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10 September 2009

Mr Lyndon Rowe
Chairman
Economic Regulation Authority
Level 6, Governor Stirling Tower
197 St Georges Terrace
Perth WA 6000

Dear Lyndon

PROPOSED ACCESS ARRANGEMENT REVISIONS

WESTERN POWER'S SECOND SUBMISSION ON ERA DRAFT DECISION

I am pleased to provide the second of two submissions by Western Power on the Authority's Draft Decision.

The previous submission, dated 13 August 2009, provided Western Power's responses to 22 of the Authority's required amendments. This second submission provides responses to the remaining 14 required amendments, plus information on two related matters of revenue and price outcomes and service standards.

The attached CD contains Western Power's submission and attachments. I confirm that these documents and this letter are suitable for publication.

I am providing, under cover of a separate letter, additional supporting information for the Authority's use only, which is not for publication.

I trust that this submission will assist the Authority in the timely publication of its Final Decision. Western Power intends to submit its revised proposed Access Arrangement revisions in response to the Final Decision.

Yours sincerely

DOUG ABERLE
MANAGING DIRECTOR

DM# 6431186

Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN

Document release information

Project name	Access Arrangement Revisions Submission
Document number	6377613v2
Document title	Second submission to the Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN
Revision status	FINAL

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WESTERN POWER	DOUG ABERLE

Contents

1. INTRODUCTION

On 1 October 2008, Western Power submitted its proposed revisions to its first access arrangement. Western Power's submission included detailed information on its expenditure plans for the second access arrangement period, and proposed changes to some of the policies and procedures relating to its provision of network services.

On 16 July 2009, the Economic Regulation Authority (**Authority**) published its Draft Decision which was not to approve Western Power's proposed revisions to the access arrangement. In total the Authority's Draft Decision sets out 46 Required Amendments in response to Western Power's submission.

Western Power has reviewed the Authority's Draft Decision in detail and formulated a response that seeks to address each of the Authority's issues in the context of the Electricity Networks Access Code (Access Code) and Energy Safety requirements, key external drivers (such as current economic conditions) and customer needs and expectations.

Western Power responded to the majority (32 out of 46) of the Authority's Required Amendments in a submission lodged on 13 August 2009. These Required Amendments did not raise issues relating to future expenditure or service levels, and therefore were relatively straightforward to address.

This further submission addresses the remaining 14 Required Amendments. It is written in accordance with section 4.15 of the Access Code because this facilitates a focus on the matters of interest rather than resubmitting the complete revised access arrangement proposal.

If Western Power's submissions are accepted, a number of changes will be required to the proposed revisions to the access arrangement submitted on 1 October 2008. Western Power's current intention is to respond to the Authority's Final Decision by submitting amended proposed revisions to the access arrangement to reflect the necessary changes.

This document is structured to provide both an overview and key supporting arguments for Western Power's response to the remaining 14 Required Amendments set out in the Authority's Draft Decision. The overview contains the high level principles and justifications for:

1. Western Power's total revised expenditure proposals for the second three year access period.

2. Western Power's revised opening regulatory asset base for 1 July 2009.

3. Western Power's revised WACC proposal.

4. The service performance (including public safety, compliance and load & generator connections) that Western Power plans to deliver.

5. The revenue and price increases necessary over the second regulatory period to support Western Power's revised submission.

The full submission and its attachments contain the detailed justifications for Western Power's position as summarised in the overview.

2. OVERVIEW

2.1 Executive summary

Western Power supports 32 of the Authority's 46 required amendments, either unconditionally or with minor variations and has responded in an earlier submission on these matters. Of the remaining 14 Required Amendments that are addressed in this submission, a number have a material impact on Western Power's revenue requirements, determined in accordance with the Access Code. The Amendments, Western Power's response and the rationale for its response is summarised in Table 1. In addition, information is provided to explain to stakeholders and electricity customers the price and service outcomes that would be delivered if the parameters in Western Power's response to the Draft Decision are adopted.

Western Power has taken a pragmatic approach in formulating its response to the Draft Decision. In particular, it has sought to balance the additional expenditure required to deliver the network services expected by our customers and the affordability considerations that are now front-of-mind for so many businesses and households in Western Australia. Investment to satisfy Western Power's duty of care obligations and to improve public and operator safety has been retained as a priority. The Board and management are confident that an appropriate balance between these competing objectives has been struck.

During two years of operation under the current access arrangement, Western Power has faced a number of challenges in adapting the business to meet the requirements of operating in what is quite a complex regulated environment. Many of these challenges have been met and are now considered "business as usual", while others are the subject of further business improvement initiatives, some of which (such as operational efficiency improvements) will naturally be ongoing.

In responding to the Draft Decision, Western Power has examined in detail the reasoning of the Authority in arriving at the Required Amendments and has addressed the key matters and any areas of concern. In particular, it is acknowledged that a number of the critical Required Amendments reflect, quite correctly, the fundamental efficiency objectives of the Access Code. It is Western Power's view that the Authority should consider performance against good electricity industry practice (as defined in the Access Code), rather than other benchmarks which might be considered to be "best practice" per se.

In particular, Western Power has specifically addressed those aspects of the Draft Decision relating to the Authority's views on inefficiency of past capital expenditure and with the supported of independent expert opinions which address critical issues raised in the Draft Decision. The experts have international reputations and specialist expertise in relation to regulatory economic and engineering aspects of efficiency and were asked to give independent views on the issues. In the course of this activity further information was identified and this is being provided (under the cover of a separate letter) to assist the Authority in making its determination. The conclusion we have reached is that only a minor efficiency adjustment of $28M is required to Western Power's starting regulatory asset base.

Further adjustments totalling $10.1M have been made to the value of two specific transmission projects. This brings the total adjustment to the regulatory asset base to $38M.

Lower increases in capital and operating expenditure are now proposed by Western Power, providing for a $1.1B reduction from expenditures proposed in the initial submission for the second access arrangement period made in October 2008. These expenditures will naturally imply more modest achievable improvements in network reliability than that proposed in the October 2008 submission. In fact, Western Power's ageing network requires increased expenditure just to maintain (rather than improve) existing reliability performance.

Western Power proposes a weighted average cost of capital at least in line with that recently approved by the Australian Energy Regulator for other similar electricity network businesses in Australia.

Western Power welcomes the Authority's agreement to implementing new incentive mechanisms to drive ongoing improvements in operational efficiency and service performance standards for the benefit of customers.

Western Power believes that a further price increase in 2009/10 (at the commencement of the new access arrangement period, on or around 1 January) is required to provide the sufficient revenue to fund proposed expenditures and to manage price increases in 2010/11 and 2011/12. Western Power proposes a price path that results in average price increases of 15.3% and 18.5%, for transmission and distribution respectively, in each of the 3 financial years from 2009/10 to 2011/12.

Table 1 below provides a high level summary of Western Power's responses to the required amendments addressed in this submission.

Table 1: Required Amendments addressed in this submission

AMENDMENT	ERA CHANGE REQUIRED	WP RESPONSE	MATERIALITY	RATIONALE
25	Opex forecasts not approved	**Addressed** Revised forecasts submitted	High	Detailed supporting information provided; Expenditure critical to deliver service
26	Exclusion of overstatement of costs of $63.5M	**Addressed** reflects actual spend. Specific reductions of $10.1M proposed	High	Expected spend at time of submission did not eventuate; Identified specific items that do not meet NFIT
	Exclusion of distribution investment of $65M	**Addressed** All investment should pass NFIT	High	Expenditure relates to shared infrastructure
	Major write-down of AA1 capex (reduction in regulated asset base) ~$380M	**Addressed** 15% write-down rejected; Some specific reductions proposed ~$28M	High	Additional information provided; Advice from independent experts that Authority's decision is not supportable
28	Capex forecasts not approved	**Addressed** Revised forecasts submitted	High	Detailed supporting information provided to reflect reduced demand and current economic environment
29	WACC value 7.06%	**Addressed** Propose 7.59%	High	Authority proposal much less than AER decision for eastern states utilities
32	Capcons treatment change to have off-set revenue deferral; Relates to Amendment 36	**Accepted** with qualifications	High	Produces significant cash flow issue; Full recovery of deferred revenue by the end of AA#3 possible without significant price shock
34	Gain sharing mechanism - all gains subject to achieving annual performance targets	**Accepted** with qualification; Portion of gains not linked to service standards	High	Not appropriate to link **all** potential efficiency improvements to service performance outcomes
35	Modifed service standards adjustment mechanism	**Accepted** with qualifications	High	Revenue "at risk" capped at 1%; Features of amendment not consistent with AER incentive mechanism
36	Deferral of revenue over life of assets	**Addressed**	High	Rationale as for Amendment 32
22	Service standard benchmarks - additional transmission indicators	**Accepted**	Low	WP now has data to support additional indicators; Consistency with national reporting requirements
23	Service standard benchmarks - modify reliability indicators to include single customer faults	**Accepted**	Low	WP has the required data; Consistency with national reporting requirements
24	Service standard benchmarks - additional reliability indicators for worst performing feeders	**Addressed** Use Long Rural performance as proxy	Low	Difficult to set meaningful targets; Currently no expenditure allocated for this purpose; Not consistent with national reporting requirements
33	Modified tariff side constraints	**Accepted** with qualifications	Low	Final price path may require different side constraints
37	D factor replaced with provision in gain sharing mechanism	**Addressed**	Low	Authority proposal still results in barrier to recover non-network option operating costs
43	Contributions policy - additional information required on distribution headworks	**Accepted** Required documentation provided	Low	Improved documentation and transparency for customers

2.2 Major issues

2.2.1 Western Power's revised expenditure proposals

The re-forecasting challenge is to strike a balance of competing expenditures and risks within the constraints of affordability for Western Power, its customers and the business owner (the Government), recognising the current economic conditions.

The competing areas and consequential risks are characterised as:

- maintenance and/or improvement to service levels,
- growth in the network, and
- maintenance and/or improvement of security of supply.

In October 2008, Western Power's initial Access Arrangement (**AA2**) revisions submission included a total expenditure program of $6.1B (real 30 June 2009).[1] This program was developed at a time of significant expansion and unprecedented economic activity in the State. The rapid shift in the State and global financial conditions since that time led to Western Power providing further advice to the Authority of the likely revised expenditure needs on 25 May 2009. Indicative capital expenditure and operating expenditure were proposed. In its Draft Decision, the Authority reduced the proposed expenditure. Table 2 summarises the changes in expenditure proposals since the time of the original AA2 submission.

Table 2: Historical comparisons of expenditure proposals

	Western Power **AA2 Proposal** **Oct 2008**	**Western Power** **Revised AA2 Proposal** **May 2009**	**ERA** **Draft Decision** **July 2009**	**Western Power** **AA2 response** **Sept 2009**
CAPEX	4.5B	3.58B	3.46B	3.56B
OPEX	1.6B	1.39B	1.14B	1.34B
TOTAL	**6.1B**	**4.97B**	**4.60B**	**4.9B**

Western Power has now revised its forecast expenditure in detail. This revision has occurred in the context of:

- The matters raised by the Authority in its Draft Decision.
- The changed economic conditions, including the heightened affordability constraints and lower demand forecasts.
- The IMO forecast issued in July 2009, which showed a slight decrease in electricity maximum demand in the SWIS from its 2008 report. This is supplemented by additional relevant information available to Western Power such as revised connection applications from major loads and forecast demand information relevant to specific load areas within the SWIS. The outcome is illustrated in Figure 1 below.

[1] Unless otherwise stated all dollars presented in this report relate to 30 June 2009 real dollars

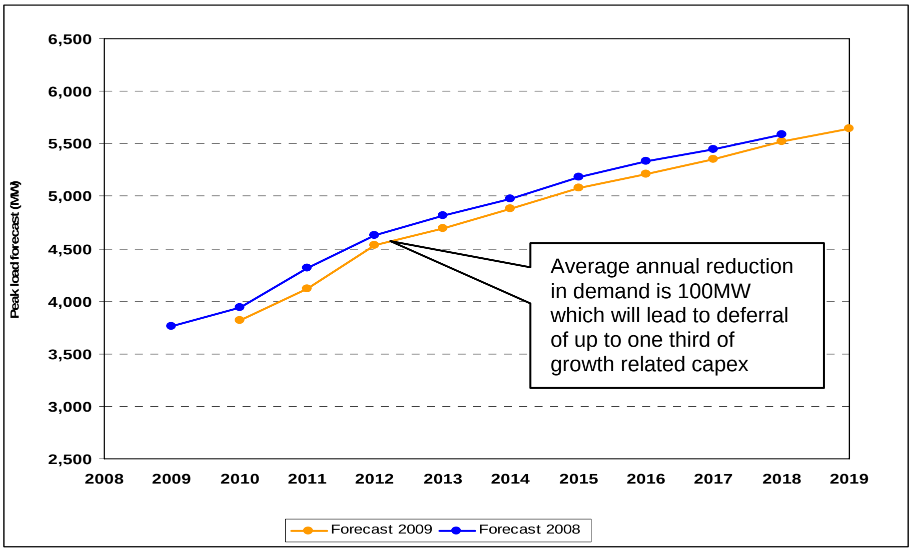
- A detailed assessment of Western Power's actual expenditure for 2008/09 and the budget for 2009/10.

- A reconsideration of the key priority areas for expenditure within what is a more challenging funding environment.

- Detailed consideration of Western Power's ability to deliver the proposed expenditure.

- Identification of drivers of efficiency to further enhance the business's cost control and investment decision processes.

Figure 1: Comparison of demand forecasts made in 2008 and 2009



In light of the above considerations, Western Power has significantly reduced its total expenditure forecast for the second access arrangement period from the level sought in October 2008. Specifically, **Western Power proposes a total expenditure of $4.9B (real 30 June 2009) over the 3 year access arrangement period.** This is summarised in table 2 below which also illustrates the expenditure over the three years of the first access arrangement.

Table 3: Summary of expenditures, actual and forecast ($M)

	AA1				AA2			
Category	**06/07**	**07/08**	**08/09**	**Total**	**09/10**	**10/11**	**11/12**	**Total**
Transmission capital	302	312	319	933	307	561	607	1475
Distribution capital	441	474	636	1551	611	722	752	2085
Total capital	743	786	955	2484	918	1,283	1,359	3560
Transmission operating	74	75	73	221	76	97	104	277
Distribution operating	251	256	284	791	284	360	418	1062
Total operating	325	331	357	1,021	360	457	522	1339
Total expenditure	1068	1,117	1,312	3,496	1,278	1,740	1,881	4899

Further details of Western Power's revised expenditure forecasts are contained in attachment D.

2.2.2 Opening regulatory asset base 1 July 2009

The Authority has proposed a flat 15% reduction in Western Power's opening regulatory asset base at 1 July 2009 to provide for assumed inefficiencies in capital investment over the first access arrangement period. This is covered in the Authority's Required Amendment 26 (dot point 3) in respect of its application of the New Facilities Investment Test ("NFIT") and specifically the "efficiency test" in section 6.52(a) of the Code.

Western Power asks the Authority to reconsider its Draft Decision on the application of the efficiency test to Western Power's capital expenditure in the first access arrangement period.

Western Power maintains that it has previously provided the Authority with sufficient information to demonstrate satisfaction of the NFIT. However, with a view to addressing the Authority's concerns raised in the Draft Decision, Western Power is providing (under cover of a separate letter) additional information to demonstrate that its planning, design and delivery approaches are generally consistent in method and unit cost with those in similar network businesses in Eastern Australia.

Western Power is of a firm view that the appropriate application of the efficiency test would result in a write down of much less than that proposed by the Authority and has itself, with the assistance of experts, only identified inefficiencies of not more than $28 million (or approximately 1.2% using the terms in which the Authority has described its estimate).

Given the extraordinary magnitude of the proposed write down in the starting regulatory asset base proposed by the Authority, Western Power has engaged the following independent experts to review the Authority's analysis and conclusions set out in its Draft Decision:

- Professor George Yarrow and Dr Christopher Decker – to provide an economic opinion on the application of the efficiency test;[2] These experts find that the Authority:

    - has not explicitly defined the standard it has used in assessing efficiency, but appears to have used an excessively high standard;

    - has used a standard that is inconsistent with the reasonableness standard typically applied by regulators in ex post prudency reviews; and

    - has derived an estimate of inefficiency that is not soundly based.

  Yarrow and Decker conclude that the Authority's approach is not consistent with the Access Code objectives and is not consistent with good regulatory principles and practice in other, comparable jurisdictions.

- Sinclair Knight Merz ("SKM") - to provide a technical engineering opinion on the efficiency of Western Power's new facilities investment.[3] SKM conclude that:

    - Western Power has solid planning, engineering and execution policies and processes generally consistent with good industry practice.

    - Western Power's capital expenditure decisions were not systematically inefficient, particularly when assessed against the appropriate standard and in light of the market conditions prevailing at the time.

  SKM has, however, identified two areas where Western Power's performance could have been better, and it concludes that in relation to those areas the amount of "inefficiency" in the new facilities investment undertaken by Western Power was in the order of $28M. However, SKM acknowledge that improvements in these areas have been made over the first access arrangement period.

Taken together, these independent expert opinions strongly question the Authority's view that it is appropriate to apply an across the board write-down of 15% to Western Power capital expenditure in the first access arrangement period.

Further adjustments to Western Power's opening regulatory asset base totalling $10.1M have been made in relation to the value of two specific transmission projects. This brings the total adjustment to the regulatory asset base to $38M.

Further details of Western Power's response on this matter are contained in attachments E and F.

[2] Professor George Yarrow and Dr Christopher Decker, Report to the ERA's Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 1 September 2009.

[3] SKM, Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2, September 2009.

2.2.3 Weighted Average Cost of Capital (WACC)

In its Draft Decision, the Authority proposed a real pre-tax WACC of 7.06% subject to revision of the risk free rate and debt margin prior to the final determination.

In May of this year, the Australian Energy Regulator (**AER**) completed an extensive review of the WACC parameters to be applied to regulated electricity distribution and transmission businesses in the National Electricity Market. The AER's review concluded that particular values for the WACC parameters are applicable to the regulated electricity network businesses. Use of these same parameter values would result in a WACC of 7.59% real pre-tax for Western Power.

The pre-tax WACC value of 7.06 % specified in Required Amendment 29 is materially below this value, and if applied would have a significant impact on Western Power's financial capacity to deliver services at the level required. Western Power contends that there are no valid reasons to suppose that the cost of capital faced by a Western Australian electricity network business would be any lower than that determined by the AER as being applicable to similar businesses in the Australian National Electricity Market.

Western Power also notes that its advisor on this matter, KPMG, has indicated that there may be grounds for further upward revision of values for parameters used in the calculation of the WACC. These include the development risk associated with the quantum and volatility of new infrastructure requirements prevalent in Western Australia, together with the consequent *ex post* prudency assessment. Western Power requests that the Authority also considers these issues in relation to its WACC determination.

Western Power's position is that the WACC should be no less than the value obtained by applying the WACC parameters determined by the AER, that is 7.59% real pre-tax. Therefore, for modelling purposes in preparing this submission, Western Power has used a WACC of 7.59% real pre-tax which reflects the AER parameters and current market conditions (up to 30 June 2009).

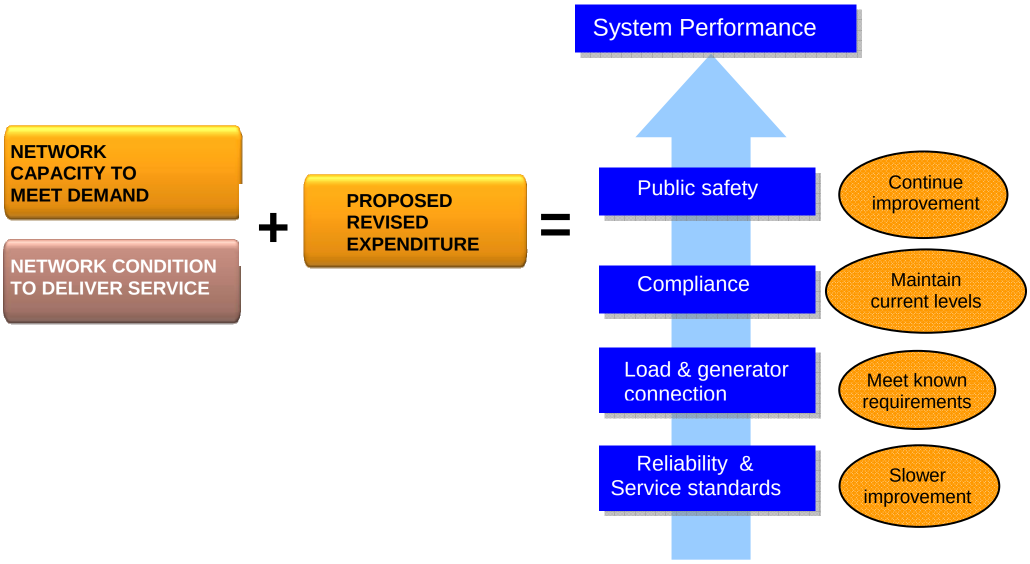
Further details of Western Power's response on this matter are contained in attachments G and H.

2.3 What will Western Power deliver?

A forecast expenditure reduction of $1.1 billion from the original submission will have a material impact on Western Power's ability to deliver service improvement, even with the acknowledged scope for improved efficiency in some areas.

Figure 2 depicts the service imperatives that are impacted by the revised expenditure in order of importance.

Figure 2: Service impacts of proposed revised expenditure



2.3.1 Public safety

Expenditures to mitigate critical safety risks including bushfires, pole failures and broken conductors were incorporated in the initial submission. Western Power proposes to continue the improvement in these areas, but at a slightly slower rate.

2.3.2 Compliance

The very significant demand on resources over the first access arrangement period has led to a build up of higher levels of maintenance work backlogs than are considered prudent. As a result, Western Power has not been able to fully comply with the Technical Rules and related obligations. The initial submission proposed expenditures that would significantly reduce this backlog and improve levels of compliance. However, the reduced level of expenditure now proposed will mean that maintenance work backlogs and consequently current levels of compliance will not improve significantly. Western Power plans to deliver improvements in these areas in the third and subsequent access arrangement periods.

2.3.3 Load and generator connection

The proposed forecast expenditures are based on firm[4] customer connection requirements for new block loads and new generation necessary to meet the IMO's projected reserve capacity target. Western Power believes that the reduction in its forecast expenditures will not critically impact the delivery of key infrastructure projects. Importantly, provision for stage one of the North Country Reinforcement project and the South West Bulk 330kV projects has been made.

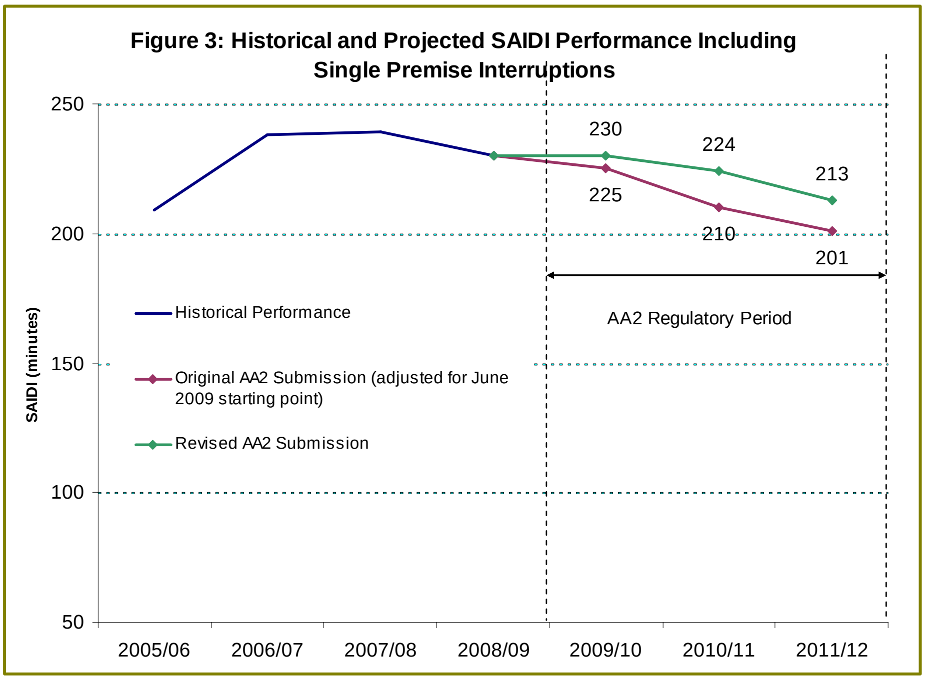
2.3.4 Reliability

Overall reliability is influenced by both the performance of the transmission and distribution systems. Transmission incidents occur as low frequency major loss of load events and distribution incidents as higher frequency but smaller load loss events.

[4] Firm = Committed or high probability of project proceeding

The performance of the transmission network is expected to remain at the current satisfactory level and no specific improvement works have been included in expenditure forecasts for the transmission network.

An improvement in the overall performance of the distribution network of 29 minutes, as measured by the SAIDI (System Average Interruption Duration Index) indicator was proposed by Western Power in its initial submission. A reduction in reliability driven capital and operating expenditure means that reliability improvements will take longer to achieve. The net improvement in SAIDI is now expected to be reduced to 17 minutes over the 3 year period, as shown in Figure 3 below.



Western Power previously indicated, in its letter to the Authority on 25 May 2009 regarding reductions in forecast expenditures, the need for consequential changes to service standard targets. While this is not ideal, it is unavoidable, given other competing priorities, and the need to meet the requirements of the Access Code.

2.3.5 Reliability Driven capital expenditure

While most capital expenditure will have some impact on performance, reliability driven capital expenditure involves a range of initiatives aimed at selectively maintaining or improving the service delivered by the network. The revised reliability driven capital expenditure forecast has been reduced to approximately 50% lower than in Western Power's original AA2 revisions submission with the programs targeted to deliver the greatest impact in terms of reliability improvement. However, this reduction has a direct negative impact on the achievable improvements in network performance over the 3 year term.

2.3.6 Reductions in operating expenditure

Unfortunately, higher maintenance work backlogs than considered prudent will continue to exist under the proposed reduced forecast operating expenditures for the 2009/10 to 2011/12 regulatory period. An effect of the higher backlogs is an increased likelihood of low probability but high impact events occurring. This will contribute to a lower level of network reliability performance than could otherwise be achieved.

2.3.7 Changes to reliability measures

The Authority requires that definitions of SAIDI and SAIFI be modified to include the effects of single customer interruptions. Western Power supports this change but it will have the effect of producing slightly inflated measures of reliability, compared to the definitions previously applied. This does not mean actual performance will deteriorate, but the targets need to be increased by an average of 9 SAIDI minutes per annum to adjust for the new, more comprehensive definition of SAIDI.

Further details of Western Power's response on service performance targets are contained in attachment P.

2.4 Revenue and price paths

2.4.1 Revenue Outcomes

This section sets out the revenue and price outcomes that would be delivered if the financial parameters in Western Power's response to the Draft Decision were to be adopted, taking into account a reasonable price path to provide the required revenue streams and minimise price shock to customers.

Table 4 below sets out the annual target revenues for transmission and distribution for the second access arrangement period compared with the outcomes in the Draft Decision.

Table 4: Revenue Comparison

		2008/09	2009/10	2010/11	2011/12	Total
ERA Draft Decision 16 July 2009	**Annual Revenue (Real)**	$671m	$783m	$914m	$1,067m	$2,764
	Average Revenue[5] Increase		CPI +16.7%	CPI +16.7%	CPI +16.8%	
Western Power Resubmission September 2009	**Annual Revenue (Real)**	$671m	$775m	$982m	$1,179m	$2,936
	Average Revenue[6] Increase		CPI +15.4%	CPI +26.8%	CPI +20.1%	
	Average Price[7] Outcome		CPI +17.6%	CPI +17.6%	CPI +17.6%	

5 The ERA draft Decision bases the average tariff increases on increases in revenue.
6 These figures have been calculated using the approach used by the ERA and represent a comparison to the Average Revenue Increase of CPI +16.7% reported in the Draft Decision. They reflect an increase in price and also an increase in forecast energy sales.
7 These figures represent in real terms, equal year on year increases in price.

2.4.2 Price Increases

A further price increase in 2009/10 (on 1 January 2010) is required to manage the average price increases in 2010/11 and 2011/12 and to support Western Power's proposed works program.

Western Power requires the income received from network revenues to support its proposed expenditures. Without sufficient revenue, operating and capital expenditure plans will be placed under pressure. Any shortfalls in revenue could lead to an increase in borrowings. However, increased borrowing levels may also create challenges for the financial sustainability and long-term performance of the business.

Western Power has accepted required amendment 32, and deferred a substantial amount of revenue into the next access arrangement period in order to assist with the avoidance of price shock.

Western Power is also concerned that the current approved 2009/10 level of pricing may result in price shock during the second access arrangement period. Western Power has calculated that with no price increase on 1 January 2010, and if the current prices are maintained for the full 2009/10 financial year, average tariff increases of CPI+29% would be required in 2010/11 and 2011/12 in order to recover the required revenues over the remaining two years of the regulatory period.

The following section sets out the average price outcomes that minimise price shock and collect the revenue required over the second access arrangement period.

2.4.3 Average Price Outcomes

Table 5 below sets out the proposed price paths for transmission and distribution for the second access arrangement period. Western Power has set the price path so as to provide for equal price increases over each year of the access arrangement period. In particular the proposed increase on 1 Jan 2010 ensures that the prices at the end of the 2009/10 year would be 15.3% and 18.5% higher than the transmission and distribution prices in 2008/09 respectively. This provides a smooth price path for both transmission and distribution over the whole of the second access arrangement period.

Table 5: Average Price Path

Price Year commencing	1 July 2009	1 Jan 2010[8]	1 July 2011	1 July 2012
Transmission Price Path	CPI+5%	CPI+9.0%	CPI+15.3%	CPI+15.3%
Bundled Distribution Price Path	CPI+5%	CPI+12.3%	CPI+18.5%	CPI+18.5%

Figure 4 shows the trend in average transmission prices in real dollars from July 2006 to the end of the forthcoming access arrangement period.

[8] 1 Jan 2010 – assumed start date of the amended proposed access arrangement revisions

Figure 4: Transmission Average Price (c/kWh real as at 30 June 2009)

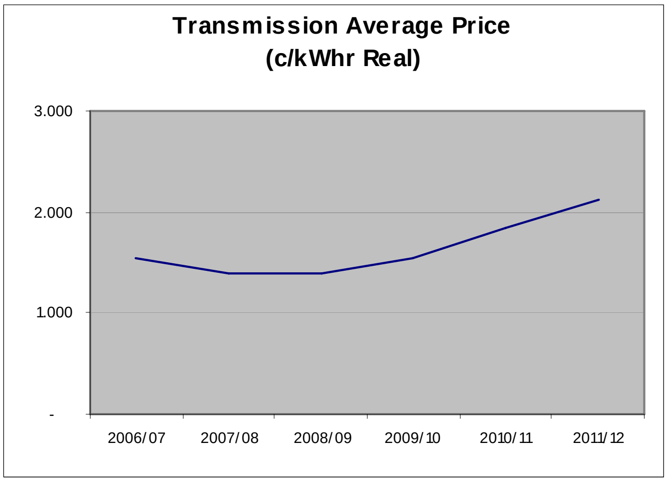
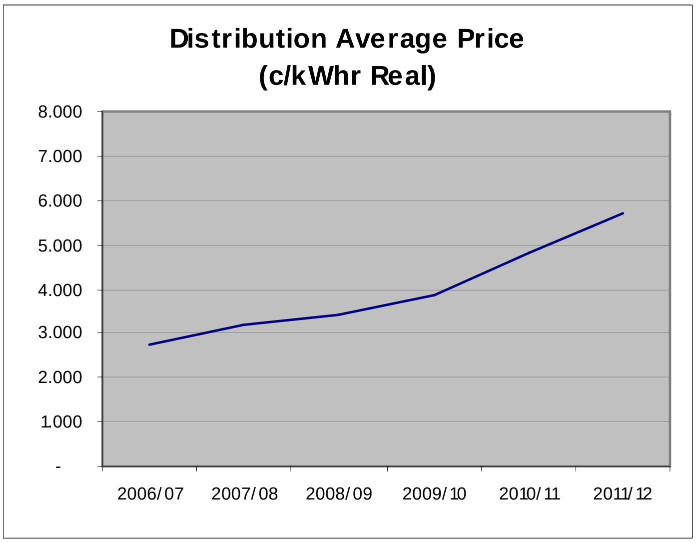


Figure 5 shows the trend in average distribution prices in real dollars from July 2006 to the end of the forthcoming access arrangement period.

Figure 5: Distribution Average Price (c/kWh real as at 30 June 2009)



Further details of Western Power's response on proposed revenue and price paths are contained in attachment O.

3. WESTERN POWER'S RESPONSES TO THE REQUIRED AMENDMENTS

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
1	This Required Amendment relates to the inclusion of one or more reference services to address the requirements of small-scale renewable energy systems where electricity consumers participate in the Renewable Energy Buyback Scheme. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
2 to 21	These Required Amendments relate to various provisions in Western Power's Electricity Transfer Access Contract. Western Power's responses to these Required Amendments were provided in its first submission, which was lodged with the Authority on 13 August 2009.			
22	The proposed access arrangement revisions should be amended to include service standard benchmarks for: • loss of supply event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and • average outage duration, measured in minutes.	**Amendment accepted.** Western Power will provide definitions and targets for 2 new transmission service standard benchmarks being loss of supply event frequency and average outage duration, generally consistent with those that apply to transmission businesses in the National Electricity Market. Further details are contained in the Attachment.	A	Sections 1.3; 5.1(c); and 5.6
23	The proposed access arrangement revisions should be amended such that definitions of SAIDI and SAIFI do not make provision for the exclusion of single customer interruptions.	**Amendment accepted.** Western Power will revise definitions and targets for SAIDI and SAIFI to include single customer interruptions. Further details are contained in the Attachment.	B	Sections 1.3; 5.1(c); and 5.6

<table>
<tr><th colspan="2">Required Amendment</th><th>Western Power's response</th><th>Cross reference to attachment</th><th>Code provisions relevant to the Required Amendment</th></tr>
<tr><td>24</td><td>The proposed access arrangement revisions should be amended to include service standard benchmarks for SAIDI and SAIFI for customers served by the 15 per cent of worst performing feeders.</td><td>Amendment addressed.

Western Power has demonstrated a reasonable correlation between performance of the 15 per cent of worst performing feeders and Rural Long category feeders. The required amendment is not consistent with the new requirements of the AER Service Target Performance Incentive Scheme [May 2009] and Western Power respectfully requests the Authority to reconsider the need for this amendment.

Further details are contained in the Attachment.</td><td>C</td><td>Sections 1.3; 5.1(c); and 5.6</td></tr>
<tr><td>25</td><td>The proposed access arrangement revisions should be amended to reflect a forecast of non-capital costs as follows (real $ million at 30 June 2009):

<table>
<tr><th></th><th>2009/10</th><th>2010/11</th><th>2011/12</th></tr>
<tr><td>Transmission:</td><td>69.58</td><td>81.14</td><td>89.03</td></tr>
<tr><td>Distribution:</td><td>263.74</td><td>301.38</td><td>330.75</td></tr>
<tr><td>Total:</td><td>333.32</td><td>382.52</td><td>419.77</td></tr>
</table></td><td>Amendment addressed.

Western Power has provided justification for non-capital costs as follows (Tables E2 and E4 of the attachment):

Transmission operating expenditures, actual and forecast ($M)
<table>
<tr><th>Item</th><th>06/07</th><th>07/08</th><th>08/09</th><th>09/10</th><th>10/11</th><th>11/12</th><th>TOTAL</th></tr>
<tr><td>Network</td><td>55.9</td><td>54.1</td><td>48.5</td><td>49.1</td><td>68.5</td><td>74.3</td><td>191.9</td></tr>
<tr><td>Business support costs</td><td>18.2</td><td>20.3</td><td>24.6</td><td>26.8</td><td>28.3</td><td>29.6</td><td>84.6</td></tr>
<tr><td>Total Opex</td><td>74.1</td><td>74.4</td><td>73.1</td><td>75.9</td><td>96.7</td><td>103.8</td><td>276.5</td></tr>
</table>
Distribution operating expenditures, actual and forecast ($M)
<table>
<tr><th>Item</th><th>06/07</th><th>07/08</th><th>08/09</th><th>09/10</th><th>10/11</th><th>11/12</th><th>TOTAL</th></tr>
<tr><td>Network</td><td>204.9</td><td>201.2</td><td>214.2</td><td>210.8</td><td>283.0</td><td>336.8</td><td>830.6</td></tr>
<tr><td>Business support costs</td><td>46.2</td><td>54.5</td><td>69.8</td><td>72.8</td><td>77.2</td><td>81.2</td><td>231.2</td></tr>
<tr><td>Total Opex</td><td>251.1</td><td>255.6</td><td>284.0</td><td>283.7</td><td>360.1</td><td>418.0</td><td>1,061.8</td></tr>
</table>
Revised opex forecasts are expressed in real $ million at 30 June 2009, including escalation factors based on current economic forecasts. Specific responses to issues raised under Required Amendment 25 are provided in section 5 of the Attachment.</td><td>D</td><td>Sections 6.40; 6.41 and 6.42</td></tr>
</table>

	Required Amendment	Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
26	The proposed access arrangement revisions should be amended to reflect actual new facilities investment in the first access arrangement period reduced to: • exclude investment to the value of \$63.5 million (nominal) for the transmission network in 2008/09 that comprises an overstatement of costs for 2008/09; • exclude investment to the value of \$65 million (nominal in 2007/08 dollar values) for the distribution network that comprises an amount of costs that is not appropriately considered as new facilities investment; and • exclude a further amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) to reflect likely inefficiencies in the undertaking of investment.	**Amendment addressed.** <u>Dot point 1</u> This exclusion relates primarily to the difference between forecast expenditures for 2008/09 (as assessed by the Authority) and final actual expenditures for that year. For the purposes of this item, Western Power's proposed revised opening capital base for AA#2 is based on actual transmission capital expenditures with the exception of two items: • Exclusion of an amount of \$6.969M (real) for the Busselton-Margaret River line project (100% of the total project expenditure); and • Exclusion of an amount of \$3.151M (real) related to the portion of cost of the 490MVA transformers at Wells Terminal not recovered from the customer. (Note: Western Power may request re-inclusion of this amount in the capital base at a later date.) Western Power proposes to maintain an amount of \$9.9M actual expenditure incurred for the NCR 330kV project in the opening capital base, on the grounds that this expenditure satisfies Clauses 6.52(a) & 6.52(b)(iii) of the Code. It is noted that the project has "passed" the regulatory test and has been given the conditional go-ahead by the State Government, albeit with a modified scope.	N/A	Sections 6.43 to 6.63.
		<u>Dot point 2</u> Western Power's analysis demonstrates that the actual expenditure relating to subdivisional development satisfies the new facilities investment test. Further information and the results of Western Power's analysis are provided in Attachment E.	E	

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
		<u>Dot point 3</u> In view of the very significant implications for shareholder value arising from this Required Amendment, Western Power engaged the following independent experts to examine this matter: • Professor George Yarrow and Dr Christopher Decker were engaged to provide an economic opinion on the application of the new facilities investment test; and • Sinclair Knight Merz ("SKM") were engaged to provide an engineering opinion on the efficiency of Western Power's actual new facilities investment. Based on the independent expert advice provided, Western Power does not accept this exclusion and submits that in formulating its final decision, the Authority should reconsider its application of the NFIT to Western Power's capital expenditure in the first access arrangement period. Based on SKM's findings, the appropriate application of the NFIT would result in the identification of inefficiencies of not more than $28 million, compared with the $343.8M (real) write-down proposed by Required Amendment 26.	F	
27	This Required Amendment relates to the addition of revenues from disposal of assets in the first access arrangement period to the value of redundant assets applied in calculation of the capital base at the commencement of the second access arrangement period. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			

<table>
<tr><th colspan="2">Required Amendment</th><th>Western Power's response</th><th>Cross reference to attachment</th><th>Code provisions relevant to the Required Amendment</th></tr>
<tr><td>28</td><td>The proposed access arrangement revisions should be amended to incorporate a forecast of new facilities investment that:
• reflects a revised program of capital works that takes into account revised forecasts of demand for network services;
• reflects a zero rate of escalation in unit costs over the second access arrangement period; and
• excludes any "estimating risk margin".</td><td>Amendment addressed.

Western Power has provided justification for capital expenditure forecasts reflecting current economic climate, taking into account reduced forecast demand, affordability impacts and deliverability. Recent actual and forecast capital expenditure for AA2 are as follows:

Transmission Capex (real $ million at 30 June 2009)
<table>
<tr><th>Category</th><th>06/07</th><th>07/08</th><th>08/09</th><th>09/10</th><th>10/11</th><th>11/12</th><th>TOTAL</th></tr>
<tr><td>Network:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- Growth related</td><td>264.0</td><td>271.4</td><td>260.7</td><td>247.7</td><td>466.2</td><td>504.3</td><td>1,218.2</td></tr>
<tr><td>- Non-growth related</td><td>28.7</td><td>26.4</td><td>43.0</td><td>48.3</td><td>77.8</td><td>90.3</td><td>216.4</td></tr>
<tr><td>Estimating risk factor</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Business support cost</td><td>9.5</td><td>14.5</td><td>15.1</td><td>10.9</td><td>16.4</td><td>12.9</td><td>40.2</td></tr>
<tr><td>Total Capex</td><td>302.3</td><td>312.3</td><td>318.7</td><td>306.9</td><td>560.5</td><td>607.4</td><td>1,474.8</td></tr>
</table>
Distribution Capex (real $ million at 30 June 2009)
<table>
<tr><th>Category</th><th>06/07</th><th>07/08</th><th>08/09</th><th>09/10</th><th>10/11</th><th>11/12</th><th>TOTAL</th></tr>
<tr><td>Network:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- Growth related</td><td>295.7</td><td>275.2</td><td>379.3</td><td>370.5</td><td>393.6</td><td>387.3</td><td>1,151.4</td></tr>
<tr><td>- Non-growth related</td><td>117.0</td><td>155.3</td><td>211.9</td><td>207.9</td><td>279.2</td><td>326.3</td><td>813.3</td></tr>
<tr><td>Estimating risk factor</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td></td></tr>
<tr><td>Business support costs</td><td>28.7</td><td>43.7</td><td>45.3</td><td>32.8</td><td>49.3</td><td>38.6</td><td>120.6</td></tr>
<tr><td>Total Capex</td><td>441.5</td><td>474.2</td><td>636.5</td><td>611.2</td><td>722.0</td><td>752.1</td><td>2,085.3</td></tr>
</table>
Western Power agrees that escalation factors used in preparing the original AA2 capital expenditure forecasts are out-of-date. The revised capital expenditure forecasts include escalation factors derived from economic forecasts reflecting the current economic climate.

Western Power agrees to exclude "estimating risk margin" from the forecast capital expenditure.

Further details are provided in the Attachment.</td><td>D</td><td>Sections 6.43 to 6.63.</td></tr>
</table>

	Required Amendment	Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
29	The target revenue should be revised to reflect a real pre-tax WACC value of 7.06 per cent, subject to revision of the risk free rate and debt margin at a date to be advised and prior to the Authority's final decision.	**Amendment addressed.** Western Power contends that there are no valid reasons to suppose that the cost of capital faced by a Western Australian electricity network business would be any lower than that determined by the Australian Energy Regulator (AER) as being applicable to similar businesses in the Australian National Electricity Market. On this basis, Western Power considers that the point estimate of the WACC should be no less than the WACC value obtained by applying the parameter values determined by the AER following the conclusion, in May 2009, of an extensive review of WACC parameters. The pre-tax WACC value of 7.06 percent specified in Required Amendment 29 is materially below the WACC value obtained by adopting the parameters determined by the AER for application in the National Electricity Market. Given the reasoning set out above, Western Power has not adopted Required Amendment 29. Western Power's position is that the WACC should be no less than the value obtained by applying the WACC parameters determined by the AER. Therefore, for modelling purposes in preparing this submission, Western Power has used a WACC of 7.59% real pre-tax which reflects the AER parameters and current market conditions (up to 30 June 2009). Western Power has commissioned a report from KPMG (refer Attachment H) setting out an analysis of WACC parameters. The KPMG report also indicates that some parameters applying to Western Power may be increased above the levels determined by the AER.	Attachment G, together with a paper from KPMG, which is provided as Attachment H.	Sections 6.64 to 6.69.
30	This Required Amendment relates to the revision of target revenue to reflect an allowance for a cost of working capital calculated as a return on the opening value of a stock of working capital in each year of the second access arrangement period. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
31	This Required Amendment relates to the amendment of target revenue for reference services by taking into account forecast revenue from non-reference services at least equal to the forecast of non-capital costs attributed to provision of these services. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
32	The proposed access arrangement revisions should be amended to provide for deferral of revenue from the second to the third and subsequent access arrangement periods in an amount that fully offsets the effect of the change in the treatment of capital contributions in the determination of target revenue.	**Amendment accepted**, subject to Western Power's response to Required Amendment 36.	Attachment I together with a paper from NERA, which is provided as Attachment J	Sections 6.1; 6.2; 6.4 and 7.4(d)
33	The proposed access arrangement revisions should be amended such that clauses 3.11, 5.35 and 5.46 provide for maximum proportional changes in reference tariffs from 2009/10 to 2010/11 and from 2010/11 to 2011/12 of: • +/- (percentage change in the CPI + 13%) for the transmission network; and • +/- (percentage change in the CPI + 7%) for the transmission network.	**Amendment to be addressed.** The Authority's proposed percentage changes reflect the tariff outcomes of the Draft Decision. It is noted that providing a small additional margin to allow for periodic tariff re-balancing is accepted practice and applies to the current access arrangement. Western Power will propose appropriate tariff side constraints in its submission of amended proposed access arrangement revisions following the Authority's Final Decision, commensurate with final tariff outcomes and incorporating a margin to accommodate prudent tariff rebalancing in subsequent years.	N/A	Sections 6.1; 6.2; 6.4; and 7.4(d).
34	The proposed access arrangement revisions should be amended to specify the gain sharing mechanism set out in the Draft Decision.	**Amendment addressed.** Western Power accepts this required amendment in principle but proposes a variation that provides for Western Power's retention of efficiency gains achieved in non-capital costs not directly related to service standards. Further details are provided in the Attachment.	K	Sections 6.19 to 6.28.

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
35	The proposed access arrangement revisions should be amended to alter the specification of the service standard adjustment mechanism at clauses 5.24A and 5.24B to: (a) remove the dead-bands and limits around target values of service standards; and (b) adopt the mechanism specified in the Draft Decision (c) increase incentive rates by a factor of 2.5	**Amendment addressed.** Western Power generally accepts this Required Amendment, but proposes some variations to ensure that the SSAM is consistent with the relevant AER Service Target Performance Incentive Scheme (STPIS). The variations proposed by Western Power in relation to each of parts (a), (b) and (c) of the Required Amendment are as follows: a) Removal of the dead-bands and limits for distribution, and removal of dead-bands but retention of limits for transmission. Total revenue at risk to be capped at 1% for both Distribution and Transmission. b) This portion of the Required Amendment is not consistent with the AER STPIS, and so Western Power requests the Authority to reconsider the need for this particular requirement. c) Generally increase incentive rates by a factor of 2.5 except for the rates applying to System Minutes. Further details are contained in the Attachment.	L	Sections 6.29 to 6.32.

