser extent programs, is well established. However, in the three cases that have gone before the AER, no applications for risk allowances have been made in relation to operations and maintenance expenditure. It is our current understanding that neither Transend nor Transgrid are preparing a case for such an allowance. Further complicating Western Power's issues from a precedence point of view, is the fact that no distributor has yet made a case to the AER. The NSW distributors submitted their applications on 30 may 2008.

Western Power has provided an indicative budget for Transmission / distribution Capex and Opex over the regulatory period[13]. The relative values are shown in Figure 6.1.

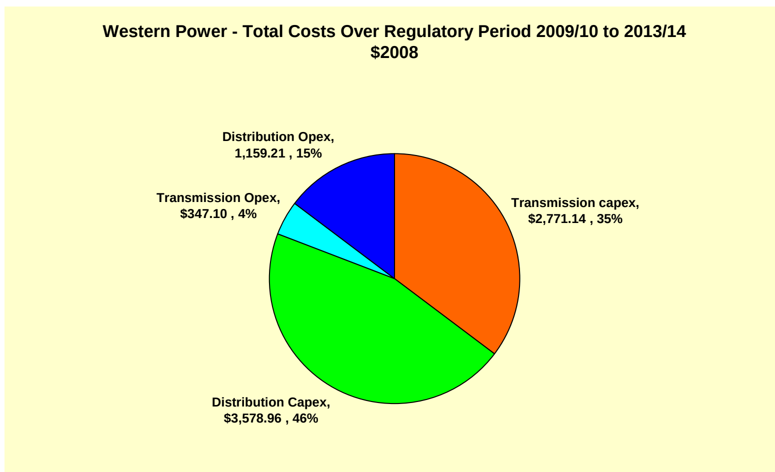

Figure 6.1 Relative Proportions of Capex and Opex over Regulatory Period

Distribution Opex amounts to approximately 15% of the total budget, whilst Transmission Opex only accounts for approximately 4%. Distribution Capex is the largest contributor at 46%.

Notwithstanding the lack of precedent for Opex, and Distribution Capex, it is worth considering whether or not the issues associated with each are sufficiently similar to the transmission Capex case to warrant inclusion in Western Power's application to the ERA given that they collectively represent 65% of expenditure. In examining this issue, we have initially adopted the Powerlink "High, Medium and Low" risk approach, not so much

[13] These values were provided at an early stage of Western Power's budget development. As they are being used only to provide broad indications of likely magnitudes of risk, we have not updated them and the budget has been refined. **We also acknowledge that the regulatory period has been reduced from 5 years to 3 years during the course of this strategy development.**

because we think it represents the real level of risk in activities, but because the AER has chosen (somewhat pragmatically we suspect) to use the framework as a "safe house" in other decisions. Both transmission and distribution Opex are considered in Section 6.2, Distribution Capex in Section 6.3 and Transmission Capex in Section 6.4.

6.1 TRANSMISSION AND DISTRIBUTION OPEX

Western Power has provided budgets for Distribution Opex and Transmission Opex over the next 7 years as shown in Table 6.1 and Figure 6.2 below.

DISTRIBUTION OPEX	2007/08 $M	2008/09 $M	2009/10 $M	2010/11 $M	2011/12 $M	2012/13 $M	2013/14 $M	Total 2009/10 to 2013/14 $M
Maintenance Strategy	8.70	9.54	13.54	14.36	15.32	16.35	17.43	76.99
Environmental Strategy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
Preventive Condition	31.40	20.84	38.56	42.61	45.18	47.91	50.70	224.97
Preventive Routine	32.70	34.40	33.21	33.84	35.24	39.67	41.33	183.28
Corrective Deferred	22.30	22.70	39.00	42.77	46.71	50.18	53.53	232.20
Corrective Emergency	47.90	51.22	65.71	72.39	79.02	84.60	89.70	391.41
SCADA & Comms	0.80	0.80	1.02	1.08	1.14	1.19	1.25	5.67
Meter Maintenance	0.60	2.10	1.58	1.65	1.74	1.83	1.91	8.71
SUPP Opex	4.80	5.20	3.40	3.00	3.00	3.00	3.00	15.40
Reliability	3.80	3.10	3.63	3.85	4.10	4.36	4.64	20.57
Total	**153.00**	**149.90**	**199.66**	**215.54**	**231.44**	**249.09**	**263.49**	**$ 1,159.21**

Table 6.1 – Projected Distribution Opex – 2007/08 to 2013/14[14]

TRANSMISSION OPEX	2007/08 $M	2008/09 $M	2009/10 $M	2010/11 $M	2011/12 $M	2012/13 $M	2013/14 $M	Total 2009/10 to 2013/14 $M
Maintenance Strategy	7.75	8.66	10.16	10.78	11.52	12.30	13.12	$ 57.89
Preventive Condition	7.55	7.10	14.70	15.57	16.58	17.65	18.77	$ 83.27
Preventive Routine	9.40	9.10	16.94	17.96	19.14	20.41	21.73	$ 96.19
Corrective Deferred	4.10	4.40	6.08	6.55	7.00	6.84	6.67	$ 33.14
Corrective Emergency	2.60	2.90	3.17	3.54	3.95	4.38	4.88	$ 19.92
SCADA & Comms	5.80	6.69	6.26	6.59	6.94	7.28	7.62	$ 34.69
Customer NRS	8.50	9.58	6.00	4.00	4.00	4.00	4.00	$ 22.00
Environmental Strategy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$ -
Total	**45.70**	**48.43**	**63.33**	**64.98**	**69.13**	**72.87**	**76.79**	**$ 347.10**

Table 6.2 – Projected Transmission Opex – 2007/08 to 2013/14[15]

Whilst acknowledging that there is no adjustment mechanism relating to Opex (other than in the case of an extreme event which may qualify as a "Trigger Event", extending risk

[14] Opcit

[15] Opcit

analysis to the regulatory case involving Opex gives rise to two key concerns. Firstly, Western Power is showing significant real growth in expenditure over the regulatory period (cumulatively 9.5% per annum in the case of Distribution Opex, and 9% in the case of Transmission Opex). This, in itself, will attract significant regulatory scrutiny and the need for significant analysis to support the case. Secondly, from a risk methodology perspective and taken in the context of comments commonly made by the AER, Opex activities are a series of repetitive tasks (albeit at a higher level of activity) that Western Power is very familiar with. As such, the current estimating process, based on a long history of completing such tasks, should already include an "average" risk allowance in time and cost allocations. That is not to say that residual risks and opportunities do not exist. These potentially include:

- Price variations from the assumed escalation indices
- Higher or lower levels of activity than forecast
- Estimation error in issues such as traffic management
- Changes in OH&S, environmental or other laws that impact productivity.

As outlined in earlier sections, for these issues to have any impact on the regulatory case, western Power must be able to demonstrate that the risks are asymmetric.

In order to "test" the impact of a risk based approach to OPEX budgeting and following discussions with Western Power representatives on where perceived risks exist, we have intuitively ranked the activities above into "low" , "medium" and "high" risk categories as follows shown in Table 6.3.

Opex Category	Distribution Risk Rating	Transmission Risk Rating
Maintenance Strategy	Low	Low
Environmental Strategy	Low	Low
Preventive Condition	Medium	Medium
Preventive Routine	Low	Low
Corrective Deferred	High	High
Corrective Emergency	High	High
SCADA & Comms	Low	Low
Meter Maintenance	Low	
SUPP Opex	Low	
Reliability	Low	
Customer NRS		Low

Table 6.3 – Allocation of Maintenance Activities to Risk Categories

We have used the "Powerlink" risk distributions (refer Section 4.1) and constructed a risk model to determine the likely magnitude of the risk factor applicable to Distribution and Transmission Opex over the 5 year period. The result is shown in Figure 6.2. It can be seen that the expected result is a "risk premium" of 1.04%. On a base of $1,506 million this represents a premium of $19.3 million. Put another way, with these risk distributions there is an 80% chance that the outcome will be between 99.6% and 103.0% of the estimated values.

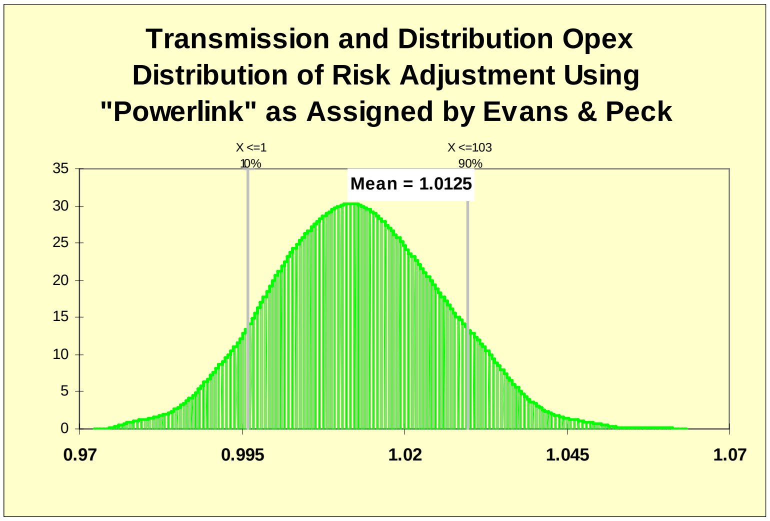

Figure 6.2 Opex Risk Simulation Using Powerlink Risk Profiles and Evans & Peck Assigned Ratings

We will deal with strategy development more in Section 8. However, acknowledging the deficiencies of the Powerlink profiles, based on these results we are of the view that pursuit of a risk adjustment on Opex expenditure presents a possibility of only minimal gains to Western Power. This is particularly so in the context of the significant increase in expenditure sought, and the lack of precedent. Our recommendation would be to not pursue a risk adjustment in relation to Opex, focussing resources instead on justifying the programs and the risk adjustments for Capex.

6.2 DISTRIBUTION CAPEX

Western Power has provided Evans & Peck with a list of approximately 75 Distribution Programs “NSDD District Capex” planned for the 2009/10 to 2013/14 regulatory period. In order to assist in the development of a quantitative risk strategy, we[16] have broadly categorised these programs into the following 6 categories:

- Brownfield Line
- Brownfield Substation
- Greenfield Line
- Greenfield Substation
- Land

[16] We have completed this in isolation of Western Power, based on broad descriptions associated with each category. As this project has evolved, Western Power has been able to complete

- Secondary Systems

The relative value of each category is shown in Figure 6.3.

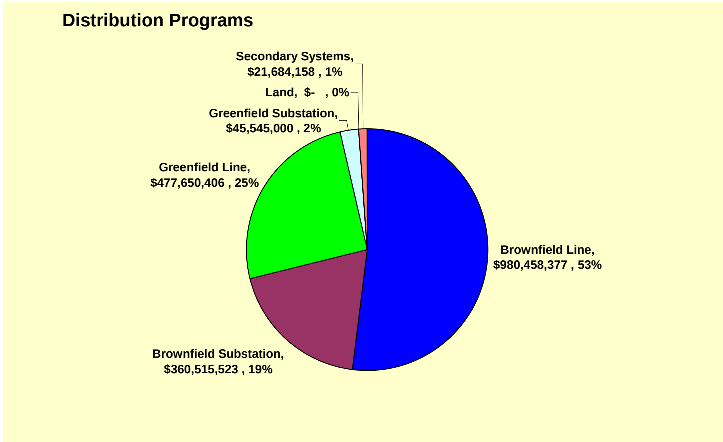

Figure 6.3 – Distribution Programs over the period 2009/10 to 2013/14

In order to "test" the potential value to Western Power of quantifying the risk associated with these programs, we have used the Powerlink "High, Medium, Low" framework and applied risk distributions as shown in Table 6.4.