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
36	The proposed access arrangement revisions should be amended to provide for the recovery of deferred revenue as a constant amount in each year subsequent to the second access arrangement period and over a total period of recovery equal to the average economic life of network assets.	**Amendment addressed.** Western Power considers that this Required Amendment may adversely affect the long term financial performance of the business. Western Power has undertaken modelling of the impacts of Required Amendment 36, to assess the price path outcomes under alternative timeframes for recovery of deferred revenue. The modelling also tests whether the Required Amendment in fact gives rise to neutral commercial impacts. In addition, Western Power commissioned NERA Economic Consulting to provide a report examining issues relating to revenue deferral. That report is included as Attachment J for consideration by the Authority. Western Power's analysis indicates that all deferred revenue can be recovered during the third access arrangement period without causing "price shock" (within the meaning set out in section 6.4(c) of the Code). On the basis of its analysis, Western Power proposes that revenue deferred from the second access arrangement period should be recovered in full over the course of the third access arrangement period.	Attachment I together with a paper from NERA, which is provided as Attachment J	Sections 6.1; 6.2; 6.4; and 7.4(d).
37	The proposed access arrangement revisions should be amended to delete the proposed D-factor scheme at clauses 5.54 to 5.57.	**Amendment addressed.** The Authority proposed an amendment to the Gain Sharing Mechanism (GSM) in lieu of the D-Factor scheme. Western Power accepts the required amendment to the GSM is appropriate however it does not fully address the acknowledged barrier to facilitate the recovery of all efficient costs for non-network options. Western Power requests the Authority reconsiders the need for this amendment. Further details are contained in the Attachment.	M	Sections 6.1; 6.2; 6.4
38	This Required Amendment relates to resolving inconsistencies between clause 10 of the applications and queuing policy and clauses 3.4 and 3.5 of the electricity transfer access contract in relation to changes to covered services, including increases or decreases in contracted capacity at a connection point. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
39	This Required Amendment relates to the amendment of clause 11.2 of the applications and queuing policy to indicate that nothing in clause 11.2 provides Western Power with a derogation of obligations to energise connection points within the timeframes specified under clause 8.2 of the Code of Conduct for the Supply of Electricity to Small Use Customers or regulations 7 and 8 the Electricity Industry (Obligation to Connect) Regulations 2005. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
40	This Required Amendment relates to the deletion of the proposed change to clause 24.17(a) of the applications and queuing policy and maintaining the obligation on Western Power to provide queue information in the initial response to an application. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
41	This Required Amendment relates to the contributions policy and the obligation it places on Western Power to provide an applicant or user with details of the calculation of any contribution required from the applicant or user. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
42	This Required Amendment relates to the inclusion of definitions of "rural zone" and "mixed zone" in the proposed contributions policy. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			

	Required Amendment	Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
43	The proposed access arrangement revisions should be amended such that clause 6 of the contributions policy sets out: • the method or calculation and assumptions applied in determining the amount of costs to be recovered by headworks contributions; • the method or calculation and assumptions applied in determining the allocation of costs across a forecast of connections to the network and determining the magnitude of headworks contributions; • the procedures or methods applied by Western Power to ensure that headworks contributions will, in the long term, recover no more than Western Power's costs of the headworks; and • a mechanism, which may involve a system of accounting records, to ensure that any amount of the costs of headworks recovered by headworks contributions are not also recovered, or sought to be recovered, through other contributions or through tariffs for services.	**Amendment accepted.** In response to the first three dot points, Western Power proposes to include the required information in a new Appendix 9 to the Access Arrangement. A draft of the proposed document, titled "Distribution Headworks Methodology", is provided in the Attachment for the Authority's consideration. Note also that the contributions policy will make reference to this Appendix in a new introductory clause following the heading "6 Distribution headworks scheme" with the proposed wording: "The methodology used to develop the distribution headworks prices that apply in this distribution headworks scheme is described in Appendix 9 of this Access Arrangement." The following comments apply to the fourth dot point: With respect to the requirement to "ensure that any amount of costs of headworks recovered by headworks contributions are not also recovered, or sought to be recovered, through other contributions", Western Power believes that the existing clause 6.2(b) of the Contributions Policy already addresses the Authority's concern. With respect to the requirement to "ensure that any amount of costs of headworks recovered by headworks contributions are not also recovered, or sought to be recovered … through tariffs for services", a new clause 6.2(c) has been drafted for the Authority's consideration. The proposed clause ensures that the headworks contribution is treated as a capital contribution (as defined in the Code) and for regulatory purposes will therefore be treated as any other capital contribution. The existing clause 6.2(b) and proposed new clause 6.2(c) are set out below. "6.2 Headworks contribution (b) Where a *headworks contribution* is made by an applicant in accordance with clause 6.2(a) no further *contribution* shall be required from the *applicant* in relation to the *headworks* in question. (c) For the purpose of this *contributions policy* the *headworks contribution* is a *capital contribution*."	N	Sections 5.17A(c) and 5.17A(d).

Required Amendment		Western Power's response	Cross reference to attachment	Code provisions relevant to the Required Amendment
44	This Required Amendment requires the deletion of clause 2(c)(iii) of the contributions policy, which relates to the recovery of certain non-capital costs by Western Power. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
45	This Required Amendment relates to the amendment of the contributions policy to allow for contributions in respect of non-capital costs incurred in the implementation of an alternative option. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			
46	This Required Amendment relates Western Power's proposed expanded requirements for security proposed under clause 1.3 of the contributions policy. Western Power's response to this Required Amendment was provided in its first submission, which was lodged with the Authority on 13 August 2009.			

4. DETAILED SUPPORTING INFORMATION

In accordance with the information presented in the table in section 2 of this submission, the table below lists Attachments A to N of this submission, and the Required Amendments to which each attachment relates. As noted in section 1 of this submission, the purpose of these Attachments A to N is to provide further detailed supporting information where necessary to substantiate Western Power's approach to addressing the relevant Required Amendment.

Two further attachments are provided as Attachments O and P. Attachment O explains the revenue and tariff outcomes that would be delivered if the Authority accepts Western Power's response to the Draft Decision. Attachment P explains the relationship between network expenditure and service performance, and concludes that it is appropriate to adjust downwards the service targets that Western Power initially proposed in its submission in October 2008.

It is noted that Attachments O and P do not directly address particular Required Amendments. However, Western Power expects that the Authority will want to take this information into account in its Final Decision.

Attachment	Required Amendment or matters addressed
A	**Western Power's detailed response to Required Amendment 22** This Required Amendment addresses the establishment of new transmission service standard benchmarks.
B	**Western Power's detailed response to Required Amendment 23** This Required Amendment addresses revised definitions of SAIDI and SAIFI.
C	**Western Power's detailed response to Required Amendment 24** This Required Amendment addresses service standard benchmarks for SAIDI and SAIFI for customers served by the 15 per cent of worst performing feeders.
D	**Western Power's detailed response to Required Amendments 25 and 28** These Required Amendments relate to Western Power's amended operating and capital expenditure plans in light of the Draft Decision and the latest available information.
E	**Western Power's detailed response to Required Amendment 26, Dot Point 2** This Required Amendment relates to the exclusion of certain capital expenditure from the capital base through the Authority's application of the New Facilities Investment Test.
F	**Western Power's detailed response to Required Amendment 26, Dot Point 3** This Required Amendment relates to the exclusion of 15% of capital expenditure from the capital base through the Authority's application of the New Facilities Investment Test.
G	**Western Power's detailed response to Required Amendment 29** This Required Amendment relates to the value of the real pre-tax WACC.

Attachment	Required Amendment or matters addressed
H	**KPMG's report on the Cost of Capital, which relates to Required Amendment 29.**
I	**Western Power's detailed response to Required Amendments 32 and 36** These Required Amendments relate to the deferral of revenue from the second to the third and subsequent access arrangement periods.
J	**NERA's report on revenue deferral, which relates to Required Amendments 32 and 36.**
K	**Western Power's detailed response to Required Amendment 34** This Required Amendment relates to the design of the gain sharing mechanism.
L	**Western Power's detailed response to Required Amendment 35** This Required Amendment relates to the design of the service standard adjustment mechanism.
M	**Western Power's detailed response to Required Amendment 37** This Required Amendment relates to Western Power's proposed D-factor scheme.
N	**Western Power's detailed response to Required Amendment 43** This Required Amendment relates to Western Power's proposed contributions policy.
O	**Western Power's Revenue and Tariff Proposal** This attachment explains the revenue and tariff outcomes that would be delivered if the Authority accepts Western Power's response to the Draft Decision.
P	**Western Power's revised Service Performance Targets** This attachment explains the relationship between network expenditure and service performance, and concludes that it is appropriate to adjust downwards the service targets that Western Power initially proposed in its submission in October 2008.

ATTACHMENT A
Western Power's detailed response to Required Amendment 22

1. Introduction

Western Power accepts Required Amendment 22, which states:

Required Amendment 22

The proposed access arrangement revisions should be amended to include service standard benchmarks for:

- *loss of supply event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and*
- *average outage duration, measured in minutes.*

Section 2 sets out Western Power's comments on Required Amendment 22. In light of this discussion, Section 3 presents Western Power's proposed definitions and values for the additional service standard benchmarks.

2. Western Power's comments on Required Amendment

Western Power did not propose any substantive changes to the service standards benchmarks for the transmission network in its access arrangement revisions.

In respect of the reference services A11 and B2, which are available to users directly connected to the transmission network, the proposed service standard benchmarks were Circuit Availability and System Minutes Interrupted. These benchmarks were also included in the Service Standard Adjustment Mechanism.

The proposed targets were as follows:

	Year ending June 2010	Year ending June 2011	Year ending June 2012
Circuit Availability (% of total time)	98.0	98.0	98.0
System Minutes Interrupted (meshed network)	9.3	9.3	9.3
System Minutes Interrupted (radial network)	1.4	1.4	1.4

During the approval of the current access arrangement, the Authority suggested that the service standard benchmarks for the transmission network in the second access arrangement period should include benchmarks for average outage duration and frequency of off-supply events.

The principal reasons for not including these service standard benchmarks in the first access arrangement period were the absence of appropriate reporting systems and the lack of historical data to establish the benchmarks. During the first access arrangement period, however, Western Power developed the required systems and commenced the collection of the relevant data. However, the amount of data suitable for establishing a historical trend of the proposed benchmarks is somewhat limited.

The Authority's Draft Decision requires Western Power to amend the access arrangement to include benchmarks for average outage duration and frequency of off-supply events to be generally consistent with those that apply to transmission businesses in the National Electricity Market.

3. Western Power's proposal to give effect to Required Amendment 22

Western Power accepts the required amendment.

In respect of the reference services A11 and B2, which are available to users directly connected to the transmission network, Western Power proposes to include additional benchmarks for loss of supply event frequency (for both major and minor events) and average outage duration. The definitions of the new benchmarks are as follows.

Loss of Supply event frequency

Sub-parameters	Frequency of events where loss of supply exceeds 0.1 system minutes Frequency of events where loss of supply exceeds 1.0 system minutes
Unit of measure	Number of events per annum
Source of data	SCADA Network Status Processor (NSP), PI Server database, System Disturbance database
Definition/formula	Number of events greater than 0.1 system minutes Number of events greater than 1.0 system minutes System minutes are calculated for each supply interruption by the "load integration method" using the following formula: $\frac{\Sigma \text{ (MWh unsupplied x 60)}}{\text{MW Peak Demand}}$ Where: MWh unsupplied is the energy not supplied as determined by using Western Power metering and PI server database. This data is used to estimate the profile of the load over the period of the interruption by reference to historical load. Period of the interruption starts when a loss of supply occurs and ends when Western Power offers supply restoration to the customer. MW Peak Demand is the maximum demand recorded on the South West Interconnected System for the previous financial year.
Inclusions	all unplanned customer outages on all parts of the regulated transmission system.
Exclusions	unregulated transmission assets any outages shown to be caused by a 'third party system' Eg intertrip signal, generator outage, customer installation, customer request or Western Power direction momentary interruptions (less than one minute) planned outages *force majeure events*

Average Outage Duration

Sub-parameters	total average outage duration
Unit of measure	minutes
Source of data	SCADA Network Status Processor (NSP), PI Server database, System Disturbance database and ASI Availability reporting database
Definition/formula	$\frac{\text{Aggregate minutes duration of all unplanned outages}}{\text{No. of events}}$
Inclusions	Faults on all parts of the regulated transmission system All forced and fault outages whether or not loss of supply occurs Circuits include regulated overhead lines, underground cables and "bulk" power transformers (each with a designated Western Power SCADA ASI tag). Regional transformers, reactive plant and other primary plant are excluded from the performance parameter
Exclusions	planned outages momentary interruptions (less than one minute) *force majeure events* unregulated transmission assets any outages shown to be caused by a 'third party system' Eg intertrip signal, generator outage, customer installation, customer request or System Management direction. the impact of each event is capped at 14 days

The following table summarises Western Powers' current performance and proposed targets for the new proposed transmission service standard benchmarks.

	Loss of Supply Event Frequency				Average Outage Duration	
	Minor (>0.1 System Minutes)		**Major**(>1 System Minutes)			
	B'mark	Actual	B'mark	Actual	B'mark	Actual
Current AA period						
Jun-06		20		0		744
Jun-07		30		3		834
Jun-08		27		2		715
Jun-09		18		3		507
Proposed Revisions						
Jun-10	25		2		764	
Jun-11	25		2		764	
Jun-12	25		2		764	

The new proposed benchmarks are based on the 3 years of historical performance prior to the current year (i.e. in this case, historical performance for 2005/06 to 2007/08 inclusive). This approach for setting benchmarks is similar to that employed to set benchmarks for other service measures.

The proposed transmission service standard benchmark targets as follows:

	Year ending June 2010	Year ending June 2011	Year ending June 2012
Circuit Availability (%)	98.0	98.0	98.0
System Minutes Interrupted (meshed network)	9.3	9.3	9.3
System Minutes Interrupted (radial network)	1.4	1.4	1.4
Loss of Supply Event Frequency (No.) > 0.1 System Minutes	25	25	25
Loss of Supply Event Frequency (No.) > 1 System Minutes	2	2	2
Average Outage Duration (Minutes)	764	764	764

However, it should be noted that the Authority has not required the new benchmarks to be included in the Service Standard Adjustment Mechanism, and therefore these benchmarks will not be subject to financial incentives during the forthcoming access arrangement period. Western Power will consider introducing financial incentives for the third access arrangement period, as more data will be available at that time.

ATTACHMENT B

Western Power's detailed response to Required Amendment 23

1. Introduction

Western Power accepts Required Amendment 23, which states:

> **Required Amendment 23**
>
> *The proposed access arrangement revisions should be amended such that definitions of SAIDI and SAIFI do not make provision for the exclusion of single customer interruptions.*

Section 2 sets out Western Power's comments on Required Amendment 23. In light of this discussion, Section 3 presents Western Power's proposed approach for giving effect to this Required Amendment.

2. Western Power's comments on Required Amendment 23

Western Power proposed to include distribution service standard benchmarks to be similar as under the current access arrangement; that is, SAIDI and SAIFI. Western Power reiterated that the calculation methods for SAIDI and SAIFI should be consistent with nationally accepted procedures, and in particular the "normalised unplanned" methodology of the Steering Committee on National Regulatory Reporting Requirements (SCNRRR), and proposed a clarification to the calculation method for these service standards to exclude outages for single customers. The Authority concurred with Western Power that the measures of service standards applied under the access arrangement should be consistent with nationally consistent methods.

However, the SCNRRR methods explicitly include outages affecting a single customer in measures of SAIDI and SAIFI. Accordingly, the Authority considers that this exclusion should not apply to measures of SAIDI and SAIFI under the access arrangement. The Authority's Draft Decision appears to be generally consistent with the nationally accepted standards of the SCNRRR.

Further, Western Power understands the Authority accepts the industry practice that major event days should be defined in accordance with IEEE1366-2003, however note that this has not been formally adopted by the SCNRRR as Western Power suggested in the revisions submission. Western Power consequently proposes to delete the relevant words referring to SCNRRR in the definitions for SAIDI and SAIFI for clarity.

3. Western Power's proposed approach for giving effect to Required Amendment 23

Western Power accepts this Required Amendment. However, it should be noted that the inclusion of single customer outages in the calculation of SAIDI and SAIFI will result in an apparent, small decrease in performance historically, which will also need to be reflected in revised targets for the second Access Arrangement period. (For further details see Attachment L of this submission)

Western Power proposes SAIDI shall be defined as follows:

Performance Indicator:	System Average Interruption Duration Index (SAIDI)
Unit of measure:	System minutes per annum
Definition:	Over a 12 month period, the sum of the duration of each sustained (greater than 1 minute) customer interruption (in minutes) attributable solely to distribution (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.
Exclusions:	• Major event days in accordance with IEEE1366-2003 definitions ~~as adopted by Steering Committee on National Regulatory Reporting Requirements (SCNRRR).~~ • Outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation). ~~• Single Customer Interruptions~~ • Planned Outages. • *Force majeure* events.

SAIFI shall be defined as follows:

Performance Indicator:	System Average Interruption Frequency Index (SAIFI)
Unit of measure:	Supply interruptions per annum
Definition:	Over a 12 month period, the total number of sustained (greater than 1 minute) customer interruptions (number) attributable solely to distribution (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.
Exclusions:	• Major event days in accordance with IEEE1366-2003 definitions ~~as adopted by Steering Committee on National Regulatory Reporting Requirements (SCNRRR).~~ • Outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation). ~~• Single Customer Interruptions~~ • Planned Outages. • *Force majeure* events.

The service standard benchmarks expressed in terms of SAIDI for the reference services A1 to A10 and B1 for each year of the access arrangement period are shown in the following table:

SAIDI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2010	230	38	165	259	612
June 2011	224	38	162	253	588
June 2012	213	38	153	244	556

The *service standard benchmarks* expressed in terms of SAIFI for the *reference services* A1 to A10 and B1 for each year of the *access arrangement period* are shown in the following table:

SAIFI	SWIN total	CBD	Urban	Rural Short	Rural Long
June 2010	2.50	0.24	1.92	3.12	5.00
June 2011	2.46	0.24	1.89	3.06	4.85
June 2012	2.41	0.24	1.83	2.98	4.80

ATTACHMENT C
Western Power's detailed response to Required Amendment 24

1. Introduction

Western Power proposes to address the matters raised by the Authority in proposing Required Amendment 24, which states:

> **Required Amendment 24**
>
> *The proposed access arrangement revisions should be amended to include service standard benchmarks for SAIDI and SAIFI for customers served by the 15 per cent of worst performing feeders.*

Section 2 sets out Western Power's comments on Required Amendment 24. In light of this discussion, Section 3 presents Western Power's suggested approach for addressing this Required Amendment.

2. Western Power's comments on Required Amendment 24

The wording of the required amendment suggests new benchmarks are required for "customers served by the 15 per cent of worst performing feeders". However a similar ESC Victoria benchmark (which the Authority have referred to in its Draft Decision) is actually based on the feeders which serve the 15% of customers who experience the worst performance. Subsequently, discussions with the Authority suggested the Required Amendment was intended to establish new benchmarks for the feeders which serve the 15% of customers who experience the worst performance, and this is the interpretation Western Power has adopted for the purpose of this response.

Western Power proposed similar distribution service standard benchmarks to those that apply in the current access arrangement; that is, SAIDI and SAIFI to be reported by feeder classifications of CBD, Urban, Rural Short and Rural Long.

In its proposed revisions in October 2008, Western Power reiterated its view that the calculation methods for SAIDI and SAIFI should be consistent with nationally accepted procedures, and in particular the "normalised unplanned" methodology of the Steering Committee on National Regulatory Reporting Requirements (SCNRRR), and that the definitions of CBD, Urban, Rural Short and Rural Long feeder classifications should also be consistent with the SCNRRR.

In the Draft Decision, the Authority cited the ESC's requirement that Victorian distributors report SAIDI for planned and unplanned interruptions for the 15 per cent of customers experiencing the longest time off supply. The Authority considered that service standard benchmarks relating to the worst levels of service reliability are important to enable a user to assess the value of a reference tariff. The Authority's concerns were particularly focused on rural feeders where it suggested that low levels of reliability may be masked by system-wide average measures of SAIDI and SAIFI.

The Authority considered that service standard benchmarks should be established for the worst performing feeders in the distribution network to establish an element of accountability for expenditure undertaken to maintain or improve reliability.

Western Power notes that the Authority has commented in paragraph 306 of the Draft Decision that service standard benchmarks should be nationally consistent. Although the Required Amendment is generally consistent with the requirements of the ESC (Victoria) 2006 Electricity Distribution Price Review 2006, it is not consistent with the requirements of the AER's Distribution Service Target Performance Incentive Scheme (May 2009). It is also noted that the Victorian distribution businesses will shortly be subject to the AER scheme.

Western Power has examined the SAIDI and SAIFI benchmarks for the feeders which service the 15% of customers who experience the worst service. These benchmarks are calculated by ranking the feeders and selecting the worst ones until 15% of customers are covered and deriving the performance of the list where SAIDI15% = (Customer Minutes Interrupted 15%) / (Customers Served 15%), and are shown in the table below:

Period Ending Financial Year	**Jun-06**	**Jun-07**	**Jun-08**	**Jun-09**
SAIDI for worst 15% CS	631	728	711	711
SAIFI for worst 15% CS	5.47	6.30	6.03	5.91

The actual feeders which would be included in the calculation of the benchmarks for the 15% of customers who experience the worst performance is expected to be significantly dominated by Rural Long feeders. Historical performance of SAIDI and SAIFI for the Customers Served by Rural Long feeders is shown below:

Period Ending Financial Year	**Jun-06**	**Jun-07**	**Jun-08**	**Jun-09**
SAIDI for Rural Long	472	624	611	573
SAIFI for Rural Long	3.69	4.72	4.99	4.27

Although there is a reasonable difference between the historical performance for the worst 15% CS and Rural Long, the difference is not considered enough to materially affect a user's assessment of the value of a reference tariff. In fact, the group of feeders which serves the 15% of customers who experience the worst performance will by definition be dynamic and constantly changing due to factors beyond Western Powers' control, and customers will not always know whether their feeder is in that group. Western Power consequently contends that the benchmarks for Rural Long feeders are an appropriate indication of the worst level of performance that customers should reasonably expect and which will also enable them to assess the value of any relevant reference tariff.

Accountability for Western Powers' expenditure undertaken to maintain or improve reliability is provided through the Service Standard Adjustment Mechanism (SSAM) as required by the Access Code. Although not explicitly required by the Authority at this stage, Western Power considers that to include a service standard benchmark in the SSAM based on worst performing feeders would be inappropriate. The year to year performance of individual feeders (particularly the worst performing feeders) is governed significantly by factors beyond Western Powers' control. It is exceptionally difficult (if not impossible) to forecast which feeders will be in the group of worst performing feeders (which will be constantly changing) and hence it is very difficult to make forecasts of future performance and the required expenditure to meet that performance for this group of feeders. Western Power proposes that the required accountability for expenditure to maintain or improve reliability should be via the SSAM as proposed for the feeder categories by which Western Power has planned its work (being CBD, Urban, Rural Short and Rural Long) which are consistent with the requirements of the SCNRRR and the AER.

3. Western Power's proposed approach for addressing Required Amendment 24

Western Power considers that the service obtained by the 15% of customers served by the worst performing feeders is not significantly different to the service on rural long feeders. In addition, the AER's distribution service performance scheme does not require a benchmark to reflect the worst performing feeders. In light of these observations, Western Power believes that the Authority should reconsider the need for this Required Amendment.

Western Power is able to comply, however respectfully requests the Authority to reconsider the need for this required amendment 24.

ATTACHMENT D

Supplementary Report

Capital and operating expenditure

2009/10 to 2011/12

September 2009
DM 6390547

Foreword

This report provides a detailed response to the ERA's Draft Decision, Amendments 25 and 28, regarding Western Power's forecast capital and operating expenditures for the 3 year regulatory term commencing 1 July 2009. It builds on the previous report submitted to the ERA as Appendix 1 to Western Power's initial Access Arrangement Information. It incorporates revised expenditure forecasts consistent with Western Power's indicative revised expenditure forecasts submitted in a letter dated 25 May 2009.

The expenditure plans have been reduced from the initial Access Arrangement Submission to take into account the economic down turn associated with the global economic crisis and other factors that have emerged in the nine months since the initial submission. The forecast expenditures are in response to a range of key business drivers, based on sound analysis of needs and supporting justification, followed by review by an expert consultant.

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Expenditure summary

Western Power proposes to invest $4.9B (real 30 June 2009) for the three year regulatory period that commenced 1 July 2009. The proposed capital and operating expenditures for the transmission system totalling $1.8B are detailed in tables E1 and E2. The proposed distribution system capital and operating expenditure totalling $3.1B are detailed in tables E3 and E4.

Table E1 Transmission capital expenditures, actual and proposed ($M)

Category	06/07	07/08	08/09	09/10	10/11	11/12	TOTAL
Network:							
- Growth related	264.0	271.4	260.7	247.7	466.2	504.3	**1,218.2**
- Non-growth related	28.7	26.4	43.0	48.3	77.8	90.3	**216.4**
Estimating risk factor	-	-	-	-	-	-	**-**
Business support cost	9.5	14.5	15.1	10.9	16.4	12.9	**40.2**
Total Capex	302.3	312.3	318.7	**306.9**	**560.5**	**607.4**	**1,474.8**

Table E2 Transmission operating expenditures, actual and proposed ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12	TOTAL
Network	55.9	54.1	48.5	49.1	68.5	74.3	**191.9**
Business support costs	18.2	20.3	24.6	26.8	28.3	29.6	**84.6**
Total Opex	74.1	74.4	73.1	**75.9**	**96.7**	**103.8**	**276.5**

Table E3 Distribution capital expenditures, actual and proposed ($M)

Category	06/07	07/08	08/09	09/10	10/11	11/12	TOTAL
Network:							
- Growth related	295.7	275.2	379.3	370.5	393.6	387.3	**1,151.4**
- Non-growth related	117.0	155.3	211.9	207.9	279.2	326.3	**813.3**
Estimating risk factor	-	-	-	-	-	-	
Business support costs	28.7	43.7	45.3	32.8	49.3	38.6	**120.6**
Total Capex	441.5	474.2	636.5	**611.2**	**722.0**	**752.1**	**2,085.3**

Table E4 Distribution operational expenditures, actual and proposed ($M)

Item	06/07	07/08	08/09	09/10	10/11	11/12	TOTAL
Network	204.9	201.2	214.2	210.8	283.0	336.8	**830.6**
Business support costs	46.2	54.5	69.8	72.8	77.2	81.2	**231.2**
Total Opex	251.1	255.6	284.0	**283.7**	**360.1**	**418.0**	**1,061.8**

1 Introduction and background

Western Power is required to develop an Access Arrangement, which describes the terms and conditions under which users can obtain access to Western Power's South West Interconnected System (**SWIS**). The Access Arrangement defines network revenue projections and access tariffs, service standards and required capital and operating expenditures to meet these standards over the regulatory period.

The purpose of this document is to set out the capital expenditure (Capex) and operating expenditure (Opex) programs that are forecast for the regulatory period from July 2009 to June 2012 inclusive.

1.1 Structure and coverage of this document

This document is a Supplementary Submission to the Access Arrangement proposed in September 2008 and builds on the information provided in the initial submission. The Supplementary Submission does not repeat the high level network overview and business related information provided in the initial submission as this has not changed.

The Supplementary Submission does provide a complete response to issues raised in the ERA's Draft Decision regarding the revised Capex and Opex amounts proposed. Where an expenditure level has not changed from the level accepted by the ERA in its Draft Decision[1] this expenditure is restated, but detailed explanations are not repeated. Where the expenditure level has changed compared to the Draft Decision or clarifications were required, additional information has been included in this document.

The expenditure forecasts discussed in this document cover all transmission and distribution assets comprising the SWIS. Separate expenditure forecasts are provided for the transmission network and the distribution network. The expenditure forecasts for non-network assets and business operating costs not directly related to the SWIS are also included. These are presented and discussed as business support costs.

Section 1 describes the structure and coverage of this document and outlines the reasons for the changes in expenditure forecasts set out in this submission, compared to those in the initial Access Arrangement Information of 1 October 2008.

Section 2 sets out Western Power's approach to forecasting the revised expenditure forecasts, provides detailed information about some of the drivers for these changes compared to the Draft Decision, and provides a high level overview of the impact of changed expenditure levels on the network risk profile and standards for service delivery.

Sections 3 and 4 set out the expenditure forecasts for Transmission Capex and Distribution Capex respectively.

Section 5 sets out the expenditure forecasts for the proposed Transmission and Distribution Opex.

The structure of the sections that discuss individual expenditure line items, as included in sections 3, 4, and 5, is;

[1] Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, Submitted by Western Power*, 16 July 2009

- A brief description of the expenditure category,
- A table showing the proposed expenditure for the category,
- Summary of the ERA Draft Decision findings with respect to the category, and
- If required, address comments from the ERA and provide supporting data to explain and justify the proposed expenditure.

1.2 Key changes

In early 2008, Western Power prepared the initial Access Arrangement (AA2) submission for the period July 2009 to June 2012 (the initial submission) including a total expenditure program of $6.05B (real 30 June 2009)[2] comprising Capex of $4.48B and Opex of $1.57B. The initial submission was submitted to the ERA on 1 October 2008. At the time of submission the global financial crisis (GFC) had just begun and the short, medium and long term impacts were uncertain. The initial submission was based on the best information available at that time.

The key events and changes since September 2008 that have resulted in the need for Western Power to provide this Supplementary Submission are;

- changes in the economic climate,
- the Draft Decision released by the ERA in July 2009,
- changes to the Unit Cost Escalation incorporated in Western Power's forecasts, and
- actual expenditures for 2008/09 and firm budget expenditures for 2009/10 have been established.

Details of these changes and events and a summary of their impact on the Capex and Opex forecasts are provided below.

Note that the historical actual expenditures for 2006/07 and 2007/08 presented in this report have been calculated using the actual inflation rate for 2008/09 of 1.46%. This differs from the forecast inflation rate of 2.98% used in the initial submission. This change has resulted in a 1.5% reduction in real historical expenditures for these years.

1.2.1 Changes in Economic Climate

Between September 2008 and August 2009 the global and local economic climates have changed significantly, with a slowing of development and demand, particularly in the mining and resources sector. Both government and the private sector have reacted to the changes in the financial markets, reducing the availability of funding and the appetite of investors to take on risk. Whilst the long term impacts of the GFC are still uncertain, in the short to medium term the economic climate has impacted Western Power's AA2 plans as follows:

- **Forecast load growth** has been revised downwards, and consequently the associated Capex forecast has been reduced due primarily to deferral of a number of large new connection projects.

[2] Unless otherwise stated all dollars presented in this report relate to 30 June 2009 real dollars

- **Affordability constraints:** Western Power is subject to funding constraints imposed by the State budgeting process and has therefore reconsidered the proposed expenditure for AA2 taking these funding constraints into consideration. The impact of the AA2 submission on tariff increases also requires responsible moderation of the level of expenditure to minimise the direct impact of tariff increases on consumers.

- **Deliverability:** The initial AA2 submission described a clear plan to ramp up physical resources (both internal and external) to ensure that Western Power could deliver the increased capital program as forecast. This ramp up relied on gradual increases in the capital program in 2008/09 and 2009/10 that would enable more significant increases to occur for the 2010/11 and 2011/12 capital programs. However, funding constraints in 2008/09 and 2009/10 have led to a more moderate ramp up of resources over the regulatory period.

In May 2009, Western Power provided a letter to the ERA[3] that signalled Western Power's intention to revise the expenditure forecasts to account for the factors outlined above. The letter contained an indicative forecast for Capex and Opex by category with a nominal total expenditure for the AA2 period of $5.1B ($4.9B June 2009 real dollars). Western Power has since conducted a rigorous process to revise the forecast expenditure on a category by category basis following overarching risk-based optimisation principles. As a result, some of the line items differ from the indicative figures provided in the May 2009 letter.

1.2.2 ERA Draft Decision - July 2009

This report responds to Amendments 25 and 28 of the ERA's July 2009 Draft Decision, which are reproduced below:

Required Amendment 25

The proposed access arrangement revisions should be amended to reflect a forecast of non-capital costs as follows (real $ million at 30 June 2009):

	2009/10	*2010/11*	*2011/12*
Transmission:	*69.58*	*81.14*	*89.03*
Distribution:	*263.74*	*301.38*	*330.75*
Total:	*333.32*	*382.52*	*419.77*

[3] Western Power's Proposed Access Arrangement Revisions – Expenditure Forecasts DM 6081422

Required Amendment 28

The proposed access arrangement revisions should be amended to incorporate a forecast of new facilities investment that:

- *reflects a revised program of capital works that takes into account revised forecasts of demand for network services*
- *reflects a zero rate of escalation in unit costs over the second access arrangement period, and*
- *excludes any "estimating risk margin".*

Specific issues were also raised. These issues are set out in Attachment 1, together with a reference to the sections of this Supplementary Submission that address each issue.

1.2.3 Cost Escalation

Western Power's initial submission anticipated real increases in unit costs during the AA2 period and incorporated these into expenditure forecasts through the use of escalation factors.

The escalation factors incorporated real increases in wages, contract services, and materials. The escalators were based on information prepared prior to the GFC and some of the assumptions used to prepare this information have changed in the interim period. In paragraph 416 of the Draft Decision the ERA requested Western Power to reconsider cost escalation rates. Section 2.2.2 of this document provides detailed information relating to the revised escalators.

1.2.4 2008/09 Actual and 2009/10 Budget expenditure established

Since the initial submission the 2008/09 financial year has concluded and actual expenditures for that year are now available instead of the forecasts that were considered by the ERA in its Draft Decision. The inclusion of these actual expenditures provides a more robust basis for establishing the current efficient expenditure baseline, which may be used to inform future expenditure levels.

Table 1-1 provides the 2008/09 actual expenditure compared with the forecasts provided as part of the initial submission to the ERA.

Table 1-1 Actual 2008/09 expenditure compared with forecasts in initial submission ($M)

Real $M as at 30 June 2009	Forecast 2008/09	Actual 2008/09	% difference from forecast
Transmission opex	74.5	73.1	-1.9%
Transmission capex	443.6	318.7	-28.2%
Distribution opex	262.9	284.0	+8.0%
Distribution capex	575.5	636.5	+10.6%

Transmission Capex actual expenditure was lower than forecast for 2008/09 mostly because of deferral of significant capacity expansion projects due to the impact of the GFC. The principal projects deferred in 2008/09 were the North Country Reinforcement project ($38M) and the South West Bulk reinforcement project ($10M), the Busselton-Margaret River 132kV transmission line project ($32M), and a number of strategic land purchases ($21M). There was also a general slowdown of Transmission customer funded works, accounting for the remainder of the deferral of work. Regulatory Compliance Capex was $12M below forecast and Reliability Driven Capex was $5M above forecast.

The 2008/09 Distribution Opex was $21M above forecast. This was mostly due to an additional $4M of Corporate support costs allocated to this category as well as $4.4M to address the impact of severe storms experienced in May and June, bringing the number of severe storms to three for the year, one more than allowed for in the forecast. The remaining overspend was due to higher funds required than forecast for Emergency work.

Distribution Capex for 2008/09 was principally impacted by a $113M increase in Customer Access works. This was due to the combined impact of higher than forecast requirements from customers and improved delivery performance resulting in completion of 2355 projects carried over from the prior year. Conversely, gifted assets were lower than forcast due to deferred new subdivisions ($22M). Other categories of Capex were also generally lower than forecast, mostly due to a tight labour market, industrial action in the last quarter of 2008/09, and a need to give priority to some Opex and customer funded works. This impacted Capacity Expansion (-$27M), Regulatory Compliance (-$7M), and sundry other regulatory categories (net -$3M). The Corporate support cost allocation was $7M higher than forecast.

The 2009/10 budget for Western Power has also been agreed and therefore the expenditure levels represented in this Supplementary Submission reflect the expenditure levels agreed for the business for the first year of the regulatory period. Clearly these have been constrained by the factors mentioned in the above sections when compared with the forecasts initially provided to the ERA.

1.3 Supporting information

Documents supporting this Supplementary Submission are listed in Table 1.2.

Table 1-2 References of Supporting Documents

Document name	DM number	Where mentioned
Western Power's Proposed Access Arrangement Revisions – Expenditure Forecasts (May 2009 letter to the ERA)	6081422	1.2.1
Western Power's Asset Risk Management Framework Procedure	5286989	2.2.1
Risk Assessment Matrix and Criteria	3341162	2.2.1
Risk Management Framework	3017083	2.2.1
Access Economics Pty Ltd, 2008, *Material and Labour Cost Escalation Factors*	4575552	2.2.2
Access Economics, *Material and labour cost escalation factors, Report by Access Economics Pty Ltd for Western Power*, 29 May 2009	6144247	2.2.2

Order (01-2009) and (02-2009) from EnergySafety	(Unpublished)	4.4
Smart Grid foundation program	5444221	4.8
Energy Systems Services Contracting White Paper	353666	5.3.1
Works Program Delivery Framework	4410371	5.3.2
Western Power's Delivery Mechanism Options Paper	4418227	5.3.3
Work Allocation System	4422376	5.3.4
Revised contracting strategy	6218320	5.6
Executive Summary of Structural Assessments	6356309	5.8
Smart Grid Submission	6321652	Attachment 2

Codes, Acts and publicly available documents	Where first mentioned
Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, Submitted by Western Power*, 16 July 2009	1.1
Initial Access Arrangement (AA2) submission	1.2
IMO *Statement of Opportunities* 2009	2.2.3
Electricity Industry (Network Quality and Reliability of Supply) Code 2005	4.6
Access Code (*Electricity Networks Access Code 2004)*	2.4
Electricity (Supply Standards and System Safety) Regulations 2001	4.4
Electricity Industry Act 2004	4.4
Environmental Protection (Noise) Regulations 1997	3.6
Electricity Industry (Network Quality and Reliability of Supply) Code 2005	3.7
Energy Operators Act 2005	5.6
Contaminated Sites Act 2003 (Act)	5.7
AASB116 (Compiled Accounting Standard - Property, Plant and Equipment)	5.16.3
Existing safety and environmental regulations	5.5

2 Preparation of Supplementary Submission

This section discusses Western Power's approach to forecasting expenditures to account for the changes outlined in section 1. The approach reflects the need to balance competing priorities within the current constraints and manage risks associated with the reduction of Capex and Opex levels.

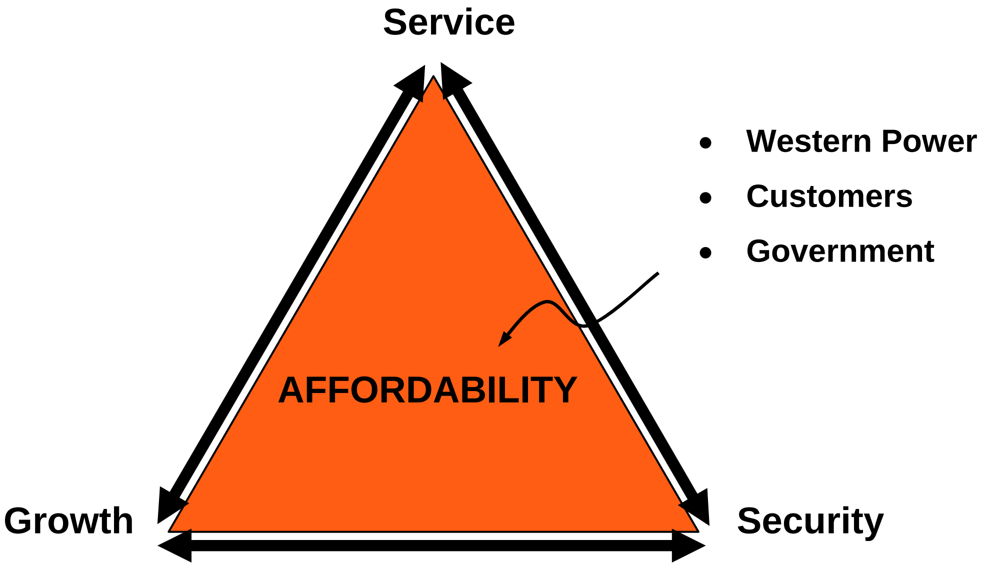
2.1 Approach to re-forecasting expenditures

Figure 2-1 illustrates the tension between competing expenditure areas that will cater for:

- growth in the network,
- sustain and/or improve service levels, and
- sustain and/or improve security of supply,

overlaid on the constraint of affordability for Western Power, its customers and the business owner (the Government).

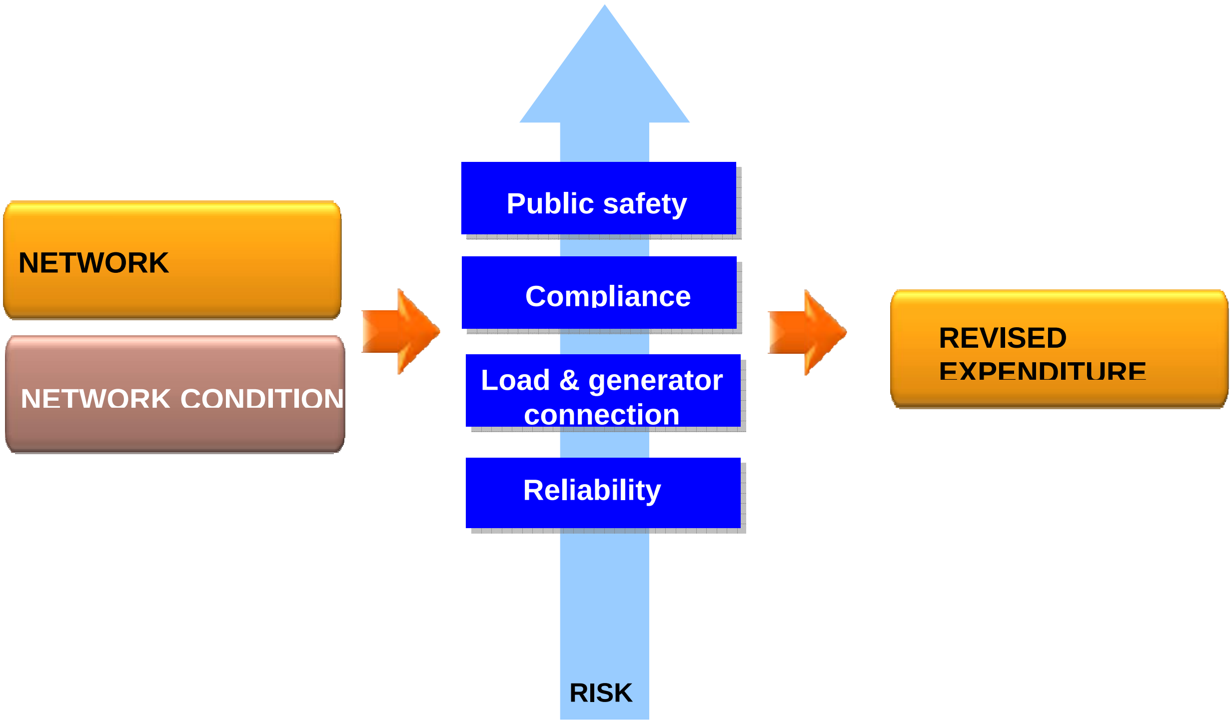
Figure 2-1 Balance competing areas of expenditure against affordability constraints



Western Power has considered the current network capacity, condition and associated risk profile and adjusted expenditures giving priority to expenditure in the following descending order of priority, as illustrated in Figure 2.2:

1. public safety
2. compliance
3. load and generator connection, and
4. reliability.

Figure 2-2 Prioritisation process for expenditure review



Through the application of these constraints and guiding principles, Western Power has undertaken a top down review of the initial submission forecasts. This is in contrast to the bottom up approach adopted for the initial submission, which involved the build up of the forecast from base volume and cost estimates.

The top down process involved allocating responsible levels of Capex according to the priority/risk classification of works as recognised above to the original forecasts. Consequently, the specific programs and projects of works are broadly as proposed in the initial submission, with lower priority/risk projects/programs being deferred until later in the regulatory period, or moved into the next regulatory period.

The revised expenditure forecasts have preserved necessary expenditure on public safety and made allowance for the most important elements of regulatory compliance. Works associated with capacity expansion have been deferred in response to lower growth forecasts published since the GFC, and with a greater acceptance of growth related risks in the current economic climate. New facilities investment targeting improved reliability has been deferred to future regulatory periods to enable the allocation of funds to higher priority areas.

In response to reduced preventative works, Opex has been re-forecast to provide a reasonable level of expenditure necessary to preserve service standards and address expected increased fault rates.

2.2 Specific issues

This sub section discusses the specific issues considered in re-forecasting expenditures, which are:

- regulatory compliance,
- public safety,
- cost escalation,
- demand forecasts, and
- estimating risk margin.

2.2.1 Critical public safety and regulatory compliance works

The initial submission recognised the need to incorporate expenditure to improve public safety and regulatory compliance for Western Power's network and used the Capital Project Risk Management[4] process and Investment Optimisation Planning Tool[5] to ensure that these expenditures are prudent.

Expenditure related to critical risks in the areas of public safety, bushfires, maintenance backlog, pole failures, network security, and major outages were incorporated in the initial submission. In a number of these areas, programs were proposed that would allow a rapid and significant improvement on the current level of compliance and the level of risk being managed.

To meet the State budget constraints, Western Power has reviewed the critical areas and proposes to continue the improvement in these areas, while slowing the rate of improvement.

2.2.2 Cost Escalation - Revised

Western Power's initial submission anticipated increases in unit costs during the AA2 period and incorporated these into expenditure forecasts through the use of escalation factors. The escalation factors incorporated real increases in wages, contract services, land and materials. Escalation rates were applied using composite escalators that were prepared separately for distribution and transmission Capex and Opex, based on the proportions of each of these inputs to the relevant activities. The escalation factors were based on data for expected increases in internal labour costs and information on other components from a report prepared by Access Economics in April 2008[6].

In the Draft Decision (paragraph 414 and 415) the ERA discounted the assumptions underlying these escalators in light of the GFC and noted that Western Power had been asked to reconsider cost escalation rates. In response to the ERA's request Western

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[4] Western Power's Asset Risk Management Framework Procedure DM 5286989

[5] Risk Assessment Matrix and Criteria DM 3341162; Risk Management Framework DM 3017083

[6] Access Economics Pty Ltd, 2008, *Material and Labour Cost Escalation Factors*, DM 4575552

Power provided an updated report by Access Economics dated May 2009[7], but did not provide revised composite cost escalators.

The ERA produced a summary of the labour and materials escalators from the Access Economics report and concluded, based on an overview of this data, that it is “reasonable to assume no real increase in unit costs during the course of the second access arrangement period”. This view underpins the Opex figures stated in Amendment 25 and is repeated with reference to Capex in Amendment 28 of the Draft Decision.

Western Power has recalculated the cost escalators using the same methodology as described in the initial submission, and has incorporated the updated Access Economics data, together with confirmed data on internal labour cost escalation, to provide revised unit cost escalators. The revised cost escalators are shown in Table 2-2. The internal labour escalation data is based on the Certified Agreement (ref: Western Power and CEPU Union Collective Agreement 2008) which was entered into between Western Power and its wages staff group on 1 October 2008 and remains effective until 1 October 2013. This agreement allows for a 4.5% increase to labour rates in 2008/09, 2009/10, 2010/11 and 2011/12. Western Power and the ASU are currently negotiating the salaried Certified Agreement which will confirm future increases for salaried staff over the coming years. Internal labour accounts for the majority of real cost escalation forecast in 2009/10.

In forming assumptions about labour cost escalation, a comparison of prevailing market rates confirms that companies operating in the Australian power industry and associated industries in Western Australia with whom we directly compete for our skilled labour, already pay remuneration rates that are at least comparable or higher than the rates paid by Western Power.