Program Category	Assigned Risk Profile
Brownfield Line	High
Brownfield Substation	Low
Greenfield Line	High
Greenfield Substation	High
Land	High
Secondary Systems	Medium

Table 6.3 – Distribution Programs – Assigned Risk Profile

Utilising @Risk, we have applied the Powerlink risk profiles to each program in accordance with the above allocation. The resultant risk distribution is shown in Figure 6.3. On the basis of this analysis, the expected value of the risk premium is 2.7%.

analysis on each program. Notwithstanding, for the purpose of strategy development we have retained our initial analysis.

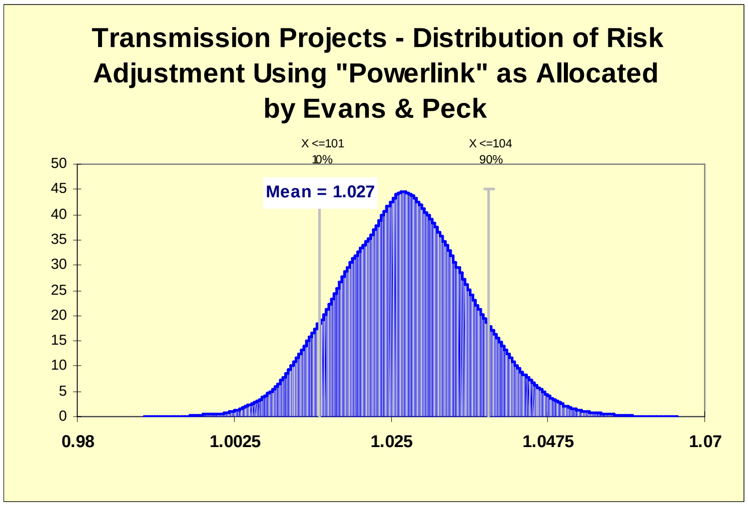

Figure 6.4 – Distribution Programs Risk Profile

6 programs represent 52.3% of the expenditure analysed:

- Capacity Reinforcement (Dist & Trans Driven) – 18.6%
- Pole Replacement (10.1%)
- Undergrounding (6.5%)
- L V Network Upgrade (6%)
- Service Replacement (5.2%)
- Reliability Reinforcement (5.9%)

Based on our allocation of broad risk factors, these 6 programs account for approximately 65% of the risk. Of these, capacity reinforcement, low voltage network upgrades and pole replacements represent 43.5% of the total risk using our allocation. Of the six programs listed above, these would seem to be more subject to external influences than the others which are more of a “program” nature. Our recommendation would be to focus additional analysis on these programs.

We again emphasise that this is intended only to provide a broad indication of possible risk levels based on the Powerlink approach. Western Power would need to supplement this analysis with detailed consideration of the risks within each program, the appropriateness of the classification, and the quantification of the risk levels. This has been completed by Western Power as this project has evolved, and the results are summarised in Part 2 of our report. In completing this analysis, we have also separated those projects that are subject to the IAM.

6.3 TRANSMISSION CAPEX PROJECTS AND PROGRAMS

Western Power has provided estimates for approximately 355 Transmission Capex projects and programs over the 5 year regulatory period 2009/10 to 2013/14. We believe this is a subset of the final list of projects, but is sufficient for the purpose at hand. We have again categorised these as follows:

- Brownfield Substation
- Greenfield Line
- Greenfield Substation
- Land
- Secondary Systems

The allocation of projects / programs to these categories is shown in Figure 6.5.

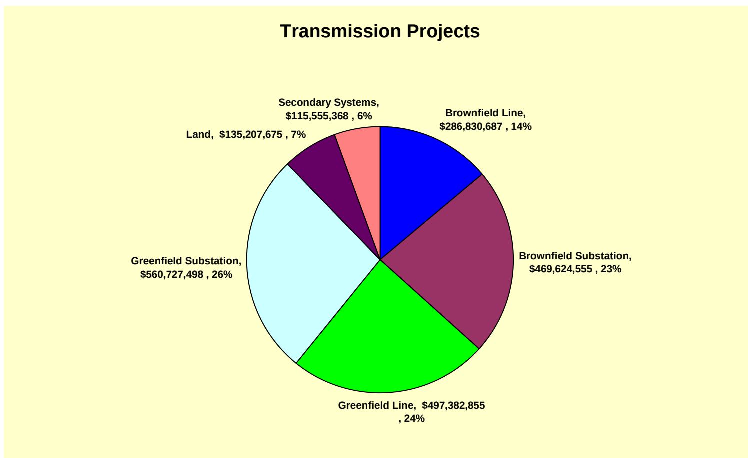

Figure 6.5 Transmission Projects – Break-up of Expenditure

In order to gain some insight into the magnitude of likely risk adjustments, or at least the level based on the precedents set by the AER, we have again allocated Powerlink's risk profiles as set out in Table 6.3, and applied these in a simplified @RISK adaption of Western Power's spreadsheet. The resultant risk distribution is shown in Figure 6.6.

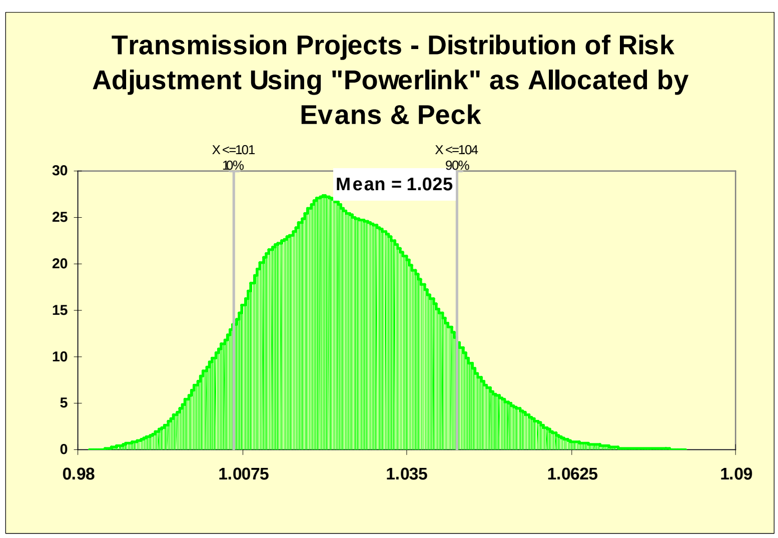

Figure 6.6 Transmission Projects – Risk Profile

Application of the Powerlink profiles to Western Power's portfolio of Transmission Capex projects / programs results in an expected risk adjustment factor of 2.5%.

In presenting these results, we have quoted the mean (or expected value) of the adjustments. In more recent regulatory cases, the P50 (i.e. there is a 50/50 chance of being above or below the value) has been used. This measure is more commonly used in commercial processes (albeit usually at a much higher level such as P80). However, the P50 value has been used to argue the point that it represents a fair distribution of risk between the utility and its customers. In the case of Transmission Capex, the P50 risk adjustment value is 2.37%, slightly below the mean value of 2.41%. In the case of distribution Capex, the P50 value is 2.63%, slightly below the mean or expected value of 2.65%. For Opex, the P50 value is 1.22%, again fractionally below the expected value of 1.22%.

The purpose of the preceding analysis has to demonstrate that when Powerlink values and methodologies are applied to Western Power data, similar results are obtained.

In our view, the Powerlink values are at the low end of the risk spectrum. The key focus of Western Power's strategy is not only establishing that the AER precedent is relevant, but demonstrating through detailed analysis that higher values are justified. This is likely to be more straightforward for "one of" projects, than program type activities.

7 RECOMMENDED STRATEGY

As outlined in Section 4, the AER has made some allowances in recent regulatory decisions recognising estimation risk in regulatory submissions. This has:

- Been limited to transmission, if for no other reason that no distributor as yet made a regulatory submission to the AER. Western Power's transmission classification extends to lower levels of system than most other transmission network service providers.
- Only applied to Capex
- In the case of Powerlink, applied to both projects and programs, in the case of Electranet projects generally and in the case of SP AusNet, specific projects only.
- Been limited to around 2.6% of Capex, or a subset thereof.

Based on our initial "order of magnitude" analysis of Western Power's projects and programs, extension of the "2.6%" principles to Western Power's entire portfolio translates to risk adjustments of:

Expenditure	Indicative P50	Expenditure Base	Indicative Risk

Category	Risk Adjustment	2009/10 to 2013 / 14	"Premium"
Transmission / Distribution Opex	1.22%	$1,506m	$18.4m
Distribution Capex	2.63%	$3,579m	$94.1m
Transmission Capex	2.37%	$2,771m	$65.7m
TOTAL			**$178.2**

In dollar terms, this is 2-3 times the largest of the allowances made to date. Whilst Evans & Peck believe it unlikely that the ERA would allow this amount, the quantum is significant. In addition, the Electranet decision will determine if the AER is prepared to accept levels higher that that approved in the cases so far.

The key issues that continue to concern the AER are:

- The judgemental nature of the determination of the risk ranges, particularly those determined in a workshop environment, and the ability to complete specific analysis to specific projects / programs
- The overlap between explicit risk allowances under this mechanism, and the inclusion of "Business as Usual" risk notionally incorporated in the Weighted Average Cost of Capital
- Potential overlap between explicit risk allowances, and allowances already incorporated in the estimating process
- Risks should be manageable without incurring additional costs
- The need to realistically assess opportunities, as well as risks.
- The unreasonable transfer of risks to customers.

Based on this analysis, and our experience with and observation of the regulatory process to date, we believe that Western Power should pursue the issue on the basis of precedent and the reality of real risks in the business. In order to manage resource limitations, and achieve the best outcome, our recommended approach to each sector is as shown in Table 7.1

Table 7.1 – Recommended Risk Approach to Expenditure Categories

Expenditure Category	Risk Approach
Distribution Opex	No explicit risk adjustment – focus on justification of level of activity
Transmission Opex	No explicit risk adjustment - focus on justification of level of activity
Distribution Programs / Projects	Differentiate between growth related programs subject to IAM and

	non growth related programs not eligible for IAM consideration. Develop high level risk model for each major program utilising Excel / @Risk software tools.
Transmission Programs /Projects	Differentiate between growth related programs subject to IAM and non growth related programs not eligible for IAM consideration. Utilise existing risk adjustment capability inherent in “Success Estimator” to assess risk at individual project / program level. Externally to Success Estimator, adjust results to be more in line with probability distributions more commonly accepted by AER.

As an adjunct to this work, Western Power a risk accumulation model will be developed to enable the separation of the “global” risk adjustment applicable to Western Power’s entire capital spend between projects / programs subject to the IAM, and those that are not.