Benchmark data provided from recognised market survey sources showed average gaps of between 10% - 31% across Western Power's workforce. Western Power's new and proposed remuneration rates through to 2011/12 lift existing Western Power rates to prevailing market benchmark rates. Variable rates of pay ensure that market relativity is maintained. Performance based remuneration, labour efficiency and productivity gains as a consequence of new work flexibility and alternate work pattern provisions provided within the new agreement will ensure competitive offsets to increased labour costs.

Market benchmarking has been based on market median from four market survey sources; Hay, Mercer MEHRC and Geoff Nunn and Associates. Forecast remuneration increases over the next 12 months (2009/10) are for a general market increase of around 3.0%, with the engineering segment continuing slightly more strongly at around 4.0%.

The resulting cost escalation factors are lower than those forecast in the initial submission as shown by Table 2-1, but are forecast to be greater than zero over the AA2 period. The forecast cost escalators in Table 2-1 indicate that the real unit costs will:

1. increase in 2009/10 at a rate higher than initially forecast,
2. be static or slightly decrease in 2010/11, and
3. increase in 2011/12 at a rate less than initially forecast.

[7] Access Economics, *Material and labour cost escalation factors, Report by Access Economics Pty Ltd for Western Power*, 29 May 2009, DM 6144247

Table 2-1 Comparison of original and revised cost escalators (real annual rate of change, per cent)

Real	09/10	10/11	11/12
Transmission opex – Revised July 2009	3.37	0.00	0.88
Transmission opex – Sept. 2008	*2.40*	*1.71*	*2.57*
Transmission capex – Revised July 2009	2.48	-2.25	-0.19
Transmission capex – Sept. 2008	*1.58*	*0.08*	*2.98*
Distribution opex – Revised July 2009	3.37	0.00	0.88
Distribution opex – Sept. 2008	*2.30*	*1.60*	*2.61*
Distribution capex – Revised July 2009	2.28	-0.78	0.88
Distribution capex – Sept. 2008	*2.08*	*0.94*	*2.80*

*September 2008 real cost escalators reproduced from ERA Draft Decision Table 18

Table 2-2 Cost escalators (nominal)

Cost Escalation Factors	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12
Labour Escalation (%)									
External - WA utilities workers	3.20%	4.45%	4.28%	5.12%	6.10%	5.60%	4.40%	1.20%	2.10%
Internal*	4.00%	4.00%	6.10%	6.10%	5.00%	6.50%	5.75%	4.75%	5.00%
Land Escalation (%)									
Perth	6.47%	8.50%	6.99%	8.70%	8.16%	7.66%	0.00%	5.00%	5.00%
Remainder of WA	5.79%	7.70%	6.91%	8.15%	7.36%	6.90%	0.00%	5.00%	5.00%
Material Cost Escalation (%)									
Concrete	2.74%	2.82%	2.82%	2.62%	3.60%	6.20%	-0.10%	3.00%	1.60%
Fabricated steel	3.80%	15.80%	3.68%	1.47%	5.80%	30.90%	-2.50%	-7.20%	-3.80%
Wooden poles	4.13%	1.40%	2.99%	3.41%	5.70%	4.90%	0.40%	2.50%	3.50%
Electrical cable	1.66%	11.37%	15.19%	40.74%	-1.40%	-10.40%	-1.70%	1.40%	5.50%
Raw copper	47.18%	34.83%	58.77%	40.53%	9.10%	-47.50%	-7.00%	7.20%	0.20%
Raw aluminium	15.63%	15.13%	23.57%	20.19%	0.70%	-33.70%	0.30%	0.90%	2.50%
Electrical and control equip.	0.40%	1.62%	5.30%	5.70%	3.50%	4.90%	3.90%	-2.20%	3.40%
Lights	-1.62%	-1.74%	3.12%	-0.09%	4.80%	4.20%	-1.20%	0.40%	3.00%
Nuts, bolts, screws	-0.25%	-1.09%	5.29%	1.35%	0.40%	12.50%	-1.70%	-1.30%	0.30%
Earthworks	4.07%	4.16%	5.92%	5.01%	5.50%	6.40%	0.90%	3.20%	2.80%
Sheet metal	1.49%	4.47%	8.63%	0.69%	1.60%	6.90%	-0.60%	0.70%	3.40%
Combined Material Escalators (%)									
Transmission operating	1.12%	4.54%	8.29%	17.33%	2.29%	-1.37%	0.63%	-0.34%	3.93%
Transmission capital	0.94%	2.16%	5.36%	6.80%	3.87%	5.49%	1.07%	-1.12%	2.69%
Distribution operating	0.71%	3.44%	7.28%	13.33%	3.66%	5.64%	1.77%	-2.16%	2.62%
Distribution capital	1.12%	5.56%	9.04%	19.96%	1.95%	-2.31%	0.15%	-0.29%	3.99%
Weighted Average % (Nominal)									
Transmission Operating	3.12%	4.29%	5.75%	7.82%	4.84%	4.63%	4.21%	2.29%	3.58%
Distribution operating	3.01%	3.66%	5.41%	6.00%	4.95%	6.00%	4.20%	2.29%	3.61%
Transmission capital	1.77%	3.76%	6.40%	10.35%	4.37%	5.62%	3.31%	-0.04%	2.48%
Distribution capital	2.58%	4.78%	6.66%	11.31%	4.07%	2.67%	3.05%	1.53%	3.61%
Inflation (CPI)	2.48%	2.49%	3.98%	2.07%	4.51%	1.46%	0.84%	2.31%	2.72%

* 2008/09 through to 2011/12 provided by Human Resources Division

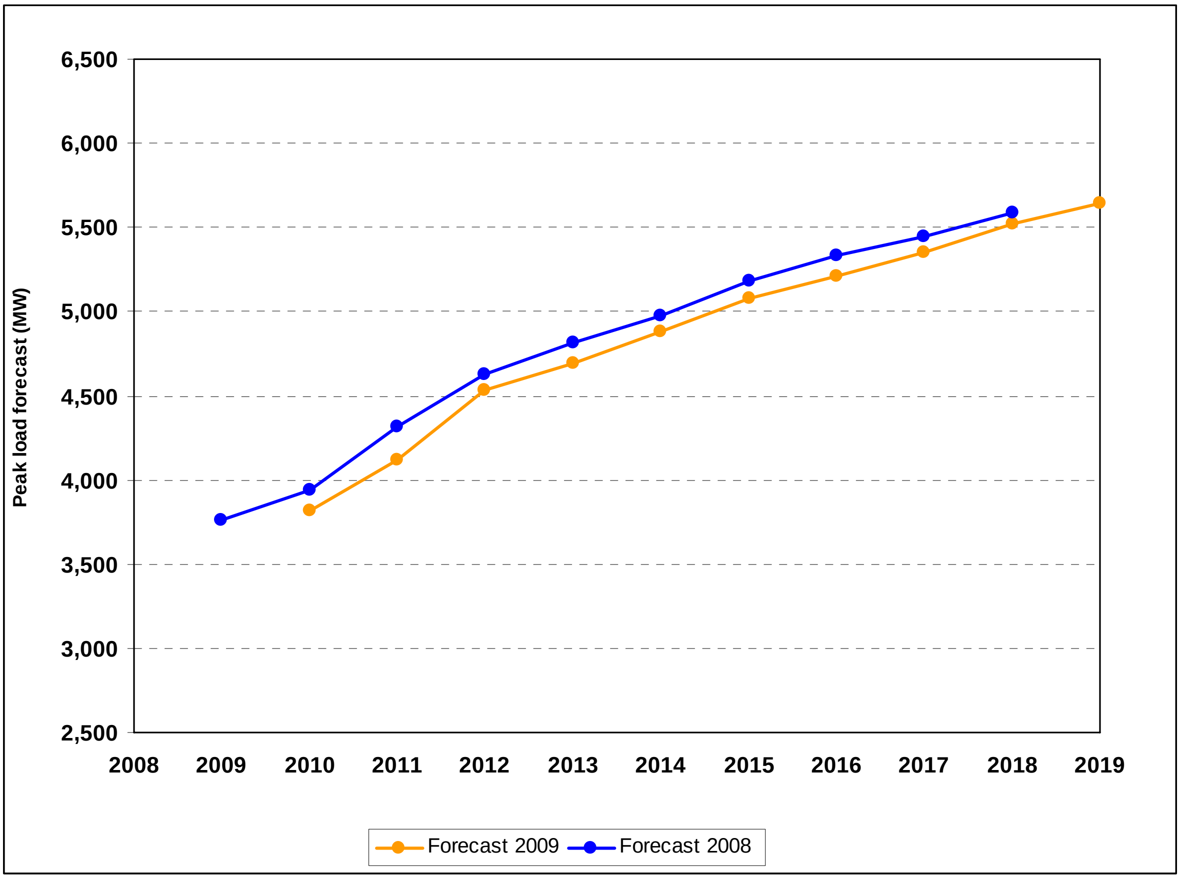
Western Power believes that the resulting combined escalators for Distribution and Transmission Opex and Capex are a reasonable reflection of the increases in unit costs that are likely to occur during the AA2 period. As such, these escalators have been applied to the expenditure forecasts provided in this Supplementary Submission. Western Power considers that the inclusion of these revised escalators in its expenditure forecasts addresses the matters in Required Amendment 28 regarding the application of unit cost escalators.

2.2.3 Demand forecasts

The Independent Market Operator's (IMO) system demand forecast, revised in July 2009, (Figure 2-3) shows a slight decrease in maximum demand for electricity in the SWIS from the 2008 report that was available at the time of Western Power's initial submission. This revised forecast is consistent with Western Power's assumptions regarding the deferral of new block load connections and a decline in requests for increased capacity. Western Power has assumed that the underlying demand from existing customers will be consistent with previous forecasts.

In re-forecasting Transmission Capex, Western Power has considered the revised connection requirements of the proposed major block load customers and has deferred projects to reflect the expected slowing in connection of new customer loads. This includes the deferral of the substation development in the Perth CBD area and several transmission line projects. The deferrals are further discussed under the appropriate expenditure category in section 3.

Figure 2-3 Comparison of IMO "Statement of Opportunities" demand forecasts made in 2008 and 2009



The key driver for Distribution network Capex is local demand on individual elements of the distribution network. Western Power has reduced the total Capex to reflect a forecast slowing of new customer connections.

2.2.4 Estimating risk margin

The initial submission included a 3.5% mark-up for estimating risk margin in the estimates for forecast Distribution and Transmission Capex. The estimating risk margin was designed to mitigate the asymmetric quantitative risks associated with estimation and delivery of Transmission and Distribution Capex over the regulatory period. Application of the estimating risk margin was proposed to give the highest probability of appropriate cash flows, reducing the likelihood of subsequent price adjustments.

In its Draft Decision (paragraph 641), the ERA stated that it "is not satisfied that Western Power has provided adequate justification for inclusion of this margin in cost forecasts. In particular, Western Power has not established that its processes for estimating costs are expected to systematically under-estimate costs by the amount of the margin and, if this is the case, why the process for estimating costs should not be altered, so as to remove the systematic error rather than addressing this through a universally applied risk margin."

Western Power notes that it sought the margin as a separate line item to present the issue in a transparent manner.

Given the top down nature of the re-forecasting in most expenditure categories, Western Power has removed the estimating risk margin in this Supplementary Submission. However, the application of an estimating risk margin may be reconsidered in future submissions should market conditions, project performance or other factors require it.

2.3 Impact of expenditure changes

Reductions in the forecast expenditures will have a direct impact on network performance and on the risk that a low probability high impact event may occur. Both these impacts are a result of the high levels of maintenance backlog that exist and the reduced reliability driven expenditures now proposed. The expected impacts of the proposed forecast expenditures are discussed in sections 2.3.1 to 2.3.4.

2.3.1 Public safety

Only a small reduction in Distribution Capex relating to public safety is proposed. Safety outcomes remain consistent with Western Power's initial submission.

For Distribution Opex the constraints on expenditures in 2009/10 due to the State budgeting process are expected to result in an increase in maintenance work backlogs in that year. To limit the impact of work backlogs on safety outcomes, increased expenditure in some expenditure categories is planned for 2010/11 and 2011/12, as discussed in the relevant expenditure categories in this Supplementary Submission.

2.3.2 Compliance

As an outcome of higher maintenance work backlogs, Western Power is currently experiencing low levels of compliance with reliability obligations and the broad requirements of the Technical Rules. Specific details of the impact of the backlogs are provided in the relevant expenditure categories in sections 3 and 4, while reliability is discussed further in section 2.3.4.

The initial submission proposed expenditures that would significantly improve levels of compliance. This Supplementary Submission proposes reduced expenditures due to the lower expenditures proposed in 2009/10, resulting from the State budgeting process, and the proposed overall reductions in expenditures (other than those related to safety) in 2010/11 and 2011/12. The result is that maintenance work backlogs will continue to exist.

Hence, Western Power does not expect that levels of compliance will change significantly over the AA2 regulatory period. Western Power intends to seek sufficient expenditure in future regulatory periods to address this issue.

2.3.3 Load and generator connection

The proposed forecast expenditures are based on current firm customer requirements for the connection of new block loads and the connection of new generation projects necessary to meet the IMO's 2009 projected reserve capacity target in its recently released *Statement of Opportunities* 2009.

Western Power notes that the deferral of the new southern section of the Pinjar to Geraldton 330kV line by at least one year may restrict connection of potential new block loads and generation in the mid-west region. The northern section of this line (Eneabba to Geraldton) has been deferred indefinitely. Western Power has previously advised the ERA about this project and will continue to track the key block loads that are influencing the timing of this project.

2.3.4 Reliability

The performance of the Transmission network as measured by the parameter 'system minutes interrupted' is expected to remain in the range of 10 to 15 minutes on average, with a target level of 10.7 minutes average annually for the AA2 regulatory period. No specific improvement work has been included in the 2009/10 to 2011/12 regulatory period.

The performance of the Distribution network does not currently meet the reliability standards set out in the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005.* In the initial submission, Western Power intended to improve the overall performance of the network by 29 minutes, as measured by the parameter SAIDI. A reduction in reliability driven (RD) expenditure means that reliability improvements will be sought over a longer timeframe, with 17 minutes of improvement now proposed for the 2009/10 to 2011/12 regulatory period.

The high maintenance work backlog that will persist during the regulatory period increases the risk of a high impact event occurring. However, the SWIS network was exposed to severe storms and relatively hot conditions over the 2008/09 summer period without such an event occurring. While work backlogs must be reduced to provide a sustainable level of satisfactory network performance, it is unlikely that current work backlogs will result in a high impact event occurring in the short term. Rather, the work backlog will contribute to a lower level of network reliability performance than could otherwise be achieved.

Using the SCONRRR[8] definitions of SAIDI and SAIFI, Table 2-3 and Table 2-4 set out the proposed targets for SAIDI and SAIFI respectively and compares these with the targets set under the initial submission. Table 2-5 shows how each type of work contributes to the planned improvements.

[8] Steering Committee on National Regulatory Reporting Requirements

Table 2-3 SAIDI service standards benchmarks

Period	SAIDI Minutes				
	SWIN total	CBD	Urban	Rural short	Rural long
year ending June 2010					
- initial submission	225	38	161	253	599
- supplementary submission	230	38	165	259	612
year ending June 2011					
- initial submission	210	38	150	233	567
- supplementary submission	224	38	162	253	588
year ending June 2012					
- initial submission	201	38	142	222	548
- supplementary submission	213	38	153	244	556

Table 2-4 SAIFI service standards benchmarks

Period	SAIFI				
	SWIN total	CBD	Urban	Rural short	Rural long
year ending June 2010					
- initial submission	2.44	0.24	1.88	3.05	4.89
- supplementary submission	2.50	0.24	1.92	3.12	5.00
year ending June 2011					
- initial submission	2.29	0.24	1.76	2.83	4.64
- supplementary submission	2.46	0.24	1.89	3.06	4.85
year ending June 2012					
- initial submission	2.18	0.24	1.67	2.70	4.47
- supplementary submission	2.41	0.24	1.83	2.98	4.80

Table 2-5 Planned reliability improvements (based on probability weighting) to 2011/12

Strategy	SAIDI saving minutes pa initial submission	SAIDI saving minutes pa supplementary submission
RELIABILITY IMPROVEMENT		
- Reliability Improvement Work in 2008/09	5.00	3.00
- Targeted reinforcement (Metro)	2.01	3.00
- Targeted reinforcement (North Country)	0.24	0.00
- Targeted reinforcement (South Country)	0.34	0.00
- Automated sequence switching	2.98	0.00
- Recloser, load break switch and RMU placement	9.36	6.30
- North Country pole reinforcement	0.28	1.15
- First section undergrounding	1.14	0.00
- Telemetry retro fit	0.25	0.25
- Wildlife proofing	0.34	0.54
- Lighting mitigation	0.20	0.65
- Fault indicators	1.06	1.21
- Re-occurring trips management	0.37	0.00
- LV networks	1.47	0.17
SAFETY		
- "Hills" covered conductors	0.72	1.29
- Pole Top Replacement	0.10	0.14
- BFMP Wires Down Mitigation	0.73	0.78
ASSET REPLACEMENT		
- Pole replacement	0.69	0.74
- LV Spreaders	0.01	0.02
- Distribution substation replacement	0.04	0.05
OTHER		
- SUPP	1.27	0.71
- Rural power improvement program (RPIP)	0.42	0.00
- Opex (impact of backlogs)	-	-3.00
Total forecast SAIDI saving	**29.00**	**17.00**

3 Transmission forecast capital expenditure

In this section, Western Power sets out its revised forecast Transmission Capex over the 2009/10 to 2011/12 regulatory period. A high level overview of the proposed expenditure, as well as an overview of the expenditure drivers, and the rationale for the change at the expenditure category level is presented. Details of the specific programs and projects at the category and sub-category level, as well as timing and estimating details were provided in the initial submission for each of the categories discussed in this section.

The details of the basis for this revision, as well as the forecasting process, are discussed in more detail in section 2**.**

3.1 Overview

Western Power proposes investing $1.47B during the next three year regulatory period on its transmission asset base. This is a reduction of $719M from Western Power's initial submission. Key changes from the initial submission are:

- the 3.5% risk estimating factor has been removed,
- revised cost escalation factors have been applied,
- for growth driven Capex, the forecasts have been revised in line with updated demand forecasts and advice from customers about the timing of required works, and
- for non-growth driven Capex, the revised expenditures have been determined through a top down allocation process, rather than through a bottom up approach as presented in the initial submission (i.e. directly from volume and cost estimates). This process involved allocating capital funds according to the priority/risk classification of works (e.g. public safety, essential works, etc). Consequently, the specific programs and projects of works are broadly as proposed in the initial submission, with lower priority/risk projects/programs being deferred until later in the regulatory period, or moved into the next regulatory period.

The revised Transmission Capex by primary driver is summarised in Figure 3-1, with the details presented in Table 3-1. The following sections provide details at the line item level corresponding to Table 3-1.

A third of the Transmission network Capex can be directly attributed to three major projects totalling $500M:

- Pinjar-Eneabba 330kV line (NCR South line section) - deferred by 2 years
- South West bulk transmission reinforcement - deferred by 2 years
- Binningup Desalination Plant - deferred by 1 year

Four major transmission lines projects that were included in the initial submission have been deferred. They are:

- the Grange Resources mine 220kV supply - deferred by 5-10 years
- the new Wanneroo-Hocking-Wangara 132kV line - deferred by 3 years
- the new Kojonup-Albany 132kV line - deferred by 5-10 years
- Eneabba-Geraldton 330kV line (NCR North line section) - deferred by 3-5 years

The Perth CBD substation has also been deferred and the Eneabba-Three Springs 330kV line to connect to Gindalbie Metals' Karara line is now expected to be built and owned by the customer, and so has been removed from the Capex forecast. Capital contributions of $1.2M have already been received from the customer for early works on this project.

Figure 3-1 Transmission capital expenditure ($M)

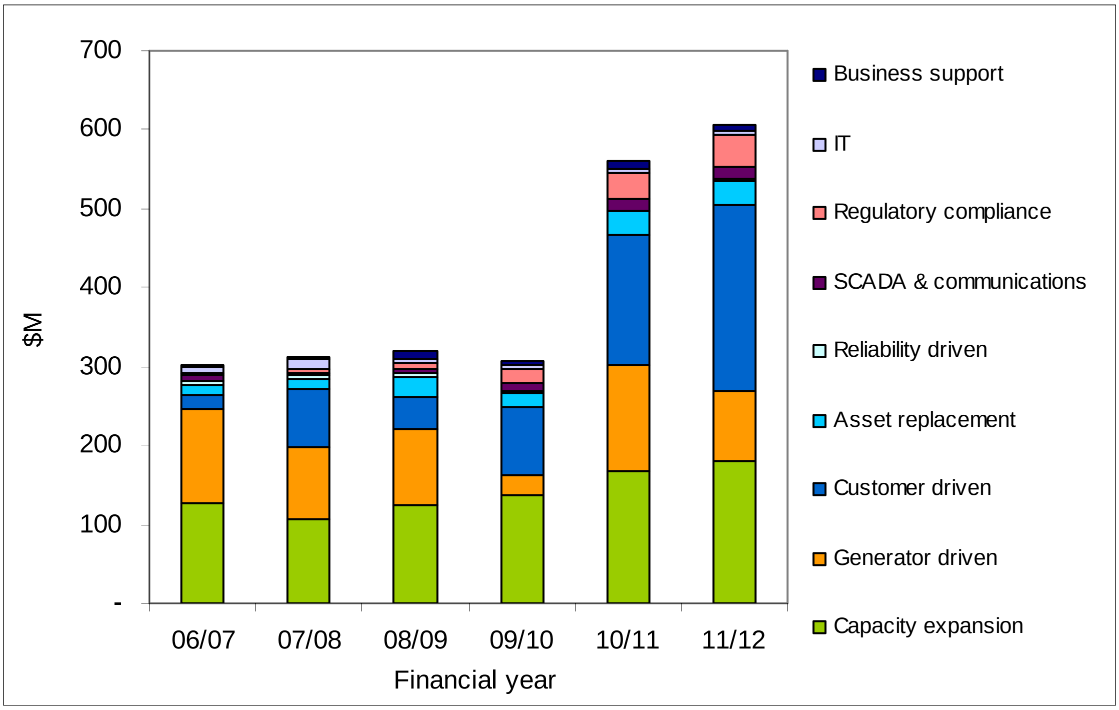


Table 3-1 Transmission capital expenditure ($M)

Expenditure category	06/07	07/08	08/09	09/10	10/11	11/12
GROWTH						
Capacity expansion	125.5	107.5	124.1	136.8	167.0	179.5
Generation driven	119.5	89.4	95.6	26.4	134.9	89.2
Customer driven	19.0	74.5	40.9	84.5	164.3	235.6
ASSET REPLACEMENT & RENEWAL						
Asset replacement	13.7	11.6	24.7	19.6	30.2	31.6
IMPROVEMENT IN SERVICE						
Reliability driven	5.1	5.2	7.1	1.8	1.9	1.1
SCADA & communications	5.9	3.9	4.6	11.0	13.0	15.4
COMPLIANCE						
Regulatory compliance	4.1	5.8	6.6	16.0	32.8	42.3
CORPORATE						
IT	6.4	11.5	6.9	6.0	7.5	5.2
Business support	3.2	3.0	8.2	5.0	8.9	7.7
Total ($M)	**302.3**	**312.3**	**318.7**	**306.9**	**560.5**	**607.4**

3.2 Capacity expansion capex

The Capacity Expansion (CE) expenditure category includes all growth driven reinforcement of the transmission and sub-transmission systems, including zone substations, but excludes the work for the local connections to give customer access to the network for new generators and bulk loads. The primary driver for capacity expansion Capex is growth of the peak summer demand supplied within the SWIS. The nature of the SWIS demand growth is primarily informed through independent forecasts produced by the IMO.

In re-forecasting the need for increased capacity, the expenditure associated with the proposed new and augmented assets has been substantially reduced from that initially forecast. While the total number of separate projects proposed to start in the AA2 period has only reduced slightly (80 to 70), the timing of the projects means that a significant portion of the overall expenditure is now forecast to occur beyond the 2009/10 to 2011/12 regulatory period. The reduction in expenditure from the initial submission is $781.4M or 62.8%. Of this, $253M relates to recasting of the Neerabup to Eneabba 330kV line into the Customer Driven regulatory category because of the government's conclusion that the primary driver of this project is new customer loads (particularly Gindalbie Metal's proposed Karara mine).

Significantly, the proposed new Perth CBD substation project has been deferred by 1 year based on the revised demand forecasts in the area. The revised forecast expenditures for key projects are set out in Table 3-2.

Table 3-2 Transmission capital projects – CE projects ($M)

Transmission - Capacity Expansion	09/10	10/11	11/12	Total
Picton and Busselton 132kV Line	0.0	10.3	10.0	20.2
Balcatta – Establish new substation	1.1	10.4	4.3	15.8
Bennett St or Tully Rd new substation	0.0	0.0	12.3	12.3
Baldivis new substation	0.0	3.4	8.9	12.3
East Perth to Belmont 132kV transmission line rebuild	0.2	2.5	8.7	11.5
Maddington new substation	8.8	2.0	0.00	10.8
Sawyers Valley substation conversion to 132kV	9.0	1.6	0.0	10.6
Merredin terminal - Merredin Substation new 132kV line	0.5	3.0	6.9	10.4
Reinforce Guildford network: Build Cannington to Forrestfield and Kalamunda 132kV Tee Line	8.1	2.2	0.0	10.3
Uprate Cannington terminal to Kewdale Substation 132kV transmission line	4.6	5.6	0.0	10.2
Other projects (151)	104.4	118.2	116.2	338.8
Total ($M)	**136.6**	**159.3**	**167.3**	**463.1**

3.3 Generator driven capex

The Capex in the Generator Driven (GD) category allows for the expenditure required to upgrade or augment the existing network to allow unconstrained access for new generators under the most feasible dispatch scenarios. It excludes the costs of assets (often dedicated) at the connection point for generation access (GA) to the network, which is either partially or fully funded by the generator.

Approximately $250M of Western Power's forecast Capex over the next regulatory period is in the GD category. The majority of the forecast expenditure relates to work in progress ($200M). Re-forecasting the expenditure has resulted in a $45.1M (22%) increase in this expenditure category from that contained in the initial submission due to the revised timing of the South West Bulk transmission project (+$10M in AA2) plus aggregation of line route easement costs (+$17M), the new Collgar Windfarm project (+$7.4M), and a review estimate for the Wandi terminal station site (+$11M).

The revised forecast expenditures and projects are set out in Table 3-3. Note that the projects have changed slightly from that contained in the initial submission, based on the current view of likely generation projects over the forecast period.

Table 3-3 Transmission capital expenditure – GD projects ($M)

Transmission - Generator Driven	09/10	10/11	11/12	Total
South West bulk transmission reinforcement	5.0	110.7	75.6	191.2
Wandi 330 kV terminal station site acquisition	5.0	9.7	0.0	14.7
Land acquisition: future Terminal Stations	0.0	3.8	9.4	13.2
Collgar Windfarm Reactive Support	6.4	1.0	0.0	7.4
Installation of under voltage load shedding at Metro stations	0.8	5.6	1.1	7.4
Reactive power compensation future	0.0	3.1	3.1	6.3
Other projects (8)	9.2	1.0	0.0	10.3
Total ($M)	**26.4**	**134.9**	**89.2**	**250.5**

3.4 Customer driven capex

Capex in the Customer Driven (CD) category includes provides for work required to maintain compliance with network planning criteria, and to meet load growth caused by discrete customer loads (Block Loads). This category includes projects that are either partly or fully funded by the customer. It generally includes assets (often dedicated) installed at the connection point to the network.

In re-forecasting CD expenditures, Western Power has taken into account the forecast requirement for connection of new generation projects necessary to meet the IMO's projected reserve capacity target in its recently released *Statement of Opportunities* 2009. It has also taken into account current information about the timing of connection of block loads. The result is that some projects have been deferred until later in the regulatory period, or moved into the next regulatory period. Some projects have also been confirmed and moved forward in the works program, such as the Binningup desalination plant.

This category shows a net increase of $112.2M (28.6%) from the initial submission. This is due mostly to the inclusion of the Neerabup to Eneabba line and the Chapman to Oakajee line, which have been reclassified from Capacity Expansion. This addition more than offsets the significant forecast reductions in other customer-driven work.

The revised forecast expenditures and projects are set out in Table 3-4.

Table 3-4 Transmission capital expenditure – CD projects ($M)

Transmission - Customer Driven	09/10	10/11	11/12	Total
Pinjar to Eneabba 330kV line (South section)	8.1	76.2	169.0	253.3[9]
Binningup desalination plant	29.8	24.2	0.0	54.0
Transmission Line Relocations	8.7	8.5	9.0	26.2
Chapman to Oakajee new 132kV line	0.3	7.8	12.2	20.2
Collgar windfarm substation regulated works	7.4	12.4	0.0	19.9
Mundaring Weir substation upgrade - Water Corp	0.2	7.8	9.3	17.2
Westralia Airports - Munday substation	7.7	5.8	2.8	16.4
Beenup/Myleanup windfarm	0.5	7.3	7.6	15.3
Establish Lukin substation (Jandakot Airport Dev)	0.3	4.8	9.4	14.6
Other projects (20)	21.8	17.2	28.5	67.5
Total ($M)	**84.8**	**172.1**	**247.8**	**504.6**

3.5 Asset replacement capex

The capital expenditure in the Asset Replacement (AR) category is for the replacement of existing assets with a modern equivalent asset[10]. The primary drivers of expenditure in this category are the age, condition and performance of assets and the associated risk of plant failure. Plant failure impacts on areas such as safety, reliability, the environment, financial performance and operational issues.

Electricity (Supply Standards and System Safety) Regulations 2001 requires prudent levels of asset replacement in order to deliver acceptable public safety outcomes. Additionally, the *Electricity Industry Act* 2004 requires, as part of licence conditions, effective asset management systems that effectively ensure prudent management of assets that are not fit for service.

In light of economic conditions outlined in section 2, Western Power has deferred some of the lower priority asset replacement activities. To ensure adequate long term performance, the total forecast expenditure over the regulatory period for the replacement of current transformers, transformers and surge arrestors has been maintained as per the initial submission. The impact of deferring other asset replacement expenditure to future regulatory periods is a slightly increased risk of asset failure and associated corrective maintenance expenditures.

Given the systematic annual process undertaken by Western Power in determining its Transmission asset replacement Capex, numerous separate programs of work have been

9 The NBT-ENT 330kV project estimate has been derived from the estimate for Pinjar – Moonyoonooka (Geraldton) 330kV project. Following the government decision to deliver the project in two stages, a revised, a detailed estimate is still being prepared for the new project.

10 Given the advanced age of the assets typically identified for replacement, the new assets are usually not a direct like-for-like replacement and provide some degree of technological improvements, often with a greater capacity and with increased monitoring facilities.

identified over the 2009/10 to 2011/12 regulatory period. These are summarised in Table 3-5. This category shows a $22.3M (21.5%) reduction from the initial submission.

Table 3-5 Transmission capital expenditure – AR projects ($M)

Transmission - Asset Replacement	09/10	10/11	11/12	Total
Circuit breaker	4.7	4.8	6.0	15.4
Current transformer	4.9	6.5	5.0	16.3
Transformer	0.0	5.2	5.8	11.0
Relay	2.3	5.2	3.4	10.9
Disconnector	1.6	2.0	3.7	7.3
Surge diverter	1.4	1.9	1.6	5.0
Voltage transformer	1.0	0.9	1.1	3.0
General	3.7	3.6	5.0	12.3
Total ($M)	**19.6**	**30.2**	**31.6**	**81.3**

3.6 Regulatory compliance capex

Western Power's Transmission Regulatory Compliance (RC) Capex is related to directly meeting external obligations, including technical and safety requirements.

In its initial submission, Western Power proposed to materially increase the Compliance/Safety/Environmental Capex to achieve compliance in certain low compliance areas over a reasonable timeframe. In re-forecasting expenditures, only those activities that have a direct impact on safety have been maintained, with other work programs being significantly curtailed. An exception is expenditure on transmission substation transformer noise mitigation. In total, the expenditure in this category has been reduced by $37.7M (29.3%) from the initial submission.

The Environmental Protection (Noise) Regulations 1997 (WA) (Noise Regulations), commenced on 31 October 1997 and Western Power is currently required to comply with these. At present, 28 transmission substations have noise emission levels that do not comply with the Noise Regulations, although these are not currently in breach, due to a time-bound Ministerial Approval for a variation under the Noise Regulations. However, in the absence of further action, 21 of these would be in breach as of 1 January 2010 and all 28 would be in breach as of 1 January 2020.

The Department of Environment and Conservation (DEC) has foreshadowed that it does not support an extension of the Ministerial Approval for the transmission substations that are non-compliant as of 1 January 2010. In the absence of a change to the Noise Regulations to exempt Western Power from compliance, or some other action, Western Power holds serious concern that the DEC will consider prosecutions - placing Western Power at risk of significant financial and reputational consequences.

Compliance with these regulations presented significant engineering challenges and at the time of the preparation of the initial submission, estimates for remedial action to address only the worst 10 sites were included. This was due to the uncertainty surrounding the effectiveness of the design, and the considerable resourcing implications. Since that time a new solution has been trialled (using noise curtains), which will be significantly quicker to implement. The current level of funding is sufficient to achieve full compliance with the Noise Regulations at all transmission substations during the 2009/10 to 2011/12 regulatory period.

Western Power is working with the Minister for Energy to explore the possibility of a further exemption from the noise requirements however, at this time, the outcome is not certain, so it is prudent to provide for the mitigation work.

The RC Capex comprises 38 projects, with 5 projects exceeding $5M in the 2009/10 to 2011/12 period, as outlined in Table 3-6.

Table 3-6 Transmission capital expenditure – RC projects ($M)

Transmission – Regulatory Compliance	09/10	10/11	11/12	Total
Substations noise mitigation	1.4	12.9	18.5	32.8
Transmission pole replacement	3.0	4.8	4.7	12.5
Transformer bunding program	1.8	3.3	4.3	9.4
Upgrade of substation security	1.0	2.3	3.0	6.3
Replacement of non complying stays and insulators	0.1	2.2	2.9	5.2
Other (x33)	8.8	7.2	8.7	24.6
Total ($M)	**16.0**	**32.8**	**42.3**	**91.1**

3.7 Reliability driven capex

Western Power's Transmission Reliability Driven (RD) Capex is required to maintain the reliability of the Transmission network. This is in the form of specific projects or additions to other projects to achieve the targets in the *Electricity Industry (Network Quality and Reliability of Supply) Code* 2005.

There are nine discrete Transmission reliability driven projects with expenditure in the 2009/10 to 2011/12 period, as outlined in Table 3-7. When compared to the initial submission, one project (reliability driven zone substations) has been deferred beyond the regulatory period and three projects that were not completed as planned prior to 1 July 2009 will incur expenditures in 2009/10 (Margaret River 3rd 22kV feeder (Prevelly), Fault recording upgrade - Stage 3, and TPES Data Cleansing). All other work programmes have had some expenditure deferred to future years, resulting in a substantial reduction from the original forecast of 81.8% or $21.2M.

The impact of the deferral of expenditures is a small increased risk of a network outage. This is not expected to impact the overall Transmission network performance, because the deferred expenditure relates mainly to the reliability driven zone substation project ($16.7M) to improve distribution reliability performance in the Sawyers Valley and Byford areas.

Table 3-7 Transmission capital expenditure – RD projects ($M)

Transmission – Reliability Driven	09/10	10/11	11/12	Total
Margaret River 3rd 22kV feeder (Prevelly)	0.3	0.0	0.0	0.3
Fault recording upgrade - Stage 3	0.9	0.0	0.0	0.9
Fault recording upgrade - Stage 4	0.0	0.7	0.0	0.7
Implement 2MB communications to 7SD relays	0.0	0.1	0.0	0.1
Upgrade to OPGW circuits	0.2	0.1	0.0	0.4
Tpes Data Cleansing	0.0	0.0	0.0	0.0
Removal of shared VTs	0.3	0.2	0.1	0.6
Wildlife proofing In Zone Substations	0.0	0.3	0.4	0.7
Reliability improvement pilot project - ground fault neutralizer	0.1	0.4	0.6	1.1
Total ($M)	**1.8**	**1.9**	**1.1**	**4.7**

3.8 SCADA & communications capex

Western Power's Transmission based SCADA and communications Capex is related to the supervisory control and data acquisition (SCADA) system that provides the link between system operations and the primary system assets: the communications systems that carry SCADA information, tele-protection signalling information, voice communications and ancillary communications (such as Ethernet) to operational sites.

Forecast expenditure over the 2009/10 to 2011/12 regulatory period has been reduced slightly (-$4.4M or -10.1%) from that initially proposed as shown in Table 3-8.

Table 3-8 Transmission capital expenditure – SCADA projects ($M)

Transmission – SCADA & Communications	09/10	10/11	11/12	Total
Asset replacement	2.2	5.4	6.2	13.8
System operations	5.6	2.9	3.6	12.0
Core infrastructure growth	0.1	2.2	2.6	4.8
Performance driven	2.0	0.7	0.7	3.4
Systems for energy solutions	0.0	0.4	2.3	2.8
General upgrades	1.1	1.4	0.0	2.5
Total ($M)	**11.0**	**13.0**	**15.4**	**39.3**

3.9 Business support costs

The support capital budget includes expenditure requirements for capital items to support and maintain office and depot accommodation. Budget items include tools and equipment required for construction, commissioning and maintenance functions and labour costs for the management or the capital works processes and programs. Also included in this budget are the costs relating to Project Vista. Project Vista covers the refurbishment of the Perth head office and metropolitan depots.

Business support Transmission Capex has been reduced by 24.3% and IT Capex by 10.5% when compared to the initial submission, reflecting the overall constraints on expenditures as discussed in section 2. This has been achieved by deferring expenditure to beyond 2012.

The forecast expenditures are shown in Table 3-9.

Table 3-9 Business support capex costs ($M)

Transmission – Business support costs	09/10	10/11	11/12	Total
IT	6.0	7.5	5.2	18.7
Support	5.0	8.9	7.7	21.5
Total ($M)	**10.9**	**16.4**	**12.9**	**40.2**

4 Distribution forecast capital expenditure

In this section, the revised forecast Distribution Capex over the 2009/10 to 2011/12 regulatory period is presented. A high level overview of the proposed expenditure, as well as an overview of the expenditure drivers, and the reason for the change at the expenditure category level, is presented. Details of the specific programs and projects at the category and sub-category level, as well as timing and estimating details were provided in the initial submission for each of the categories discussed in this section.

The details of the basis for this revision, as well as the forecasting process are discussed in more detail in section 2.

4.1 Overview

Western Power proposes to invest $2.09B during the next three year regulatory period on its distribution asset base. This is a reduction of $204M (8.9%) from Western Power's initial submission.

Key changes from the initial submission are:

- the 3.5% risk estimating factor has been removed,
- revised cost escalation factors have been applied,
- for growth driven Capex, the forecasts have been revised in line with updated demand forecasts and advice from customers about the timing of required works, and
- for non-growth driven Capex, the revised expenditures have been determined through a top down allocation process, rather than through a bottom up approach as presented in the initial submission (i.e. directly from volume and cost estimates). This process involved allocating capital funds according to the priority/risk classification of works (e.g. public safety, essential works, etc). Consequently, the specific programs and projects of works are broadly as proposed in the initial submission, with lower priority/risk projects/programs being deferred until later in the regulatory period, or moved into the next regulatory period.

The revised Distribution Capex by primary driver is summarised in Figure 4.1, with the details presented in Table 4-1.

Figure 4-1 Revised distribution capital expenditure ($M)

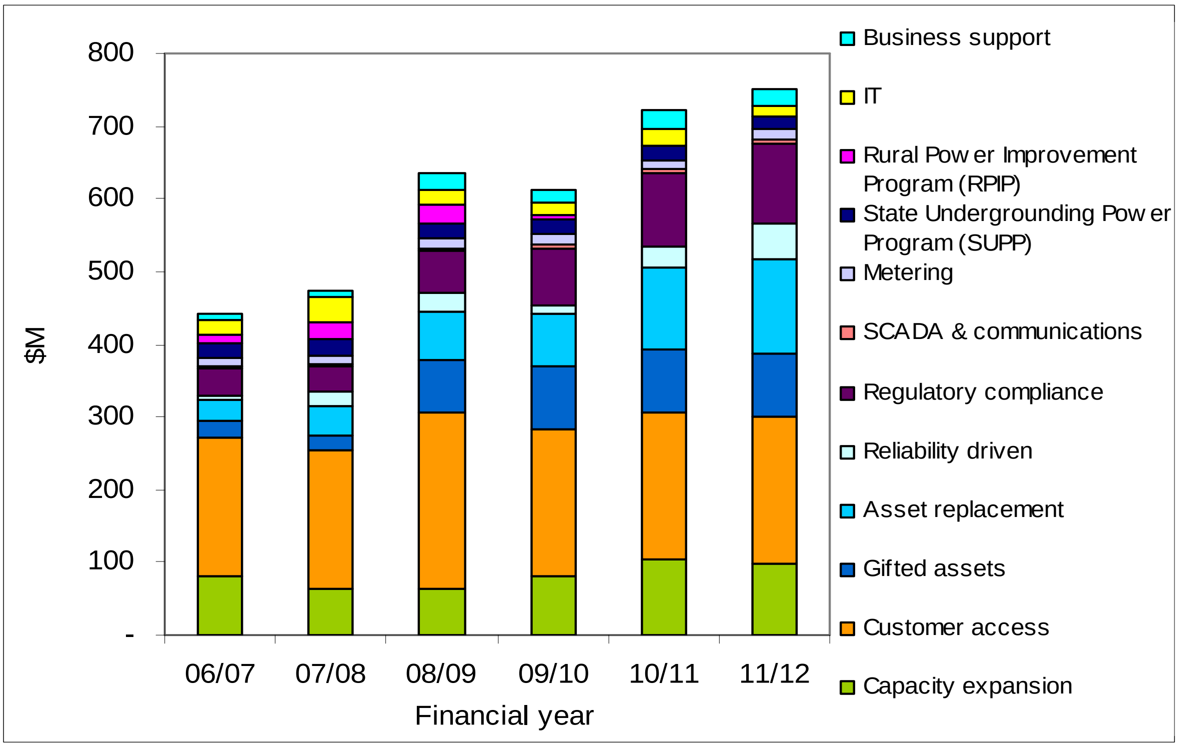


Table 4-1 Distribution capital expenditure ($M)

Expenditure category	06/07	07/08	08/09	09/10	10/11	11/12
GROWTH						
Capacity expansion	80.5	62.3	62.6	81.5	104.0	98.3
Customer access	191.9	192.3	244.8	202.4	202.8	202.4
Gifted assets	23.3	20.6	72.0	86.6	86.8	86.6
ASSET REPLACEMENT & RENEWAL						
Asset replacement	28.9	40.0	64.0	71.4	110.5	131.0
State undergrounding power program (SUPP)	22.3	22.3	22.9	19.8	19.4	18.9
Metering	11.4	12.6	14.0	12.2	12.3	12.8
IMPROVEMENT IN SERVICE						
Reliability driven	5.8	19.2	27.0	11.0	29.1	47.0
Rural power improvement program (RPIP)	10.2	23.9	23.9	7.9	0.0	0.0
SCADA & communications	2.4	2.1	2.0	5.6	6.0	5.6
COMPLIANCE						
Regulatory compliance	36.0	35.2	58.1	80.0	101.8	111.0
CORPORATE						
IT	19.1	34.5	20.7	17.9	22.5	15.6
Business support	9.6	9.2	24.6	14.9	26.7	23.0
Total ($M)	**441.4**	**474.2**	**636.5**	**611.2**	**722.0**	**752.1**

4.2 Capacity expansion

The magnitude and timing of Distribution capacity expansion Capex is driven by two key inputs to the Distribution capacity planning process: Transmission capital works and the application of Western Power's Distribution network planning criteria to the forecast load growth.

While this expenditure is fundamentally growth-driven, the large reduction in Transmission Capacity Expansion expenditure ($761M) means that Western Power must increase expenditure for Distribution Capacity Projects to mitigate the most critical capacity issues, especially in Country areas. As a result, there is a slight increase ($8.9M or 3.2%) in this category from the initial submission.

The revised Distribution capacity expansion Capex forecast is presented in Table 4-2.

Table 4-2 Distribution capital expenditure – capacity expansion projects ($M)

Distribution – Capacity Expansion	09/10	10/11	11/12	Total
Transmission driven	20.7	38.4	23.7	82.7
HV reinforcement	52.7	55.5	64.4	172.6
Distribution transformers and LV network optimisation	8.2	10.2	10.2	28.6
Total ($M)	**81.5**	**104.0**	**98.3**	**283.8**

4.3 Customer access & gifted assets

Distribution customer access includes all Capex required to connect customer loads onto Western Power's Distribution network. It does not include expenditures associated with the installation of meters or capacity related network augmentations. The Distribution Headworks Scheme is included in this expenditure category, and applies to the provision of distribution infrastructure, particularly to customers seeking to connect to the network in rural and regional areas of the SWIS. However, this scheme does not apply to transmission infrastructure, to the Central Business District of Perth, the Perth metropolitan area, or the Goldfields.

Actual expenditure on customer access and gifted assets for 2008/09 was $316.7M, $90.5M more that forecast in the initial submission. Customer access works of $244.8M were significantly higher (+$112.8M) than forecast, while gifted assets of $72.0M were significantly less (-$22.3M) than forecast.

Based on this new information, and knowledge of work levels in the 'pipeline' for customer access works, a new forecast of customer access and gifted assets has been prepared. The proposed expenditure has been moderated from the 2008/09 levels to account for additional works that were undertaken in 2008/09 to reduce the work backlog from prior years, and the impacts of the GFC. The balance of works between customer access and gifted assets has also been moderated based on the 2008/09 actual results.

The revised gifted asset and customer access Capex forecast is presented in Table 4-3.

Table 4-3 Distribution capital expenditure – customer access and gifted assets ($M)

Distribution – Customer Access & Gifted Assets	09/10	10/11	11/12	Total
Customer access	202.4	202.8	202.4	607.5
Gifted assets	86.6	86.8	86.6	260.0
Total ($M)	**289.0**	**289.6**	**289.0**	**867.5**

4.4 Asset replacement

Asset replacement (AR) is associated with non run-to-failure assets, including poles and other assets that have network performance and/or public safety impacts.

Electricity (Supply Standards and System Safety) Regulations 2001 require prudent levels of asset replacement in order to deliver acceptable public safety outcomes. Additionally, the *Electricity Industry Act* 2004 requires, as part of its licence conditions, effective asset management systems that effectively ensure prudent management of assets that are not fit for service.

The initial submission proposed expenditures that would largely address the current backlog of work over the next regulatory period. The current economic conditions have, however, forced a reconsideration of the rate at which Western Power can move the network to a sustainable and manageable level of operation as required by its regulatory obligations. The incremental risk resulting from a reduced rate of replacement has been considered, and a mitigation strategy has been adopted to prioritise significant public safety needs over network performance and other Capex categories. Further discussion of the risks inherent in the reduced funding proposal is presented in section 2. In general, the reduction in asset replacement Capex will result in the backlog of identified defects increasing during the first year, remaining relatively constant in year 2 and slowly reducing over the third and final year of the regulatory period.

Based on this priority/risk approach, the estimates for each asset replacement project/program proposed in the initial submission have in general been revised downward across the Distribution capital works portfolio. Work that mitigates the highest business risks has been protected to the maximum extent possible. This has resulted in significant reductions in percentage terms to the Drop out Fuse (DOF) replacement program and some other minor asset replacement strategies, such as the Street Light Metal Pole Replacement program and the Sectionaliser Replacement program. In the case of DOF replacement this risk can be mitigated to some extent through reinstating the savings originally proposed to the Opex fuse pole based clearing program. In other cases it involves accepting the residual risk of the reduced Capex.