Western Power

2009/10 – 2011/12
Regulatory Reset

Quantitative Risk Assessment of CAPEX and OPEX Expenditures

Part 2 – Model Outcomes
July 2008

(DMS#4783429)

Table of Contents

1 EXECUTIVE SUMMARY

In January 2008, Western Power engaged Evans & Peck to develop a strategy dealing with the asymmetric quantitative risks associated with estimation and delivery of Transmission and Distribution Capital expenditure (Capex) and Operations expenditure (Opex) over the 2009/10 to 2011/12 regulatory period. The background to this strategy and the evolution that has occurred following submission of an initial draft report is outlined in Part 1 of our report. The recommended strategy can be summarised as:

- Western Power should use the precedent in recent AER rulings to justify a risk based approach to the ERA.
- The primary focus in Opex should be on developing unit costs which fully reflect risks actually experienced by Western Power in performing comparatively repetitive tasks over a long period of time.
- No explicit allowances should be made for contingent risks such as Force Majeure initiated events
- Application of the risk factor to IAM projects gives the highest probability of appropriate cash flows and reduces the likelihood of the need for subsequent price adjustments. The underlying risk implicit in these projects should be outlined to the ERA.
- To the maximum extent possible, existing estimating packages and experienced internal estimating skills be utilised to quantify risks.
- The focus for detailed analysis be as outlined in the following table:

Expenditure Category	Risk Approach
Distribution Opex	No explicit risk adjustment – focus on justification of level of activity
Transmission Opex	No explicit risk adjustment - focus on justification of level of activity
Distribution Programs / Projects	Differentiate between growth related programs subject to IAM and non growth related programs not eligible for IAM consideration. Develop high level risk model for each major program utilising Excel / @Risk software tools.
Transmission Programs /Projects	Differentiate between growth related programs subject to IAM and non growth related programs not eligible for IAM consideration. Utilise existing risk adjustment capability inherent in "Success Estimator" to assess risk at individual project / program level. Externally to Success Estimator, adjust results to be more in line with probability distributions more commonly accepted by AER.

This "Part 2" report focuses on the modelling outcomes arising from the application of the strategy as it evolved. Through the use of Western Power estimating expertise and the risk assessment capability inherent in Western Power's project costing software – Success Estimator – Western Power has been able to individually assess the risk relating to 328 transmission projects / programs. This provided a far greater level of analysis than has been achieved by any of the transmission operators in support of their applications to the Australian Energy Regulator. In addition, Western Power has constructed risk models relating to 77 Distribution Capex programs accounting for approximately 95% of distribution Capex.

Some adjustment is required to the output from Success Estimator to reflect the use of triangular distributions in that software. In Evans & Peck's view, triangular risk distributions tend to place too much weight on extreme outcomes, and too little weight on outcomes around the expected value. We have re-estimated the risk based on a Pert distribution.

In analysing Western Power estimates for distribution and transmission projects / programs, we have developed an accumulation model which separates them according to whether or not they are likely to be eligible for adjustment under the "Investment Adjustment Mechanism" contained in the Electricity Networks Access Code 2004. Notwithstanding this adjustment mechanism, we believe it prudent to price in the inherent risk in these projects from the outset if price shocks due to future adjustment are to be avoided. This model also reflects the diversification of risk between projects and programs.

We have calculated the risk outcomes in terms of both the "P50" value and a "P80" value. There remains a 20% probability that the actual outcome will exceed the P80 value and a 50/50 chance that the outcome will be above or below the P50 value. In a commercial environment Evans & Peck would recommend that the P80 value be selected as the prudent value for budget approval. However, in a regulatory environment where a more conservative approach is applied to balancing the allocation of risk between the service provider and its customers, the P50 value is commonly applied.

Based on the data provided by Western Power, and our subsequent analysis, we have calculated the relevant risk adjustment factors as:

Cost Category	Calculated Risk Adjustment Factor
Distribution IAM	**7.30%**
Distribution Non IAM	**3.35%**
Transmission IAM	**3.95%**
Transmission Non IAM	**2.11%**

Evans & Peck has not considered the timing of individual projects. Western Power has developed a capital accumulation model which takes both of these factors into account. Due to the relatively large number of both transmission and distribution projects, we are of the view that variations in the timing or escalation of individual projects will have minimal impact on the overall "percentage" risk adjustment.

Western Power has provided details of the "base" (i.e. $2007/08) project costs during the 2009/10, 2010/11 and 2011/12 financial years in three categories:

- Distribution
- Transmission – AA2 period
- Transmission – Work in Progress.

Application of the risk factors above to these base costs, and aggregation of the transmission categories, results in the following adjustments:

Cost Category	3 year Capex ($2007/08m)	Risk Adjustment ($2007/08m)
Distribution IAM	**$ 1,023.63**	**$ 40.69**
Distribution Non IAM	**$ 1,305.16**	**$ 43.72**
Transmission IAM	**$ 1,912.78**	**$ 68.06**
Transmission Non IAM	**$ 295.18**	**$ 6.23**
Total	**$ 4,536.75**	**$ 158.70**

On the basis of this analysis, Evans & Peck recommends that Western Power include a "global" risk allowance of 3.5% in their AA2 regulatory application. It is important to recognise that the dollar values expressed in the following table are un-escalated (i.e. base $2007/08). The ***percentage*** adjustment applies equally to escalated dollar values.

2 TRANSMISSION PROJECTS

Western Power has provided Evans & Peck with a spreadsheet detailing budget estimates relating to 328 transmission capital works projects and programs. These have all been estimated in Success Estimator. Estimates of the level of risk associated with individual line items within Success Estimator have been made by Western Power personnel. For each project, a summary has been provided detailing:

- Line Material $
- Line Labour $
- Substation Material $
- Substation Labour $
- P5% $ adjustment
- P50% $ adjustment
- P80% $ adjustment
- P95% $ adjustment
- Regulatory category

It is inappropriate to assess the overall Transmission Project portfolio risk by simply adding up the relevant percentile values (whether it be P5, P50, P80 or P90) as there will be diversification of risks between projects. This diversification increases significantly for the P5, P80 and P95 values.

In Section 5, page 23 of Part 1 of this report, we discussed a mechanism for adjusting the output of Success Estimator to accommodate the transition from Triangular to Pert distributions.

We have adjusted the P50, P80 and P95 outputs by the following factors:

- P50 48%
- P80 65%
- P95 73%

and applied the Alternative Pert function to develop a continuous risk profile for each project. In a few cases, this resulted in an invalid fit and the P50 value was applied with no further risk adjustment.

A Monte Carlo based accumulation model was developed to enable the diversified risk to be calculated at the regulatory category level, at the IAM / non IAM level and at the corporation level. The results are shown in Figure 2.1.

Regulatory Category	Unrisked $mil	Risked $mil	Expected (Mean) Risk Adjustment	Mean % Adjustment	P50 $mil Adjustment	P50 % Adjustment	P80 % Adjustment
AR	$125.0	$129.3	$4.3	3.45%	$4.3	3.43%	4.33%
RC	$169.3	$169.6	$0.3	0.18%	$0.3	0.16%	0.39%
RD	$37.7	$38.3	$0.6	1.67%	$0.6	1.57%	2.54%
SC	$75.4	$78.7	$3.4	4.45%	$3.3	4.42%	5.60%
Non IAM Eligible	**$407.4**	**$416.0**	**$8.6**	**2.11%**	**$8.6**	**2.11%**	**2.47%**
CA	$66.1	$68.6	$2.5	3.81%	$2.4	3.57%	7.47%
CE	$2,827	$2,939	$112.7	3.99%	$111.2	3.94%	5.88%
GA	$52.9	$55.7	$2.8	5.25%	$2.6	4.82%	8.96%
GD	$140.9	$146.9	$6.0	4.23%	$4.7	3.32%	8.19%
IAM Eligible	**$3,087**	**$3,211**	**$124.0**	**4.02%**	**$121.8**	**3.95%**	**5.79%**
Total	**$3,494**	**$3,635**	**$141.2**	**4.04%**	**$140.1**	**4.01%**	**5.63%**

Table 2.1 – Transmission Projects – Risk Adjusted Estimates Based on Pert Distribution.

The P50 risk adjustment across the transmission project portfolio under this model is $140.1 million, or 4.01%. This compares with $253.9 million if the raw triangular distribution values (undiversified) were taken directly from Success Estimator. The comparative P80 values are $196.9 million vs. $502.8 million. In addition to the Pert / Triangular scaling factor, this reduction encapsulates risk diversification.

It can be seen that 87% of the calculated risk is in projects covered by the IAM mechanism. Notwithstanding this adjustment mechanism, we believe it prudent to price in the inherent risk in these projects from the outset if price shocks due to future adjustment are to be avoided.

We have calculated the risk outcomes in terms of both the “P50” value and a “P80” value. We have also shown the “mean” outcome. Numerically, this is the expected outcome. However, the P50 and P80 values are intuitively simpler to explain. There remains a 20% probability that the actual outcome will exceed the P80 value and a 50/50 chance that the outcome will be above or below the P50 value. In a commercial environment Evans & Peck would recommend that the P80 value be selected as the prudent value for budget approval. However, in a regulatory environment where a more conservative approach is applied to balancing the allocation of risk between the service provider and its customers, the P50 value is commonly applied.

Based on the information made available, our minimum recommended “global” risk adjustment to the Transmission works capital expenditure portfolio is:

- **Non IAM eligible Projects 2.11%**
- **IAM eligible Projects 3.95%**

3 DISTRIBUTION PROJECTS AND PROGRAMS

Western Power has identified 77 distribution works programs accounting for approximately 95% of distribution capital expenditure and developed a risk based estimate for each program of the form shown in Figure 3.1 below. This approach, developed in an Excel / @Risk environment, is similar to the approach adopted by Evans & Peck in assessing representative projects for other transmission operators. Projects are broken down into cost line items, and an assessment made of the relative risk associated with each item. The analysis has been performed using the same risk categories as used within Western Power's Transmission risk assessments.

Distribution Carrier Replacement

Risk (L, M, H, E)	Cost elements	Total Base case $k	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Sampled
L	Planning	$0.00	90%	100%	110%	$ -	$ -	$ -	$ -
H	Design	$5,344.95	85%	100%	165%	$ 4,543	$ 5,345	$ 8,819	$ 5,790
L	ELMS	$0.00	90%	100%	110%	$ -	$ -	$ -	$ -
M	Project management	$7,467.32	90%	100%	135%	$ 6,721	$ 7,467	$ 10,081	$ 7,778
H	Construction	$180,659.53	85%	100%	165%	$ 153,561	$ 180,660	$ 298,088	$ 195,714
H	Commissioning	$643.11	85%	100%	165%	$ 547	$ 643	$ 1,061	$ 697
H	Quality Assurance	$165.63	85%	100%	165%	$ 141	$ 166	$ 273	$ 179
	Total	**$ 194,281**							**$ 210,159**

Score	Risk rank	Typical range around most likely	Minimum Values	Maximum
1 – 6	Low	-10% to +10%	90.00%	110.00%
7 – 14	Medium	-10% to +35%	90.00%	135.00%
15 - 39	High	-15% to +65%	85.00%	165.00%
> 40	Extreme	-20% to 100 %	80.00%	200.00%

Risk (L, M, H, E)	Cost elements	Reasons for Risk assessment
L	Planning	No cost item
H	Design	High Risk as the SOW does not accurately identify the exact locations of conductor replacement. DFIS is also inaccurate in relation to conductor sizes. This will mean that there is a risk to the change in design due to variations in SOWs.
L	ELMS	No cost item
M	Project management	The variations in SOW's will have a moderate affect to the cost to Project management, as a variation in the SOW's or issues with construction, will impact the design and actual construction more than it will impact the project management costs.
H	Construction	The variations in SOW's is seen as a common liklhood with a high consequence, which leads to an overall rating of 32 in the risk matrix making it a high risk item
H	Commissioning	Same as construction
H	Quality Assurance	Same as construction

Figure 3.1 – Typical Risk Model – Distribution Programs

The Pert distribution has been used as the basis of assessment. The analysis has been completed by experienced estimators within Western Power.