Conversely, distribution wood pole replacement has been increased in line with an order (01-2009) from EnergySafety in accordance with the *Electricity (Supply Standards and System Safety) Regulations* 2001 to replace a minimum of 15,000 poles per annum by the end of the AA2 regulatory period. The replacement of ground mounted HV switchgear has also been increased based on the outcomes of Western Power's condition assessment program, which identified a particular model of switchgear that will require increased levels of replacement (47 units at a cost of approximately $6M) in the 2010/11 to 2011/12 period.

The revised asset replacement Capex forecast is $18.4M (6.2%) greater than the initial submission and is presented in Table 4-4.

Table 4-4 Distribution capital expenditure – asset replacement ($M)

Distribution – Asset Replacement	09/10	10/11	11/12	Total
Distribution poles replacement	41.7	64.2	80.0	185.8
Distribution poles reinforcement	10.9	11.8	11.5	34.2
Distribution carrier (conductor)	7.3	12.5	16.3	36.2
Distribution transformer	2.9	4.0	5.1	12.0
Drop-out fuse	0.1	0.5	0.6	1.1
Surge arrestors	0.1	1.1	0.9	2.1
Streetlight luminaires	0.5	1.8	1.9	4.2
Other minor asset replacement strategies	8.0	14.6	14.6	37.2
Total ($M)	**71.4**	**110.5**	**131.0**	**312.9**

4.5 Regulatory compliance

Western Power's Distribution based Regulatory Compliance (RC) Capex is related to meeting external obligations including technical and safety requirements.

This program of work is driven by the need to achieve and maintain compliance with safety, environmental and statutory obligations, particularly in regard to public safety, environmental management, and power quality (PQ). As discussed in the initial proposal, this category of capital works includes initiatives such as:

- Replacement of overhead customer service connections – which involves the replacement of overhead PVC customer service connections and supporting equipment that pose a public safety hazard.
- Wires down – which involves the targeting replacement of overhead distribution conductors and associated pole top hardware assessed to be in poor condition in high and extreme bushfire zones to comply with the *Electricity (Supply Standards and System Safety) Regulations* 2001.
- PQ compliance reinforcement – this strategy provides remedial works to maintain network power quality within statutory limits and the *Electric Industry (Network Quality and Reliability of Supply) Code* 2005, and is driven by customer PQ complaints, as well as compliance with the requirements of the Technical Rules.
- Energy Solutions / Smart Grid program – this program has been confirmed since the initial submission. The program is described in detail in Attachment 2, and includes:
    - advanced metering infrastructure,
    - making changes to regulations, technical standards and policies to support new energy solutions,
    - communications and change management,
    - Green Town project in Denmark/Walpole, and
    - specific demand management projects (Energy Wade and HVAC).[11]

[11] Associated metering costs and Opex have been included in sections 4.8 and 5.14.

- HV conductor clashing – this strategy involves work to prevent HV overhead conductor clashing to mitigate the risk of igniting fires to comply with the *Electricity (Supply Standards and System Safety) Regulations* 2001.
- Pole top replacement in high and extreme fire zones– is a strategy aimed at replacement of pole tops that do not comply with C(b)1 and are situated in high and extreme fire zones.
- Fire safe fuses – this strategy involves targeting specific types of DOF in high and extreme fire zones, and replacing them with arc free operation fuses (i.e. boric acid fuses).
- Other safety, environmental, and statutory strategies – in addition to the above initiatives, Western Power has a number of other minor strategies that are being progressively implemented to progressively comply with safety, environmental, or statutory requirements.

The majority of these programs were initiated during AA1 and in general have been ramped up in terms of work volumes as delivery capability has been built up, to reduce the risks to tolerable levels within more reasonable timeframes.

In re-forecasting expenditures, regulatory compliance has been assigned a high priority and only minor reductions amounting to $44.9M (13.3%) have been made to this category.

The revised compliance Capex forecast is presented in Table 4-5.

Table 4-5 Distribution capital expenditure – regulatory compliance ($M)

Distribution – Regulatory Compliance	09/10	10/11	11/12	Total
Replacement of overhead customer service connections	19.4	24.7	24.6	68.7
Bushfire mitigation wires down	9.0	11.5	16.9	37.4
PQ compliance reinforcement	9.9	10.5	11.9	32.4
Energy Solutions / Smart Grid	15.5	15.5	9.4	40.4
HV conductor clashing	7.7	9.4	11.3	28.4
Pole top replacement in high fire risk areas	3.9	5.6	11.0	20.5
Fire safe fuses	0.0	6.6	6.3	12.9
Open neutral detection	0.0	0.5	0.5	1.0
Other minor safety, environmental, and statutory strategies	14.6	17.5	19.0	51.2
Total ($M)	**80.0**	**101.8**	**111.0**	**292.8**

4.6 Reliability

Reliability driven (RD) Capex is aimed at selectively maintaining or improving the service delivered by the SWIS network targeting expenditure to maximise reliability gains for dollars invested. This category of expenditure involves a range of initiatives including:

- Automation – this strategy is driven by the need to reduce the number of customers affected by supply interruptions, and maintain or improve supply restoration time through the targeted use of network automation

- Reconductoring – this strategy is driven by the need to improve supply reliability through selective reconductoring to improve load transfer capacity under network fault conditions
- Reinforcement – this strategy is driven by the need to improve supply reliability through selective pole reinforcement, a proven cost-effective method of extending pole life and returning poles to a serviceable condition.

While this Capex is driven by the need to improve the existing network service performance, current economic conditions have forced a reconsideration of the rate at which Western Power can move the network closer to the standards set out in the *Electricity Industry (Network Quality and Reliability of Supply) Code* 2005 and the reliability targets specified in Western Power's approved AA1 Access Arrangement.

The revised reliability Capex forecast is presented in Table 4-6. This is an $85M (49.4%) reduction from the initial submission. The proposed level of reliability associated with the forecast expenditure is discussed in section 2.3.4.

Table 4-6 Distribution capital expenditure – reliability ($M)

Distribution - Reliability	09/10	10/11	11/12	Total
Reinforcement	6.1	11.0	15.8	32.9
Automation	4.2	12.4	16.0	32.6
Reconductoring	0.0	5.3	6.9	12.2
Other	0.7	0.3	8.4	9.3
Total ($M)	**11.0**	**29.1**	**47.0**	**87.0**

4.7 SCADA & communications

Western Power's SCADA and communications infrastructure are essential elements in the overall delivery of supply reliability, operator safety, and environmental outcomes. SCADA and communications strategies are driven by the need to maintain and improve network service.

Capex on SCADA and communications is similar to that proposed in the initial submission ($1.2M or 6.4% reduction). The forecast SCADA and communications Capex is presented in Table 4-7.

Table 4-7 Distribution capital expenditure – SCADA and communications ($M)

Distribution – SCADA & Communications	09/10	10/11	11/12	Total
Distribution automation expansion	1.2	2.0	2.1	5.3
System operations Capex	1.5	1.2	1.3	3.9
Metro recloser system RFI radio replacement	1.0	0.8	0.0	1.8
Trunked Mobile Radio replacement	0.2	0.9	0.5	1.6
CBD SCADA replacement	0.0	0.6	0.6	1.3
Other (x7)	1.7	0.5	1.2	3.4
Total ($M)	**5.6**	**6.0**	**5.6**	**17.2**

4.8 Metering

Metering Capex includes all expenditures relating to the supply of meters and communications equipment, capitalised meter installation and commissioning activities, new CT metered installations, and the creation of the network connection points.

New connections and regulatory compliance issues (meter accuracy and condition) drive the magnitude and timing of the metering Capex. A downturn in new connections is anticipated in line with revised demand forecasts. Consequently, expenditure on metering has been revised downwards by $144M (74.1%) from the initial submission.

Additional expenditure to implement the Smart Grid foundation program has been included. Refer to Attachment 2 for details.

The revised metering Capex forecast is presented in Table 4-8.

Table 4-8 Distribution capital expenditure – metering ($M)

Distribution - Metering	09/10	10/11	11/12	Total
Metering	11.9	12.0	12.4	36.3
Smart grid foundation program	0.4	0.3	0.4	1.0
Total ($M)	**12.2**	**12.3**	**12.8**	**37.3**

4.9 Special programs

4.9.1 State underground power program (SUPP)

This expenditure is driven by a Government initiative to retrofit older urban areas with underground power with a target of providing underground power services to 50% of residential properties in Perth by 2010, with corresponding improvements in regional towns. The State Underground Power Program (SUPP) is a partnership between Western Power, the State Government, and local Governments, which involves a funding arrangement of 25%, 25% and 50% respectively.

SUPP expenditure has been reduced through the State budgeting process for 2009/10 and represents a 42% decrease over the three year period. The revised SUPP Capex forecast is presented in Table 4-9.

4.9.2 Rural power improvement program (RPIP)

The Rural Power Improvement Program (RPIP) is partially (50%) funded by the State Government through contributions by the Office of Energy. The objective of the program is to improve the network service for rural customers, particularly where improvements are difficult to justify due to the high cost of the work, and the relatively small numbers of customers benefiting from them. While the program was scheduled to be completed in 2008/09, some work has been carried forward to 2009/10. The State Government has not yet decided to continue the RPIP program, so expenditure is forecast to end after the current year.

The revised RPIP Capex forecast is presented in Table 4-9.

Table 4-9 Distribution capital expenditure – special programs ($M)

Distribution – Special Programs	09/10	10/11	11/12	Total
SUPP	19.8	19.4	18.9	58.1
RPIP	7.9	0.0	0.0	7.9
Total ($M)	**27.8**	**19.4**	**18.9**	**66.1**

4.10 Business support costs

The support capital budget includes expenditure requirements for capital items to support and maintain office and depot accommodation. Budget items include tools and equipment required for construction, commissioning and maintenance functions and labour costs for the management or the capital works processes and programs. Also included in this budget are the costs relating to Project Vista. Project Vista covers the refurbishment of the Perth head office and metropolitan depots. The forecast expenditure is split between Distribution and Transmission in the ratio of 75% to 25% based on staff full time equivalents.

Business support Distribution Capex has been reduced by 20.7% and IT Capex by 10.5% when compared to the initial submission, reflecting the overall constraints on expenditures as discussed in section 2. This has been achieved by deferring expenditure to beyond 2012. The forecast expenditures are shown in Table 4-10.

Table 4-10 Business support capex costs ($M)

Distribution – Business support costs	09/10	10/11	11/12	Total
IT	17.9	22.5	15.6	56.0
Support	14.9	26.7	23.0	64.6
Total ($M)	**32.8**	**49.3**	**38.6**	**120.6**

5 Forecast operating expenditure

In this section, Western Power presents the revised forecast Distribution and Transmission Opex over the 2009/10 to 2011/12 three year regulatory period. A high level overview of the proposed expenditure, as well as the reasons for the change from the initial submission at the expenditure category level, is described.

The details of the basis for this revision, as well as the forecasting process are discussed in more detail in Section 2 of this document.

5.1 Overview

As described in the initial submission, Western Power compiled the original forecast Opex for Transmission and Distribution using a bottom up approach wherever possible. Trend analysis and historical ratios were also used where appropriate.

This approach was undertaken to ensure that the forecast expenditure would allow the Transmission and Distribution maintenance programs to comply with Western Power's asset missions and maintenance policies, and the requirements of the *Electricity (Supply Standards and System Safety) Regulations* 2001 and the *Electricity Operators Act* 2004.

The forecast included sufficient expenditure to address all defects within the specified periods. Hence the backlog of asset defects (conditions) was not expected to increase during the 2009/10 to 2011/12 regulatory period. Additional expenditures were included to reduce the existing defect backlog over time.

The Opex presented in this Supplementary Submission has been revised to reflect:

- changes in the economic climate and other changes as detailed in Section 1.2 of this document,
- revised cost escalation factors detailed in section 2.2.2 of this document,
- delivery implications, and
- actual maintenance costs for 2008/09.

The result is a significant reduction in proposed Opex in 2009/10 and to a lesser extent in 2011/12. The 2011/12 expenditures are forecast at a similar level to that detailed in the initial submission. The rate of increase in the expenditures over the regulatory period has been limited by the ability to resource the work as discussed in the deliverability assessment at section 5.3.

The summary of revised Opex for the AA2 period is provided in Table 5-1.

Table 5-1 Revised forecast Opex ($M)

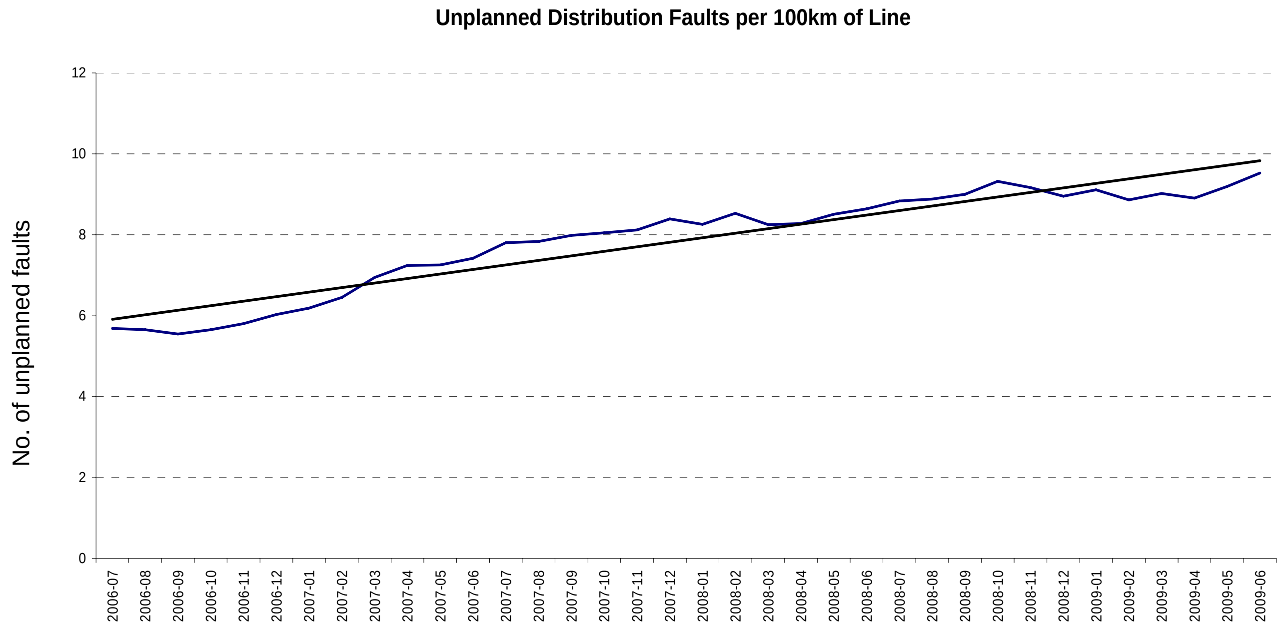
Opex forecast	09/10	10/11	11/12	TOTAL
Transmission Opex	49.1	68.5	74.3	191.9
Distribution Opex	210.8	283.0	336.8	830.6
Business Support	99.6	105.4	110.7	315.7
TOTAL Forecast Opex	**359.5**	**456.9**	**521.8**	**1,338.2**

This reduction in the forecasts will impact directly on Western Power's risk profile over the 2009/10 to 2011/12 regulatory period. The proposed maintenance work has been systematically reduced in the first and second years of the regulatory period using a risk-based approach to minimise the safety, environmental and performance risks. In particular, maintenance has been directed to the overhead network at the expense of the underground network. Equipment failure in the overhead network presents the highest risks, including electric shock from fallen conductors and poles, bushfires, pole top fires and deteriorating reliability.

The reduction in Opex will also result in the backlog of identified condition based defects increasing during the first and second years of the AA2 period, and remaining relatively constant in the third year.

An increasing backlog means the risk of equipment failure is increased. This trend is demonstrated in Figure 5.1 where, despite the increase in preventative maintenance over the period from mid-2006 to mid-2009, faults have continued to increase.

Figure 5-1 Unplanned Distribution faults per 100km of line



The following tables show the revised forecast Opex for Transmission and Distribution and the actual expenditure by category for the AA1 regulatory period. The revised forecasts incorporate actual costs for the 2008/09 financial year and the revised unit cost escalation factors detailed in section 2.2.2 of this document.

The revised Transmission Opex forecast for the AA2 regulatory period is shown in Table 5-2 and Figure 5-2. The revised Distribution Opex forecast for the AA2 regulatory period is shown in Table 5-3 and Figure 5-3.

Table 5-2 Transmission Opex actual and forecast ($M)

TRANSMISSION	AA1 (Actual)			AA2 (Forecast)		
Item	06/07	07/08	08/09	09/10	10/11	11/12
SCADA/communications	6.9	7.1	6.0	6.5	8.7	9.5
Network operations	6.4	12.6	10.5	13.6	14.3	14.6
Misc Network Services	10.6	5.4	1.8	0.9	0.9	0.9
Maintenance strategy*	5.9	4.3	-	-	-	-
Preventive routine maintenance	11.7	11.6	14.7	13.0	20.4	25.2
Preventive condition maintenance	9.2	6.7	8.6	8.9	13.4	12.5
Corrective deferred maintenance	3.4	4.8	5.7	4.3	7.9	8.3
Corrective emergency maintenance	1.7	1.8	1.2	1.9	2.2	2.6
Non recurring opex	0.0	0.00	0.0	0.0	0.6	0.6
Business support costs	18.2	20.3	24.6	26.8	28.3	29.6
Total (M)	**74.1**	**74.4**	**73.1**	**75.9**	**96.7**	**103.8**

** Note: Maintenance Strategy Costs now form part of an indirect cost pool allocated across the works program*

Figure 5-2 Transmission Opex actual and forecast ($M)

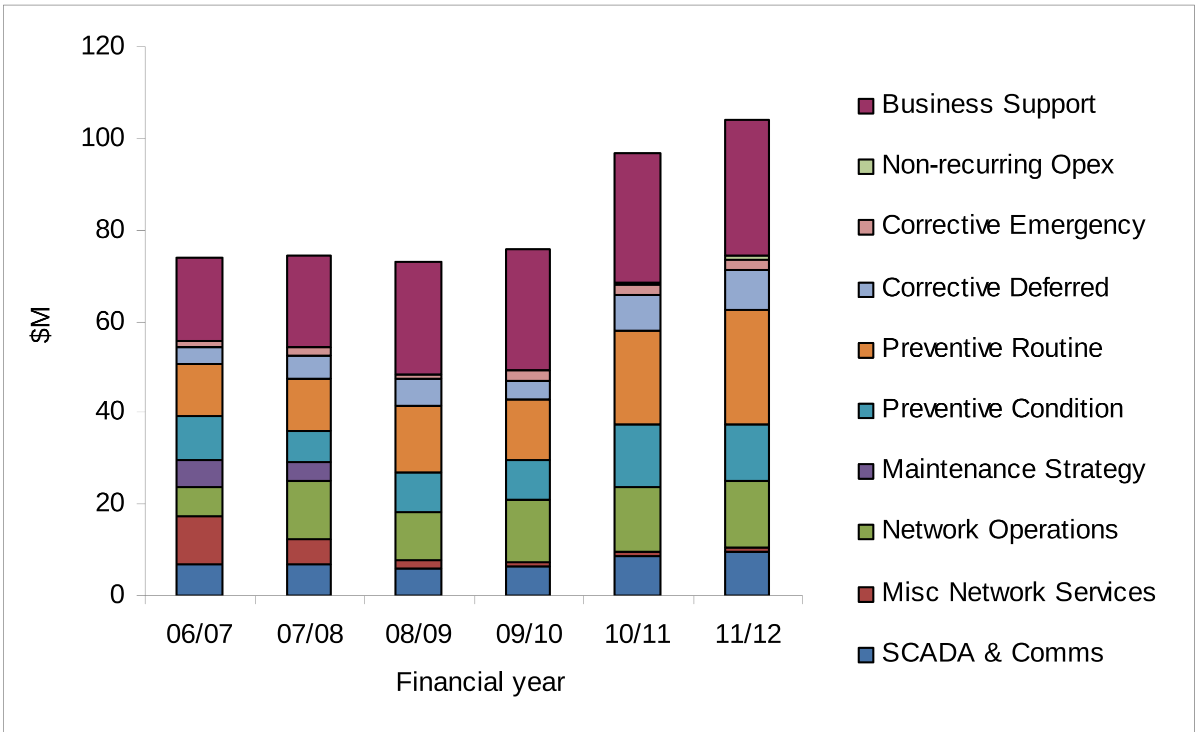
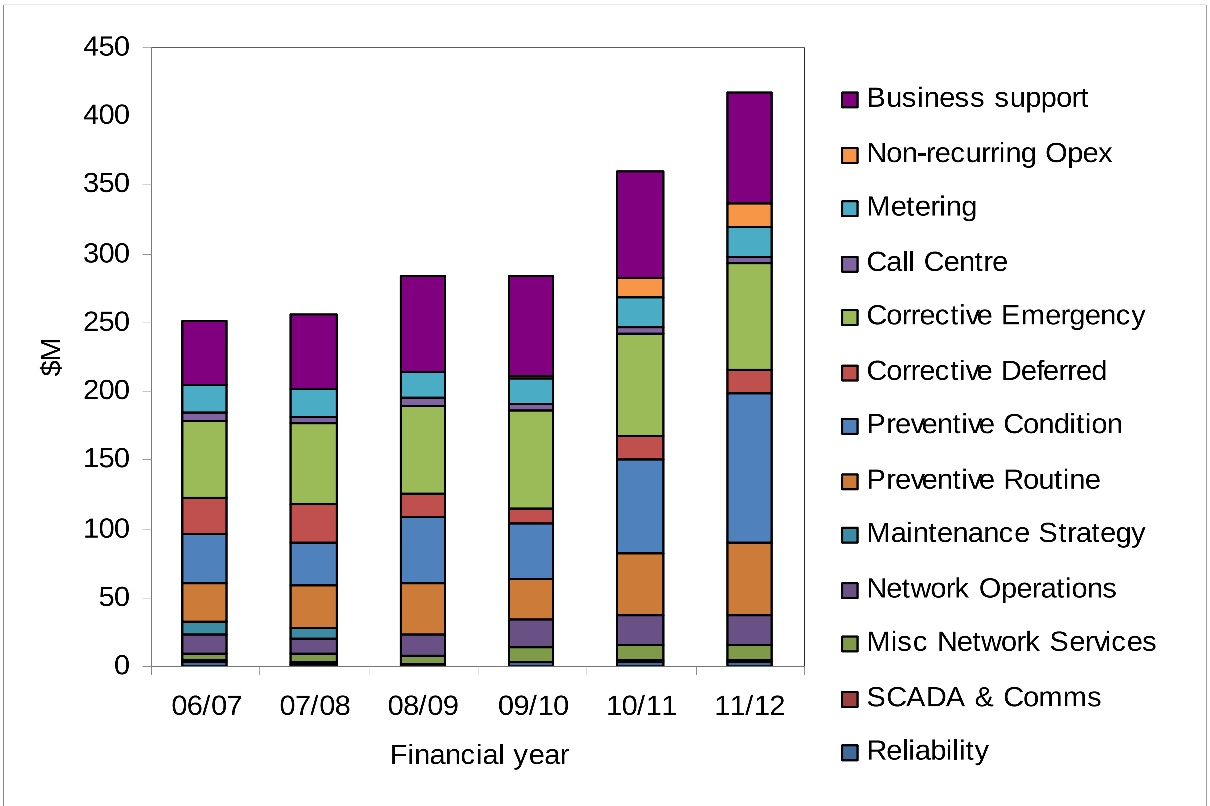


Table 5-3 Distribution Opex actual and forecast ($M)

DISTRIBUTION	AA1 (Actual)			AA2 (Forecast)		
OPEX	06/07	07/08	08/09	09/10	10/11	11/12
Reliability	3.7	1.5	0.7	2.9	3.1	3.2
SCADA/communications	1.4	1.2	0.9	0.9	1.4	1.6
Network operations	13.1	10.7	15.8	20.1	21.2	21.9
Misc network Services	4.8	6.0	6.3	10.1	10.8	11.4
Maintenance strategy*	9.4	8.7	-	-	-	-
Preventive routine maintenance	28.5	30.4	36.4	29.5	46.0	52.4
Preventive condition maintenance	35.1	31.4	48.1	40.1	68.8	107.6
Corrective deferred maintenance	27.3	27.7	16.7	11.3	16.7	17.9
Corrective emergency maintenance	55.7	59.6	64.5	70.6	74.0	76.6
Call Centre	5.2	5.0	6.1	4.6	4.6	4.7
Metering	20.7	18.9	18.7	19.8	21.7	21.7
Non recurring opex	0.0	0.0	0.0	0.9	14.7	17.8
Business support costs	46.2	54.5	69.8	72.8	77.2	81.2
Total ($M)	**251.1**	**255.6**	**284.0**	**283.7**	**360.1**	**418.0**

** Note: Maintenance Strategy Costs now form part of an indirect cost pool allocated to works programs*

Figure 5-3 Distribution Opex actual and forecast ($M)



5.2 Comparison with initial submission

The tables and charts in this section illustrate the comparison between the Opex forecasts included in the initial Submission and the revised forecast expenditure in this Supplementary Submission. The purpose of including these comparisons is to clearly illustrate that whilst the forecast expenditure in the first year of the second access arrangement period has been reduced significantly, the requirement to increase this level of expenditure remains. Accordingly, the expenditure forecast increases in the second and third years, so that the final year's expenditure forecast is similar to the level forecast in the initial Submission. The need to increase Opex levels to address network issues and rising backlogs of maintenance work has not changed. It is Western Power's intention to return to the initial forecast levels as quickly as affordability and deliverability constraints will allow.

For the Transmission network, Table 5-4 shows the comparison between the forecast Opex in the initial submission and the revised Opex forecasts in this Supplementary Submission. The impact of the GFC has contributed to a 24.8% reduction in the revised forecast expenditures for 2009/10. The revised forecast for 2010/11 is 8.7% lower and the revised forecast for 2011/12 is 7.9% lower than the initial forecasts. In all, the total reduction in the revised Opex forecasts is 13.5% compared to the initial forecasts. These changes are illustrated in Figure 5.4.

Table 5-4 Comparison of the initial to revised forecast transmission Opex ($M)

TRANSMISSION	Initial submission			Supplementary Submission		
	09/10	10/11	11/12	09/10	10/11	11/12
SCADA/communications	8.1	8.9	9.9	6.5	8.7	9.5
Network operations	12.9	14.0	14.7	13.6	14.3	14.6
Misc network Services	6.0	5.7	5.9	0.9	0.9	0.9
Preventive routine maintenance	21.4	22.7	23.9	13.0	20.4	25.2
Preventive condition maintenance	14.2	14.9	17.3	8.9	13.4	12.5
Corrective deferred maintenance	5.7	6.5	7.2	4.3	7.9	8.3
Corrective emergency maintenance	3.0	3.3	3.4	1.9	2.2	2.6
Non recurring opex	2.2	1.9	1.7	0.0	0.6	0.6
Business support costs	27.4	28.0	28.7	26.8	28.3	29.6
Total (M)	**100.9**	**106.0**	**112.8**	**75.9**	**96.7**	**103.8**

Figure 5-4 Comparison of the initial to revised forecast transmission Opex ($M)

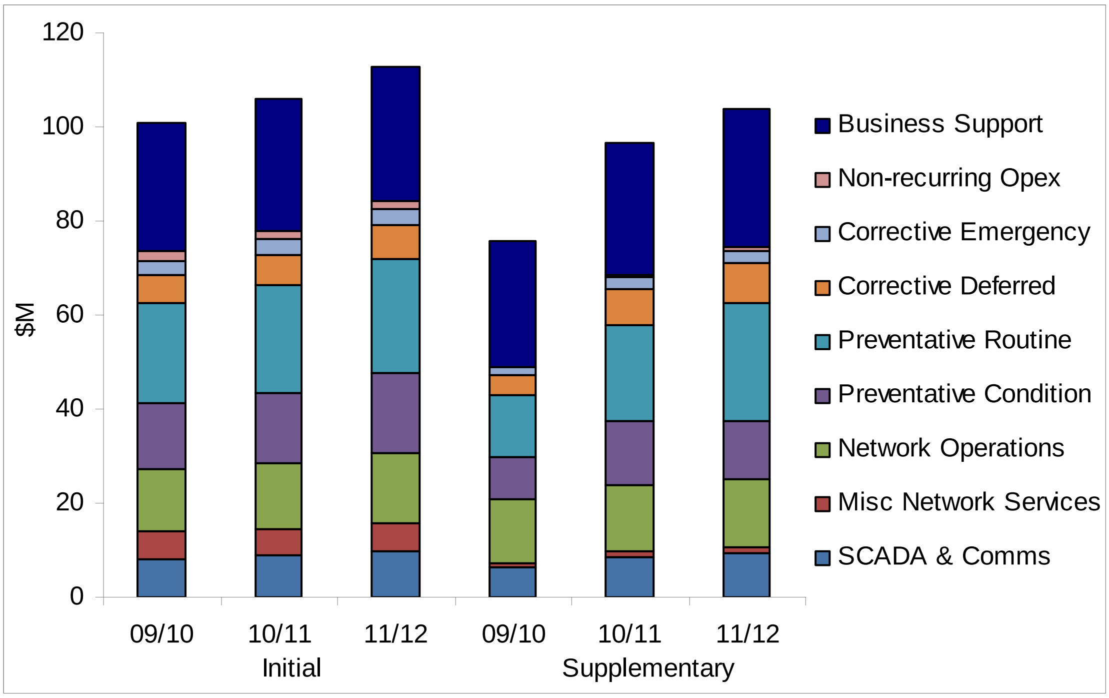


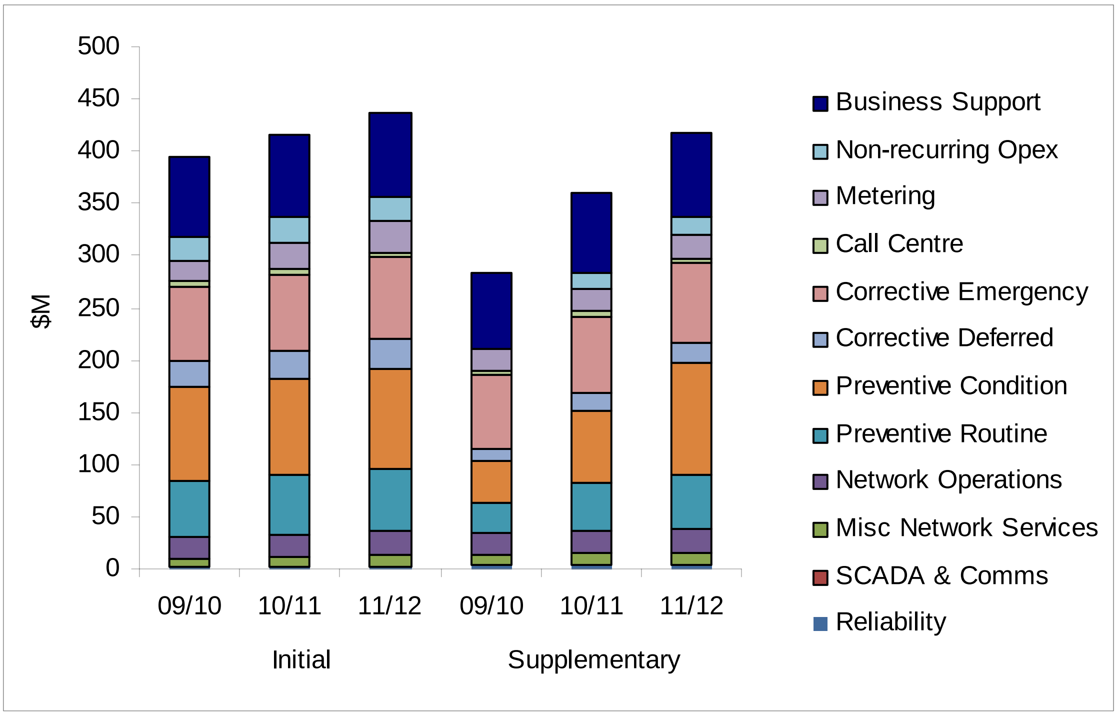
Table 5-5 shows the forecast Distribution Opex in the initial Submission compared to the revised Opex forecasts in this Supplementary Submission, including the revised real labour and material escalators and the impacts of the revised Capex programs. In real terms the revised total Opex for the period represent a 14.8% reduction over the three year regulatory period compared to the initial submission.

This reduction is not spread evenly over the period. In 2009/10 the reduction is 28.0% and in 20010/11 it is 13.5%. In 2012/12 the revised forecast is reduced by 4.2% when compared with the initial Submission. These changes are illustrated in Figure 5.5.

Table 5-5 Comparison of the initial to the revised forecast distribution Opex ($M)

DISTRIBUTION	Initial submission			Supplementary Submission		
OPEX	09/10	10/11	11/12	09/10	10/11	11/12
Reliability	1.1	1.1	1.1	2.9	3.1	3.2
SCADA/communications	1.4	1.4	1.6	0.9	1.4	1.6
Network operations	20.0	21.8	23.2	20.1	21.2	21.9
Misc network Services	7.4	8.6	9.8	10.1	10.8	11.4
Preventive routine maintenance	54.1	56.3	59.4	29.5	46.0	52.4
Preventive condition maintenance	91.2	93.1	95.9	40.1	68.8	107.6
Corrective deferred maintenance	23.3	25.7	28.4	11.3	16.7	17.9
Corrective emergency maintenance	71.0	74.3	78.4	70.6	74.0	76.6
Call Centre	5.4	5.5	5.5	4.6	4.6	4.7
Metering	20.2	24.5	29.1	19.8	21.7	21.7
Non recurring opex	22.2	25.5	23.1	0.9	14.7	17.8
Business support costs	76.6	78.7	80.8	72.8	77.2	81.2
Total ($M)	**394.0**	**416.5**	**436.4**	**283.7**	**360.1**	**418.0**

Figure 5-5 Comparison of the initial to the revised forecast distribution Opex ($M)



The impact of the reduced forecasts is discussed in detail in the sections covering each of the regulatory categories from section 5.6 onwards.

5.3 Expenditure Forecast Delivery Assessment

This section provides a summary of the works delivery strategy for the period 2009/10 to 2011/12.

Diversity of work and resource types and the changing economic landscape provide a challenging environment for efficiently executing delivery of Western Power's current and future work programs.

Western Power has developed a Strategic Delivery Framework for the delivery and resourcing of the work. The focus of this framework is to establish a balanced portfolio of service delivery options to maximise Western Power's flexibility as well as reduce the long-term cost of service delivery.

The status of key strategic initiatives resulting from the application of the delivery framework is provided as follows;

Establishment of the Alliances: Two alliance agreements were executed in April 2008. Work has been allocated and a customer funded distribution and transmission alliance workforce has been mobilised. With the implementation of a KPI framework in April 2009, and adjustments in commercial arrangements in July 2009 to reflect changing work volumes, the alliances are now fully implemented and delivering the required outcomes.

The Distribution Delivery Strategy: The implementation of the Distribution Delivery Strategy is progressing with expressions of interest released to the market in May 2009. Evaluation and selection documents are being completed throughout July and August in preparation for release to the market in September 2009. The strategy will improve delivery through a more appropriate market engagement model (performance based contracts) and a centralised work allocation office, which seeks to improve work flow and provide visibility of future works to suppliers on the panel.

In summary, the strategy seeks to reduce the number of service providers engaging directly with Western Power, increase the diversity of service provider offerings, increase the volumes of work offered to the market in single packages and deepen project management capabilities within external service providers.

Enhanced Planning and Workforce Management: The implementation of one of Western Power's key strategic initiatives - Enhanced Planning and Workforce Management (EPWM) - commenced with the launch of Stream One in May 2009. This program will provide a single source of data, improve long-term work and resource planning functionality, and improve program and portfolio management.

Two key challenges that EPWM will address are;

- Timeliness in Project Approvals: On schedule delivery of projects, particularly transmission capital projects are becoming increasingly challenging due to increasing community concerns and environmental requirements. Improved forward visibility and prioritisation of the work plans together with the governance underpinning EPWM will ensure project approvals through each gate will be managed more proactively.

- Management of Network Access: Gaining access to the network to undertake planned maintenance or commissioning new assets is an operational challenge. Increase network loadings and utilisation results in smaller windows for outages, which limits some work activities to spring and autumn periods when system loadings are more manageable to accommodate outages. EPWM together with other targeted works scheduling initiatives will provide the ability to optimise network access windows.

In conjunction with these strategic initiatives, several operational improvement programs were implemented in 2008 resulting in increased delivery performance in Distribution and Transmission.

Distribution

The distribution maintenance program exceeded its financial and schedule performance for 2008/09. Throughout distribution delivery, significant project governance enhancements were completed, driving improved monitoring and reporting which has led to increased network reliability and a reduction in the occurrences of public safety incidents. A number of mechanisms, such as increased project and program planning, enhanced work allocation, monitoring and reporting were put in place. A revised management structure created greater end-to-end accountability driving delivery outcomes and efficiency.

Achievements included:

- Bushfire mitigation, which included pole replacement, reinforcement and increased vegetation cutting, was completed on time.
- Bundled pole inspections were completed at a rate not seen before with 195,000 inspections completed at 30 June 2009.
- The 40 Worst Feeder project showed strong performance during 2008/09, as a result of the North and South Country Bundling project, with 98% of conditions across 176 feeders rectified.
- The Summer Ready 08/09 program was completed on time by December 2008, with 98% of projects completed.
- The Rural Power Improvement Program was implemented fully in 2008/09, with the 2007/08 backlog eliminated.

Transmission

The transmission major projects program met its financial and schedule performance for 2008/09. This included the successful delivery of Neerabup Terminal, Southern Terminal SVC and Boddington Gold Mine Connection. The transmission maintenance program was delivered on time and to budget and included vegetation inspections, line easement vegetation management and asset replacement. The successful delivery is attributed to the formation of a focused transmission delivery group dedicated to the delivery of transmission Capex and Opex.

Enhanced governance mechanisms were established to enhance project and program management. The asset replacement program identified work packages based on risk prioritisation and led to efficiencies as Western Power was able to complete multiple projects simultaneously within geographical locations.

The significant improvement in both Transmission and Distribution delivery towards the end of AA1 is a result of enhanced planning and governance, improved supplier engagement and improved monitoring and reporting. This provides confidence that with the full implementation of its delivery plans, Western Power's delivery performance will continue to improve throughout AA2.

A summary of the key components of the Strategic Delivery Framework follows.

5.3.1 Strategic Delivery Framework

The Strategic Delivery Framework[12] was developed and implemented in 2008.

The three main components of the framework are;

- Balanced portfolio of Delivery Mechanisms,
- Work Allocation System, and
- Optimal Resource Planning.

5.3.2 Delivery Mechanisms

The following mechanisms were selected as the most appropriate to transition into a more commercially focused and flexible delivery workforce;

- Internal Delivery,
- Partner Delivery Agreements,
- Commercial Contracts,
- Preferred Vendors, and
- Alternate Delivery[13].

5.3.3 Work Allocation System

Work allocation is performed at two levels in the organisation;

- Strategic work allocation identifies work mix and volumes required to maintain value for money across the delivery mechanisms. This level has a year one to five focus.

- Not withstanding the strategic basis for work allocation, Western Power will always test the assumptions and adjust the actual work allocation depending on the prevailing conditions at the time, including the performance of the delivery mechanism. This tactical work allocation level has a year zero focus and performs quarterly work allocation reviews.

Strategic work allocation decisions are guided by a work allocation matrix and governed by a work allocation committee and a set of work allocation business rules[14].

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[12] For more detail on the Works Program Delivery Framework refer to DM 4410371

[13] A detailed analysis of delivery mechanism options is provided in Western Power's Delivery Mechanism Options Paper (DM 4418227).

[14] A detailed outline of the work allocation system is set out in DM 4422376

5.3.4 Optimal Resource Planning

As part of the delivery strategy it is very important to understand the resource demand and supply for the delivery of the entire works program and to perform periodic scenario studies to manage any potential gaps or constraints in delivering the work. Resource models have been used to calculate the operational workforce resource demand, which is shown in Table 5-6.

Table 5-6 Operational Workforce Demand

ITEM	AA1			AA2		
	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Works Program Total Spend ($M Base)	817	1014	1120	1069	1507	1646
Works Program Demand **Internal** Total (FTE)	1100	1250	1390	1390	1540	1700
Works Program Demand **External** Total (FTE)	1180	1473	1423	1289	1629	1554
Works Program Demand Grand Total (FTE)	**2280**	**2723**	**2813**	**2679**	**3169**	**3254**
Internal / External Mix	48%	46%	49%	42%	49%	52%

**FTE = full time equivalent employee*

Western Power continuously monitors the resource capability of external service providers to ensure that the scale and skills of resources necessary to implement the works program are available within a reasonable timeframe.

The latest information on external resources in Western Australia indicates that within Western Australia large numbers of distribution resources are available and can be engaged to assist in delivering Western Power's program of works, although some areas of skills, such as switching operators, are in short supply. Transmission resources for major line construction are sourced from a highly mobile workforce external to WA.

Analysis of current resource supply and demand indicates that Western Power has sufficient resources internally and externally to deliver the AA2 works program. Internal resource strategies will target increasing operational and maintenance skills to ensure Western Power maintains core competencies and can respond effectively to customer needs.

5.4 Asset escalation

A revised Capex program has been included in this Supplementary Submission and this will result in different asset escalators to those used in the initial submission. The annual Capex has a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

Forecast expenditures are based on a top down approach to constraining of expenditures as described in Section 2 rather than a bottom up approach. Western Power has not adopted a modelling approach to determine the increase in Opex due to the expanding network, as was done in the initial submission. Rather, the expected impact of increased asset inspections, etc, has been specifically forecast for relevant expenditure categories.

5.5 Opex/Capex trade-off

In its initial submission, Western Power incorporated an adjustment for an Opex/ replacement Capex trade-off in the forecast Transmission and Distribution Opex. The asset replacement/refurbishment Capex proposed for the next regulatory period has an impact on the forecast Opex as the new replacement or refurbished assets should require less corrective maintenance than the assets they replaced.

Table 5-7 shows the percentage decrease in Opex due to the trade-off based on the reduced asset replacement Capex as proposed in this Supplementary Submission. The same model was used as in the initial submission. The decease applies to the maintenance expenditure categories of preventative routine, preventative condition, corrective deferred, corrective emergency, and SCADA/ communications. The table shows that the decrease ranges from -0.03% to -0.28%. Given the top down methodology adopted in the forecasting process as set out in section 2 and the low level of materiality, the trade-off is not reflected in the forecast expenditure.

Table 5-7 Percentage reduction in some Opex categories due to replacement Capex

	09/10	10/11	11/12
Transmission	-0.03%	-0.10%	-0.18%
Distribution	-0.04%	-0.14%	-0.28%

5.6 Preventive routine maintenance

The preventive routine maintenance forecast expenditure relates to proactive maintenance carried out to reduce the probability of failure or degradation of the performance of specific network assets. The activities include monitoring, testing and inspection of equipment that is undertaken either at predetermined intervals or is initiated by equipment operations or condition. This work typically includes visual inspection, testing, lubrication and routine minor part replacement. The revised expenditure for these activities is provided in Table 5-8.

Table 5-8 Preventive routine maintenance expenditure ($M)

Preventive Routine	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	11.7	11.6	14.7	13.0	20.4	25.2
Transmission % change per annum		-0.9	26.7	-11.6	56.9	23.5
Distribution - cost	28.5	30.4	36.4	29.5	46.0	52.4
Distribution % change per annum		6.7	19.7	-19.0	55.9	13.9
Total - cost	40.2	42.0	51.1	42.5	66.4	77.6
Total % change per annum		4.5	21.7	-16.8	56.2	16.9

In the Draft Decision the ERA raised two issues about preventive maintenance. The first issue (paragraphs 443 and 444) concerned the indicative forecasts for preventive routine maintenance provided by Western Power in the May 2009 Letter. The ERA concluded that Western Power had not provided sufficient information to justify why the anticipated revised forecasts incorporate a large reduction in expenditure in 2009/10 ($46.55M) from the initial submission and then a progressive increase over the period, such that forecast expenditure in 2011/12 ($83.27M) returns to the same levels as in the initial submission. Forecast amounts for 2009/10 were accepted. Year-to-year increases limited to 15 per cent, with the real cost escalation removed, were recommended for 2010/11 and 2011/12.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. Western Power has now completed its review of the forecasts for preventive routine maintenance in response to the changes detailed in section 2 of this report. The revised requirement for preventive routine maintenance totals $186.5M for AA2, which is a significant reduction ($51.2M) to the forecasts indicated in the initial submission. Unit cost escalation consistent with the revised cost escalators detailed in section 2 has been included in the forecasts.

Expenditures forecast over the three years of the regulatory period have been constrained for the reasons set out in section 2. This has lead to lower levels of expenditure in 2009/10 (44% less) when compared to the forecasts proposed in the initial submission. Expenditures in the later years are also lower than the initial submission by 16% and 7% respectively. The rate of increase in the expenditures over the regulatory period has been limited by the ability to resource the work as discussed in the deliverability assessment at section 5.3.

The second issue raised by the ERA in its Draft Decision (paragraph 417 and 418) is that Western Power has not shown any relevant changes in regulations to justify increased expenditure, and has therefore disallowed proposed expenditures in this category. Western Power confirms that there have been no changes in new safety or environmental regulations that have had a material impact on maintenance expenditures. Rather, Western Power has recognised that its level of compliance with existing safety and environmental regulations is currently low and needs to be substantially improved.

While the current regulations have existed for the AA1 regulatory period, all the required work specified in Western Power's maintenance policies has not been able to be completed given the available budget. This has lead to a growing backlog of work that has impacted the level of compliance. The ERA in its Notice issued in 2008 expressed concern over inspection backlogs requiring them to be addressed. Western Power advises that the level of inspections forecast for the regulatory period is aimed at allowing most critical assessments to be undertaken but recognises that a balance is required between expenditures to identify conditions and the expenditure available for the preventive condition maintenance then required to address the conditions found.

5.6.1 Distribution Preventative Routine

Detailed justifications for the expenditure increases from 2008/09 actual costs in the Distribution preventative routine category are provided in Table 5.9 and Table 5.10, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-9 Distribution Preventative Routine - Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – includes original escalation rate)	54.1	56.3	59.4	**169.8**
ERA Draft Determination (no escalation)	32.9	37.8	43.5	**114.2**
ERA Draft Determination with new escalation rates added	**33.9**	**39.3**	**45.6**	**118.8**

Table 5-10 Distribution Preventative Routine – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual	36.4	36.4	36.4	**109.2**
Power Pole Bundled Inspection	(1.0)	7.2	7.2	**13.4**
Backlog Volume	0.0	1.7	6.5	**8.2**
Bulk Globe Replacement	(0.9)	1.2	1.2	**1.5**
OH Switchgear Bundled Inspections	0.0	0.7	0.7	**1.4**
Asset Growth	0.0	1.0	1.6	**2.6**
Misc. Overhead System Inspections	(3.4)	(3.0)	(3.0)	**(9.4)**
Substations Bundled Inspections	(1.9)	0.6	1.6	**0.3**
Other Miscellaneous	(0.6)	(1.3)	(1.9)	**(3.9)**
Escalation	1.0	1.5	2.2	**4.6**
New Proposed (Real – new escalation rate)	**29.5**	**46.0**	**52.4**	**128.0**

Table 5-9 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-10 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Each of the line items in Table 5-10 is discussed below.

Power Pole Bundled Inspection

Accurate assessment of the condition of wood poles is critical to identifying those poles at risk of failure. This informs the pole replacement program so that unserviceable poles are replaced prior to unassisted failure which can cause bushfires, electric shock incidents, mechanical damage and transformer oil spills.

Additional expenditure is required to meet EnergySafety draft orders 01-2009 and 02-2009 issued in accordance with the *Electricity (Supply Standards and System Safety) Regulations* 2001. These orders require Western Power to modify its pole inspection practices to

- inspect all wood poles around the full circumference of the pole, including poles that are in concrete and paving, in the safety critical zone 100-200 mm below ground,
- conduct accurate dimensioning of below ground diameter,
- undertake a full engineering analysis of strength versus load, and

- modify its management systems to integrate this information into risk-based decision making for wood pole replacement.

Failure to adhere to this order will place Western Power in breach and subject to fines and reputation damage.

The enhanced inspection practices will approximately double the time taken for each inspection over the methodology employed during the AA1 period resulting in an increased cost per pole as shown in Table 5-11. As the new procedure will begin in January 2010, the average rate per pole is reduced for 2009/10. The available expenditure in 2009/10 will mean that all of the required inspections will not be completed in this year. Western Power proposes to make up the shortfall in the following years.

Table 5-11 Power Pole Bundled Inspections

Power Pole Bundled Inspections	08/09	09/10	10/11	11/12	TOTAL
Volumes (excl. growth & backlog)	195,846	125,813	170,098	170,098	
Rate per unit	67.32	96.50	120.00	120.00	
Cost ($M)	13.2	12.1	20.4	20.4	
Variance from 2008/09 spend		**(1.0)**	**7.2**	**7.2**	**13.4**

This enhanced pole inspection process, which is consistent with Australian best practice, when combined with adequate levels of pole replacement, will lead to a reduction in unassisted pole failures from 118 in 2008/09 to less than 40 by 2015.

Backlog volumes

As previously mentioned, increasing backlogs of condition based work translate into more equipment failures with consequent public safety and performance impacts.

Western Power currently has significant backlogs in power pole and vegetation inspections, and in bulk globe replacements. The purpose of reducing these backlogs is to;

- ensure that assets are maintained in accordance with policies and that service levels are maintained,
- reduce the level of equipment failures and emergency maintenance,
- ensure a thorough understanding of asset condition is obtained so that maintenance and refurbishment strategies can be precisely targeted, and
- comply with the ERA notice requiring action to address inspection backlog volumes.

Table 5-12 identifies the backlog volumes that will be addressed over the AA2 regulatory period.

The focus on targeting the backlogs for pole and vegetation inspections is consistent with the risk based approach of prioritising work on the overhead network and in particular mitigating the risk of bushfires, electric shock, and reduced reliability.

A reduction in the bulk globe replacement backlog is needed to meet the commitments given to local government street lighting customers to complete the replacement program over a 3 year cycle. Due to the sensitive nature of street lighting in the community, there is a high risk of reputational damage should the program not be met.

Table 5-12 Distribution Preventative Routine Backlog

Backlog	Backlog allocated 10/11	Backlog allocated 11/12	Rate per unit	10/11 Backlog ($M)	11/12 Backlog ($M)
Power Pole Bundled Inspection	8,000	37,000	120.00	1.0	4.4
Vegetation Inspection	35,538	26,090	7.16	0.3	1.2
Bulk Globe Replacement	5,658	22,631	83.16	0.5	1.9
BTotal Backlog				**1.7**	**6.5**

Bulk Globe Replacement

Bulk Globe Replacement

The bulk globe replacement program is a fixed 3 year cycle of replacement of streetlight globes as detailed in the initial submission. Compared with 2008/09 (the last year of a four year cycle), additional streetlight replacements will be undertaken each year in AA2. These are in addition to the backlog in bulk globe replacements discussed in the previous section that are also planned to be undertaken.

Since the initial submission new tenders have been received for this work and the expenditure forecasts have been adjusted to reflect this.

Available funding in 2009/10 has meant re-profiling the proposed spend over the AA2 period compared to the initial submission. Western Power has a contractual commitment with Synergy to deliver this program.

Forecasts for streetlight fault repairs in the corrective emergency category have been reduced to reflect the change from a 4 year to 3 year replacement cycle.

O/H Switchgear Bundled Inspections

The justification for this inspection program is set out in the initial submission. In re-forecasting expenditures, Western Power has taken a risk based approach to this category of work, with no expenditures planned in 2009/10 and increased expenditures in the remaining years of the AA2 period. Full recovery of the required program will be achieved in the following regulatory period.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

Volumes of new assets are estimated for each activity based on proposed spend and unit costs calculated using predetermined growth rates applied to the base unconstrained volumes (without backlog and without growth). The new unit cost rates are determined from the 2008/09 actual unit rates or specific contract rates if recently changed. The cost change due to asset growth is determined from the product of the above volume changes and unit rates for each activity.

Miscellaneous Overhead System Inspections

Expenditure in this category has been significantly reduced due to the transfer of the cost of high load survey costs to Non Reference Services. The costs of metal pole inspections has also reduced based on 2008/09 actual costs which showed that rationalisation of the scope of the inspection has enabled efficiencies to be gained.

Substation bundled inspections

The initial submission proposed an increased number of inspections to comply with Western Power's maintenance policies and the overarching safety regulations. With the reduced funding available in 2009/10, approximately 80% of the planned program has been deferred. In the case of substation inspections, work will be limited to the inspection of Western Power's assets in the CBD area, with maintenance of only the most unreliable switchgear being conducted. While a small increase in the number of units failing can be expected, the impact on supply reliability in 2009/10 is likely to be small and has been accounted for in the revised service standard performance discussed in section 2. The shortfall will be progressively made up over the remaining years of the AA2 period and full recovery of the program will be achieved in the following regulatory period.

Other Miscellaneous

A reduction in proposed expenditure is due to using actual 2008/09 costs and combining some minor activities into the major inspection programs.

5.6.2 Transmission Preventative Routine

Detailed justifications for the expenditure increases from 2008/09 actual costs in the transmission preventative routine category are provided below, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-13 Transmission Preventative Routine Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – including original escalation rate)	21.4	22.7	23.9	**68.0**
ERA Draft Determination (no escalation)	13.7	15.7	18.1	**47.4**
ERA Draft Determination including new escalation rate	**14.1**	**16.4**	**19.1**	**49.6**

Table 5-14 Transmission Preventative Routine - Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual	**14.7**	**14.7**	**14.7**	**44.1**
Power Pole Bundled Inspection	0.3	0.6	0.6	**1.5**
Substation Primary Plant Maintenance	(0.7)	0.9	0.9	**1.1**
Structure Inspection & Line Patrols	0.4	1.6	1.5	**3.5**
Asset Growth	0.6	1.2	1.8	**3.6**
Backlog volume	0.0	1.0	4.9	**5.9**
Other Miscellaneous	(2.7)	(0.2)	(0.2)	**(3.2)**
Escalation	0.4	0.7	1.0	**2.1**
New Proposed (new escalation rate)	**13.0**	**20.4**	**25.2**	**58.6**

Table 5-13 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-14 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Each of the line items in Table 5-14 is discussed below.

Power Pole Bundled Inspection

Accurate assessment of the condition of wood poles is critical to identifying those poles at risk of failure. This informs the pole replacement program so that unserviceable poles are replaced prior to unassisted failure which can cause bushfires, electric shock incidents, mechanical damage and transformer oil spills.

Additional expenditure is required to meet the conditions set out in EnergySafety draft orders 01-2009 and 02-2009 issued in accordance with the *Electricity (Supply Standards and System Safety) Regulations* 2001. These orders require Western Power to modify its pole inspection practices to:

- inspect all wood poles around the full circumference of the pole, including poles that are in concrete and paving, in the safety critical zone 100-200 mm below ground,
- conduct accurate dimensioning of below ground diameter,
- undertake a full engineering analysis of strength versus load, and
- modify its management systems to integrate this information into risk-based decision making for wood pole replacement.

Failure to adhere to this order will place Western Power in breach and subject to fines and reputation damage.

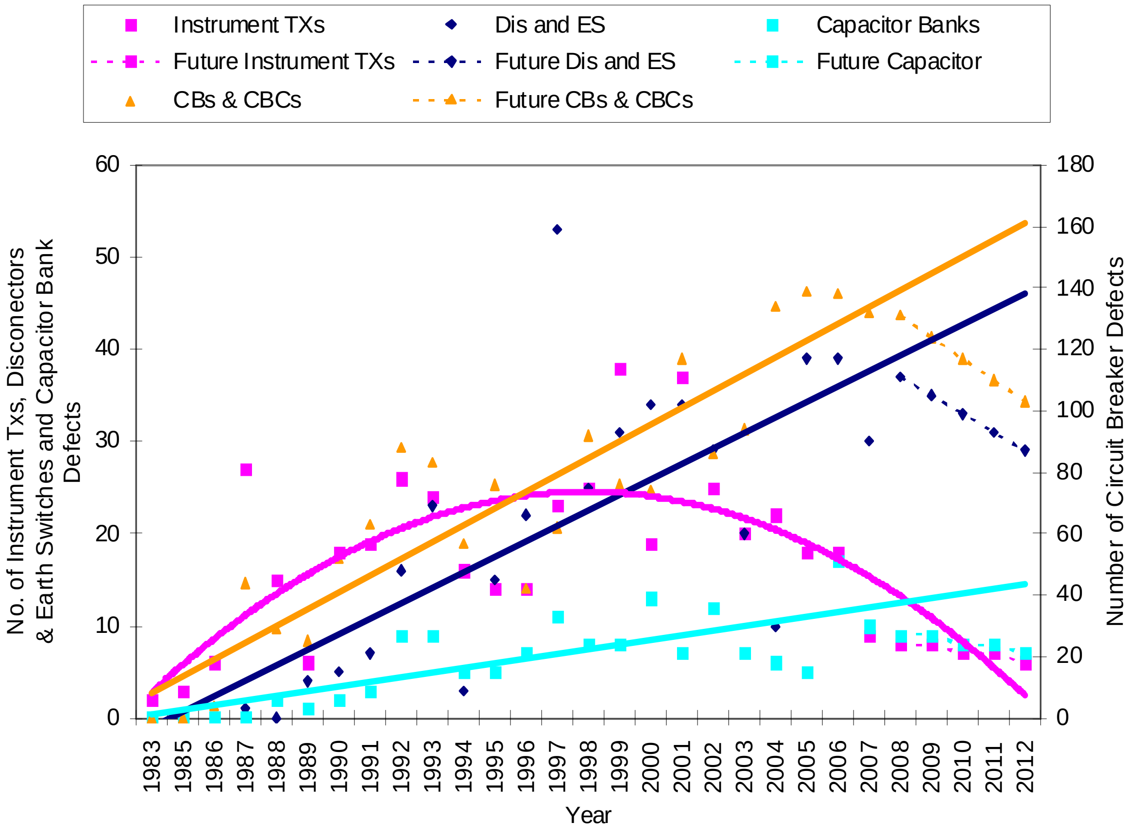
The enhanced inspection practices will approximately double the time taken for each inspection over the methodology employed during the AA1 period resulting in an increased cost per pole of $58.

Substation primary plant maintenance

Preventative Routine Maintenance is critical for substation equipment such as switchgear, disconnectors and transformers, particularly as they have moving parts. As equipment wears with age and use, failure is likely before the end of its expected life if the equipment is not maintained. Catastrophic failure is a safety risk to people and there is a risk of further plant being damaged, prolonging unplanned outages.

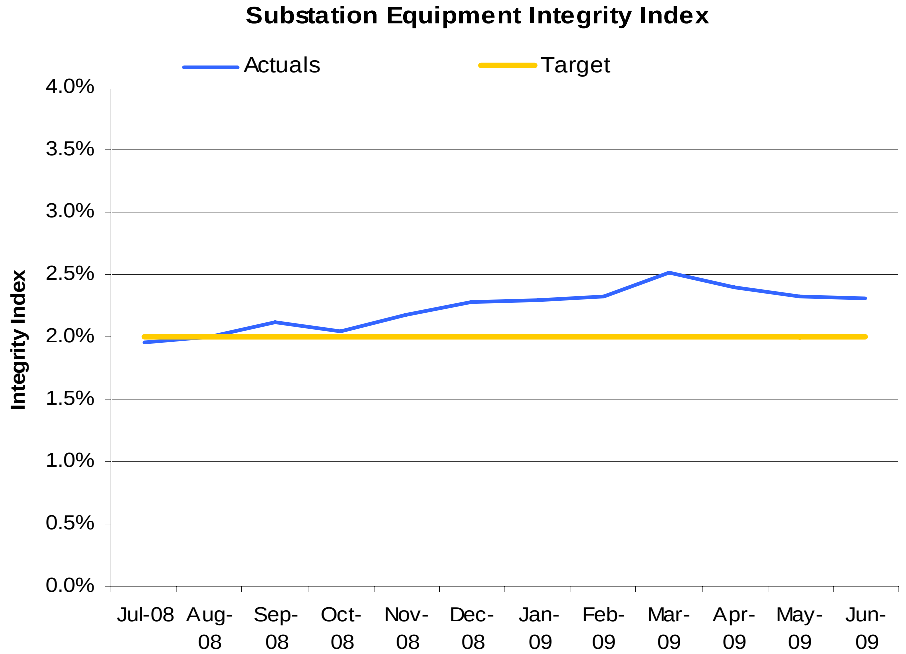
The current rate of failures and defects for some equipment types is unacceptably high and increasing. Maintenance aligned with online condition monitoring and improved condition identification will reduce the failures and defects of equipment by 5% per annum. This strategy has already achieved results with instrument transformers as shown in figure 5.6.

Figure 5-6 Transmission Substation Plan Defects by Year



This maintenance program was slowed by 50% in 2008/09 due to budget constraints and reprioritization of works. The available budget for 2009/10 will constrain work to similar levels and increased fault activity is expected as was experienced in 2008/09 and shown in Figure 5-7. The program will be progressively made up over the remaining years of the AA2 period.

Figure 5-7 2008/09 Substation Integrity Index Performance



$$SEII_{SWIS} = \left(\frac{\sum_{12\ \text{Months}} \text{Number of Defects}}{\text{Total number of Substation primary plant units}} \right) * 100$$

The forecast expenditure also includes an engineering life and condition assessment study on a whole of substation basis. Existing condition assessments have been undertaken for most primary plant items, however in accordance with good industry practice, this needs to be extended to the other parts of the substation including foundations and structures, busbar, earthing, buildings and fences. This will identify structural components that are at risk of failure and provide a holistic view of substation condition to facilitate optimisation of the asset replacement and augmentation capital programs.

This detailed view of substation condition will be conducted over four years on 85 of the oldest terminals and substations.

Structure Inspection and line patrols

Western Power has a policy of detailed structural inspections of lattice towers and steel poles every 5 years. The purpose of this strategy is to prevent a catastrophic failure of a structure though early identification of degraded components. Such a failure could have serious consequences including impacting the security of the transmission system with potential load shedding, and public safety impacts due to mechanical damage or fire.

Only 9 lines were able to be inspected within the available 2008/09 budget. This inspection revealed their condition to be worse than anticipated; with the presence of extensive rust on members being identified and insulator hardware being in poor condition. Detailed condition assessment reports are available for review. It is imperative that the inspection program comply with the existing policy requirements so that a comprehensive assessment of structure condition can be obtained. This is crucial in determining an optimal refurbishment strategy which will be planned for the following regulatory periods.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

Over the last 3 years, 23 new or upgraded substations have been installed with plant items that need to be inspected and maintained, representing an increase of 5% per annum. Additional new circuits in existing substations also require inspection and maintenance. Plans are well advanced for 9 new substations and 17 new transformers at existing sites in years 2009/10 and 2010/11, representing a growth increase of approximately 3% per annum.

Failure to adequately cater for the maintenance requirements of new assets will ultimately mean that some equipment cannot be maintained in accordance with maintenance policies and backlogs will be incurred. Increasing backlogs lead to increased levels of equipment failure.

Backlog volume

Western Power currently has significant backlogs in distribution system inspection work. Table 5-15 identifies the backlog volumes that will be addressed over the AA2 regulatory period. The purpose of reducing these backlogs is to;

- ensure that assets are maintained in accordance with policies and that service levels are maintained,
- reduce the level of equipment failures and emergency maintenance,
- ensure a thorough understanding of asset condition is obtained so that maintenance and refurbishment strategies can be precisely targeted, and
- comply with the 2008 ERA notice requiring action to address inspection backlog volumes.

Table 5-15 Transmission Preventative Routine – Backlog

	Backlog cleared 09/10 (Volume of defects)	Backlog cleared 10/11 (Volume of defects)	Backlog cleared 11/12 (Volume of defects)	Rate per unit ($)	Backlog cleared 09/10 ($M)	Backlog cleared 10/11 ($M)	Backlog cleared 11/12 ($M)
Pole Base Inspection/Treatment	0.0	757	880	171	0.0	0.1	0.2
Line Insulator Washing	0.0	0	1879	22	0.0	0.0	0.0
Insulator Siliconing	0.0	218	348	530	0.0	0.1	0.2
Underground System Inspect	0.0	144	16	129	0.0	0.0	0.0
Warranty Inspection & Testing	0.0	6	26	136	0.0	0.0	0.0
Substation Primary Plant Maintenance	0.0	14	628	3580	0.0	0.0	2.2
Secondary Equipment Maintenance	0.0	126	325	2541	0.0	0.3	0.8
Thermographic Surveys Substations	0.0	0	39	322	0.0	0.0	0.0
Substation Maintenance Buildings & Grounds	0.0	13	83	4082	0.0	0.1	0.3
Substation Battery Maintenance & Insp	0.0	0	308	757	0.0	0.0	0.2
Substation HV Equipment Testing	0.0	142	341	2425	0.0	0.3	0.8
Tran Substation Inspect	0.0	3	132	402	0.0	0.0	0.1
Total Backlog					**0.0**	**1.0**	**4.9**

Other Miscellaneous: A reduction in forecast cost is due to using actual 2008/09 costs and combining minor activities into the major inspection programs.

5.7 Preventive condition maintenance

Preventive condition maintenance forecast expenditure relates to the follow-up maintenance activities performed as a result of conditions/defects identified during the preventive routine maintenance programs. Hence the driver for this maintenance category is the find rate from the preventive routine inspection maintenance. The quantum of preventive condition maintenance is directly related to the amount of preventive routine maintenance programmed and the find rates for defects. The revised expenditure for these activities is provided in Table 5-16.

Table 5-16 Preventive condition maintenance expenditure ($M)

Preventive Condition	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	9.2	6.7	8.6	8.9	13.4	12.5
Transmission % change per annum		-27.2	28.4	3.5	50.6	-6.7
Distribution - cost	35.1	31.4	48.1	40.1	68.8	107.6
Distribution % change per annum		-10.5	53.2	-16.6	71.6	56.4
Total - cost	44.3	38.1	56.7	49.1	82.2	120.0
Total % change per annum		-14.0	48.8	-13.4	67.4	46.0

In the Draft Decision (paragraphs 443 and 444), the ERA considered the indicative forecasts for preventive condition maintenance provided by Western Power in the May 2009 Letter. The ERA concluded that Western Power had not provided sufficient information to justify why the anticipated revised forecasts incorporate a large reduction in expenditure in 2009/10 ($48.99M) from the initial submission and then a progressive increase over the period, such that forecast expenditure in 2011/12 ($113.18M) returns to the same levels as in the initial submission. Forecast amounts for 2009/10 were accepted. Forecast amounts with year-to-year increases limited to 15 per cent, with the real cost escalation removed, were recommended for 2010/11 and 2011/12.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. Western Power has now completed its review of the forecasts for preventive condition maintenance in response to the changes detailed earlier in this report. The revised requirement for preventive condition maintenance totals $251.3M for AA2, which is a significant reduction ($75.3M) to the forecasts indicated in the initial submission. Unit cost escalation consistent with the revised cost escalators has been included in the forecasts provided above. Western Power significantly enhanced its condition assessment programs over the course of AA1 in line with good industry practice. It used the latest find rates for defective work to determine forecast work volumes and expenditures based on the latest actual costs available.

The ERA's concerns in paragraphs 417 and 418 of the Draft Decision, and discussed above with respect to preventive routine maintenance, are also relevant to preventive condition maintenance, in particular vegetation management activities. Western Power confirms that there has been no new safety and environmental regulations in respect to vegetation management, although the regulations are currently under review by Energy Safety. The increased expenditures are to improve levels of compliance with existing regulations.

5.7.1 Distribution Preventative Condition

Detailed justifications for the expenditure increases from 2008/09 actual costs in the distribution preventative condition category are provided below, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-17 Distribution Preventative Condition – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – includes original escalation rate)	91.2	93.1	95.9	**280.2**
ERA Draft Determination (no escalation)	40.6	46.7	53.7	**141.0**
ERA Draft Determination including new escalation rate	**41.9**	**48.9**	**58.1**	**148.9**

Table 5-18 Distribution Preventative Condition – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual Expenditure	48.1	48.1	48.1	**144.3**
Pole Maintenance	(2.0)	11.7	22.5	**32.2**
Vegetation Management	(2.4)	(0.4)	(0.4)	**(3.2)**
Additional Emergency Generation	(0.3)	6.0	6.0	**11.7**
Asset Growth	0.1	0.5	2.2	**2.8**
Backlog Volume	1.5	2.7	24.1	**28.3**
Other Miscellaneous	(6.2)	(2.0)	0.7	**(7.6)**
Escalation	1.3	2.2	4.4	**8.0**
New Proposed (Real – new escalation rate)	**40.1**	**68.8**	**107.6**	**216.5**

Table 5-17 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-18 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Each of the line items in Table 5-18 is discussed below.

Pole Maintenance

This activity includes pole top maintenance, conductor work, white ant treatment and other miscellaneous repairs and represents the largest increase in this category. This work is aimed at mitigating the highest asset related risks including bushfires, mechanical damage and electric shocks. Forecast pole maintenance volumes are shown in Table 5.19.

Table 5-19 Distribution Pole Maintenance Forecast

	08/09	09/10	10/11	11/12	TOTAL
Actual Volume replaced	13,435				
New Volumes based on find rate		35,900	36,000	36,200	**108,100**
Constrained Volume (excl Growth & Backlog)		11,400	25,000	35,600	**72,000**
Rate ($) per pole	1,013.24	1,013.24	1,013.24	1,013.24	
Expenditure ($M)	13.6	11.6	25.3	36.1	
Variance from 2008/09 Expenditure		**(2.0)**	**11.7**	**22.5**	**32.2**

The forecast has been revised based on actual find rates of 0.21 defects per pole inspection in 2008/09. The severity of these defects requires remediation within twelve months. Other defects were identified but not included in the find rate as they can be managed through to the next inspection cycle.

The increase in find rates are in part due to significant work Western Power has undertaken in enhancing its inspection practices over the last 2 years. This find rate is expected to be sustained over AA2 until one full inspection cycle has been completed. Enhancements to the delivery of this work have seen efficiency improvements with a reduced unit rate based on 2008/09 actual cost being used.

Vegetation Management

Increases in vegetation management were justified in the initial submission; however a revised contracting strategy[15] and reduced find rates in 2008/09 have led to a reduced forecast.

Additional Emergency Generation

Western Power has a requirement under the Electricity Industry (Network Quality and Reliability of Supply) Code 2005, where practicable to supply generators for customer supplies if planned outages are expected to exceed 6 hours or 4 hours on days where the temperatures are expected to exceed 30 degrees.

This activity was justified in the initial submission; however the prioritisation of available funding in 2009/10 has deferred its start to the following year. The risk is that more customers will be off supply longer than otherwise would have been the case, but the impact is small and has been reflected in the revised services standards.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

[15] Western Power's Contracting Strategy DM 6218320

Volumes of new assets are estimated for each activity based on proposed capital spends and unit costs. The new unit cost rates for maintenance are determined from the 2008/09 actual unit rates or specific contract rates if recently changed. The cost change due to asset growth is determined from the product of the above volume changes and unit rates for each activity.

Backlog volumes

Table 5-20 shows the projected condition backlog at June 30 of each year from 2008/09 to 2011/12.

Table 5-20 Distribution Preventive Condition Maintenance backlog volumes of defects

	08/09	09/10	10/11	11/12
Distribution Pole Maintenance	25,800	50,300	61,300	52,700
Line Easement Vegetation Maintenance	7,500	5,000	2,500	0
Overhead Switchgear Maintenance	1,500	2,200	2,700	2,600
Ground mounted Switchgear Maintenance	63,100	62,600	59,500	44,500
Substation Maintenance	11,400	13,400	14,800	12,800
Earthing Maintenance	13,200	17,300	20,000	18,100
Underground System Maintenance	10	60	100	120
Street Light Maintenance	5,800	5,700	5,400	4,000
Minor Asset Replacement	15,900	17,000	17,000	12,500

Table 5-21 shows the projected condition backlog clearance at June 30 of each year from 2008/09 to 2011/12.

Table 5-21 Distribution Preventive Condition Maintenance backlog clearance

	Backlog cleared 09/10 (Volume of defects)	Backlog cleared 10/11 (Volume of defects)	Backlog cleared 11/12 (Volume of defects)	Rate per unit ($)	Backlog cleared 09/10 ($M)	Backlog cleared 10/11 ($M)	Backlog cleared 11/12 ($M)
Pole Maintenance	0	0	8,600	1,000	0.0	0.0	8.7
Vegetation Management	2,500	2,500	2,500	500	1.3	1.3	1.3
OH Switchgear Maintenance	0	0	130	1,600	0.0	0.0	0.2
Ground Mounted Switchgear Maintenance	460	3,100	15,000	320	0.1	1.0	4.8
Substation Maintenance	0	0	2,000	390	0.0	0.0	0.8
Earthing Maintenance	0	0	2,000	640	0.0	0.0	1.2
Street Light Maintenance	80	300	1,400	1,200	0.1	0.4	1.6
Minor Asset Replacement	0	80	4,400	1,200	0.0	0.1	5.5
Total Backlog					**1.5**	**2.7**	**24.1**

It is vital that a sustainable level of expenditure is targeted at clearing defects at a rate that is consistent with the find rate; otherwise backlogs will eventuate and increase over time. Appropriately managing the level of condition based work is a requirement of both the *Electricity (Supply Standards and System Safety) Regulations* 2001 and the licence conditions under the *Energy Operators Act* 2005.

The backlog resulting from the AA1 period combined with the available budget for 2009/10 will result in increased backlogs in most work categories. The purpose of reducing these backlogs is to:

- ensure that assets are maintained in accordance with policies and that service levels are maintained,
- reduce the level of equipment failures and emergency maintenance and consequent public safety risks such as bushfires and electric shocks, and
- comply with the ERA notice requiring action to address outstanding backlog volumes.

Sufficient expenditure is sought to reduce the distribution backlog by the end of the next regulatory period. Resourcing constraints prevent clearing the backlog at a faster rate. The majority of the expenditure is targeted at the overhead network consistent with the risk based approach of prioritising work to mitigate the risk of bushfires, electric shock, and reliability impacts.

5.7.2 Transmission Preventative Condition

Detailed justifications for the expenditure increases from 2008/09 actual costs in the transmission preventative condition category are provided below, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-22 Transmission preventative Condition – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – includes original escalation rate)	14.2	14.9	17.2	**46.4**
ERA Draft Determination (no escalation)	8.4	9.7	11.1	**29.1**
ERA Draft Determination including new escalation rate	**8.7**	**10.1**	**11.6**	**30.4**

Table 5-23 Transmission preventative Condition – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual Expenditure	8.6	8.6	8.6	**25.8**
Substation Transformer Reclamping	0.3	0.6	0.6	**1.5**
Plant & Building Mods / Refurbishment	(0.1)	0.7	0.6	**1.2**
Asset Growth	0.0	0.6	1.1	**1.7**
Backlog volume	0.0	2.1	0.7	**2.8**
Other miscellaneous	(0.2)	0.3	0.3	**0.5**
Escalation	0.3	0.4	0.5	**1.2**
New Proposed (Real – new escalation rate)	**8.9**	**13.4**	**12.5**	**34.8**

Table 5-22 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-23 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Line items from table 5-23 are discussed in turn.

Substation transformer reclamping

This is an ongoing project and was justified in the initial submission. For a particular model of 27MVA transformer, a type fault has led to catastrophic failure. Rather than replace these units, a cost effective repair strategy has been implemented and prioritised based on risk of failure. Budget prioritisation in 2008/09 meant that no units could be repaired, and fortunately no units failed during the year. Several of these transformers have failed in previous years while on the list to be repaired.

Plant & Building Mods / Refurbishment

The control and removal of asbestos from Western Power's network assets ensures compliance with the Code of Practice for the Management and Control of Asbestos in Workplaces [NOHSC: 2018 (2005)].

It is a statutory requirement to inspect asbestos material remaining on site on a regular basis (every 3 – 5 years depending on the risk) by a suitably qualified person. The asbestos register will be updated at the completion of the inspection work.

Ad hoc asbestos removal and management was justified in the initial submission, but the available budget for 2009/10 has meant deferring this activity to the following years of the AA2 period. The impact is a delay in meeting the compliance obligation. Works practices at sites containing asbestos are adequate to manage the health risk.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures

Over the last 3 years, 23 new or upgraded substations have been installed with plant items that need to be inspected and maintained, representing an increase of 5% per annum. Additional new circuits in existing substations also require inspection and maintenance. Plans are well advanced for 9 new substations and 17 new transformers at existing sites in years 2009/10 and 2010/11, representing a growth increase of approximately 3% per annum.

Failure to adequately cater for the maintenance requirements of new assets will ultimately mean that some equipment cannot be maintained in accordance with maintenance policies and backlogs will be incurred. Increasing backlogs lead to increased levels of equipment failure.

Backlog volumes

Table 5-24 shows the projected condition backlog at June 30 of each year from 2008/09 to 2011/12.

Table 5-24 Transmission Preventive Condition Maintenance backlog volumes of defects

	08/09	09/10	10/11	11/12
Line Easement Vegetation Maintenance	110	650	510	30
Overhead Lines Maintenance	36	50	0	0
Plant & Building Mods / Refurbishment	0	110	9	0
Condition Monitoring	0	18	23	23
Plant Test Failure Replacement	0	4	7	8
Protection Mods / Refurbishments	0	6	17	28
Investigative / Triggered Maintenance	0	7	10	12

Table 5-26 shows the projected condition backlog at June 30 of each year from 2008/09 to 2011/12.

Table 5-26 Transmission Preventative Condition - Backlog

	Backlog cleared 09/10 **(Volume of defects)**	Backlog cleared 10/11 **(Volume of defects)**	Backlog cleared 11/12 **(Volume of defects)**	Rate per unit ($)	Backlog cleared 09/10 ($M)	Backlog cleared 10/11 ($M)	Backlog cleared 11/12 ($M)
Line Easement Vegetation Maintenance	140	140	480	796	0.1	0.1	0.4
Earthing Maintenance	0	0	2	3,538	0.0	0.0	0.0
Overhead Lines Maintenance	54	54	0	21,907	1.2	1.2	0.0
Plant & Building Mods / Refurbishment	100	100	9	7,279	0.7	0.7	0.1
Substation Primary Plant Maintenance	46	46	87	2,210	0.1	0.1	0.2
Total Backlog ($M)					**2.1**	**2.1**	**0.7**

It is vital that a sustainable level of expenditure is targeted at clearing defects at a rate that is consistent with the find rate; otherwise backlogs will eventuate and increase over time. Appropriately managing the level of condition based work is a requirement of both the *Electricity (Supply Standards and System Safety) Regulations* 2001 and the licence conditions under the *Energy Operators Act* 2005.

The backlog resulting from the AA1 period combined with the available budget for 2009/10 will result in increased backlogs in most work categories. The purpose of reducing these backlogs is to:

- ensure that assets are maintained in accordance with policies and that service levels are maintained,
- reduce the level of equipment failures and emergency maintenance and consequent public safety risks such as bushfires and electric shocks, and
- comply with the 2008 ERA notice requiring action to address outstanding backlog volumes.

Sufficient expenditure is sought to effectively clear the Transmission backlog by June 2012. Resourcing constraints prevent clearing the backlog at a faster rate.

5.8 Corrective deferred maintenance

Corrective deferred maintenance forecast expenditure it to repair of failed or damaged equipment that does not present an emergency situation. These works usually arise following an emergency supply restoration where the supply is restored and/or the situation has been made safe and crews can be scheduled to complete the works at a later stage. The revised expenditure for these activities is provided in Table 5-26.

Table 5-26 Corrective deferred maintenance expenditure ($M)

Corrective deferred	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	3.4	4.8	5.7	4.3	7.9	8.3
Transmission % change per annum		41.2	18.8	-24.6	83.7	5.1
Distribution - cost	27.3	27.7	16.7	11.3	16.7	17.9
Distribution % change per annum		1.5	-39.7	-32.3	47.8	7.2
Total - cost	30.7	32.5	22.4	15.6	24.6	26.3
Total % change		5.9	-31.1	-30.4	57.7	6.9

In the Draft Decision (paragraphs 450-452), the ERA points out an apparent inconsistency with the increased preventive maintenance activities and corresponding rising trend in corrective maintenance costs, rather than these costs remaining approximately constant in real terms.

In the Draft Decision (paragraphs 454 and 455), the ERA considered the indicative forecasts for corrective deferred maintenance provided by Western Power in the May 2009 Letter. The ERA concluded that Western Power had not provided sufficient information to justify why the anticipated revised forecasts incorporate a large reduction in expenditure in 2009/10 ($20.01M) from the initial submission and then a progressive increase over the period, such that forecast expenditure in 2011/12 ($35.66M) returns to the same levels as in the initial submission. Forecast amounts for 2009/10 were accepted. Forecast amounts with year-to-year increases were limited to 15 per cent, with the real cost escalation removed, were recommended for 2010/11 and 2011/12.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. Western Power has now completed its review of the forecasts for corrective deferred maintenance in response to changes detailed in section 2 of this report. The revised requirement for corrective deferred maintenance totals $66.5M for AA2, which is a significant reduction to the forecasts indicated in the initial submission ($30.5M). Unit cost escalation consistent with the revised cost escalators has been included in the forecasts provided above.

The expenditure level for 2009/10 has been constrained to suit the State budgeting requirements, which preceded the Draft Decision. This has lead to lower levels of expenditure in 2009/10 when compared to the forecasts proposed in the initial submission. As discussed in the preventive routine maintenance section 5.5, the impact of this will be a rise in the work backlog, that is, a deferral of repair work into future years. In order to limit the impact of the work backlogs on service deliverables, increased expenditure is planned for 2010/11 and 2011/12. Western Power notes that the proposed forecast expenditure will not address the current backlog of work, but aims to maintain the backlog at around the current levels in the longer term.

Western Power notes that there are a number of activities in this expenditure category that are not related to the amount of preventative maintenance undertaken on the network. For example “Dial Before You Dig” services, graffiti cleanup, vandalism, power quality investigations, and car versus pole costs. A number of these activities have been transferred to the Non Reference Services category.

5.8.1 Distribution Corrective Deferred

Detailed justifications for the expenditure increases from 2008/09 actual costs in the distribution corrective deferred category are provided in table 5-28, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-27 Distribution Corrective Deferred – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real - includes original escalation rate)	23.3	25.7	28.5	**77.5**
ERA Draft Determination (no escalation)	15.6	17.8	20.5	**53.9**
ERA Draft Determination including new escalation rate	**15.9**	**18.4**	**21.3**	**55.5**

Table 5-28 Distribution Corrective Deferred – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual expenditure	**13.4**	**13.4**	**13.4**	**40.2**
Emergency follow-up corrective maintenance underground	0.2	1.0	2.3	**3.5**
PQ Investigation	(0.8)	0.4	(0.5)	**(0.9)**
Asset Growth	0.0	0.6	1.2	**1.8**
Other miscellaneous	(1.9)	0.7	0.8	**(0.4)**
Escalation	0.4	0.5	0.7	**1.6**
New Proposed (Real – new escalation rate)	**11.3**	**16.7**	**17.9**	**45.9**

Table 5-27 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-28 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Line items in table 5-28 are discussed below.

Emergency follow-up corrective maintenance (Underground)

This activity involves the permanent repair of temporarily repaired underground network assets such as switchgear and cables.

Western Power took a risk based approach to managing the 2008/09 budget and had to slow down work on this activity to approximately a third of the previous two years levels.

There is a significant corrective deferred backlog which in August 2009 totalled 8,100 work orders and the increased forecast expenditure in 2010/11 and 2011/12 reflect clearing the highest priority work on backlog and an achievable level of work activity, notwithstanding the increased levels of preventative maintenance.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex as the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures

The methodology uses the ratio of the above total cost change due to growth for preventative routine to the total unconstrained cost of preventative routine (excluding backlog). This ratio is then multiplied by the unconstrained dollars for each activity in the corrective categories to get the cost change due to growth.

5.8.2 Transmission Corrective Deferred

Detailed justifications for the expenditure increases from 2008/09 actual costs in the transmission corrective deferred category are provided below, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-29 Transmission Corrective Deferred – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real - includes original escalation rate)	5.7	6.5	7.2	**19.5**
ERA Draft Determination (no escalation)	4.5	5.2	5.9	**15.6**
ERA Draft Determination including new escalation rate	**4.6**	**5.4**	**6.3**	**16.3**

Table 5-30 Transmission Corrective Deferred – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual expenditure	5.7	5.7	5.7	**17.1**
Backlog	0.0	1.0	0.6	**1.6**
Asset Growth	0.2	0.3	0.6	**1.1**
Environmental Cleanup	(0.4)	1.1	1.0	**1.7**
Substation Primary Plant	(1.3)	(1.0)	(0.8)	**(3.1)**
Emergency follow-up corrective maintenance U/G & O/H	0.3	0.9	1.0	**2.2**
Other miscellaneous	(0.3)	(0.3)	(0.1)	**(0.7)**
Escalation	0.1	0.3	0.3	**0.7**
New Proposed (Real – new escalation rate)	**4.3**	**7.9**	**8.3**	**20.6**

Table 5-29 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-30 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Line items in table 5-30 are discussed below.

Backlog

There is a significant corrective deferred backlog which in August 2009 totalled 12,100 work orders. The increases in 2010/11 and 2011/12 reflect clearing the highest priority work on backlog and an achievable level of work activity, notwithstanding the increased levels of preventative maintenance.

Asset Growth

The same approach as described for the transmission preventative condition category is used to forecast the growth impact.

Environmental Cleanup

A requirement to remediate contamination at a former Western Power depot in Wagin in accordance with the Contaminated Sites Act accounts for the majority of this increase. Failure to undertake this work may lead to legal action and fines with associated reputational impacts.

Emergency follow up corrective maintenance

Removal of redundant assets was identified in the initial submission and has been allocated to this category. However only highest risk work will be undertaken in 2009/10 and the remainder has been re-profiled over 2010/11 and 2011/12.

Western Power's policy is to remove redundant assets after 4 years from being formally disconnected from the network. Redundant assets are typically old and in poor condition and therefore have an inherently high risk of failure. Failing to undertake this work exposes Western Power to public safety risks including mechanical damage and bushfire.

5.9 Corrective emergency maintenance

Corrective emergency maintenance forecast expenditure relates to maintenance activities carried out to immediately restore supply or make a site safe following equipment failure, usually as a result of an accident, unplanned equipment failure or inclement weather. The need for this type of work usually arises without warning and the work is performed immediately to establish restoration of supply, ensure safety to the public and personnel, and to prevent further damage to equipment. The revised expenditure for these activities is provided in Table 5-31.

Table 5-31 Corrective emergency maintenance expenditure ($M)

Corrective emergency	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	1.7	1.8	1.2	1.9	2.2	2.6
Transmission % change per annum		5.9	-33.3	58.3	15.8	18.2
Distribution - cost	55.7	59.6	64.5	70.6	74.0	76.6
Distribution % change per annum		7.0	8.2	9.5	4.8	3.5
Total - cost	57.4	61.4	65.7	72.5	76.2	79.3
Total % change per annum		7.0	7.0	10.4	5.1	4.1

In the Draft Decision (paragraphs 450-452), the ERA points out an apparent inconsistency with the increased preventative maintenance activities and corresponding rising trend in corrective maintenance costs, rather than these costs remaining approximately constant in real terms.

In the Draft Decision (paragraphs 454 and 455), the ERA considered the indicative forecasts for corrective emergency maintenance provided by Western Power in the May 2009 Letter. The ERA concluded that Western Power had not provided sufficient information to justify why the anticipated revised forecasts incorporate a large reduction in expenditure in 2009/10 ($59.92M) from the initial submission and then a progressive increase over the period, such that forecast expenditure in 2011/12 ($81.88M) returns to the same levels as in the initial submission. Forecast amounts for 2009/10 were accepted. Forecast amounts with year-to-year increases limited to 15 per cent, with the real cost escalation removed, were recommended for 2010/11 and 2011/12.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. Western Power has reviewed the forecasts for corrective emergency maintenance in response to the changes detailed earlier in this report. The revised requirement for corrective emergency maintenance totals $228.0M for AA2, which is a slight reduction to the forecasts indicated in the initial submission. Unit cost escalation consistent with the revised cost escalators has been included in the forecasts provided above.

5.9.1 Distribution Corrective Emergency

Detailed justifications for the expenditure increases from 2008/09 actual costs in the distribution corrective emergency category are provided in table 5-32 and 5-33, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-32 Distribution Corrective Emergency – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – includes original escalation rate)	71.0	74.3	78.5	**223.8**
ERA Draft Determination (no escalation)	58.0	66.8	76.8	**201.6**
ERA Draft Determination including new escalation rate	**60.4**	**69.2**	**79.9**	**209.5**

Table 5-33 Distribution Corrective Emergency – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual expenditure	**64.5**	**64.5**	**64.5**	**193.5**
Primary Response Group	2.3	2.7	4.4	**9.4**
Additional Emergency Generation	(0.4)	2.2	2.7	**4.5**
Streetlights	1.3	0.2	(1.6)	**(0.1)**
Asset Growth	0.0	1.8	3.2	**5.0**
Other miscellaneous	0.6	0.1	0.3	**1.0**
Escalation	2.3	2.4	3.1	**7.9**
New Proposed (Real – new escalation rate)	**70.6**	**74.0**	**76.6**	**221.2**

Table 5-32 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-33 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Table 5-33 line items are discussed below.

Primary Response Group

Primary response activity involves the making safe, restoring supply and affecting a permanent or temporary fix to faults that occur on the network. It is non-discretionary in that it must be undertaken otherwise customers are left without supply. If the level of expenditure in this category is inadequate and fault activity is greater than expected then typically preventative work must be curtailed to remain within budget parameters.

Over the AA1 period, despite increasing levels of preventive maintenance, fault activity on the distribution network has continued to increase. Coupled with continuing increases in backlogs in 2009/10 due to a real reduction in preventive maintenance work (compared with 2008/09 levels), increased corrective emergency expenditure in 2009/10 will be required. Based on trend analysis an additional $9.4M expenditure is forecast over the AA2 period.

Additional Emergency Generation

Emergency generators are used following failure of significant items of equipment where there is likely to be extended outage duration due to the scale of the repair. In these situations emergency generators are deployed to restore customer supplies. This is consistent with good industry practice across Australia.

This activity was justified in the initial submission, however the prioritisation of works in 2009/10 to meet the available budget has meant deferring the leasing an additional 15 units to the following year. The risk is that more customers will be without supply longer than otherwise would have been the case, but the impact is small at less than 1 SAIDI minute, and has been reflected in the revised services standards.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex because the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

The method for calculating corrective emergency maintenance due to asset growth uses the ratio of the above total cost change due to growth for preventative routine maintenance to the total unconstrained cost of preventative routine maintenance (excluding backlog). This ratio is then multiplied by the unconstrained dollars for each activity in the corrective categories to determine the cost change due to growth.

5.9.2 Transmission Corrective Emergency

Detailed justifications for the expenditure increases from 2008/09 actual costs in the transmission corrective emergency category are provided in Tables 5-34 and 5-35, including reference to relevant regulatory and / or compliance level changes driving these expenditures.

Table 5-34 Transmission Corrective Emergency – Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real - includes original escalation rate)	3.0	3.3	3.4	**9.7**
ERA Draft Determination (no escalation)	1.8	2.1	2.5	**6.4**
ERA Draft Determination including new escalation rate	**1.9**	**2.2**	**2.6**	**6.7**

Table 5-35 Transmission Corrective Emergency – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual expenditure	**1.2**	**1.2**	**1.2**	**3.6**
Emergency Maintenance - O/H & U/G	0.4	0.5	0.6	**1.5**
Emergency Maintenance - Substation	0.1	0.3	0.4	**0.8**
Asset Growth	0.0	0.2	0.3	**0.5**
Other miscellaneous	0.1	0.0	0.0	**0.1**
Escalation	0.1	0.1	0.1	**0.2**
New Proposed (Real – new escalation rate)	**1.9**	**2.2**	**2.7**	**6.8**

Table 5-34 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-35 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Table 5-35 line items are discussed below.

Emergency Maintenance (Overhead & Underground)

This activity involves the emergency response to faults on transmission cables and lines in order to make safe and carry out repairs. It is non-discretionary in that it must be undertaken otherwise customers are left without supply and system security criteria may be compromised. If the level of expenditure in this category is inadequate and fault activity is greater than expected then typically preventative work must be curtailed to remain within budget parameters.

Expenditure in 2008/09 was approximately 50% of the previous two years. This is considered unusually low, and as such it is considered prudent to forecast an additional $1.5M over the AA2 period for this activity.

Emergency Maintenance - Substation

This activity involves the emergency response to faults on substation and terminal station plant in order to make safe and carry out repairs. It is non-discretionary in that it must be undertaken otherwise customers are left without supply and system security criteria may be compromised. If the level of expenditure in this category is inadequate and fault activity is greater than expected than typically preventative work must be curtailed to remain within budget parameters.

The trend in 2008/09 showing increasing defects in substations coupled with a continuing backlog of work and deferment of the asset replacement program mean that an increase in the number of faults is likely, notwithstanding an increase in forecast preventative maintenance expenditures. Expenditure in 2008/09 was approximately 80% of the previous two years. This is considered unusually low, and as such it is considered prudent to forecast an additional $0.8M over the AA2 period for this activity.

Asset Growth

As the growth driven Capex program adds new assets to the network there is a compounding impact on the forecast Opex because the newly commissioned assets will require inspection, operation and potentially emergency maintenance expenditures.

The method for calculating corrective emergency maintenance due to asset growth uses the ratio of the above total cost change due to growth for preventative routine maintenance to the total unconstrained cost of preventative routine maintenance (excluding backlog). This ratio is then multiplied by the unconstrained dollars for each activity in the corrective categories to determine the cost change due to growth.

5.10 Network operations

The network operations expenditure forecasts relate primarily to the Network Operation Control Centre (NOCC). The primary driver for expenditure is the quantity of distribution network access requests that must be managed by the NOCC. The revised expenditure for this activity is provided in Table 5-36.

Table 5-36 Network operations - Expenditures ($M)

Network operations	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	6.4	12.6	10.5	13.6	14.3	14.6
Transmission % change per annum		96.9	-16.7	29.5	5.1	2.1
Distribution - cost	13.1	10.7	15.8	20.1	21.2	21.9
Distribution % change per annum		-18.3	47.7	27.2	5.5	3.3
Total - cost	19.5	23.3	26.3	33.7	35.5	36.5
Total % change per annum		19.5	12.9	28.1	5.3	2.8

The ERA reviewed the forecasts for Network Operations in the initial submission which totalled $101.02M (excluding real cost escalation), and accepted that these amounts were consistent with the requirements of section 6.40 of the Access Code. The ERA then received the indicative forecasts provided by Western Power in the May 2009 Letter which totalled $84.60M and as these amounts were lower than the amounts considered acceptable in its detailed review, the ERA amended the amounts to be included in the Access Arrangement to equal the lower forecasts.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. In the case of Network Operations the reduction indicated was overstated. The revised requirement for Network Operations totals $105.6M (including revised cost escalation) for the regulatory period, which is a slight increase to the forecasts indicated in the initial submission.