Figure 3.2 demonstrates the mean risk adjustment for each project type. It can be readily seen that many programs have not been allocated a risk profile. The vast majority of Western Power's distribution programs are not covered by the IAM.

Expenditure Category	IAM / Non IAM	Mean Risk Adjustment
Distribution Carrier Replacement	Non IAM	8.2%
Reclosers Replacement	Non IAM	0.0%
Distribution Transformer Replacement	Non IAM	7.9%
Sectionaliser Replacement	Non IAM	0.0%
Substations Replacement	Non IAM	7.6%
Switches/Disconnectors LV Replacement	Non IAM	0.0%

Distribution Pole Replacement	Non IAM	0.0%
HV Conductor Clashing	Non IAM	4.0%
LV SPREADERS in Moderate and Low Fire Risk Areas	Non IAM	0.0%
Street Light Metal Pole Replacement	Non IAM	0.0%
Wildlife Proofing	Non IAM	0.0%
Rural Power Improvement Program (RPIP)	Non IAM	7.1%
Reliability Improvement Pilot Projects	Non IAM	0.0%
DOF Replacement	Non IAM	0.0%
Surge Arrestors Replacement	Non IAM	0.0%
Distribution Wood Pole Reinforcement	Non IAM	0.0%
Switches/Disconnectors HV Replacement	Non IAM	3.8%
Pole Top Replacement in High Fire Risk Areas	Non IAM	8.3%
Compensators Replacement	Non IAM	0.0%
HV Reinforcement	IAM	7.2%
Transmission Driven	IAM	7.7%
Distribution Transformer Overload Upgrades & LV Network Optimisation	IAM	4.2%
Metro Capacity Expansion - HV Reinforcement.Distribution Driven Project (DD)	IAM	8.3%
Metro Capacity Expansion Trans DrivenTransmission Driven Project (TD)	IAM	8.3%
Lightning Mitigation	Non IAM	0.0%
Targeted Fuse Replacement	Non IAM	0.0%
'Hills' Covered Conductor	Non IAM	7.8%
North Country Feeder Rebuild	Non IAM	7.3%
North Country Pole Reinforcement (Rebutting)	Non IAM	0.0%
Query Troubles	Non IAM	0.0%
Recurring Circuit Breaker and Recloser Trip Management (RCBRTM)	Non IAM	
Distribution Feeder Rebuild - South Country	Non IAM	7.3%
Targeted Reliability Reinforcement	Non IAM	0.0%
1st Section Undergrounding	Non IAM	7.7%
Wildlife Proofing	Non IAM	0.0%
Targeted Maintenance	Non IAM	0.0%
Reliability Reconductoring for LBS Installation	Non IAM	7.8%
Pole Top Switch (PTS) Installation	Non IAM	0.0%
Street Light Luminaires Replacement	Non IAM	0.0%
Bushfire Mitigation Wires Down	Non IAM	8.2%
Cattle Care	Non IAM	0.0%
Conductive Poles	Non IAM	0.0%
Distribution River Crossings	Non IAM	8.3%
Reinforcement of Transformer Poles	Non IAM	0.0%
Retrofit Installation of Stay Insulators	Non IAM	0.0%
Substandard Conductor Clearance	Non IAM	4.2%
URD Pillars Replacement	Non IAM	0.0%
Replacement of Overhead Customer Service Connections	Non IAM	0.0%
Street Light Switchwire Replacement	Non IAM	0.0%
Rebuilding /Reinforcement of Tambellup Area Feeders	Non IAM	7.2%
PQ Compliance Reinforcement	Non IAM	8.1%
Targeted LV Network Upgrades	Non IAM	8.1%
Distribution Substation Safety & Security	Non IAM	4.0%
Cable box replacement	Non IAM	3.8%
Ring-Tail Possum Protection Devices	Non IAM	0.0%
Replacement of Under Rated Stay Wires	Non IAM	0.0%
Line Markers for Remote Road Crossings	Non IAM	0.0%
Pole Top Fire Mitigation (Retrospective Bonding)	Non IAM	0.0%
Fires Safe Fuses	Non IAM	0.0%
Pole Top Switches Replacement	Non IAM	3.8%
Vegetation Related Re-Conductoring Works	Non IAM	4.0%
Mitigation of Shock Hazard from Metal Street Light Poles	Non IAM	0.0%

Broadband Over Powerline (BPL) Trial	Non IAM	0.0%
Distribution Automation Expansion	Non IAM	0.0%
Mobile Radio Emergency Services Strategic Compliance	Non IAM	0.0%
Comms Tran Shelter & Services Asset Rep	Non IAM	0.0%
Dist Auto Data Concentrator Replacement	Non IAM	0.0%
CBD SCADA Asset Replacement	Non IAM	0.0%
Metro Recloser System RFI Radio Replacement	Non IAM	0.0%
Comms Tower Reinforcement Regulatory Compliance	Non IAM	0.0%
Trunked Mobile Radio Replacement	Non IAM	0.0%
COUNTRY MOBILE RADIO	Non IAM	0.0%
Dist Comms Tower Reinforcement Stage 2	Non IAM	0.0%
3 Phase Unbalanced Load Detection	Non IAM	0.0%
Comms Mobile Disaster Equipment	Non IAM	0.0%

Figure 3.2 – Distribution Programs – Calculated Risk Factors[1]

In order to ensure appropriate diversification of risk between programs, Evans & Peck has constructed an accumulation model within a Monte Carlo framework. We have used 5000 simulations to arrive at an overall distribution program risk allowance.

The results of our analysis of the overall distribution Capex portfolio, split according to regulatory category and IAM coverage, is tabulated in Table 3.1.