Table 5-37 Network Operations – Forecast Expenditures ($M)

	09/10	10/11	11/12	TOTAL
Initial submission (Real – includes original escalation rate)	33.0	35.8	37.9	**106.7**
ERA Draft Determination (no escalation)	26.2	28.1	30.2	**84.5**
ERA Draft Determination including new escalation rate	**27.3**	**29.3**	**31.7**	**88.3**

Table 5-38 Network Operations – Variance Drivers from 2008/09 Actual ($M)

	09/10	10/11	11/12	TOTAL
2008/09 Actual Expenditure	26.3	26.3	26.3	**78.9**
New Metro South Desk	2.2	3.0	3.8	**9.0**
Additional Daytime Desk	0.4	0.8	1.2	**2.4**
Increased SCADA & Information Systems functions	0.4	0.8	0.8	**2.0**
Increased Work Volume	0.2	0.4	0.8	**1.4**
Embedded Power Generation	1.2	1.3	1.4	**3.9**
Other miscellaneous	1.9	1.7	0.7	**4.3**
Escalation	1.1	1.2	1.5	**3.8**
New Proposed (Real – new escalation rate)	**33.7**	**35.5**	**36.5**	**105.6**

Table 5-37 compares the expenditures proposed in the initial submission and those set out in the ERA Draft Decision, while Table 5-38 sets out the revised proposed expenditures and the variances from the 2008/09 actual expenditures. Table 5-38 line items are discussed below.

New Metro South Desk

Proposed expenditures cover establishment of a new Metro South Desk with 24x7 operations to address the growing workloads in planned and unplanned switching activities from the SWIS network asset replacement and maintenance program. This will require an additional 19 staff over the AA2 period including network operations controllers, distribution switching programme writers, operations reliability and capacity engineers, and other supporting staff.

Additional Daytime Desk

Creation of an additional daytime desk in the System Operations Control Centre control room will relieve network access bottlenecks caused by the increased planned and unplanned transmission network switching activities associated with increased capital project, asset replacement and maintenance work on the SWIS transmission network. The additional desk will require an extra 6 technical staff over the AA2 period including system operations controllers, switching coordinators, a manager and an administrative assistant.

Increased SCADA and Information Systems Functions

SCADA and Information Systems has taken on management of the new ENMAC based Trouble Call System as well as management of the country distribution SCADA. Also associated with the increased capital expenditure on the SWIS distribution (including distribution automation) and transmission networks is an increase in SCADA display and database work as new capital projects are commissioned onto the SWIS. This has required the addition of 4 SCADA technical and support staff over the AA2 period. It should be noted that the requirement for additional staff has been mitigated by efficiency improvements realised in SCADA and project work process design. Annualised operating costs associated with a long term software upgrade and maintenance agreement to provide realignment of the highly customised SCADA hardware and software to the standard XA21 product are also included. This will avoid a later costly and risky change out of the system as has been required with previous systems and will also ensure continuity of vendor support.

Increased Work Volumes

With the increased work volumes associated with the increased capital project, asset replacement and maintenance work, an additional 4 System Operations Planning technical staff over the AA2 period will be required to manage the increase in network studies and planned outage approvals.

Embedded Power Generation

This expenditure provides embedded power generation at Ravensthorpe for peak lopping generation to support the nickel facility. It is sufficient to fund two more similar projects elsewhere in the SWIS distribution system. This is consistent with the current funding provided for Bremer Bay as part of the 'Edge of Grid' project. Embedded power generation Opex mainly funds fuel for generators. Embedded power generation is a more prudent and economical solution at edge of grid, compared to building additional power lines.

5.11 SCADA and communications

The SCADA and communications forecast expenditure relates to the operation and maintenance of the radio network including licences, strategic planning and network optimization for the SCADA, communications systems and distribution automation as well as the SCADA field maintenance. The revised expenditure for these activities is provided Table 5-39.

Table 5-39 SCADA and communications expenditure ($M)

SCADA and communications	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	6.9	7.1	6.0	6.5	8.7	9.5
Transmission % change per annum		2.9	-15.5	8.3	33.8	9.2
Distribution - cost	1.4	1.2	0.9	0.9	1.4	1.6
Distribution % change per annum		-14.3	-25.0	0.0	55.6	14.3
Total - cost	8.3	8.3	6.9	7.4	10.1	11.1
Total % change per annum		0.0	-16.9	7.2	36.5	9.9

The ERA reviewed the forecasts for transmission and distribution SCADA and Communications in the initial submission which totalled $29.41M (excluding real cost escalation) and accepted that these amounts were consistent with the requirements of section 6.40 of the Access Code. The forecast amounts with the real cost escalation removed were recommended for inclusion in the revised Access Arrangement.

Western Power has reviewed the forecasts for SCADA and Communications in response to the changes detailed earlier in this report and using actual costs for 2008/09. The overall value of the forecasts is $27.4M (excluding cost escalation) or $28.6M (including revised cost escalators) which represents a slight decrease in the forecast compared with that recommended by the ERA in the Draft Decision. Unit cost escalation consistent with the revised cost escalators has been included in the forecasts provided above.

5.12 Miscellaneous network services (Non-reference services)

Forecast expenditure for miscellaneous network services (also referred to as non-reference services) relates to such works as those involved in the relocation of incumbent assets for industrial, commercial and residential land and property developments. The revised expenditure for these activities is provided in Table 5-40.

Table 5-40 Miscellaneous network services expenditure ($M)

Miscellaneous network services	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	10.6	5.4	1.8	0.9	0.9	0.9
Transmission % change per annum		-49.1	-66.7	-50.0	0.0	0.0
Distribution - cost	4.8	6.0	6.3	10.1	10.8	11.4
Distribution % change per annum		25.0	5.0	60.3	6.9	5.6
Total - cost	15.4	11.4	8.1	11.0	11.8	12.3
Total % change per annum		-26.0	-28.9	35.8	7.3	4.2

In the Draft Decision, the ERA reviewed the forecasts for miscellaneous network services in the initial submission which totalled $43.45M and accepted that these amounts were consistent with the requirements of section 6.40 of the Access Code. The ERA then received the indicative forecasts provided by Western Power in the May 2009 Letter which totalled $38.6M. As the 2009/10 amounts were lower than the amounts considered acceptable in its detailed review and the forecast expenditures for 2010/11 and 2011/12 remained approximately the same, the ERA amended the amounts to be included in the Access Arrangement to equal the lower forecasts.

Western Power advised that the forecasts provided in the May 2009 letter were indicative. Western Power has reviewed the forecasts for miscellaneous network services and the revised total cost is $35.1M. The overall value of the forecasts has decreased compared with that recommended by the ERA and is 19% lower than that proposed in the initial submission. The reduction is largely due to the declining trend established by the 2008/09 actual expenditures, which is thought to be a result of the GFC slowing the demand for non-reference services. Unit cost escalation consistent with the revised cost escalators has been included in the forecasts provided above.

5.13 Call centre

The Call Centre functions as a central “gateway” for Western Power in the form of an integrated Customer Service Centre. At the time of the initial submission, the Customer Services division was in the process of establishing the in-house call centre, previously outsourced to Synergy’s call centre. The call centre has now been established. The forecast costs of the call centre are shown in Table 5-41.

Table 5-41 Call centre expenditure ($M)

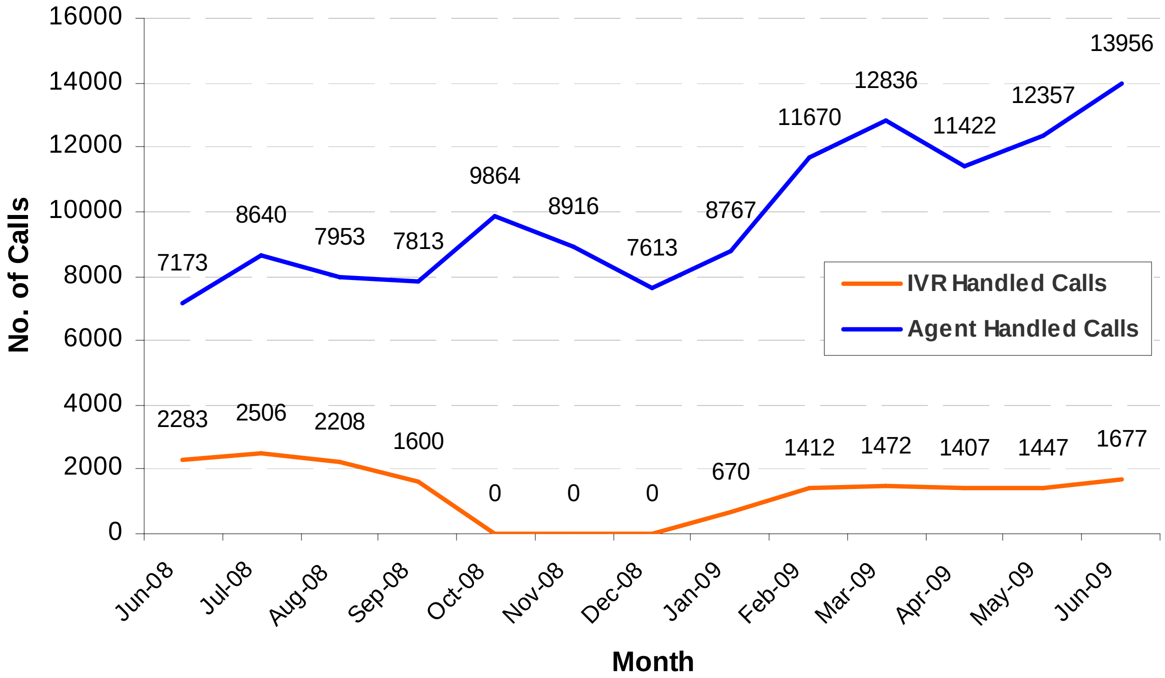
Call Centre	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	-	-	-	-	-	-
Transmission % change per annum		-	-	-	-	-
Distribution - cost	5.2	5.0	6.1	4.6	4.6	4.7
Distribution % change per annum		-3.8	22.0	-24.6	0.0	2.2
Total - cost	5.2	5.0	6.1	4.6	4.6	4.7
Total % change per annum		-3.8	22.0	-24.6	0.0	2.2

In its Draft Decision (paragraph 469 and table 39), the ERA states the forecast increases in this expenditure category can be entirely attributed to cost escalation. The ERA required an amendment to this forecast to remove escalation, but did not require any further reductions to the forecasts. The total amount included for Call Centre costs in the amended Opex total was $15.71M (excluding real cost escalation).

The revised Call Centre costs included in this Supplementary Submission totals $13.9M (including revised cost escalation). Since the transition from the Synergy call centre and the after hours service provided by East Perth office to the in-house call centre, Western Power has realized a number of efficiencies. Further efficiencies are forecast, which are expected to result in reduced overall costs despite expected increases in call volumes during the regulatory period.

Figure 5-8 shows the general increases in call volumes during 2008/09. As the expenditure forecast proposed in this Supplementary Submission is lower than the amount recommended by the ERA in the Draft Decision, no further justification is provided.

Figure 5-8 General Enquiries (not fault calls)



5.14 Metering

Metering services forecast Opex relates to the provision of the following meter and connection related services:

- regulatory inspections services,
- metering provision including field maintenance and laboratory activities, and
- data management including administration and meter reading.

The majority of the expenditure for meter reading and data management is directly related to the number of meters in the network. In re-forecasting metering expenditure, the expected number of meter readings has been reduced to reflect the downturn in new customer connections. The forecast expenditures are shown in Table 5-42.

Table 5-42 Metering expenditure ($M)

Metering	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	-	-	-	-	-	-
Transmission % change per annum		-	-	-	-	-
Distribution - cost	20.7	18.9	18.7	19.8	21.7	21.7
Distribution % change per annum		-8.7	-1.1	5.9	9.6	0.0
Total - cost	20.7	18.9	18.7	19.8	21.7	21.7
Total % change per annum		-8.7	-1.1	5.9	9.6	0.0

In its Draft Decision (paragraph 475), the ERA notes that the initial submission included an allowance for operation and maintenance of 'smart meters' in the forecast metering costs ($22M). Western Power confirms this was an error and has removed these costs from its forecast expenditure. The ERA required amendments to the proposed metering costs of $73.74M to exclude the $22M for smart meters and an amount for real cost escalation resulting in an amended total of $49.05M.

In revising the Metering costs Western Power has discovered an omission from the initial forecasts. Expenditure forecasts for IT costs for the metering sections were excluded from the initial submission. The proposed forecast in this Supplementary Submission totals $63.2M including revised cost escalation and metering IT costs, but excluding the smart meter costs as required.

5.15 Other (Non–recurrent)

Other Opex includes items that are non-recurrent in nature; i.e. expenditures that occur in one or more years, but do not reflect business as usual and are not expected to continue beyond the life of the program or issue that they relate to.

Table 5-43 below details the revised amounts of non-recurrent Opex that is forecast for the Western Power network. These amounts relate to asbestos removal from substations and the Field survey information capture project, alternative funding of training, and the energy solution R&D program in the distribution network.

Table 5-43 Non recurring opex expenditure ($M)

Non recurring opex	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission - cost	-	-	-	0.0	0.6	0.6
Transmission % change per annum					-	0.0
Distribution - cost	-	-	-	0.9	14.7	17.8
Distribution % change per annum					1533.3	21.1
Total - cost	-	-	-	0.9	15.3	18.4
Total % change					1600.0	20.3

In the Draft Decision (paragraphs 483, 485, 486 and 489) the ERA stated that it had received advice that the proposed non-recurrent costs were reasonable, but went on to question the level of proposed costs in a number of categories. The result of the ERA's consideration of individual items together with consideration of Western Power's indicative forecasts in the May 2009 letter was a requirement to reduce the proposed expenditure to $35.66M over the 3 year period.

Field Survey information project is retained in the forecast expenditures at $13.3M, which is consistent with the initial submission adjusted for new escalation rates.

The initial submission included $29.7M for training of staff and contractors over the AA2 period. This has been reduced to $14.5M over the AA2 period in this submission due to the reduction in size of the distribution Work Program and related labour force.

Western Power's initial submission included forecast research and development expenditure for Demand Side Management ($9.6M) and Energy Solutions projects ($16.7M). In response to the changes detailed in section 2 of this report, forecast expenditures have been reduced to $1.6M to support the Smart Grid pilot project, and $4.1M to support deployment of non-network solutions described in section 4.5 of this submission. Both initiatives are detailed in attachment 2.

Western Power has reviewed the proposed expenditure and revised the forecasts to $34.6M (including revised cost escalators) as outlined above. As this amount represents a slight reduction (in non escalated terms) on the amended forecasts accepted by the ERA, no further supporting data is provided.

5.16 Reliability-driven maintenance

Reliability driven Opex includes two specific categories of work, reliability initiated line patrols and automation maintenance Request for Repairs (RFR).The revised expenditure required for these activities is provided in Table 5-44.

Table 5-44 Reliability expenditure ($M)

Reliability	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission – cost*	-	-	-	-	-	-
Transmission % change per annum		-	-	-	-	-
Distribution - cost	3.7	1.5	0.7	2.9	3.1	3.2
Distribution % change per annum		-59.5	-53.3	314.3	6.9	3.2
Total - cost	**3.7**	**1.5**	**0.7**	**2.9**	**3.1**	**3.2**
Total % change per annum		-59.5	-53.3	314.3	6.9	3.2

**Note: There are no reliability expenditures proposed for the transmission network*

In its Draft Decision the ERA considered the increased reliability expenditure level indicated in Western Power's May 2009 letter and concluded that it was not unreasonable. The Amended forecast stated in the Draft Decision accepted expenditure of $2.83M, $1.05M and $1.11M for 2009/10, 2010/11 and 2011/12 respectively.

The reduction in reliability expenditure in 2010/11 and 2011/12 indicated in the May 2009 letter was an oversight and has been corrected in the table above. Western Power's revised forecast maintains the reliability Opex level accepted for 2009/10 and sustains this level of expenditure (with cost escalation) throughout the remainder of the regulatory period.

The ERA has already stated that it considers some increase in activities related to maintaining and improving the reliability of distribution services is reasonable and has accepted the costs of $2.83M in 2009/10. The programs of work anticipated by the 2009/10 forecast will continue throughout the regulatory period with similar levels of expenditure.

5.17 Business Support Costs

Business Support costs are the costs required to provide key corporate functions to the operational divisions of Western Power. As outlined in the initial submission Western Power has conducted some restructuring of the corporate functions to better align business support with the requirements of the growing Work Program and in a move to ensure maximum efficiency in terms of activity and financial investment across the business support areas.

Western Power's support divisions comprise of Finance, Human Resources (HR), Strategy and Corporate Affairs (S&CA), Legal and Governance, Chief Executive Officer (CEO) and the newly created Enterprise Solutions Partner (ESP). Business Support costs also incorporate costs for insurance, rates and taxes, the Energy Safety Levy, Design and Estimating, Fringe Benefits Tax (FBT), and Extended Outage Payments (EOP).

The revised forecasts for 2009/10 to 20011/12 are provided in Table 5-45, together with a summary of the actual costs for the first access arrangement period. Also shown are the Initial Submission Business Support Costs at a total level.

Table 5-45 Business support costs expenditure ($M Real)

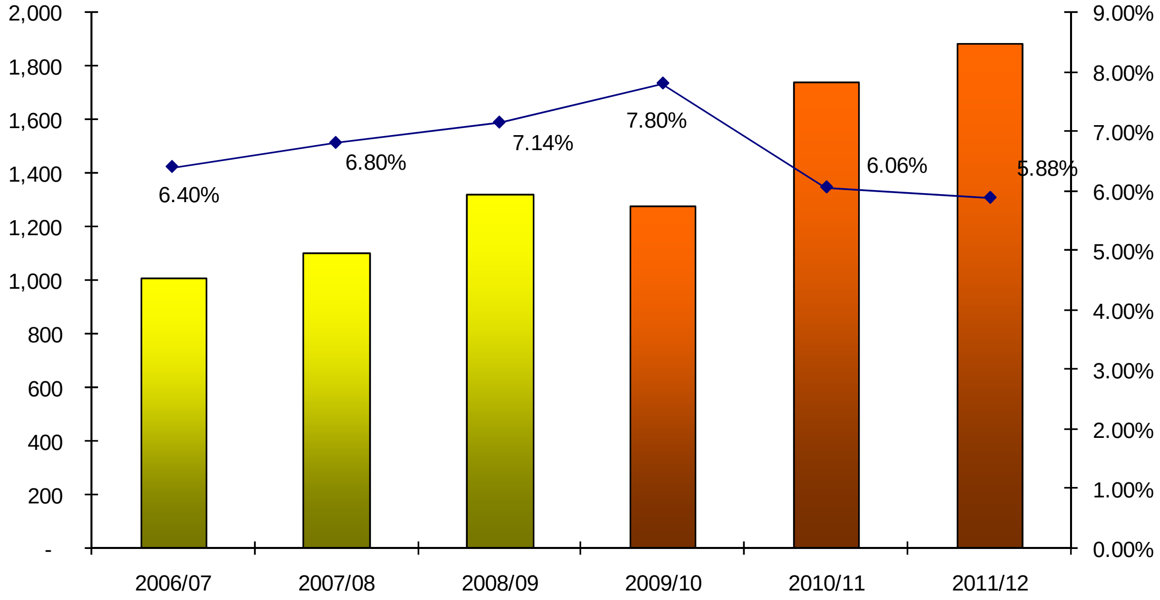
Business support costs	AA1 (Actual)			AA2 (Forecast)		
	06/07	07/08	08/09	09/10	10/11	11/12
Transmission – cost	18.3	20.3	24.6	26.8	28.2	29.5
Transmission % change per annum		11.2	20.9	9.1	5.4	4.6
Distribution - cost	46.3	54.5	69.8	72.8	77.1	81.1
Distribution % change per annum		17.9	28.0	4.3	5.9	5.2
Total – cost	**64.5**	**74.9**	**94.4**	**99.6**	**105.4**	**110.7**
Total % change per annum		16.0	26.1	5.5	5.8	5.0
Initial Submission Total – Cost			**90.1**	**104.0**	**106.7**	**109.5**
Variance from Initial Submission			4.3	(4.4)	(1.3)	1.2

The revised forecast for Business Support costs has decreased from the initial submission by $4.5M across the AA2 period. There are several drivers behind this movement and these are noted below and will be expanded upon further in the relevant section of the report.

- Insurance costs have increased by $11.1M across the AA2 period.
- There has been a net reduction in Non Discretionary payments of $5.7M. This section includes Rates & Taxes, Energy Safety Levy, Fringe Benefits Tax and Extended Outage Payments (EOP). The reduction is primarily driven by making less conservative assumptions on EOP payments required of the business.
- A reduction in Legal and Governance forecast expenditure and Design and Estimating expenditure of $4.0M in total.
- Functional indirect cost reviews carried out in 2008/09 have yielded savings in areas such as facilities management, contractors and consultancy spend. This has reduced the forecast across the AA2 period by $3.1M and further savings from these initiatives will be realised across the Work Program. In 2008/9 one-off restructuring costs of $3.1M were incurred in order to deliver these efficiencies through the AA2 period.
- Due to a forecast reduction in the rate of growth of the Work Program, there has been a reduction in the forecast growth in labour required in HR and Finance over the period 2010/11 to 2011/12 to support the smaller program. The HR growth rate has declined by 5%, from 20% p.a. to 15% p.a., whilst Finance growth rate has declined from 10% p.a. to 7.5% p.a. The impact of lower growth rates combined with forecast lower internal labour escalation rates across all divisions has reduced Business Support costs by $2.8M.

The forecast Business Support costs have been reviewed from an overall efficiency perspective considering business support costs as a proportion of the forecast total works program. Through the AA2 period Western Power forecasts economies of scale in 2010/11 and 2011/12 as Business Support becomes a lower proportion of the Work Program. At their peak Business Support costs represent 7.8% of the total works program spend in 2009/10, which declines to 5.9% by 2011/12.

Figure 5-9 Business Support expenditure as a % of Total Work Program Expenditure (Opex & Capex) ($M Real)

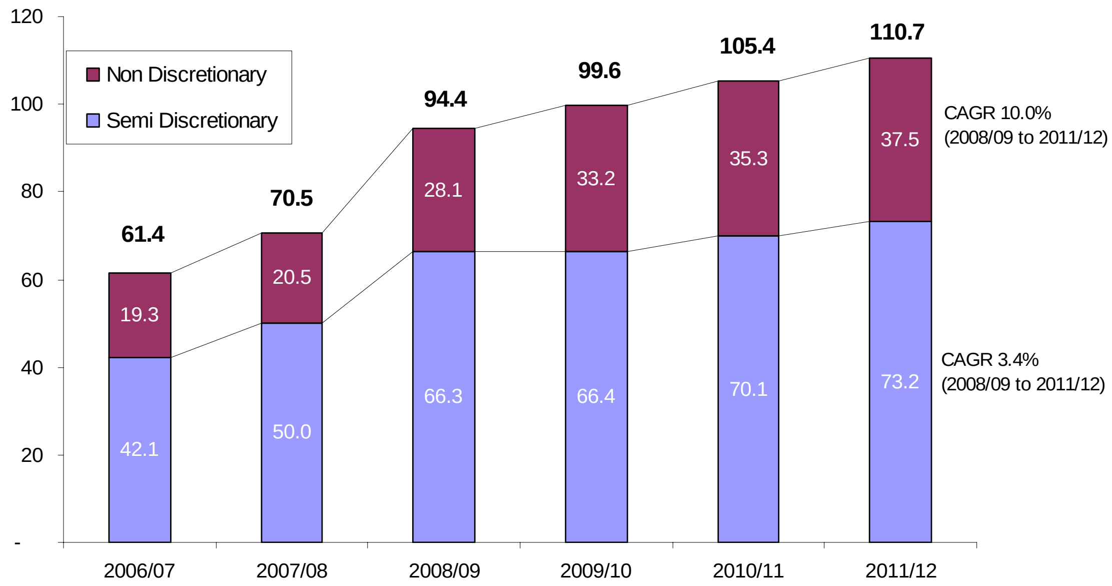


Within the Business Support costs category there are sub categories which Western Powers is able to strongly influence and control (Semi Discretionary) and those that are controlled and influenced by external forces such as taxation regimes and regulation (Non Discretionary) and are effectively outside of Western Power's control. Applying the broad categorization to these costs and charting the respective growth rates for each demonstrates that much of the growth in Business Support costs from the period 2008/09 to the forecast for 2011/12 is in the Non Discretionary category which has grown at a Compound Annual Growth Rate (CAGR) of 10.0% compared with a 3.4% CAGR for the internally driven costs.

Semi discretionary divisional expenditure is considered to be - Finance, Human Resources (HR), Strategy and Corporate Affairs (S&CA), Legal and Governance, Chief Executive Officer (CEO), the newly created Enterprise Solutions Partner (ESP).

Non discretionary expenditure is considered to be - Insurance, rates and taxes, the Energy Safety Levy, Fringe Benefits Tax (FBT), and Extended Outage Payments (EOP), and design and estimating costs.

Figure 5-10 Total Business Support expenditure split between Non Discretionary and Semi Discretionary ($M Real)



2006/07 and 2007/08 costs shown above exclude Motor Vehicles & Workers Compensation Insurance to create a like for like comparison with AA2 expenditure (refer to section 1.1.6 on Insurance for details).

Efficiencies Program – Operational Excellence

The Enterprise Solutions Partner (ESP) Division was established early in 2008/9, with a number of Enterprise-wide strategically important programs, including SPOW (Strategic Program Of Works), VISTA (a major refurbishment program of key Western Power sites), and Operational Excellence.

The Operational Excellence (OE) branch and program were established as Western Power's principal tool for leveraging efficiencies across the business.

External consultants were used to apply benchmarking and extensive cost analysis against 2008/09 forecast expenditures to deliver $17M of efficiencies across the business. This is the Functional Indirect Cost program. The vast majority of these efficiencies have been realised in the regulatory categories of spend within the Work Program, and efficiencies are expected across the Capex and Opex components of the Work Program annually from 2009/10.

Also within Operational Excellence, an accredited process efficiency framework (LEAN Six Sigma) has been deployed. Recognising a lack of in-house capability, this framework was introduced through the use of external consultants. Toward the end of June 2009, the reliance on consultants has significantly reduced in favour of an internal capability, nurtured and developed in-house through the creation of a team of Black Belt project managers. Working together with other business resources, these individuals have developed process improvements under the banner of the Operational Value Chain. There is $11.1M of savings from 2009/10 which are committed across the Capex and Opex components of the Work Program. These are not reflected in this submission, as we have not completed the process of identifying in which regulatory category those savings land.

The costs for OE are $3.7M in 2008/9, plus a further $3.1M one-off restructuring cost. The savings described above of $28M are real evidence of the current success which this efficiencies program will deliver, in 2009/10, and successive years.

The orientation of OE through 2009/10 is to examine and target efficiency improvements across the Enterprise, which will each yield $25M Net Present Cost savings across 5 years.

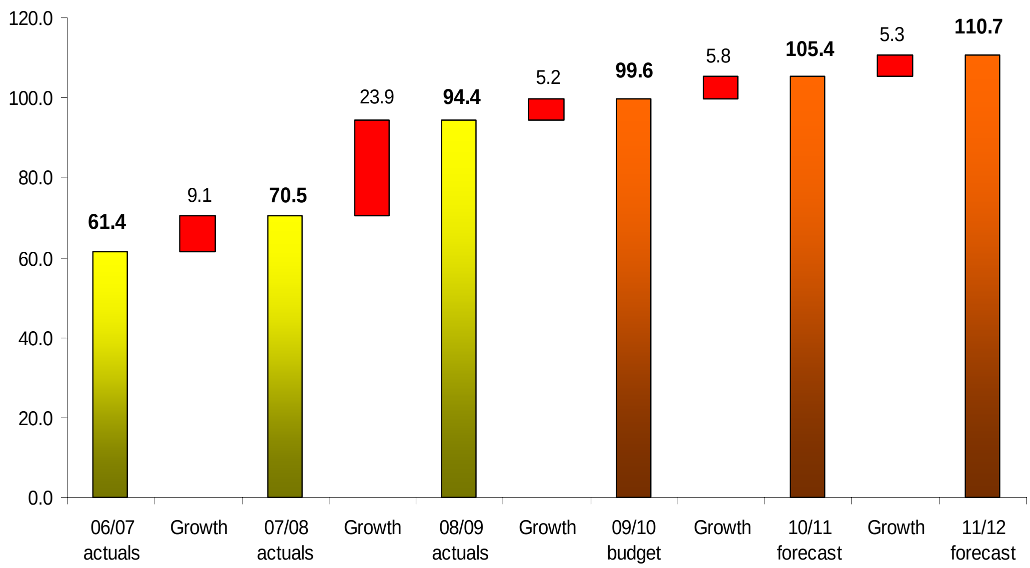
This bold statement of intent is further evidence of the real steps which WP is taking to build cost efficiency into its cost base. The savings which will be realised as a result of costs (investment) in 2009/10 and beyond are not yet known, and cannot therefore be included in this submission.

Business Support Costs – explanation of year-on-year cost increases

The ERA Draft Decision accepted the 2007/08 actual costs as a legitimate base from which to examine 2008/09 and AA2 period increases. This was shown through reviewing changes to expenditure levels forecast for 2009/10 to 2011/12 in relation to the 2007/08 base year.

Western Power has now finalised the actual Business Support costs for the 2008/09 period and believes that 2008/09 provides a more representative base year on which to forecast future Business Support expenditures. The growth in Business Support costs in the years following 2008/09 is principally due to escalations and movements in some non discretionary costs such as insurance. Figure 5 - 11 below shows the step changes in Business Support costs between 2007/08 and 2008/09 and the modest growth in forecast expenditure in the following years.

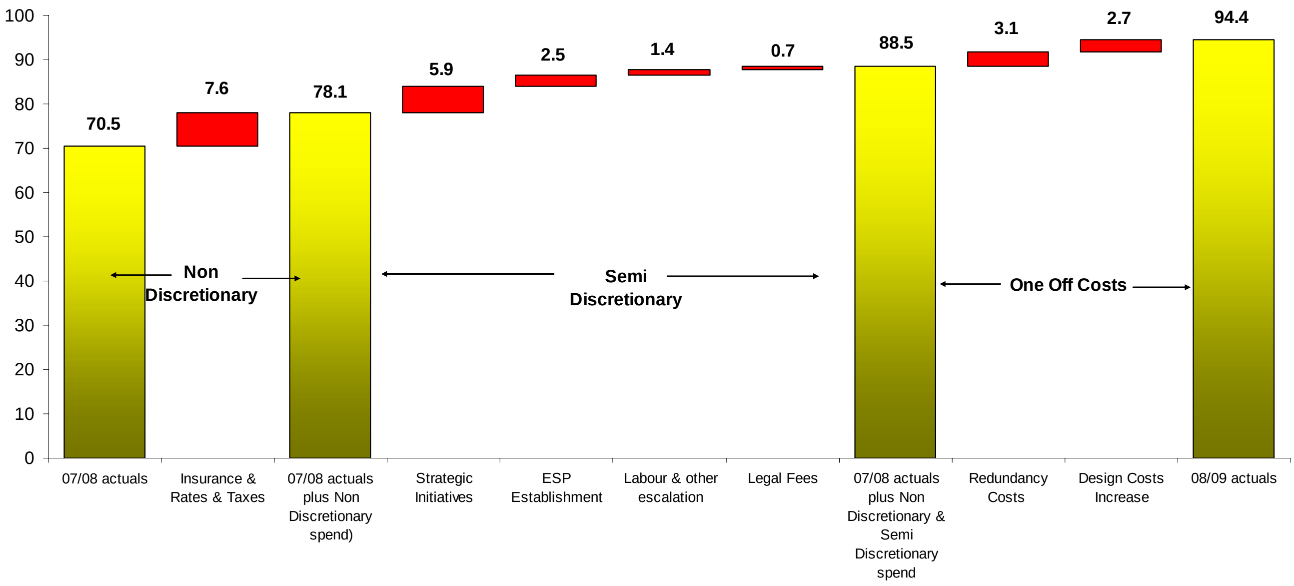
Figure 5-11 Year on Year Total Business Support expenditure ($M Real)



2006/07 and 2007/08 costs shown above exclude Motor Vehicles & Workers Compensation Insurance to create a like for like comparison with AA2 expenditure (refer to section 1.1.6 on Insurance for details).

The initial focus of this section will be to provide explanation and justification for the $23.9M increase in Business Support costs between 2007/08 and 2008/09. The major drivers behind this cost increase are shown in Figure 5-12.

Figure 5 -12 Changes in Business Support costs 2007/08 to 2008/09 ($M Real)



With reference to Figure 5 -12 above, the reasons for the increases are as follows:

5.17.1 Non discretionary costs increase (Insurance & Rates & Taxes)

- Insurance costs increased by $6.0M. This was due to increased premiums driven both by the current market environment and specific claims on Western Power. The public liability insurance covers Western Power against legal liability to a third party for their loss or injury, including personal injury, property damage, failure of supply of electricity and bushfires.

  Insurance losses associated with the Victorian bushfires in 2009 focused insurers' attention on other businesses with bushfire exposures. In this insurance environment, Western Power's liability renewal strategy was to demonstrate a sound understanding of the risk profile and differentiate our bushfire risk from that of businesses operating in the Eastern States of Australia. The strategy also included extensive marketing to international and domestic insurers, including personal presentations by senior Western Power and AON representatives. Quotations were received from DAC/QBE, AIG London and Zurich. Catlin declined to quote, despite providing competitive renewal terms for 2008/09. The only viable Australian market (Vero) was unable to secure reinsurance and declined to quote on the primary layer. An indicative quote was obtained for the excess layer from reinsurer Swiss Re, but increased capital costs and bushfire exposures were identified as reasons for their premium requirements being almost double that of the existing insurer.

  Western Power's main liability exposure is asset-initiated bushfires and a number of significant bushfires in the past 18 months have resulted in insurance claims against Western Power's insurers. A Bushfire Liability Quantitative Loss Analysis was conducted in March 2009 to forecast future losses based on previous loss history. The projected losses were applied against each of the quoted insurance options to determine the total cost of insurance, including premium and self-insured losses. The total cost of insurance and partnering with a financially strong insurer were key considerations in selecting the optimal insurance structure. Despite a difficult insurance environment and significant liability exposures, the most significant change to the program is an increase in the deductible for each and every bushfire.

- Rates and Taxes increased by $1.6M. This was based on actual market expenditure and increased primarily due to the Land Tax payable by Western Power. This is based on the value of land held by the organization and is forecast moving forward based on advice from the Western Australia Land Valuation Authority (Landgate).

5.17.2 Semi Discretionary costs increase (Strategic initiatives, ESP, Escalations & Legal Fees)

- Costs associated with a range of Strategic initiatives made up $5.9M of the increase in costs between 2007/08 and 2008/09. The concept of centrally managing specific strategic initiatives within the business was introduced in the 2008/09 period. It has proven to be a very successful management approach, and has realized some very real benefits in its first year. This new and transparent approach to the management of strategic initiatives has led to improved prioritization of funds, enhanced reporting on realization of benefits and facilitated improved executive-level decision making within the business. The breakdown of the $5.9M is as follows :

  ESP formation ($3.0M), Organisational cultural transformation for all leadership positions across Western Power ($1.7M). Employee behavioural development workshops ($0.2M). Payroll improvement project ($0.3M). Project Vista related operating expenditure ($0.3M). Development of the compliance system and governance framework for Enterprise Compliance Register ($0.2M). Establishing the sustainability framework ($0.2M) and outsourcing facilities management ($0.1M).

  Some of the strategic initiatives are ongoing in their nature and will continue to require expenditure through the AA2 period. The remaining initiatives are not ongoing but will be replaced by other new initiatives in subsequent years, in line with the business' priorities and strategic direction. Thus the level of spend on strategic initiative is forecast to remain fairly consistent throughout the AA2 period.

- The Enterprise Solutions Partner (ESP) division was established, increasing 2008/09 expenditure by $2.5M. Beyond the initial monies from the Strategic Initiative (above) additional funds were made available through the year, to the division, to provide focus, expertise and resources to successfully deliver key organization-wide strategic efficiency and productivity initiatives. As 2008/9 progressed the model for the Division has moved through embedding more economical capability, and growing capability (Black Belts) around a process efficiency methodology/framework (LEAN Six Sigma), and the creation of an Operational Excellence team within the Division.

- Escalation driven increases in unit costs contributed $1.4M of the increase. Across the business support functions of CEO, HR, Finance, ESP, Strategy & Corporate Affairs and Legal & Governance, labour related expenditure (staff and embedded contractors) represented approximately 44% of the total operating expenditure in 2008/09. The cost escalations incurred in this period were primarily due to labour related increases which were driven by a combination of Individual Agreement annual remuneration adjustments (an average increase of 6% in 2008/09) and the impact of attrition, wherein people who were leaving the business were replaced by individuals who cost more (market driven costs). This escalation of costs was required in order to more closely align Western Power with the wider Western

Australia market position. Western Power continually monitors its status in the wider market, through participation at the MERCH conference and seeking advice on an ‘as needed’ basis from industry experts, Hay Group and Mercer.

- Legal Fees increased by $0.7M, $0.5M of which related to major litigation (bushfires).

5.17.3 One off Costs increase (Redundancy Payments and Design costs)

- Redundancy payments of $3.1M were made in 2008/09. These redundancy payments were as a result of the conclusion of several of the functional indirect cost reviews that were carried out through 2008/09. These upfront costs related to a headcount reduction of more than 100 positions and will payback over the course of the AA2 period mostly through efficiency gains in Work Program related spend. Efficiencies which arise from these up-front costs are incorporated into the figures in this submission.

- Design costs for projects that do not proceed to construction increased significantly, adding an additional $2.8M when compared to prior year. $1.2M of this was due to the internal decision to defer the Busselton Margaret River transmission capital project to 2018. While most of the costs incurred in terms of early stage investment and procurement could be held as a capital asset until the project proceeds to completion in 2018, the planning, project management and environmental and land management costs were written off as an operating expense. This was all done in line with the requirements of AASB116 which sets out the asset criteria for capitalization. The increase in costs recognized due to customer driven quotes not proceeding to construction is widely understood to be due to the changing priorities for our customers in light of the new economic challenges facing the State (rates of applications proceeding to construction have reduced from 64% in 2006/07 to 52% in 2007/08 and 42% in 2008/09).

  A summary of the actual and forecast Business Support costs is provided in Table 5-46.

Table 5-46 Business Support costs by category ($M Real)

Business support costs	Actual			Forecast		
	06/07	07/08	08/09	09/10	10/11	11/12
Human Resources *	15.4	14.9	17.3	12.4	13.8	15.5
Strategy and Corporate Affairs *	12.2	12.1	10.4	13.0	13.1	13.2
Enterprise Solutions Partner *	-	-	10.4	15.4	15.6	15.8
Finance	10.5	11.8	12.8	14.5	16.2	17.2
Legal and Governance	3.0	4.0	4.8	6.2	6.3	6.4
CEO	1.1	3.1	3.9	1.1	1.1	1.1
Insurance	12.8	14.8	16.5	20.0	21.8	23.4
Rates and Taxes	4.7	5.4	6.9	7.7	7.9	8.5
Energy Safety Levy	3.0	3.6	3.7	4.0	4.0	4.0
Design & Estimating	-	4.0	6.7	3.8	3.9	4.0
FBT	1.5	0.8	0.6	1.0	1.1	1.1
Extended Outage Payments	0.5	0.3	0.4	0.5	0.5	0.5
Total	**64.5**	**74.9**	**94.4**	**99.6**	**105.4**	**110.7**

* Internal restructures and branch movements have occurred between HR, S&CA and ESP.

The following sections review the individual elements of Business Support costs in detail and provide explanation and justification of the movement in expenditure between a 2008/09 base line and the forecast AA2 period.

5.17.4 Human resources (HR)

The Human Resources (HR) division develops strategies and systems to ensure Western Power has the ability to attract, develop and retain a talented workforce with the skills and capabilities to achieve its business goals. The forecast expenditure for these activities is provided in Table 5-47.

Table 5-47 Business support costs - Human Resources ($M)

HR ($M)	06/07	07/08	08/09	09/10	10/11	11/12
Human Resources	15.4	14.9	17.3	12.4	13.8	15.5
Less : Admin Services Function	*(5.6)*	*(5.1)*	*(5.5)*	*	*	*
Restated HR	*9.8*	*9.8*	*11.8*	12.4	13.8	15.5

* - Admin Services Function transferred to ESP Division from 2009/10 onwards

The forecast position reflected for HR in the AA2 period differs significantly to that shown in actuals for AA1 due to an internal restructure which saw the transfer of the Admin Services function from HR to the newly established Corporate Real Estate group within ESP. A restated position has been reflected in Table 3 above.

Considering 2008/09 actuals ($11.8 M) as a baseline position, across the AA2 period the forecast expenditure has increased by $6.3 M in real terms. The factors driving this increase are;

- $3.3M is due to an assumed 15% labour related increase in HR costs through 2010/11 and 2011/12, based on anticipated increase in support required for a significant ramp up the Work Program, leading to higher recruitment costs. From a 2008/09 starting point, the Work Program spend is forecast to grow at 36.7% into 2010/11 and 46.1% into 2011/12 and the associated costs relating to management of required recruitment and employee integration reflect the assumed increase in HR expenditure. Our initial submission forecast the labour related costs within HR to grow at 20%. This has been reduced in recognition of the reduced size of the Work Program.

- The assumed internal labour escalation rates drive an increase in HR expenditure of $1.3 M across the AA2 period.

- HR has also been allocated $2.6M (out of a total strategic initiatives allocation of $5.6M) to spend on strategic initiatives in 2009/10 which is $1M more than their allocation in 2008/09. This additional allocation will be spent on expanding the culture change programs that are currently running. The divisional allocation of strategic initiative spend has not occurred for 2010/11 and 2011/12 (although a similar amount of strategic initiative spend is forecast to occur) and thus the 2009/10 forecast costs have been retained within the same divisions for the later years of AA2. This has driven an overall increase within HR due to strategic initiatives of $3.0M across AA2.

- Driven in part by the functional indirect costs efficiency initiatives, the HR division has reduced expenditure on consultants and contractors over the AA2 period compared with the 2008/09 baseline. This has resulted in savings of $1.3M across the AA2 period.

5.17.5 Strategy and corporate affairs and Enterprise Solutions Partner

Strategy and Corporate Affairs (S&CA) enable Western Power's internal and external communications including staff, government, media and stakeholder liaison, and community partnerships; Western Power's strategy planning process; and leads the pricing and economic regulatory management process.

The Enterprise Solutions Partner (ESP) division was set up in 2008/09 to provide the focus, expertise and resources to successfully deliver key organisation-wide strategic initiatives. ESP is responsible for the successful delivery of the Operational Excellence initiatives, the Strategic Program of Work, Corporate Real Estate function and Project Vista. ESP provides support in areas such as program coordination, reporting, change management, communications, and the management of resource impacts and competing priorities, so that teams can focus on project delivery.

The forecast expenditure for these activities is provided in Table 5-48.

Table 5-48 Business support costs – Strategy and Corporate Affairs, & ESP ($M Real)

$M	06/07	07/08	08/09	09/10	10/11	11/12
S&CA	12.2	12.1	10.4	13.0	13.1	13.2
ESP			10.4	15.4	15.6	15.8
TOTAL	**12.2**	**12.1**	**20.8**	**28.4**	**28.7**	**29.0**

This position has been restated to illustrate a more accurate run rate following the transfer of Admin Services to ESP from HR in 2009/10.

$M						
S&CA	*12.2*	*12.1*	*10.4*	13.0	13.1	13.2
ESP			*10.4*	11.6	11.8	12.0
Add : Admin Services Transfer from HR	*5.6*	*5.1*	*5.5*	3.8	3.8	3.8
Total ESP	*5.6*	*5.1*	*15.9*	15.4	15.6	15.8
Total ESP & S&CA	***17.8***	***17.2***	***26.3***	**28.4**	**28.7**	**29.0**

In the initial submission, Western Power allowed for the full cost of the Strategic Initiatives within the S&CA division and these had been estimated as $5.0M per annum. Within the 2008/09 actuals and the finalized 2009/10 budget, the individual divisions who are responsible or the delivery of the initiatives have either incurred or been allocated their portion of the Strategic Initiative funds. In 2008/09 the actual spend on strategic initiatives amounted to $5.9M and $5.6M has been included in the 2009/10 budget with similar levels included in 2010/11 and 2011/12.

The reduction in S&CA spend from 2007/08 to 2008/09 is due to the restructure which created the ESP division and transferred the costs of the former Business Transformation (BT) branch in S&CA which has since become part of ESP. Costs for the BT branch in 2007/08 were $2.6M and in 2008/09 were $1.6M.

Compared with the 2008/09 baseline S&CA actuals of $10.4 M, the expenditure level is forecast to increase by $8.1M across the AA2 period. The key drivers behind this increase are as follows:

- An incremental $1.5M per annum has been allocated to strategic initiatives in S&CA in 2009/10 compared with 2008/09. This will cover additional personnel and media costs for Energy Education (through investing in internal and external engagement in order to shift behaviours around energy efficiency) and improving our Regulatory support & strategy (extending our regulatory capacity to improve internal capability and effectively prepare for AA3). This increased level of spend will be maintained throughout the AA2 period, resulting in an overall increase of $4.5M across the AA2 period.

- The carbon neutral program has been included within Sustainability branch in S&CA from 2009/10 at a forecast expenditure of $0.6M per annum resulting in an overall increase of $1.8M across the AA2 period. These costs have been transferred from

CSD Division (and so a compensating reduction has occurred to the Work Program).

- Internal labour growth, assumed escalations and business unit charges across the AA2 period amounted to $1.8M.

Included in the AA2 forecasts for ESP are the costs associated with the Admin Facilities function that has transferred from HR. This represents approximately $5.5M in 2008/09 reducing to $3.8M for the 2009/10 period following the establishment of the centralised Corporate Real Estate function which has realised some efficiency.

In Table 5 -48 above the ESP forecast expenditure has been restated to provide a more accurate position following the transfer of Admin Services function from HR in 2009/10. If we consider the restated 2008/09 ESP expenditure of $15.9M as a baseline, ESP expenditure is forecast to reduce by $0.9M across the AA2 period. This reduction is driven by the following factors:

- A reduction in the expenditure on the Admin Services functions through efficiency realisation on consolidation, centralisation of contracts etc. This has realised savings of $5.1M across the period.

- A reduction through not incurring the $3.1M one off redundancy charge that was within the 2008/09 actual expenditures.

- One of the Functional Indirect Cost initiatives has generated a $4.0M reduction in consultant expenditures across Western Power in 2009/10 compared to actual spend in 2008/09. The remaining budget of $2.4M was pooled and allocated to ESP from 2009/10 onwards, which appears as an increase in ESP. Forecast expenditures for ESP include $2.4M per annum for consultant expenditure, totalling $7.2M across the AA2 period.

- Assumed internal labour growth and rate escalation of $1.5M over the AA2 period.

5.17.6 Finance

The objective of the Finance division is to deliver finance and administrative services including Business Analysis, Corporate Accounting and Tax, Risk and Treasury functions. The forecast expenditure for these activities is provided in table 5-49.