Regulatory Category	Unrisked $mil	Risked $mil	Expected (Mean) Risk Adjustment	Mean % Adjustment	P50 $mil Adjustment	P50 % Adjustment	P80 % Adjustment
AR, RD, RC	$1,840	$1,903	$63.40	3.45%	$ 62.19	3.38%	5.10%
SC	$19.00	$19.00	$0.00	0.00%	$ -	0.00%	0.00%
Total Ineligible IAM	$1,859	$1,922	$63.40	3.41%	$ 62.19	3.35%	5.05%
CE	$605.47	$651.85	$46.38	7.66%	$ 44.22	7.30%	12.60%
Total Distribution	$2,464	$2,574	$109.78	4.45%	$ 107.22	4.35%	6.20%

Table 3.1 – Distribution Projects – Risk Adjusted Estimates

For the reasons outlined in Section 2, we believe the P50 estimate provides a reasonable balance between the network provider and its customers in a regulatory environment. Based on the information made available, our minimum recommended risk adjustment to the Distribution works capital expenditure portfolio is:

- **Non IAM eligible Projects 3.35%**
- **IAM eligible Projects 7.30%**

[1] The above categories account for approximately 95% of distribution expenditure. The remaining 5% has not been analysed in detail, and through the calculation methodology applied in the next section, has been assumed to carry the same average risk of those above.

4 APPLICATION OF RISK ADJUSTMENTS TO FINAL CAPITAL PROGRAM

In developing the above estimates we have determined the risk factor applicable to the portfolio of projects without consideration of:

- The timing of the project with respect to the AA2 regulatory period
- Escalation

Western Power has developed a capital accumulation model which takes both of these factors into account. Due to the relatively large number of both transmission and distribution projects, we are of the view that variations in the timing or escalation of individual projects will have minimal impact on the overall "percentage" risk adjustment.

Western Power has provided details of the "base" (i.e. $2007/08) project costs during the 2009/10, 2010/11 and 2011/12 financial years in three categories:

- Distribution
- Transmission – AA2 period
- Transmission – Work in Progress.

These are shown in tables 4.1 (a), 4.1 (b) and 4.1(c) respectively. We have categorised each cost category according to the applicability of the Investment Adjustment Factor, and applied the risk adjustment factors determined above accordingly. "Customer Access Gifted Assets" are not subject to estimation risk, and no risk allowance is applied.

Distribution AA2 Activities	2009/10 $m	2010/11 $m	2011/12 $m	IAM	Risk Factor
Capacity Expansion	107.87	99.93	87.43	IAM	7.30%
Customer Access	86.60	87.39	88.19	IAM	7.30%
Customer Access Gifted	154.00	155.41	156.81	IAM	0%
Asset Replacement	141.27	152.94	161.69	Non IAM	3.35%
Reliability Driven	59.05	58.63	62.06	Non IAM	3.35%
Safety,Enviro, & Statutory	144.23	147.07	146.66	Non IAM	3.35%
SCADA & Comms	4.00	4.24	4.03	Non IAM	3.35%
SUPP	32.30	34.80	20.00	Non IAM	3.35%
RPIP	7.69	4.89	2.75	Non IAM	3.35%
Metering	37.03	37.03	37.33	Non IAM	3.35%
System Operations	1.95	1.87	1.64	Non IAM	3.35%
Total	**775.99**	**784.2**	**768.59**		

Table 4.1 (a) Distribution Capital ($2007/08)

Transmission AA2 Activities	2009/10 $m	2010/11 $m	2011/12 $m	IAM	Risk Factor
Capacity Expansion	477.37	422.78	195.88	IAM	3.95%
Customer Access	60.41	99.59	83.54	IAM	3.95%
Generation Access	19.09	13.00	0.00	IAM	3.95%
Generation Driven	37.33	117.86	34.54	IAM	3.95%
Asset Replacement	23.18	26.70	33.54	Non IAM	2.11%
Reliability Driven	5.45	8.75	8.15	Non IAM	2.11%
Safety,Enviro, & Statutory	44.97	45.09	40.24	Non IAM	2.11%
SCADA & Comms	7.17	9.40	10.57	Non IAM	2.11%
System Operation	4.74	3.51	3.85	Non IAM	2.11%
Total	**679.71**	**746.68**	**410.31**		

Table 4.1 (b) Transmission Capital – AA2 Activities ($2007/08)

Transmission AA2 Activities	2009/10 $m	2010/11 $m	2011/12 $m	IAM	Risk Factor
Capacity Expansion	70.48	55.44	10.33	IAM	3.95%
Customer Access	10.63	0.60	1.40	IAM	3.95%
Generation Access	6.70	0.00	0.00	IAM	3.95%
Generation Driven	6.04	0.04	0.00	IAM	3.95%
Asset Replacement	3.48	0.06	0.00	Non IAM	2.11%
Reliability Driven	0.14	0.00	0.00	Non IAM	2.11%
Safety,Enviro, & Statutory	8.31	2.7	2.00	Non IAM	2.11%
SCADA & Comms	1.95	0.88	0.34	Non IAM	2.11%
Total	**107.73**	**59.72**	**14.07**		

Table 4.1 (c) Transmission Capital – WIP Activities ($2007/08)

Application of the risk factors results outlined above results in the risk allocation for transmission / distribution IAM / non IAM as shown in Table 4.2.

Cost Category	3 year Capex ($2007/08m)	Risk Adjustment ($2007/08m)
Distribution IAM	**$ 1,023.63**	**$ 40.69**
Distribution Non IAM	**$ 1,305.16**	**$ 43.72**
Transmission IAM	**$ 1,912.78**	**$ 68.06**
Transmission Non IAM	**$ 295.18**	**$ 6.23**
Total	**$ 4,536.75**	**$ 158.70**

Table 4.2 Distribution and Transmission Capital – Risk Allocation ($2007/08)

On the basis of this analysis, Evans & Peck recommends that Western Power include a “global” risk allowance of 3.50% in their AA2 regulatory application.