Table 5-49 Business support costs - Finance ($M)

Finance	06/07	07/08	08/09	09/10	10/11	11/12
Finance	10.5	11.8	12.8	14.5	16.2	17.2

Using 2008/09 actuals as a baseline position where Finance expenditure was $12.8 M, the forecast expenditure across the AA2 period is forecast to increase by $9.6 M. This increase is driven by the following factors:

- Labour costs are forecast to increase by 10% in 2009/10 (through filling vacancies) and 7.5% per annum for 2010/11 and 2011/12. This has generated a $3.7M increase in expenditure across the AA2 period. The forecast increase in expenditure is based on the requirement to support the increased Work Program which is forecast to grow by over 35% across 2010/11 and 2011/12. The initial submission allowed for a 10% p.a. increase in labour related costs.

- In addition to the above required labour investments, there is an additional requirement for $1.0M per annum from 2010/11 ($2.0M across the AA2 period) to support the increased regulatory compliance and scrutiny of major projects and operations by the ERA and DTF. This is an acknowledgement of the shortcomings identified in the business in terms of appropriate support for recent submissions. The additional resources here will take the form of generating improved financial awareness, greater challenge and financial validation of planned business expenditure, enhanced financial performance management as well as supporting delivery of the productivity and efficiency drivers necessary to deliver our financial commitments. This investment will cover all associated costs for 8 additional members of the Business Analysis branch.

- Internal labour escalation has driven a forecast expenditure increase of $1.5M across the AA2 period.

- IT systems allocation charges have increased by $2.1M across the AA2 period driven by additional license fees, disaster recovery and systems developments intended to enhance and increasingly automate the reporting capabilities of the finance division.

- A strategic initiative spend of $0.1M aimed at improving financial awareness has been forecast within finance in 2009/10 and this level of spend will be maintained through 2010/11 and 2011/12 generating an increase across the AA2 period of $0.3M.

5.17.7 Legal and Governance

The Legal and Governance team provides advice and support to Western Power's senior management and all other areas of the corporation. The forecast expenditure for these activities is provided in Table 5-50.

Table 5-50 Business support costs – Legal and Governance ($M)

Legal & Governance ($M)	06/07	07/08	08/09	09/10	10/11	11/12
Legal & Governance	3.0	4.0	4.8	6.2	6.3	6.4

The key driver of cost increases within the Legal and Governance division across the AA1 period was costs associated with external legal advice, which increased from $0.2M in 2006/07 to $1.3M in 2008/09. The increase in costs was driven by requirements to provide advice around the response to bushfires and more recently, the negotiation of Western Power's Collective Agreement. Ongoing negotiations with regard to the Salaried Workers Collective Agreement, legal advice with regard to major transmission projects, and an increased focus on compliance are forecast to drive costs up in 2009/10 by over $1.2M to $2.5M.

Using 2008/09 actual expenditures of $4.8M as a baseline for Legal & Governance, the forecast expenditure anticipates an overall increase of $4.7M across the AA2 period. This increase is driven by the following factors;

- The increase in legal costs forecast in the 2009/10 budget and a 5% per annum assumed growth in legal fees in 2010/11 and 2011/12 contribute an expenditure increase of $3.6M. This increase is partially based on projections of cost escalations, and legal advice with respect to the protracted Collective Agreement negotiations with Western Power's salaried workforce.

- Expenditure on 2 additional employees, 1 in the Compliance section and 1 in the Internal Audit section, increasing expenditure by $0.6M.
- Internal labour escalation driving a forecast expenditure increase of $0.4M.

5.17.8 Chief Executive Officer

The overall Business Support costs include an amount for Western Power's Chief Executive Officer (CEO). The forecast expenditure for the CEO is provided in Table 5-51.

Table 5-51 Business support costs CEO ($M)

CEO	06/07	07/08	08/09	09/10	10/11	11/12
CEO	1.1	3.1	3.9	1.1	1.1	1.1

The costs incurred in the CEO division in the 2007/08 and 2008/09 periods were particularly high, as Western Power invested in a leadership & cultural change program, the costs of which were captured within this area. This investment related to building senior, middle and front line leadership capability with emphasis placed on aligning employees with corporate goals through setting clear expectations, driving for results and holding people accountable for delivery.

Investment was also directed at building a more achievement oriented, adaptive and constructive corporate culture through developing the skills of all employees as well as improving enabling key people systems and structures. There are positive indications that both leadership capability and the organisational culture is improving and this momentum will be built on further. The ongoing costs relating to continuing to drive this cultural change agenda are reflected in Human Resources Division under Strategic Initiatives.

The position represented for the AA2 period reflects the 'normal' view of the CEO division, with business as usual only costs allowed for.

5.17.9 Insurance

Insurance expenditure includes all insurance premiums and self insured losses retained by the business. This covers a range of exposures including public liability, property, motor vehicles and professional risks. The forecast expenditure for this category is provided in Table 5-52.

Table 5-52 Business support costs - Insurance ($M)

Insurance	06/07	07/08	08/09	09/10	10/11	11/12
Insurance	12.8	14.8	16.5	20.0	21.8	23.4
Less: Motor vehicles Workers Compensation Insurance	(3.2)	(4.3)				
Insurance Revised	9.6	10.5	16.5	20.0	21.8	23.4

Note: Motor vehicles & workers compensation insurance were reported in this category in 2006/07 and 2007/08. From 2008/09 these costs have been recovered directly to the Work Program.

There were significant increases in insurance costs in 2008/09, with further increases forecast for the AA2 period. In addition to a hardening liability insurance market, significant claims against insurers in the past 18 months resulted in increased premiums and a higher deductible for the major exposure - asset initiated bushfires. The deductible for each and every bushfire claim increased from $2.5 M in 2008/09 to $3.5 M in 2009/10. Western Power's self insured losses are expected to be higher than previous years based on this increase.

The 2009/10 position as presented reflects the actual insurance premiums paid for the 2009/10 insurance period combined with an estimate of the self insured losses for the period. The final position is the result of extensive marketing of the liability program to insurers both in Australia and London to ensure competitive pricing. An international insurance broker is utilised to negotiate favourable terms, conditions and pricing on behalf of Western Power.

The forecast position for 2010/11 and 2011/12 is based on estimates for both insurance premiums and self insured losses. The premium forecast considers projected market conditions, recognises growth in network infrastructure and the condition of assets. Self insured losses are projected forward based on previous loss history, allowing for one major bushfire loss per year. The self insured loss forecast also takes into account the increased deductible for each and every bushfire loss.

5.17.10 Rates and taxes

The forecast expenditure for rates and taxes is provided in Table 5-53.

Table 5-53 Business support costs – Rates and Taxes ($M)

Rates & Taxes	06/07	07/08	08/09	09/10	10/11	11/12
Rates & Taxes	4.7	5.4	6.9	7.7	7.9	8.5

Rates and taxes forecasts for the second regulatory period have been prepared in consultation with the Valuer General (Western Australian Land Information Authority, or Landgate). These forecasts are based on a number of key assumptions, as follows:

1. For 2009/10, Land Tax values should increase based on the relative 'under assessment' of some current values - while the market is going down, values should still be going up due in part to the lag effect of the date of valuation (1 August 2008).

2. For 2010/11, the Valuer General has recommended a conservative 5% increase in values be adopted for budgeting purposes, while for 2011/12 (which will be based on valuations on August 1 2010), a 10% increase was recommended, to allow for a recovery in the market.

The forecasts presented by Western Power incorporate the above recommendations and represent an efficient forecast for rates and taxes.

5.17.11 Energy Safety Levy

Expenditure for the Energy Safety Levy is per the Energy Safety Levy notice 2008, published in the Government Gazette on April 29 2008. The forecast expenditure for this category is provided in Table 5-54.

Table 5-54 Business support costs – Energy Safety Levy ($M)

Energy Safety Levy	06/07	07/08	08/09	09/10	10/11	11/12
Energy Safety levy	3.0	3.6	3.7	4.0	4.0	4.0

The Draft Decision did not make specific reference to the Energy Safety Levy expenditure except to note, in paragraph 424, that Western Power had advised this expenditure is in accordance with government requirements. Western Power assumes that this expenditure was accepted by the ERA as part of the $32M of business support costs that was explicitly justified (paragraph 430).

5.17.12 Design and estimating

Design and estimating covers operational costs associated with the preliminary engineering and design costs that are incurred for work that does not proceed to construction. This is primarily due to customer work that does not proceed beyond the quote phase. The forecast expenditure for this category is provided in Table 5-55.

Table 5-55 Business support costs - Design and estimating ($M)

Design and Estimating	06/07	07/08	08/09	09/10	10/11	11/12
Design and estimating	-	4.0	6.7	3.8	3.9	4.0

The ERA Draft Decision did not specifically make reference to the Design and Estimating forecast costs.

The design and estimating element of business support costs has proven to be particularly challenging to forecast for Western Power. These costs are those that are incurred when the Distribution Design Engineering branch arrange for the preparation of an estimate (at no cost to the customer), and then a quote if required. These design costs are all initially captured as operating expenditure. If a customer elects to proceed to the construction phase after receiving the quote, all design costs are automatically transferred from operating to capital and are capitalised as part of the project expenditure.

Western Power conducted a comprehensive internal analysis (completed in June 2009) which showed that upon receiving a desktop estimate, approximately 67% of all customers will then pay the design fee (10% of the estimate up to a maximum of $50,000) to proceed to a quote, and of these, approximately 92% will pay the quote (the full construction costs less the design fee paid) to proceed to construction. That results in 62% of all customer driven distribution jobs being constructed and capitalised to the asset base. Western Power therefore needs to recognise the remaining 38% of jobs that do not go ahead as an operating expense.

In addition to these costs which are driven by customer activity levels and behaviours, there are also operating expenditure impacts where internally driven projects do not proceed to construction. An example of this for 2008/09 is the deferral of the Busselton-Margaret river project, which led to an operating expense of $1.2M to this 'design and estimating' category.

Based on this study Western Power has forecast the operating expenditure costs for design and estimating and believes that this represents a reasonable forecast of the costs that will be borne by the business in order to conduct these activities.

Of note is that within these estimates, there is no allowance for internally driven projects which incur costs before being deferred or cancelled (i.e. Margaret River-Busselton transmission project in 2008/09). Due to this, the position as identified here is noted as being a conservative estimate of the potential impact of these design costs for projects that do not proceed.

5.17.13 Fringe Benefits Tax (FBT)

Fringe benefits tax is a tax paid on certain benefits provided to Western Power employees or the employees' associates. FBT is separate from income tax and is based on the taxable value of the various fringe benefits provided by a business. The FBT year runs from 1 April to 31 March.

Table 5-56 Business support costs - FBT ($M)

Fringe Benefits Tax	06/07	07/08	08/09	09/10	10/11	11/12
Fringe Benefits Tax	1.5	0.8	0.6	1.0	1.1	1.1

The ERA Draft Decision did not specifically make reference to the Fringe Benefits Tax forecast costs. Western Power presents the FBT costs as a standard cost of conducting business. The forecasts are based on the 2008/09 actual position with increases forecast based on the increased headcount forecast by HR to meet the increased Work Program.

5.17.14 Extended Outage Payments (EOP)

Extended Outage Payments are made to eligible customers as compensation for network outages that have affected their supply.

Table 5-57 Business support costs – Extended Outage Payments ($M)

EOP	06/07	07/08	08/09	09/10	10/11	11/12
EOP	0.5	0.3	0.4	0.5	0.5	0.5

In the ERA's Draft Decision (paragraph 429) it was noted that Western Power had based the EOP forecast on the total expected value of payments for all eligible customers affected by outages. However, payments are made only to those customers who claim the payment and as not all eligible customers make a claim this EOP amount has historically been lower than the total for all eligible customers. Hence, based on the actual amounts paid in 2006/07 and 2007/08 the ERA recommended an amendment to allow $0.5M per annum for EOP.

In response to ERA's comments, Western Power has reviewed the forecast EOP and has revised the forecast to $0.5M per year as per the ERA's advice.

Attachment 1

ERA paragraph reference	Issue extracted from the Draft Decision	Supp. Submission Section
416	"Western Power has not advised the Authority of revised escalators for capital and operating activities (activity escalators)."	2.2.2
417 - 418	**Safety, health and environmental regulations.** "While indicating that a driver of increases in non-capital costs for the distribution network is more onerous safety, health and environmental regulations, Western Power has not provided details of any relevant changes in regulations. Western Power indicates that part of the increase in non-capital costs is due to expansion in activities of vegetation management and activities to provide benefits of public safety (bulk globe replacement on streetlights on a three year rather than four year cycle) but does not relate these activities to changes in regulatory requirements.	5.6, 5.7
427	**Business Support unit cost increases.** "As already indicated in this Draft Decision, the Authority considers that there is no justification for forecast costs to reflect an expectation of real increases in unit costs over the second access arrangement period. The Authority thus considers that the forecast business support costs should account only for a real escalation of costs for 2007/08 to 2008/09."	5.17.2
428	**Strategic initiative fund** "The Authority has considered the amount of approximately $5 million per annum indicated by Western Power to be for the strategic initiative fund." … "The Authority considers that Western Power could better justify this expenditure, but accepts that an allowance of costs for activities of this type is appropriate for Western Power."	5.17.2 5.17.5
429	**Power Outage Payment Scheme** "The Authority has also considered the forecast increase of $1.7 million per annum for payments under the State Government's Power Outage Payment Scheme. Western Power has advised that the forecast amounts of payments are based on *all* eligible customers receiving payments, while not all such payments may be claimed by customers and paid. Actual and forecast payments for the period 2006/07 to 2008/09 are in the range of $0.34 to $0.48 million. The Authority considers that the values of these payments should be based on actual values of payments likely to be made, rather than a hypothetical amount determined on the basis that all possible payments were made. Accordingly, the Authority considers that an allowance for these payments would be better established at $0.5 million per annum."	5.17.14
430, 432, 433, 434 435	**Justification of the Business Support Costs** "The Authority thus considers that Western Power has explicitly justified approximately $32 million of the forecast $92 million real increase in non-capital costs for business support."	5.17
441, 443 - 444	**Preventative maintenance** "The Authority thus considers that the forecast preventative maintenance costs should not include any amount in respect of real escalation of unit costs for the years 2009/10 to 2011/12.	5.6, 5.7

	"Preventive condition and routine maintenance, increases in years 2 and 3 lack justifying information." "The Authority expects that Western Power will provide further information to support the anticipated revised forecasts following the issuing of this Draft Decision."	
454-455	**Corrective routine and emergency maintenance** "Western Power has not provided any information to indicate why, if the anticipated revised forecasts incorporate large reductions to costs in the first year of the second access arrangement period, there remains a need for the substantial increases over the period such that levels of cost in the final year (2011/12) are the same as the original forecast." "The Authority expects that Western Power will provide further information to support the anticipated revised forecasts following the issuing of this Draft Decision."	5.8, 5.9
461	**SCADA and Communications** "the Authority considers that the forecast network operations and SCADA and communications costs, less a correction to remove allowances for escalation in unit costs during the second access arrangement period (amounting to a total of $5.89 million for the transmission and distribution networks over the second access arrangement period), would be consistent with the requirements of section 6.40 of the Access Code."	3.8, 4.7
469, 471	**Call centre costs** "The Authority considers that consistency of the forecast of call centre costs with section 6.40 of the Access Code requires correction of the forecast to remove allowances for cost escalation during the second access arrangement period ($0.67 million)."	5.13
475 - 477	**Metering** "…the Authority accepts that the forecast of metering costs less the allowance for smart meters and less a correction to remove allowances for cost escalation during the second access arrangement period (amounting to a total of approximately $3.19 million) is consistent with the requirements of section 6.40 of the Access Code."	5.14
485	**Research and Development for "energy solutions" business** "On Western Power's forecast costs for research and development associated with development of Western Power as an "energy solutions" business, no further justification for these costs has been provided. The Authority is not satisfied that these research and development activities and associated costs are sufficiently closely related to the provision of covered services to warrant inclusion in the total costs and target revenue under the price control."	4.8 Attachment 2
486	Training "On Western Power's forecast costs for training, the Authority is satisfied that an amount of training activities may appropriately be included in the total costs and target revenue under the price control. However, the Authority considers that the level of costs forecast by Western Power should be reduced to reflect a	5.15

	reduction in forecast new loads for the second access arrangement period and a reduced capital investment program, as addressed later in this Draft Decision (see paragraph 637)."	
489	Non-recurrent costs "Taking the above into account, the Authority considers that the forecast of non-recurring costs is inconsistent with the requirements of section 6.40 of the Access Code. The Authority considers that consistency with section 6.40 would require a reduction in the forecast costs for research and development on demand management to a total of $3 million over the second access arrangement period, exclusion of costs for research and development for Western Power's "energy solutions" business initiative, and a halving of the forecast cost for training. This results in a reduction in the forecast non-recurrent costs by $38.2 million."	4.8, 5.15
505	Non reference Service Costs "The Authority considers that the forecast costs should be amended in accordance with Western Power's anticipated revisions to the forecast non-capital costs for non-reference services as indicated in Table 47."	5.12
638/639	Impact of economic downturn on Capex "Western Power has not provided details of the factors underlying the anticipated revised forecasts and the Authority is unable to determine the extent to which the revisions arise from a reduction in the programs of capital works and from other factors such as lower unit costs. In regard to the latter, the Authority reiterates the view expressed earlier in this Draft Decision that there does not appear to be justification for any assumption of real increases in unit costs for the second access arrangement period (paragraph 416)"	2.2.3
640, 641	Estimating risk margin The Authority is not satisfied that Western Power has provided adequate justification for inclusion of this margin in costs forecasts. In particular, Western Power has not established that its processes for estimating costs are expected to systematically under-estimate costs by the amount of the margin and, if this is the case, why the processes for estimating costs should not be altered so as to remove the systematic error rather than addressing this through a universally applied risk margin."	2.2.4
655	"The Authority expects that Western Power will provide further information to support revised forecasts of new facilities investment prior to the Authority's final decision on the proposed access arrangement revisions. The Authority also notes that all new facilities investment to occur in the second access arrangement period will still have to be assessed as to whether it satisfies the new facilities investment test, either at the time of revisions to the access arrangement for the third access arrangement period or at the time of any application by Western Power under provisions of sections 6.71 and 6.72 of the Access Code."	All sections

Attachment 2

Smart Grid - AA2 submission

Background

In 2007 the Ministerial Council on Energy (MCE) undertook an analysis of the costs and benefits of smart metering deployments across all jurisdictions in Australia. The analysis indicated that a distributor-led rollout of smart metering in Western Australia (WA) would deliver positive net benefits of between $113M and $580M on the basis of the estimated avoided meter costs and business efficiencies.

The Office of Energy, as part of the Electricity Retail Market Review, subsequently engaged Frontier Economics (September 2008) to review the MCE assessment of costs and benefits for WA. The review estimated that a smart meter roll-out in the SWIS would deliver net benefits of between $293M and $320M. Both the MCE and Frontier Economics analyses recommend the need to conduct smart meter trials in WA.

In response, Western Power seeks to deploy a Pilot of 10,500 smart meters, and the associated communications backbone, which would enable validation of the anticipated costs and benefits, as a precursor to any future decisions to deploy smart meters in the SWIS.

Objectives

The Smart Grid Pilot Program is designed to:

1. Provide specific information towards a decision to rollout smart meters in Western Australia and advise on the nature of the roll-out that is likely to offer the greatest net benefits.

   The Program has been designed to align with the National Smart Grid initiative and specifically the MCE recommendation that Western Australia undertake a smart grid Pilot(s).

2. Provide a smart grid infrastructure as the foundation for a range of new energy solutions including distributed renewable generation, direct load control, tariff trials (critical peak and time-of-use), the use of in-home displays (‘IHD’). The infrastructure will be tested to understand its ability to support outage management, improve energy efficiency and network reliability, and defer network augmentation through improved demand management.

3. Improve Western Power’s connection with its customers and its reputation by testing how smart meters can improve service performance, enable distributed generation (particularly photovoltaics (‘PVs’)) and reduce supply costs.

Scope

A Smart Grid Pilot, conducted between 2009 and 2011, would include:

(a) Installation of 10,500 smart meters and advanced communications infrastructure. These would be trialled in 4 metro locations (Bayswater, Midland, Forrestfield and Darlington) and at an “edge of grid” location (Denmark/ Walpole) to test the grid’s demand management capabilities in remote communities and the ability to defer network augmentation to this region (where expansion to the Bow Bridge line is planned for 2012 at a cost of $11M);

(b) Load control trials (air conditioners) in 1,000 premises, over 2 years, to test the ability of meters to send remote signals into the home and enable smart appliances to be remotely controlled;

(c) Tariff trials (critical peak and time-of-use price signals) and in-home display units ('IHD'). It is planned that these trials will be undertaken by Synergy as part of the Perth Solar City program, and will utilise the smart grid infrastructure to send messages from the smart meter to IHDs to inform customers about changes to their tariffs and educate about opportunities to reduce energy consumption;

(d) Facilitating the connection of 1,000 1kW PV systems to the network and enabling net feed-in data to be transmitted to IHDs in real-time. Smart grid infrastructure will be used to understand the impact of concentrations of PVs on network stability;

(e) Trialling multi-utility meter reading capabilities by partnering with Water Corporation to use smart meters to read both water and electricity consumption in 300 meters;

(f) Performing tests of outage management and distributed automation capabilities;

(g) Promotion of energy efficiency (e.g. education on energy efficient appliances)

(h) Performing a detailed cost: benefit assessment and the development of a business case for a smart grid deployment across the SWIS

Smart Grid is fundamental to the Perth Solar City

Western Power is leading the Perth Solar City (PSC) program and $13.9M of Federal funding will be allocated to the program between 2009 – 2013 to deploy energy efficient products and services to communities in the Eastern Metropolitan region of Perth. The contribution of smart grid infrastructure to the PSC is regarded by the Federal Government as a fundamental underpinning capability required to support the delivery of most elements of the program (e.g. tariff trials, IHDs, PVs). In recognition of this, a smart grid infrastructure will attract Federal funding (quantum to be determined).

Costs

Pilot costs

Smart Grid Pilot expenditure is as follows:

Category *(nominal dollars)*	2009/10 ($M)	2010/11 ($M)	TOTAL ($M)
Capex	15.6	0.8	16.4
Opex	0.9	0.9	1.8
Total	**16.5**	**1.7**	**18.2**

This estimate is to an 'A1' level of accuracy as the firm costs in advance of the proposed competitive tender process are not yet known.

Branch costs

It is intended that the Smart Grid Pilot will be supported by an ongoing Business as Usual (BAU) function. It is critical that the skills and experience acquired during the Pilot are retained and built on, to expand the smart network capabilities.

Smart Grid costs will initially be associated with the deployment of the Pilot. However, as the Pilot is planned to be largely implemented by the end of 2010, the costs of Smart Grid network activities will ramp up thereafter. The costs are as follows:

Category *(nominal dollars)*	2009/10 ($M)	2010/11 ($M)	2011/12 ($M)	TOTAL ($M)
Capex		15	10	25
Opex		1	4	5
Total		**16**	**14**	**30**

The capex costs reflect the requirement to build on the capabilities developed in the Pilot and include:

- Significant investment in demand management infrastructure (e.g. load control devices (DREDs), hybrid small scale renewable generation supported with battery storage, bio-diesel generators, HVAC systems) particularly at edge of grid locations. Demand management solutions, for example at Ravensthorpe, Geraldton and Kalbarri, are planned to address capacity constraints and offset network augmentation in these areas;
- Deployment of advanced communications infrastructure, using the smart grid, to support rapid diagnosis of power quality and outage problems.

The opex costs reflect the following requirements:

- energy efficiency programs (consumer education, energy audits, fuel switching programs) especially at locations with network constraints;
- deployment of load control programs and customer engagement incentives;
- development of standards, codes and processes for the management of the smart grid and small scale renewable systems, and the integration of advanced technologies into existing networks;
- enhancements to smart meter data management systems

Benefits

The MCE and Frontier Economics reviews have identified the following benefits:

- Avoided manual meter reading costs, both for normal cycle reads and special meter reads;
- Avoided costs of de-energisation and re-energisation of customers;
- Reduced operational costs (e.g. fewer emergency calls, avoided customer complaints investigations)
- Avoided capacity costs (in transmission and distribution) of meeting peak demand – a disproportionately large quantity of network capacity is used to cater for peak

demand during just a few days each year. If smart meters are accompanied by time of use tariffs, they can provide efficient price signals to consumers to reduce peak demand;

- Capability for more appropriate pricing – smart meters can measure use of apparent power (in kVA) which may better reflect the underlying costs of operating the distribution network than real power consumption (in kW);
- Provision of better quality data on customer usage patterns to assist with network planning;
- Provision of platform for product innovation in customer services and energy efficiency information.

Both the MCE and Frontier Economics analyses have estimated the net benefits as positive:

- MCE benefits analysis: $113M and $580M on the basis of the estimated avoided meter costs and business efficiencies;
- Frontier Economics benefits analysis: $293M and $320M.

Non compliant meters

Western Power is required to replace 330,000 non-compliant 3 phase meters. Regulations prescribe that these meters must be replaced within 3 years from December 2008. The cost to replace these non-compliant meters is estimated to be in excess of $90M.

A progressive replacement of non-compliant meters, as part of a smart grid deployment, would ensure that all new assets are MCE compliant and avoid the risk of stranded assets. The replacement costs would be avoided and could be used to offset the costs of the deployment of smart meters. A mass rollout of smart meters, instead of selectively replacing non compliant meters using a house-to-house approach, would also reduce deployment costs.

The Office of Energy Safety has recognised the benefits of replacing non-compliant meters with smart meters and has provided Western Power with an extension to the replacement timetable to 2015.

Risks

Difficulties in quantifying the benefits of a smart grid represent a significant risk. As the benefits flow to a range of parties including customers, generators, network managers and retailers, the quantification of benefits accruing to each entity makes understanding the potential and actual benefits more difficult.

There is a substantial lack of clarity around:

- the costs to procure, deploy and manage a smart grid (implementation, installation, meter data management)
- the maturity of technology, in particular the communications technology options;
- the deployment timing assumptions and resource requirements;
- demand response uptake by customers and responsiveness to price signals and energy efficiency information enabled by smart meters;

- impacts of smart meters on network reliability and ability to support direct load control devices.

A Pilot would enable a better understanding of the actual costs, risks and benefits and facilitate a decision on the form of a rollout across the SWIS. It enables the risks associated with a full-blown deployment to be mitigated through a manageable deployment (represents less than 0.01% of the entire meter population) in which all capabilities can be tested.

ATTACHMENT E
Western Power’s detailed response to Required Amendment 26, second dot point.

1. Introduction

In response to Western Power’s NFIT submissions for the AA#1 capital expenditure the Authority’s Draft Decision states:

Required Amendment 26

> The proposed access arrangement revisions should be amended to reflect actual new facilities investment in the first access arrangement period reduced to:
>
> - exclude investment to the value of $63.5 million (nominal) for the transmission network in 2008/09 that comprises an overstatement of costs for 2008/09;
> - exclude investment to the value of $65 million (nominal in 2007/08 dollar values) for the distribution network that comprises an amount of costs that is not appropriately considered as new facilities investment; and
> - exclude a further amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) to reflect likely inefficiencies in the undertaking of investment.

This attachment considers the second dot point of Amendment 26, the exclusion of $65 million for the distribution network, which is explained in paragraph 541 of the Draft Decision as follows:

> *“First, a review of a sample of capital projects indicates that some investment in the distribution network under the “subdivisions program” may be inappropriately represented as new facilities investment. Costs under this program comprise expenditure by Western Power on augmentations of the distribution network for new land subdivisions, where Western Power undertakes the works under contract to the subdivision developers. Information provided by Western Power indicates that amounts of expenditure claimed to comprise new facilities investment and to meet the new facilities investment test may include an amount of approximately $65 million that comprises a shortfall in cost recovery for the contracted works undertaken by Western Power. The Authority considers that such costs are inappropriately classified as new facilities investment for the purposes of determining the capital base as the costs relate to activities of Western Power as a contractor providing construction services. As such, the Authority considers that these costs should be removed from the amount of new facilities investment proposed to be added to the capital base for the distribution network.”*

2. Western Power's comments on the required amendment

Western Power believes that the Authority has mischaracterised the nature of the apparent shortfall between:

- the costs of the subdivisions program during the current access arrangement period; and
- the recovery of those costs from customers through capital contributions.

In particular, the Authority has incorrectly concluded that:

- this apparent shortfall relates to activities undertaken by Western Power acting as a contractor in providing construction services; and
- therefore it is inappropriate to recover any such shortfalls by including them in the capital base.

Western Power believes that the Authority's Required Amendment reflects a number of misunderstandings that Western Power would like to clarify in this response. In particular:

1) The apparent "shortfall" is actually $33.4 million, rather than $65 million. The revised figure reflects the actual data to the end of June 2009, whereas the Authority's Required Amendment (not unreasonably) reflects the forecast information for 2009, as provided in Western Power's October 2008 submission. The original and revised data are shown in Table 1 below.

Table 1 – Forecast and actual Subdivision Development[1] expenditure and capital contribution data (real $M at June 2009)

	Expenditure			Capital contributions			Apparent shortfall
	2006/07	2007/08	2008/09	2006/07	2007/08	2008/09	
Forecast data presented in October 2008 Submission	75.828	48.084	52.768	77.512	30.573	3.359	65.236
Actual data for 2008/09	75.828	48.084	23.171	77.512	30.573	5.574	33.424

2) Western Power does not systematically over-price or under-price its subdivision works. In fact, Western Power's cost information systems are updated on a weekly basis. This ensures that Western Power's charges for such works fully reflect and recover the costs of undertaking such work.

[1] Support document DMS#5458562 references the AA#1 project name as 'New Residential Subdivision Development' whereas the figures presented cover all new subdivision development work including commercial and industrial.

Moreover, in contrast to the comments made by the Authority in paragraph 541 of the Draft Decision, Western Power is not acting as a commercial “contractor”, as contractors typically determine their terms and conditions with the objective of maximising profitability (and minimising the risk of losses) on each individual project or job. As a regulated network service provider, Western Power sets subdivision contribution charges on an average cost basis, on the understanding that in aggregate, any differences between costs and capital contributions on particular projects will even out over time.

Under these arrangements (which accord with Western Power’s approved capital contributions policy), inevitably some differences between Western Power’s costs and the contributions recovered from customers will arise in relation to particular projects. However, Western Power’s customers would not welcome an after-the-event adjustment to the agreed capital contribution to correct for these natural variations between quoted and actual costs.

3) The apparent shortfall identified by the Authority relates in part to the fact that the subdivision program includes ‘upstream’ augmentation works to the distribution network. In accordance with clause 5 of Western Power’s approved capital contributions policy, the capital contributions are determined on a case by case basis reflecting the circumstances of the new facilities investment and an NFIT assessment. It is noted that a significant proportion – typically around 50% - of these upstream investments is not funded through capital contributions but is instead recovered through reference tariffs.

4) A further complicating factor that also contributes to the apparent shortfall between subdivision costs and revenues relates to timing issues. In particular, revenues in any particular year or regulatory period can relate to works that are actually carried out in subsequent years or regulatory periods. By the same token, costs incurred in relation to subdivision works in a particular year or regulatory period may relate to capital contributions (revenues) received in a prior year or regulatory period. In this regard it is noted that substantial capital contributions were paid prior to the start of the first access arrangement period. However this can be considered to be a one-off effect because the amount of work carried out by Western Power in this category is now significantly less than it was during the first access arrangement period. This is because subdivision works are now principally carried out by developers and vested to Western Power, so that cash contributions are lower.

   It follows that any detailed consideration of systematic under-pricing or over-pricing of connection works (should such an examination be considered necessary) would need to account for these timing differences. Western Power notes that the Authority’s assessment (based on advice from its consultants) does not consider this issue.

In light of the above observations, Western Power believes that the Authority should reconsider its Draft Decision, which requires the exclusion of $65 million of distribution capital expenditure from the capital base. In particular, the apparent “shortfall” identified by the Authority (reduced to $33.5M with actual data) relates to the proper application of Western Power’s capital contributions policy for upstream works, and the impact of timing differences between contributions and expenditure.

3. Western Power proposed approach for addressing the required Amendment

In view of the above discussion Western Power submits that the apparent shortfall in the recovery of costs incurred in the subdivisions program does not reflect systematic under-pricing by Western Power. Consequently there should be no write-down of assets in this category and Western Power respectfully requests the Authority rescind the decision to exclude $65 million of AA#1 capital expenditure for subdivision developments from the AA#2 capital base.

ATTACHMENT F

Western Power's response to Required Amendment 26

1. Introduction and overview

This Attachment outlines Western Power's response to the third element of Required Amendment 26 of the Authority's Draft Decision. The Required Amendment proposes that Western Power's actual new facilities investment (other than that comprising gifted assets) be reduced by 15% - or approximately $344 million - for the purpose of setting the opening capital base for the second access arrangement period.

By any measure, the magnitude of the capital loss that would be sustained by Western Power's shareholders under such a proposal is very substantial indeed.

The 15% write-down specified in Required Amendment 26 was arrived at following the Authority's application of the new facilities investment test (NFIT)[1]. In view of the very significant implications for shareholder value arising from this Required Amendment, Western Power engaged the following independent experts to examine this matter:

- Professor George Yarrow and Dr Christopher Decker were engaged to provide an economic opinion on the application of the new facilities investment test (see **Attachment F1**);[2] and

- Sinclair Knight Merz (SKM) were engaged to provide an engineering opinion on the efficiency of Western Power's actual new facilities investment (see **Attachment F2**).[3]

Taken together these expert opinions convey a strong view that the Authority's application of the NFIT provisions and its reasoning for the proposed asset write down of 15 per cent is:

- not consistent with the Code objectives;

- not consistent with good regulatory principles and practice in other comparable jurisdictions; and

- not consistent with an objective, engineering-based assessment of the prudency of Western Power's capital expenditure in the period 1 July 2006 to 30 June 2009.

Western Power maintains that it has previously provided the Authority with sufficient information to demonstrate satisfaction of the NFIT. However, with a view to addressing the concerns raised by the Authority in its Draft Decision, Western Power has made

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1 Under section 6.51A of the Code, the NFIT must be satisfied for new facilities investment to be added to the capital base (unless section 6.51A(b) of the Code is satisfied).

2 Professor George Yarrow and Dr Christopher Decker, *Report to the ERA's Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, 1 September 2009.

3 SKM, *Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2*, 3 September 2009.

additional information available (separately) to support its position that it has undertaken new facilities investment over the period 1 July 2006 to 30 June 2009 in a manner consistent with a service provider "efficiently minimising costs", as required under section 6.52(a) of the Code.

This additional information includes documents made available to SKM, but not previously provided to the Authority, along with further information relating to the 30 sample projects previously reviewed by the Authority.

As an aside, Western Power would also like to bring to the Authority's attention paragraph 20 of the ERA's *Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network* (of 26 April 2007). In this paragraph, the Authority determined the access arrangement start date for the first access arrangement period to be 1 July 2007. Consequently, there is some uncertainty as to whether the Authority is entitled to apply the NFIT to capital expenditure incurred by Western Power prior to the access arrangement start date.

In view of the information presented in this Attachment and the accompanying reports, Western Power submits that in formulating its final decision, the Authority should reconsider its application of the NFIT to Western Power's capital expenditure in the first access arrangement period. In this context, Western Power notes that based on the advice provided by SKM, the appropriate application of the NFIT would result in the identification of inefficiencies of not more than $28 million (compared with the $343.8 million write-down proposed by Required Amendment 26).

The remainder of this Attachment is structured as follows:

- Section 2 provides an overview of the reasoning set out in the Draft Decision in relation to Required Amendment 26.

- Section 3 sets out Western Power's comments on the Draft Decision, and focuses in particular on the expert opinions of Yarrow and Decker, and SKM.

- Section 4 provides some brief additional comments on matters relating to the Required Amendment.

- Section 5 sets out concluding remarks.

2. Overview of the Draft Decision

For the purpose of establishing the opening capital base for the second access arrangement period, Required Amendment 26 states:

> "The proposed access arrangement revisions should be amended to reflect actual new facilities investment in the first access arrangement period reduced to:
>
> - exclude investment to the value of $63.5 million (nominal) for the transmission network in 2008/09 that comprises an overstatement of costs for 2008/09;
>
> - exclude investment to the value of $65 million (nominal in 2007/08 dollar values) for the distribution network that comprises an amount of costs that is not appropriately considered as new facilities investment; and

- exclude a further amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) to reflect likely inefficiencies in the undertaking of investment."

It is the third element of this Required Amendment which is addressed in this Attachment and the accompanying independent expert reports.

The Draft Decision notes the Authority's views that inefficiencies in new facilities investment in the first access arrangement period arise from the following two main factors:

> "First, project-specific information available to the Authority suggests that there has been systematic over-engineering of capital projects resulting in inefficiencies in the design of network assets".[4]
>
> "Secondly, the Authority considers that there have been deficiencies in the planning and governance of capital works, including inadequate consideration of options when planning network augmentations and poor cost-control and contract management for capital projects and programs. The Authority, however, does not have sufficient information to place a precise value on the extent of such inefficiencies…"[5]

The basis of the Authority's draft finding (that 15 per cent of the new facilities investment other than that comprising gifted assets should be excluded from the capital base) is set out as follows:

> "Taking the above factors into account, the Authority considers that the extent of inefficiency is likely to be more than a nominal amount, but less than 25 per cent of the total value of new facilities investment.
>
> Taking into account the lack of information for this determination (refer to paragraph 345 and following) and the significant commercial effect that the determination will have on Western Power's business, the Authority considers that the extent of inefficiency to be taken into account in determining the value of new facilities investment to be added to the capital base should not be at the maximum of the possible range. On this basis, and having regard to the Code objective, the Authority has determined that the extent of inefficiency amounts to 15 per cent of the total amount of new facilities investment other than that amount of new facilities investment comprising assets constructed by other parties and gifted to Western Power."[6]

It is noted that the Required Amendment refers to the 15% write-down as an amount that reflects "***likely*** inefficiencies in the undertaking of investment".

3. Western Power's comments on the Draft Decision

Given the magnitude of the potential capital loss faced by Western Power, the company engaged independent experts to provide opinions on the Authority's application of the NFIT and on the efficiency of Western Power's new facilities investment. Sections 3.1 and 3.2 below provide an overview of the independent experts' reports.

4 Draft Decision, paragraph 603.

5 Draft Decision, paragraph 604.

6 Draft Decision, paragraph 605-606.

3.1 The Authority's application of the NFIT

Western Power engaged Professor Yarrow and Dr. Decker to provide an independent expert opinion on the Authority's application of the NFIT. Both are eminent economists with considerable academic qualifications and practical experience in utility regulation, particularly in advising regulatory authorities.[7]

Western Power asked Professor Yarrow and Dr. Decker to provide an independent expert opinion addressing the following question:

> "Is the ERA's application of the NFIT provisions (sections 6.51A to 6.55 of the Electricity Networks Access Code 2004) and its reasoning for the proposed asset write down of 15 per cent:
>
> (a) consistent with the Code objectives?
>
> (b) consistent with good regulatory principles and practice, including having regard to other regulatory decisions in comparable CPI-X or RPI-X regimes?"

In their report, Yarrow and Decker address this question by:

- discussing the general principles of *ex post* prudency reviews, of which the NFIT is an example;
- examining the experience of the conduct of prudency reviews both nationally and internationally; and
- in light of the above, analysing the objectives of the Code and the Authority's approach to applying the NFIT in its Draft Decision.

Yarrow and Decker's key observations in relation to each of these three matters are set out under separate sub-headings below.

(a) General principles of ex post prudency reviews

In terms of the general principles that underpin ex post reviews internationally, Yarrow and Decker comment that:

> "Although the precise role of ex post assessments tends to differ from jurisdiction to jurisdiction, there is much more international commonality in the relevant standard against which prudency should be assessed, particularly in relation to past investment decisions….
>
> The antonym of prudent is reckless, and the traditional language here provides clear indication of the relevant standard to be applied when considering whether past capital expenditure should be disallowed from the regulatory asset base (RAB). To put it simply, the standard is one of 'reasonableness' or 'non-negligence' rather than of 'best possible performance' or 'best practice'.
>
> There are a number of relatively obvious reasons for choice of a 'reasonableness' standard when assessing capital expenditures, including, but not restricted to, the following:

[7] Yarrow and Decker, Attachment F1, pages 28-30

- Investment decisions are very often subject to considerable uncertainties, and 'optimal' courses of action are rarely well defined. There is scope for reasonable, well informed experts to differ on capex questions such as whether, what, on what scale, how, where and when to build new facilities. Regulation should properly allow for these realities, and recognise that approaches based upon the notion that unambiguously optimal capex decisions can generally be identified are (a) non operational and (b) amount to a pretence to knowledge that regulators do not and can not have.

- Disallowances based on comparisons with hypothetical, best possible *outcomes* could, in practice, be expected to lead to severe disincentives for investment, *unless these adverse incentive effects are compensated for by some other aspect of regulatory decision making, such as a higher allowed rate of return on the (diminished) rate base*. If a utility could only earn a normal rate of return in conditions in which it was always making the best possible decisions – i.e. only if, in an uncertain and complex world it was always getting things 100% right – then, in effect, it could never expect, *ex ante*, to make a normal return on capital."[8]

(b) Regulatory practice in applying ex post prudency reviews

In terms of international practice and the AER's practice in Australia, Yarrow and Decker comment that:

> "The USA has the longest and most developed tradition of the application of prudency reviews as part of utility regulation regimes. A well known summary of the meaning of prudence in US law has been provided by Supreme Court Justice Brandeis:
>
> > "*The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown.*"[9]
>
> "In all of its recent determinations, the Australian Energy Regulator – for SP AusNet, Transend, Powerlink Queensland and Electranet – has made no significant *ex post* adjustment to past capital expenditure to reflect imprudent investment. This is despite concluding in some instances that oversight issues were identified with certain projects or that improvements in the capital policies and procedures could have been implemented. This is suggestive of a generally cautious approach to making such adjustments, and a reluctance to disallow capital expenditure in the absence of detailed and specific evidence of substantial flaws in the execution of that investment." [10]

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8 Yarrow and Decker, Attachment F1, page 6-7

9 Yarrow and Decker, Attachment F1, page 10.

10 Yarrow and Decker, Attachment F1, page 20.

(c) The application of the NFIT in the Draft Decision

In terms of the Authority's application of the NFIT in its Draft Decision, Yarrow and Decker comment that:

> "In our judgment, the ERA's Draft Decision appears to be inadequately reasoned in a number of respects, including the following:
>
> - First, the ERA appears to have concluded that because some aspects of the governance and planning *processes* of Western Power were deficient in the first access arrangement period, that this automatically allows for the conclusion that a proportion of the capital expenditure undertaken during this period did not minimise costs and that the *outcome* was therefore inefficient. However, as the report by Wilson Cook & Co correctly (in our view) recognises, a conclusion as to the efficiency of costs does not flow automatically from the assessment of the efficiency of planning and prioritisation process.
>
>   Processes and outcomes are, of course, linked. Speaking generally, better processes lead to better outcomes; but the linkages are neither mechanistic nor one-to-one. Thus, findings of process deficiencies are by no means sufficient to sustain a confident inference that performance (in terms of costs to serve) has been deficient, even against best practice standards.
>
> - Second, the ERA appears at a number of points to substitute presumption for analysis and evidence. Perhaps the most significant of these occurrences is when the ERA appears to jump from a view that it does not have sufficient information to allow it to determine precisely whether or not new facilities investment during the first access arrangement was efficient (in an undefined sense) to a conclusion that the new facilities investment was inefficient by an across-the-board margin of 15%, without anything much in the way of intervening reasoning. As discussed in more detail below, this presumption and the magnitude of assumed inefficiency (i.e. 15%) is, putting it quite simply, unsubstantiated.
>
> - Third, the approach of ERA in the Draft Decision appears to give insufficient weight to Western Power's responsiveness to perceived weaknesses in its business practices. Reasonable conduct does not require that utilities get everything right, but it does require that companies respond when problems are identified (the 'forseeability' point made by Cope, Dismukes and Yeargain). We note that each of the consultants' reports commissioned by ERA stated that Western Power's management and board recognised that its governance and cost estimation processes were inadequate in the past, and that, in response Western Power had taken positive steps to address identified inadequacies in ways that could be expected to lead to improvements in these processes." [11]

In examining the basis for the Authority's reasoning on the size of the efficiency disallowance in more detail, Yarrow and Decker state:

> "The relevant judgments here are, self-evidently, arbitrary. There is no basis for the 25% figure, whose only function seems to be to make a 15% figure look reasonable (because it might have been higher). The lower bound estimate of 'inefficiency' is not quantified, and is simply referred to as being (in the judgment of the ERA, but in the absence of supporting evidence) more than a nominal amount. No reason is given for the particular

[11] Yarrow and Decker, Attachment F1, pages 22 and 23.

choice of weighted average calculation that appears to lead to 15%. And, to put matters beyond doubt, that the determination lacks substantial, supporting information/evidence is explicitly recognised by the ERA in the first sentence of paragraph 606."[12]

(d) Conclusions of Yarrow and Decker

On the basis of the analysis and observations set out in their independent report, Yarrow and Decker's opinion is that:

> "In response to the two questions asked, and on the basis of the reasoning above, we conclude the ERA' s application of the NFIT provisions (sections 6.51A to 6.55 of the Electricity Networks Access Code 2004) and its reasoning for the proposed asset write down of 15 per cent is:
>
> (a) not consistent with the Code objectives.
>
> (b) not consistent with good regulatory principles and practice in other, comparable jurisdictions."[13]

3.2 The efficiency of Western Power's new facilities investment

SKM were engaged by Western Power to undertake an independent review of the application of NFIT to Western Power's capital expenditure in the period 1 July 2006 to 30 June 2009, as detailed in the Draft Decision.

SKM's report defines the standard that it believes should be adopted in applying the efficiency limb of the NFIT. The report states that in assessing efficiency:

> "…significant weight should be given to the service provider being able to demonstrate sound engineering capability and judgement as well as the effectiveness of business processes in the context of "good electricity industry practice" under comparable conditions and circumstances.
>
> In SKM's view, the "Efficiency Limb" of the NFIT is not designed to find the minimum cost solution for each new facility at every stage of every project to develop and construct or otherwise acquire the new facility. Rather, it ensures that an NSP is engaging in a process to efficiently minimise the costs in its business operations, and through a process of continuous improvements, brings about efficient investments."[14]

Western Power notes that the standard adopted by SKM is consistent with the approach recommended by Yarrow and Decker.

SKM's report also notes that the cost overruns on Western Power's major projects during the period from 1 July 2006 to 30 June 2009 are consistent with, or lower than, the increases in project costs that were experienced in other industries in Western Australia over the same period.

The SKM report explains the approach taken by SKM as follows:

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12 Yarrow and Decker, Attachment F1, page 26

13 Yarrow and Decker, Attachment F1, page 27

14 SKM, Attachment F2, page 69.

- SKM's review focused on the key Western Power processes that are relevant to the factors identified by the Authority as contributing to the 15% inefficiency factor. In particular, SKM focused on Western Power's design standards; planning policies; plant specifications and procurement processes. SKM's review also examined the information that the Draft Decision refers to in establishing the 15% inefficiency factor.

- To determine the effectiveness of Western Power's application of the key processes listed above, SKM has undertaken benchmarking of network performance and comparative utilisation; cost escalation of Western Power's major projects; the prices paid by Western Power for distribution related products and services, and selected projects against SKM's regulatory valuation database. SKM also conducted a detailed review of the efficiency of the key processes for selected projects.

SKM's key findings include:

- SKM concluded that Western Power has solid planning and governance policies and processes in place. Moreover, SKM did not find that the specific process issues raised by GBA (the Authority's consultants) could be quantified to support the 15% inefficiency factor proposed in the Draft Decision.[15]

- SKM identified some issues relating to cost estimation and contractor over-charging at the beginning of the first access arrangement period, but notes (as do the Authority's consultants) that these issues were addressed by Western Power during the first access arrangement period.

- SKM[16] has attempted to quantify the impact of these two issues as follows:

  - In relation to inadequate cost estimating, SKM finds an inefficiency factor of 5% ($18 million) should be applied to the total value of all projects identified by it as being impacted by estimation problems (a total of $351 million worth of projects). SKM also believe that any inefficiencies resulting in a factor above 5% in relation to inadequate cost estimating would have been specifically identified by the suite of reviews undertaken by SKM in preparing its report.

  - In relation to contractor overcharging, SKM notes that audits undertaken during the OSA program quantified the inefficiency to be in the range of 3.5% (in 2006/07) trending down to zero by the end of the first access arrangement period. SKM estimates that this equates to approximately $10 million of the total internally funded expenditure on distribution reinforcements (which totals $639 million).

On this basis, SKM provides an estimate of total "inefficiency" in the order of $28 million.

SKM concludes by stating:

> "Overall, SKM found that Western Power has solid planning, engineering and execution policies and processes generally consistent with good industry practice…

[15] SKM, Attachment F2, page 75.

[16] SKM, Attachment F2, page 78.

> SKM did not find any evidence to suggest "systematic over engineering" within Western Power's network, or that there are significant inefficiencies arising from poor options analysis, cost control and contract management for capital programs…
>
> … SKM considers all of Western Power's revised capital expenditure to be prudent and the amount of 'inefficiency' in the new facilities investment undertaken by Western Power was in the order of $28 million."[17]

4. Additional comments on the Required Amendment

Given the substantial errors in approach identified, Western Power is concerned that aspects of the Draft Decision in relation to the 15% reduction set out in Required Amendment 26, do not represent a proper exercise of the Authority's powers under the Code and are therefore affected by errors of law. To this extent, Western Power considers that such an approach would provide grounds for legal challenge, given the significant implications of the decision on Western Power's commercial viability. However, Western Power would prefer to see these matters resolved through constructive dialogue as part of the Code submission process.

5. Conclusions

The third element of Required Amendment 26 exposes Western Power to a potential capital loss of $344 million. By any measure, this is a very substantial amount indeed.

The independent expert opinion provided by Yarrow and Decker concludes that the Authority's approach is not consistent with the Code objectives and is not consistent with good regulatory principles and practice in other, comparable jurisdictions.

In addition, the independent engineering-based assessment of prudency conducted by SKM has concluded that:

- Western Power has solid planning, engineering and project execution policies and processes that are generally consistent with good industry practice.
- Western Power's capital expenditure decisions were not systematically inefficient, particularly when assessed against the appropriate standard and in light of the market conditions prevailing at the time.
- There are two areas where Western Power's performance could have been better, but all parties acknowledge that over the first access arrangement period improvements have been made in those areas. Total "inefficiency" arising in relation to these two areas is estimated to be in the order of $28 million.

Western Power notes that the opinions provide a sound basis for rejecting the two grounds on which the Authority's complaints of inefficiency are based (i.e. systematic inefficiency and deficiencies in planning and governance).

Given the opinions of the independent experts, Western Power submits the Authority should reconsider its application of the NFIT in its Final Decision. Specifically, Western Power's view is that a reasonable application of the NFIT provisions would produce an exclusion of no more than $28 million from the capital base to reflect inefficient practices that have now been rectified by the company.

17 SKM, Covering letter, page 3.

Attachment F1

Opinion by Professor George Yarrow and Dr Christopher Decker

REPORT ON THE ERA'S DRAFT DECISION ON PROPOSED REVISIONS TO THE ACCESS ARRANGEMENT FOR THE SOUTH WEST INTERCONNECTED NETWORK

Professor George Yarrow and Dr Christopher Decker

1 September 2009

1. TERMS OF REFERENCE AND STRUCTURE OF THE OPINION

We have been asked to provide an independent expert opinion that addresses the following question:

Is the ERA's application of the NFIT provisions (sections 6.51A to 6.55 of the Electricity Networks Access Code 2004) and its reasoning for the proposed asset write down of 15 per cent:

(a) consistent with the Code objectives?

(b) consistent with good regulatory principles and practice, including having regard to other regulatory decisions in comparable CPI-X or RPI-X regimes?

In responding to this request, we first set out our understanding of the relevant background and context. We then turn to assess the role of *ex post* disallowances, typically associated with *prudency reviews*, in regulatory principles and practice, including by reference to decisions in regulatory regimes that are comparable to that in Western Australia, Finally, on the basis of this material, we explicitly address the two questions asked.

Our qualifications are set out at the end of this report.

2. BACKGROUND AND CONTEXT

2.1 The Code and its objectives

We understand that the South West Interconnected Network (SWIN), which is owned and operated by Western Power, is regulated under the Electricity Networks Access Code 2004 (the Code) by the Economic Regulation Authority (ERA). The Code contains a New Facilities Investment Test (NFIT) which must be satisfied for new facilities investment to be added to the capital base (unless section 6.51A(b) of the Code is satisfied).

As stated in its Introduction, the Code establishes a framework for third party access to electricity transmission and distribution networks with the objective of promoting the economically efficient investment in, and operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.

2.2 Forms of price control allowable under the Code

Section 6.1 of the Code specifies that an access arrangement may contain any form of price control provided it meets the price control objectives set out in section 6.4. Among the objectives of section 6.4 is the requirement that the form of price control gives the service provider an opportunity to earn target revenue, and it includes provision for adjustments to the target revenue for: unforeseen events; technical rule changes; service standard adjustments; and finally, an amount that reflects any difference between the actual new facilities investment that occurred during the access period and the forecast of new facilities investment made at the start of the access arrangement period (the so-called ‘investment adjustment mechanism’).

In our view, the general attributes required of the price control arrangement under the Code are not radically dissimilar to those to be found in other, comparable jurisdictions. Although textbook treatments of regulatory regimes sometimes draw a sharp distinction between rate-of-return/cost-of-service and CPI/RPI-X approaches to price control, in reality most regimes are hybrids, based on mixes of elements drawn from ‘idealised’ models (such as rate-of-return systems without regulatory lags or price-cap arrangements without regulatory reviews), adapted to address specific issues arising in the particular jurisdiction. As Armstrong, Cowan and Vickers[1] have put it, the differences *“... are ones of degree rather than of a fundamental nature”.*

By way of illustration of this general point, and as an indication that some close similarities are to be found at the level of fine detail, as well as more broadly, it can be noted that the UK regulatory arrangements for electricity transmission, which are generally regarded as a prime example of the CPI/RPI-X approach, currently encompass arrangements that automatically adjust allowed revenues, *within the price control period*, to remunerate certain types of investment that are demand driven (i.e. the UK arrangements currently include what might, in the terminology used in Western Australia, have been termed a form of ‘investment adjustment mechanism’).[2]

2.3 The NFIT provisions

The terms of reference refer explicitly to the New Facilities Investment Test (NFIT), which is set out at 6.51A to 6.55 of the Code, and which is required to be passed by capital expenditure associated with new facilities[3] before it can be included in the capital base. The test applies:

- retrospectively, in relation to capital expenditure incurred from the start of the current access arrangement period to 30 June 2009; and
- prospectively, in relation to forecast capital expenditure expected to be incurred during the next access arrangement period (from 1 July 2009 to 30 June 2012).

Detailed aspects of the NFIT are set out at 6.52 of the Code:

“6.52 *New facilities investment* satisfies the *new facilities investment test* if:

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[1] Armstrong, M., Cowan, S., and J. Vickers, *Regulatory Reform: Economic Analysis and British Experience*, MIT Press, 1994.

[2] See Ofgem, *Transmission Price Control Review: Final Proposals*, December 2006, where it is explained (at para 2.14) that: *“In the light of significant uncertainty regarding the level and timing of investment necessary to accommodate new loads, we have proposed adjustment mechanisms which flex revenues automatically as the transmission licensees respond to the needs of users. For the purposes of determining the fixed "baseline" revenue allowances for each licensee, we have therefore excluded those uncertain user-driven investments.”*

[3] A new facility is defined as any capital asset developed, constructed or acquired to enable the service provider to provide covered services including assets required for the purpose of facilitating competition in retail markets for electricity, and new facilities investment as the capital costs incurred in developing, constructing and acquiring a new facility.

(a) the *new facilities investment* does not exceed the amount that would be invested by a *service provider efficiently minimising costs*, having regard, without limitation, to:

(i) whether the *new facility* exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the *covered services* forecast to be sold over a reasonable period may require the installation of a *new facility* with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the *anticipated incremental revenue* for the *new facility* is expected to at least recover the *new facilities investment*; or
B. if a *modified test* has been approved under section 6.53 and the *new facilities investment* is below the *test application threshold* – the *modified test* is satisfied;

or

(ii) the *new facility* provides a *net benefit* in the *covered network* over a reasonable period of time that justifies the approval of higher *reference tariffs*;

or

(iii) the *new facility* is necessary to maintain the safety or reliability of the *covered network* or its ability to provide contracted *covered services*.

Sections 6.13 to 6.18 of the Code outline the application of an ‘investment adjustment mechanism’ under the price control. These provisions specify how any gain or loss arising from differences between the *actual* costs of new facilities investment costs incurred and the *forecast* of those costs associated with new facilities investment made at the start of the access arrangement period should be treated. In terms of the scope of application of the ‘investment adjustment mechanism’ it is our understanding that under the first access arrangement, it only applied to particular categories of new facilities investment, which were broadly categorised as being ‘demand driven’ in nature.[4]

We understand that Western Power submitted its revenue and expenditure proposals for its second access arrangement period to the ERA in October 2008. Western Power's submission provided information that was intended to demonstrate that the

[4] Paragraph 552 of Draft Decision

NFIT had been satisfied - both in relation to actual and forecast capital expenditure. Further information was submitted by Western Power to the ERA in June 2009.

2.4 The ERA's draft decision and the required amendment

The ERA engaged consultants Geoff Brown & Associates Ltd and Wilson Cook & Co to review Western Power's actual and forecast capital expenditure, including the application of the NFIT provisions. Public versions of those reports are annexed to the ERA's Draft Decision. The ERA published the Draft Decision on 16 July 2009.
The Draft Decision proposes to write down a substantial amount of Western Power's actual capital expenditure in the first access arrangement period and specifies the following amendment:

> *Required Amendment 26*
>
> *The proposed access arrangement revisions should be amended to reflect actual new facilities investment in the first access arrangement period reduced to:*
>
> - *exclude investment to the value of $63.5 million (nominal) for the transmission network in 2008/09 that comprises an overstatement of costs for 2008109;*
>
> - *exclude investment to the value of $65 million (nominal in 2007/08 dollar values) for the distribution network that comprises an amount of costs that is not appropriately considered as new facilities investment; and*
>
> - *exclude a further amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) to reflect likely inefficiencies in the undertaking of investment.*

It is the third element of this amendment, which applies to investment in the access period to June 2009, which we are asked to assess.

3. GENERAL PRINCIPLES OF PRUDENCY REVIEWS

3.1 Development in rate of return regimes

Prudency reviews evolved naturally as a feature of the practice of rate-of-return regulation as it developed in the USA, under which a utility, in the course of serving its customers, is/was in principle entitled to recover prudently incurred costs, including investment costs, and earn a fair return on its investments. In the rate of return system, an *ex post* review or audit of a utility's expenses and investments is normally done when the utility files for a rate increase with the relevant public utility commission (PUC).

Investments that are judged not to have been prudent are disallowed from the rate base that will be used to calculate recoverable capital costs, implying that they must be borne by the shareholders/owners of the utility concerned, rather than recovered from its customers. In assessing prudence, it is a generally accepted principle that judgments should be based on the economic circumstances facing the utility at the time the relevant decisions were made, and not on the basis of hindsight.

3.2 Lesser role in regimes with more significant ex ante incentives

Prudency reviews tend to be less of a feature in regimes that place a greater emphasis on providing *ex ante* incentives for the achievement of operational and investment efficiencies. CPI/RPI–X regimes are usually of this type, although precise regulatory arrangements differ, and in reality there is a spectrum of alternatives rather than any sharp division between rate-of-return and CPI/RPI-X approaches. Different jurisdictions tend to develop their own variants of regulatory systems, taking account of 'local' contextual factors.

3.3 The relevant standard in prudency reviews

Although the precise role of *ex post* assessments tends to differ from jurisdiction to jurisdiction, there is much more international commonality in the relevant standard against which prudency should be assessed, particularly in relation to past investment decisions (see section 5 below).

The antonym of prudent is reckless, and the traditional language here provides clear indication of the relevant standard to be applied when considering whether past capital expenditure should be disallowed from the regulatory asset base (RAB). To put it simply, the standard is one of 'reasonableness' or 'non-negligence' rather than of 'best possible performance' or 'best practice'.[5]

There are a number of relatively obvious reasons for choice of a 'reasonableness' standard when assessing capital expenditures, including, but not restricted to, the following:

- Investment decisions are very often subject to considerable uncertainties, and 'optimal' courses of action are rarely well defined. There is scope for reasonable, well informed experts to differ on capex questions such as whether, what, on what scale, how, where and when to build new facilities. Regulation should properly allow for these realities, and recognise that approaches based upon the notion that unambiguously optimal capex decisions can generally be identified are (a) non operational and (b) amount to a pretence to knowledge that regulators do not and can not have.[6]

- Disallowances based on comparisons with hypothetical, best possible *outcomes* could, in practice, be expected to lead to severe disincentives for investment, *unless these adverse incentive effects are compensated for by some other aspect of regulatory decision making, such as a higher allowed*

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[5] Of course, best practice considerations may well be of interest when assessing the potential for performance improvements on a forward looking/*ex ante* basis.

[6] Keynes described this type of approach to economics as *"… one of these pretty, precise techniques which tries to deal with the present by abstracting from the fact that we know very little about the future."*

rate of return on the (diminished) rate base.[7] If a utility could only earn a normal rate of return in conditions in which it was always making the best possible decisions – i.e. only if, in an uncertain and complex world it was always getting things 100% right – then, in effect, it could never expect, *ex ante*, to make a normal return on capital. We note that the adverse incentive effect here can, as a matter of economics, be expected to be larger the greater the uncertainties in the relevant decision making environment (e.g. worse in changing business/economic environments than in static economic conditions).

3.4 The meaning of 'efficiency'

One of the things that has happened in regulatory discourse over a relatively recent period is that the older language of 'prudence' and, to a lesser extent, 'reasonableness' has been partly displaced in regulatory discourse by references to economic notions of 'efficiency'. By way of illustration, Ofgem, the UK energy regulator has tended to refer to "*efficiently incurred* investment" rather than to "*prudent* investment", and it is a stated object of the Energy Networks Access Code in Western Australia to promote *"efficient investment in … networks and services of networks"*.

We conjecture that the shift in terminology has been chiefly influenced by the much greater, explicit emphasis placed upon *ex ante, incentive regulation* over recent decades, and the change need not be a problem provided that relevant distinctions are clearly made. There is, however, scope for potential confusion here, and a number of points might usefully be borne in mind:

- The concept of efficiency has multiple meanings in economics, and various dimensions of efficiency – allocative efficiency, productive or cost efficiency, dynamic efficiency – may exhibit trade-offs such that increases in efficiency in one dimension may lead to reductions in efficiency in other dimensions.[8] It is therefore necessary to be precise about the way in which the term is being interpreted.

- The change in language does not change the underlying economic realities, which, particularly in relation to investment expenditures, involve decision making under uncertainty.

- Under uncertainty, the notions of optimality and best possible outcomes tend not to be well defined (i.e. tend to be non-operational). Thus, for example, in determining levels of capacity for projects in networks, account needs to be taken about the future evolution of customer requirements, technologies, and input prices, since incremental capacity over and above what might be required to meet immediate demand will typically have an option value. Estimation of such option values necessarily contains significant 'subjective'

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[7] Such compensation has been a major factor in relevant US and UK decisions (see section 5 below).

[8] This is part of the rationale for CPI/RPI-X regulation, which potentially gives up some allocative efficiency in exchange for an expectation of improved productive/cost and dynamic efficiencies resulting from stronger incentives. It is also the rationale for IPRs: patent protection and copyright sacrifice efficiency in the use of currently available information/content for enhanced incentives to discover/produce new information/content.

elements, such that there is typically scope for skilled and experienced experts to reach materially different views.

3.5 Consistency of the Code with the relevant standard for ex post assessment

The wording used in the Code in relation to the NFIT at 6.52(a) appears to us to be consistent with the 'reasonableness' standard. Whilst it specifies that investment should not exceed a certain "amount", the relevant amount is not explicitly defined as, say, the lowest possible cost of providing the new facilities – which might be referred to as 'frontier' cost efficiency, and which is an outcome whose measurement is inherently uncertain, even *ex post* (see the above comment on the difficulties in estimating investment option values). Rather the "amount" is defined in terms of what "would be invested by a *service provider efficiently minimising costs*."

Efficiently minimising costs is a description of a *process*, not an *outcome*; and the intended meaning is further clarified in the Glossary to the Code:

> **"efficiently minimising costs"**, in relation to a *service provider*, means the *service provider* incurring no more costs than would be incurred by a prudent *service provider*, acting efficiently, in accordance with *good electricity industry practice*, seeking to achieve the lowest sustainable cost of delivering *covered services* and without reducing *service standards* below the *service standard benchmarks* set for each *covered service* in the *access arrangement* or *contract for services*.

The references to a <u>prudent</u> service provider, <u>acting</u> efficiently, in accordance with <u>good</u> (not best possible) practice, <u>seeking</u> to achieve the lowest sustainable cost of delivering covered services individually and collectively point to the assessment of an investment *process* in the round, based on normal standards of reasonableness and competence. This is confirmed by the Code's definition of good electricity industry practice:

> **"good electricity industry practice"** means the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would <u>reasonably</u> and <u>ordinarily</u> exercise under comparable conditions and circumstances consistent with applicable *written laws* and *statutory instruments* and applicable recognised codes, standards and guidelines.

4. INCENTIVE EFFECTS OF PRUDENCY REVIEWS

As already stated, *in the absence of compensation via other elements of the regulatory bargain*, *ex post* reviews that lead to disallowances of capital expenditure on the basis of a failure to achieve unduly high performance benchmarks can be expected to have highly adverse effects on investment incentives, and hence on economic efficiency in the longer term. Investment will be discouraged in general, but the disincentive effect can be expected to be greater the greater the riskiness of the project. The chilling effects will therefore tend to be greater the more unsettled or dynamic is the economic environment in which the utility is operating.

Notwithstanding these potential problems, prudency tests based on traditional notions of ‘reasonable’ performance can have positive incentive effects, and, for this reason, cannot be discounted as one of the possible elements of an effective regulatory regime.

Prima facie it may appear that a reasonableness standard is too weak to encourage better performance on the part of a regulated utility; but complexity and uncertainty in investment projects and programmes combine to create conditions in which significant incentive effects can emerge. Briefly, it is a challenge to management to develop processes and procedures that reduce the risk of the occurrence of mistakes and failures on the part of some or other members of the relevant organisation which, *ex post*, could potentially be judged to be negligent/unreasonable.

Thus, although, in an effective organisation the occurrences of negligent or unreasonably poor performance should be infrequent, this does not mean that incentive effects are weak. The *possibility* of sanctions, combined with the ability of managements to reduce the risk of sanctions, can itself exert a consistent pressure toward better investment performance.

In this, prudency reviews are not unlike an incentive mechanism such as the risk of bankruptcy: even when the incidence of bankruptcy is low, the pressures to avoid it continue to exist and to exert an effect on business behaviour. Indeed, depending upon circumstances, it might be the strength of the incentive effect that itself helps keep the incidence of the outcome low.

The strength of the incentive effects can be expected to depend in part on the strength of the sanctions in the event of a finding of unreasonable conduct. In financial terms, an investment disallowance of given magnitude will have the same impact on any given utility, irrespective of the standard that has been used in the assessments that have led to the disallowance (although the same financial implications might have different impacts on different utilities, depending among other things on whether they are publicly or privately owned) . However, the incentive effects of regulatory actions go rather wider than a simple, aggregate financial effect, and the standard for assessing prudency can itself have an impact.

Speaking broadly, an assessment standard based on notions of unreasonableness, recklessness or negligence can be expected, if breached, to have much more significant behavioural impacts than breaches of standards based on, say, best conceivable performance (e.g. ‘frontier’ efficiency). Failure to attain the latter can be expected to be an everyday, normal event; whereas a finding of unreasonableness signifies something less common, and a much more adverse judgment. Managerial careers might be directly threatened in consequence of such public judgment, whether the utility is publicly or privately owned.

5. PRACTICE/DECISIONS IN OTHER JURISDICTIONS

5.1 The USA, and the significance of compensation

The USA has the longest and most developed tradition of the application of prudency reviews as part of utility regulation regimes. A well known summary of the meaning of prudence in US law has been provided by Supreme Court Justice Brandeis:

> *"The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown."* (Southwestern Bell Telephone Co., 1923).

As Cope, Dismukes and Yeargain[9] explain (and compare with reasoning in the Decision of the Irish Aviation Appeal Panel, 2006, discussed below):

> *"The prudence standard has been compared to the common law negligence standard for determining whether to exclude value from the rate base. In other words, the utility must show that it used a reasonable decision making process to reach a course of action, and, based on the facts known at the time, responded in a reasonable manner. This may be called foreseeability."*

The historical evidence in the USA indicates that disallowances based on findings of imprudence were not a major factor in regulatory decision making prior to the oil price shocks of the 1970s. They also do not appear as a major issue in the leading economic textbooks of this earlier period, such as the 1970 edition of F.M. Scherer's *Industrial Market Structure and Economic Performance*, which includes a chapter focused on the theory and practice of rate of return regulation in the US. Pierce[10] summarises the position as follows:

> *"A temporal analysis of disallowances based on imprudence provides a good starting point. When I researched this topic for other purposes in 1983, I conducted an exhaustive search for regulatory disallowance based on imprudence. The Federal Energy Regulatory Commission (FERC) and its predecessor, FPC, had never disallowed an investment on the basis of imprudence in the agency's fifty year history. I could find only a few cases in which state agencies had disallowed investments based on a finding of managerial imprudence. Even in those rare cases – about one per decade – the magnitude of the disallowance was relatively trivial. The aggregate amount disallowed in the history of utility regulation probably did not exceed a few hundred million dollars. By contrast, during the period 1984 through 1988, state agencies disallowed as imprudent significant portions of the investments in nineteen completed generating plants. The average amount*

[9] Cope R., Dismukes D. and J. Yeargain, "Reflections on the U.S. electric power production industry: precedent decisions vs. market pressures", *Journal of Legal, Ethical and Regulatory Issues*, July 2003.
[10] Pierce, P. (1989). "Public utility regulatory takings: Should the judiciary attempt to police the political institutions?" *Georgetown Law Journal*, 77, 2050-2051.

disallowed per plant was $610 million; the aggregate amount disallowed was $11.6 billion. If these agency findings are to be believed – that is, if the findings of the past four years are something other than a guise for politically opportunistic exercises of the raw political power to redistribute wealth from a minority to the majority – then they suggest a startling trend in the industry's management. Apparently, for decades electric utility managers were almost uniformly individuals with outstanding business acumen. At some point in the 1980s, this entire generation of exceptional managers was replaced en masse by a generation of bumbling idiots."

The precise drivers of this shift in regulatory behaviour remain a matter of debate, but it is clear that substantially higher oil prices post 1973 led to political resistance to substantially higher regulated prices ('rate shock') and gave a boost to the construction of more nuclear power plant. The second oil price shock then, unexpectedly, reduced the growth in demand for new power plant in aggregate which, coupled with tightening regulatory constraints on nuclear plant arising from environmental/safety concerns, was a factor contributing to escalating construction costs and abandonment of projects which had already given rise to substantial capex. The sharp increases in disallowances in this later period are therefore particularly associated with nuclear power plant, *not with general investment in networks.*

Perhaps the most famous case is *Duquesne*, which ended in a Supreme Court decision in 1989 and which Kolbe, Tye and Myers used to motivate their economic analysis of the concept of regulatory risk.[11] These authors summarise the matter as follows:

"In 1967, Duquesne Light Company and four other utilities joined a venture (CAPCO) to construct seven nuclear generating units. In 1980, four of the plants were cancelled because of the economic and political impacts of the Arab oil embargo, the accident at Three Mile Island, and other intervening events.

The Pennsylvania Public Utilities Commission (PUC) approved the amortization of the investment in cancelled plants over a 10-year period through rate increases in 1983. However, about a month before the close of the rate case in 1982, the Pennsylvania legislature enacted a law that precluded inclusion of costs of construction of facilities in rate bases, prior to the time such facilities were 'used and useful in service to the public.'"

A consumer group then sued Duquesne and the PUC under the new law. The PUC defended its decision to allow amortization of the relevant capex, but the Pennsylvania Supreme Court found for the consumer group, and the US Supreme Court subsequently affirmed that decision.

The US Supreme Court recognised that the State law had moved the regime away from a strict prudency system, since it found that the CAPCO decisions were, at each stage up to and including cancellation, reasonable and prudent. However, crucially, the Court noted that:

[11] Kolbe, L., Tye W. and S. Myers, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Boston: Kluwer Academic Publishers, 1993.

"Pennsylvania's modification slightly increases the overall risk of investment in utilities over the pure prudent investment rule. Presumably the PUC adjusts the risk premium element of the rate of return on equity accordingly."

The Court's reasoning, which was based on considerations of expropriation of property rights rather than on considerations of promoting efficiency, was, therefore, broadly as follows:

- *"Inconsistencies in one aspect of the methodology have no constitutional effect on the utility's property if they are compensated by countervailing factors in some other aspect."*

- The impact of the decision on investors was relatively slight: $35m of investment in the cancelled plants was disallowed, which was equal to around 1.9% of the regulatory asset base.

- Such a loss could realistically be compensated for by adjustment of the allowed rate of return on the rate base, since a 1.9% adjustment in the allowed rate of return (which stood at 11.64%) was within the normal range of variation of regulatory determinations.

In effect, this suggests that, since the Court would not have found an allowed rate of return of 11.64% - 1.9% = 9.74% unconstitutional, it could not find a disallowance that had an economically equivalent effect on the utility's allowed revenue to be unconstitutional – since what mattered was the fairness/reasonableness of the end result (the allowed revenue), not the process by which such a route is reached.

We infer two principles at work in all of this:

- Disallowances are permissible, if accompanied by offsetting compensation when utility conduct has been prudent, which is simply a reaffirmation of the principle that prudent investments should be remunerated at a fair or reasonable rate.

- The Courts will not want to get involved if, in a relevant case, the economic effects are relatively limited – which appears to us be a statement about proportionality in assessment (don't bring cases to the higher Courts based upon differences in numbers that fall within some reasonable range).

5.2 The UK

UK sectoral regulators have tended to have a strong aversion to *ex post* disallowances of capital expenditures, reflecting factors such as:

- A recognition that the regulatory asset base is the crystallisation of past 'settlements' between customers/consumers and investors which should not, in ordinary circumstances, be disturbed, and

- The focus of the (RPI-X) regulatory regime on forward looking approaches to capex evaluation.

In the energy sector, Ofgem has been no exception to this general tendency. However, in 2006 the Ofgem decided to exclude a total of £19m of incremental capex made by National Grid on the high pressure national gas transmission system. Whilst *prima facie* this might suggest a shift in policy toward greater reliance on a traditional form of prudence review – and it has been so interpreted by some analysts – the disallowance decision was made in a very specific context which, once understood, indicates otherwise (because it respects the compensation principle implicit in *Duquesne*).

Specifically, under the National Transmission Capacity Investment Incentive Scheme, National Grid auctions annual gas transmission entry capacity rights for periods between 2 and 16 years into the future.[12] The (policy) purpose of the arrangements is to encourage greater efficiency in the location of investment in new facilities, by allowing users of the system to secure rights in advance of future requirements and by providing National Grid with better signals of likely future requirements. A contextual factor that motivated the policy was the declining production of UK Continental Shelf gas fields, and increased uncertainty as to precisely where new sources of gas might be landed in the UK. For example, would there be major new flows from the Norwegian sector of the North Sea, or via increased interconnector pipeline flows from the near continent, or from new LNG terminals?

As part of the arrangements, National Grid enjoys incentives to adjust incremental investment around previously agreed, 'obligated' levels of capacity made available to network users, in the light of its views of changing customer requirements, informed, at least in part, by the information revealed by network users in the capacity auctions. In effect, National Grid was, in the relevant version of the incentive scheme, allowed to retain, for a period of five years, <u>all</u> incremental annual revenue that it could obtain from the sale of incremental entry capacity, subject to an annual cap (of 12.25% real) and collar (of 5.25% real). Thereafter, the investment, suitably depreciated, was allowed a rate of return of 6.25% real, being the estimated cost of capital and the allowed rate of return on 'obligated' capacity, up to the next quinquennial price review, at which point it was to be reviewed and, if judged efficient, incorporated into the regulatory asset base thereafter.

In effect, therefore, the incentive scheme allows for return of up to 6% <u>above</u> the cost of capital, for a period of between five and ten years, and it is against this generous 'upside' that the disallowance decision should properly be assessed.

In its Final Proposals document of December 2006, Ofgem explained its position as follows:

> *"2.11. The outcome of our review of historical capital expenditure is that we have allowed some £3.4 billion of expenditure to enter the RAV in respect of the period up to and including 2005/06. This amount includes £321 million of*

[12] Pipeline capacity is sold on an entry/exit basis, with geographically differentiated payments for rights to enter gas into the high pressure, onshore pipeline network (the NTS), typically at beach terminals, and also to withdraw gas from that system.

> *overspend incurred by NGET and some £126 million of capital expenditure for NGG in respect of a new gas pipeline and major network reinforecement to connect a Liquified Natural Gas (LNG) terminal at Milford Haven.*
>
> *2.12. Our Final Proposals for NGG exclude £19 million of some £75 million expenditure relating to the delivery of baseline capacity at St Fergus where we believe that NGG has not provided adequate justification for this investment in the light of indications of demand for capacity arising from the long term entry auctions. We considered whether this expenditure should be excluded in its entirety but have concluded that, since this project was initiated in the early days of the new entry regime when the potential implications of operating under an auction regime may have been uncertain, it would be inappropriate to do so".*

The following points, all of which distinguish the decision from that relating to Western Power, are relevant:

- The effect of a disallowance of £19m is, approximately, equivalent to the *supernormal* return (6% per annum) that could potentially have been made on an investment of £75m over the five years of the incentive period. Crucially, it does not imply that, as would be the case for Western Power, National Grid was unable to earn *any* return on the investment in question.

- The disallowance amounted to about 0.64% of National Grid's closing regulatory asset value for the relevant period and 1.9% of capex during that period (compared with 7.1% and 15% respectively for Western Power, figures that are roughly an order of magnitude higher).

- The disallowance related to a specifically identified part of the capex programme, connected to the delivery of capacity at one of the six major beach terminals (at St Fergus, in the north east of Scotland). Capex linked to developments elsewhere in the pipeline system, including at the other entry points where capacity was also auctioned and subject to the general incentive scheme, was allowed in full. Thus, unlike for Western Power, there was no across-the-board disallowance. Rather the disallowance was linked to the finding of a very specific problem.

This last point is an important one, since it is a feature of the reasonableness standard that it focuses regulatory attention on the question of whether or not there are specific and egregious failures of performance to be found. Where any such failure is discovered, attention can then be turned to the question of whether it is the result of an isolated performance deficiency, or of some more general deficiencies in the organisational processes.

5.3 Republic of Ireland

A recent decision in the Republic of Ireland may be of particular interest in the current context because it concerns a regulatory decision to disallow past capex by a publicly owned operator in circumstances of growing demand.

In 2005, the Dublin Airport Authority plc (DAA, formerly *Aer Rianta*) appealed against a decision of the Republic of Ireland's airports regulator, the Commission for Aviation Regulation (CAR), to disallow a fraction of the capital expenditures, dating from 2001, made by DAA in the course of constructing a new pier – Pier C – at Dublin airport. The disallowance in question amounted to €13.4 million, or about 22% of the relevant capital costs, and the Decision was based chiefly on a consultant's report that had concluded that the construction cost of the airport pier was higher than that of 'similar' buildings constructed in Dublin at around the same time.

In finding against the CAR's Decision on this point, the Aviation Appeal Panel (of which one of the authors of this Opinion was a member) set out some of the principles that it considered appropriate to prudence reviews:

> *"6.4.11 The Commission decision to maintain the stranding of Pier C costs raises equally fundamental issues. Disallowances for imprudent investment were a feature of rate-of-return regulation as practised particularly in the USA. This was because of concerns that rate-of – return led to incentives for inefficiently high investment. On the other hand, economic analysis based on CPI – X regulation tends to emphasise the potential danger of under-investment.*
>
> *6.4.12 In relatively new regulatory systems, where the relevant regulatory body has not had sufficient time to establish a firm reputation for respecting property rights, disallowances of capital expenditure from the RAB can potentially create material, adverse regulatory risk and uncertainty. The RAB reflects the future claims of investors on the income of the regulated company. Reductions in the RAB by the Commission amount to reductions in those claims, and unless such actions are guided by credible and legitimate principles they will be perceived as a form of capital expropriation.*
>
> *6.4.13 The Panel considers that the circumstances under which RAB disallowances might legitimately be justified are similar to those discussed in relation to clawback. That is, they are only justified in the event of some manifest deficiency in the performance of the regulated company, such as would be considered to be outside normal commercial parameters. In the specific context of Pier C, the Panel can see no evidence of such conduct on the part of DAA. While we recognise that, with the benefit of hindsight, the Commission might have concluded that the costs of Pier C could potentially have been lower than the approved budget, that is not, in our view, anywhere close to providing sufficient grounds for disallowing what appears to be an arbitrarily determined fraction of the relevant expenditure. Given the uncertainties surrounding capital projects, there is scope for a variety of views about what is the most efficient way forward, each of which might be considered reasonable. Only if DAA can be shown to have strayed outside the bounds of reasonable conduct or made an unreasonable decision about the type of capital expenditure incurred*

should there be any 'disallowance' issue for the Commission to consider.

6.4.14 The Panel finds it very difficult to understand how costs, legitimately incurred on Pier C, on budget and with the approval of the Minister (there then being no outside Regulator) can now apparently be permanently stranded. If this is because Aer Rianta did not formally appeal this aspect of the previous determination to the last Appeal Panel, this Panel does not believe that DAA are 'estopped' from contesting the decision to (apparently) permanently strand this expenditure now."

The panel therefore affirmed (at 6.4.13) a 'reasonableness' standard for *ex post* reviews, and found that CAR had come nowhere close to showing that that standard had been breached by DAA.

In relation to the 'clawback' issue, referenced in para 6.4.13 above, which involved a reduction to the RAB to compensate for allowed, within period income on capex that had been anticipated in relation to the Pier D project but that, in the event had been delayed, the Appeal Panel said the following:

"6.4.4 In relation to CAPEX, the allowances are set following an assessment of the company's capital investment programme (CIP) and its likely costs. On the basis of the 'standard' approach to CPI – X regulation, which the Commission indicates that it is seeking to follow, the projected expenditures allowed in calculating regulated charges are not linked to particular projects or project outcomes. The rationale for this is that, in general, things will not usually go exactly to plan. Indeed flexibility to adjust plans, as new information becomes available, is to be positively encouraged. Flexibility may mean some projects not going ahead at all, others being delayed or brought forward, and yet others being introduced into the investment programme for the first time.

6.4.5 It is also a key principle of the standard CPI – X approach that price or charge caps, once determined, are 'pre-determined' for the relevant period, meaning that, although the charges may be adjusted (e.g. to reflect inflation), they will be adjusted in ways that cannot be materially influenced by either the regulator or the regulated undertaking. 'Clawback' violates this principle, since it is equivalent in economic effect to retrospective, discretionary adjustment of charges that were intended, and promised, to be pre-determined. Given this, the Panel considers that 'clawback' should only be contemplated in circumstances in which there has been prior and manifest non-compliance by the company.

6.4.6 Given that the regulatory settlement between Commission and company is a relatively broad one, with performance requirements not spelled out in detail, the Panel believes that the notion of "compliance" must be given a similarly broad meeting. It does not *simply mean deviating from plan (it is very rare that the assessed CIP will actually be fully implemented), nor does it simply mean operating inefficiently (most companies in most markets operate in ways that fall short of maximum efficiency).*

6.4.7 The Panel considers that clawback could properly be considered legitimate if:

- *DAA/Aer Rianta had deliberately misled the Commission. There is an obvious rationale for seeking to prevent a company from gaining benefit from such conduct. In the context of CAPEX, this might occur if DAA/Aer Rianta had included a project in its CIP that it knew at the time (but the Commission did not know at the time) would not be feasible in the relevant period.*

- *DAA/Aer Rianta's performance can be characterised as being akin to negligence: conduct falling short of what might reasonably be expected. That is, the bar is set at a minimum acceptable standard of performance, not the economists' ideal of efficiency, which is a "best possible" standard. Again, in such circumstances the case for compensation (in the form of clawback) is obvious, on basic principles.*

The defining feature of the circumstances in which clawback might be justified is some manifest deficiency in the conduct of the DAA, such that its performance falls to an unacceptably low level.

6.4.10 In relation to 'clawback', the Panel also notes that the Commission appears to have applied this approach very selectively, to Pier D allowed CAPEX only. Whilst it is understandable that users might feel aggrieved that an allowance was made for investment activity that did not materialise within the relevant period, it is also the case that the earlier charge determination was based on projections of DAA commercial revenues that also did not materialise. These (inaccurate) projections were to the benefit of users. Again we have a concern that the Commission may, via retrospection that is focused only on investment activity, signal a rather negative regulatory attitude to CAPEX to the investment community."

We think the reasoning here requires no further elaboration, but there is one additional concern raised by the Panel that may be of relevance in Western Australia. It concerned the possible implications of CAR's approach for incentives to the operator to provide accurate information to the regulator, and it arose in connection with a regulatory finding that DAA had 'over-sized' an investment project. The relevant reasoning was as follows:

"6.3.5 The Panel considers that the Commission should have properly considered allowing a cost for the Pier D proposal on the basis of a 29m Pier width, in accordance with the planning permission already

given and following the consultation process during which, so far as we are aware from the determination, there was no strong view in favour of the lower width suggested by the Commission's consultant. If, however, such a strong view in favour of a smaller facility did exist, the Commission should properly have taken it into account in its reasoning.

6.3.6 In relation to the costings applied to a facility of given size, the Panel is of the view that the benchmarking exercise relied upon by the Commission is insufficiently robust to warrant a substantial adjustment to the DAA CAPEX plans.

6.3.7 The Panel has a concern, heightened by the abstract and theoretical nature of a discussion in the determination about the implications of "asymmetric information", that the Commission believes that DAA will always significantly over-estimate its investment costs, and that the appropriate regulatory response is to adjust those estimates downwards by a significant amount, no matter how limited the available evidence on the magnitude of the perceived bias in estimation.

6.3.8 Apart from the arbitrary nature of the cost adjustments made, there may be some confusion as to the implications of economic theory as it relates to the relevant issues. It is notable that there appears to be a procedure of making relatively arbitrary, downward adjustments to costs, with the implied intention of correcting for assessment bias. This necessarily implies a disincentive for good faith conduct by DAA and is out of line with best practice incentive regulation. If the Authority provides its best available information on projected costs, it can expect to earn less than a normal rate of return on investment, by virtue of the expected, downward adjustments that will be made. A more appropriate regulatory response to the information problem would be to seek more vigorously to verify the information provided, discuss and consult on alternatives and only substitute the Commission's own reasoned alternative when there is very clear evidence of assessment bias.

5.4 Other Australian States

There is no requirement under the current National Electricity Rules - which apply to TNSP's in the Australian National Electricity Market - for the Australian Energy Regulator to undertake an *ex post* prudency review given the particular form of regulatory framework applied which is based on the setting of an *ex ante* capex allowance.

The decision to adopt an *ex ante* approach was specifically in response to concerns that had been expressed about the adverse effects of *ex post* approaches on investment incentives. For example, the ACCC's background paper to the Statement of

Regulatory Principles for the regulation of electricity transmission revenues identified two disadvantages of *ex post* prudency assessments of capital expenditure:[13]

> *"1. It creates uncertainty for investors that, after having invested, the ACCC could decide that the investment was not prudent and hence disallow recovery of the investment cost in regulated charges.*
>
> *2. It is not clear that the threat of ex post prudency assessment provides effective efficiency incentives. If TNSPs do not think that the threat is credible, then they have no economic incentive to select the most efficient investment and develop assets at least cost. On the other hand, if they do think that the threat is credible, they may be inclined to inefficiently under-invest for fear that the ACCC will come to a different conclusion on the prudency of the investment they make.*

More recently, the reasoning for adopting this approach was re-affirmed by the Australian Energy Markets Commission (AEMC) in its 2006 review of the operation of the National Electricity Laws, where it noted that:

> *"In general the criticism of the proposed ex post prudency review was that it undermined the incentives of the ex ante cap and contributed to the investment uncertainty that the remainder of the package sought to overcome. Submissions also raised the legitimate concern that ex post prudency reviews are, by their very nature, an intrusive form of regulation. An ex post review effectively requires the regulator to put itself in the position of a TNSP at the time that they were undertaking a particular project to determine if the project was undertaken efficiently. Previously, this process has been the subject of controversy when it has been applied to network businesses. For these reasons, the Commission has removed the arrangements for ex post reviews and instead focused more on improving ex ante incentives."*[14]

However, in setting the revenue caps that apply to the TNSP in each State during the current transitional period, the AER (and the ACCC before it) has been required to apply an *ex post* prudency test when determining the amount of capital expenditure which can be included in the opening Regulatory Asset Base.

A number of observations can be made about the manner in which the AER/ACCC have applied this prudency test in practice:

- The standard applied by the ACCC/AER appears, at least to some degree, to have recognised that in some instances it may be considered prudent to allow some 'over-build' in anticipation of expected demand growth or take account of economies of scale.[15]

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[13] ACCC 'Statement of principles for the regulation of electricity transmission revenues – background paper' 8 December 2008, page 44.

[14] Australian Energy Markets Commission 'Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, No.18, 16 November 2006, page 98.

[15] In its 1999 draft statement of Principles for the Regulation of Transmission Revenues, the ACCC notes: *"Concerning asset base roll forward, the approach adopted in the Draft Regulatory Principles provides that only capital expenditures deemed to be prudent may be added to the regulatory asset*

- The general approach adopted by the AER/ACCC has been to examine a selection of large or significant capital projects and to employ external consultants to review and assess the efficiency of the projects.

- On the basis of a preliminary scan, we have only been able to identify one significant case of an *ex post* prudency adjustment. This is in relation to TransGrid's investment in the MetroGrid project. In this instance, the ACCC presented a detailed description of the underlying causes of imprudent investment, and more critically, outlined a methodology for assessing the proportion of the investment that was deemed to be imprudent.[16]

- In all of its recent determinations, the Australian Energy Regulator – for SP AusNet, Transend, Powerlink Queensland and Electranet – has made no significant *ex post* adjustment to past capital expenditure to reflect imprudent investment. This is despite concluding in some instances that oversight issues were identified with certain projects or that improvements in the capital policies and procedures could have been implemented. This is suggestive of a generally cautious approach to making such adjustments, and a reluctance to disallow capital expenditure in the absence of detailed and specific evidence of substantial flaws in the execution of that investment.

- Finally, we have been unable to identify any example of where a uniform percentage reduction has been applied to past capital expenditure in any of the regulatory determinations relating to transmission network assets in the other Australian States.

6. THE ERA'S DRAFT DECISION: ASSESSMENT

Given the above discussions of the background of the objectives of the Access Code; the purposes and effects of *ex post* prudency reviews; and the experience of the conduct of prudency reviews by regulators in comparable jurisdictions (including elsewhere in Australia), we now assess the decision of the ERA to disallow a proportion of past capital investments by Western Power in the first access arrangement period.

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base. Clearly if the full amount of the investment is not required and is not prudent, the regulator should not add the full cost to the regulatory asset base. Where additional capability/ capacity is included to allow for demand growth, some overbuilding may be considered prudent given the quantum nature of expansion and scope for economies of scale. Where there is doubt that any overbuilding is prudent, a lesser amount will be added to the regulatory asset base corresponding to what would be considered clearly identifiable demand (including a margin sufficient to satisfy normal redundancy or safety requirements). In most cases, the bulk of expenditures will be included because economies of scale would mean that a smaller capacity addition to infrastructure would be at a higher unit cost". ACCC 'Draft Statement of Principles for the Regulation of Transmission Revenues' 27 May 1999, Page 6

[16] ACCC 'NSW and ACT Transmission network revenue Cap TransGrid 2004-05 to 2008-09' 27 April 2005, pages 84 to 88.

6.1 The ERA's general approach

In the Draft Decision, ERA notes that it has discretion under sections 6.41, 6.51 and 6.51A of the Access Code as to whether to recognise costs in the total costs and the target revenue that underlie the price control. In this instance, the ERA notes that its ability to review the costs associated with new facilities investment in the first access arrangement period was hampered by a lack of necessary information:

> *"The inadequacy of information has been of particular concern in respect of actual new facilities investment in the first access arrangement period, which is required to demonstrate the amounts of new facilities investment that satisfy the relevant tests under the Access Code for addition to the capital base of the SWIN."*[17]

More specifically, the ERA concludes that the information submitted by Western Power *"has not demonstrated to the Authority's satisfaction that the actual and forecasts costs meet the relevant tests of the Access Code"*.[18]

Notwithstanding the inadequacy of the information before it, the ERA concludes that *"a degree of inefficiency in that part of new facilities investment that undertaken by Western Power"*.[19] In reaching this conclusion, the ERA relies heavily on reports by Geoff Brown and Associates which, in the Authority's interpretation, are suggestive of deficiencies in the Western Power's planning and procurement processes in the first access period.[20] In so doing, ERA largely discounts the findings of another commissioned consultant's report which concluded that capital expenditure has been well planned and major investments have been subjected to detailed studies of options and alternatives.[21]

6.2 Information provision

As a first, background point, we note that the 'adequacy' of the information provided to a regulator can only be assessed in relation to the purposes to which that information is to be put, which in turn will depend, among other things, on the standard against which performance is being assessed. The traditional prudency standard, for example, will typically require rather lower information flows than would an attempt to compare with best practice across the board. It will also tend to put more of the initiative with the regulator (and advisors), since the exercise is more in the nature of an audit, based on sampling for the existence of egregious deficiencies.

We infer that the ERA's complaints about lack of necessary information are linked to the adoption of a relatively stringent performance standard (closer to 'frontier' efficiency than to prudency). However, the point here is that, since the relevant

[17] Para 348 of Draft Decision
[18] Para 350 of Draft Decision
[19] Para 566 of Draft Decision
[20] Para 564 of Draft Decision
[21] Wilson Cook & Co. ''Review of Western Power's Expenditures for Second Access Arrangement Final Report' Report prepared for the Economic Regulation Authority, Western Australia May 2009

standard being used by the ERA in applying the NFIT itself appears to be obscure, *there is no clear basis in the Draft Decision for a judgement that the information available has been inadequate*.

As a general matter, it would be unreasonable – and *a fortiori* inefficient – for a regulator to expect a utility to offer up every piece of information that might possibly be relevant to capex assessment against every possible benchmark that might be adopted. Information provision is not a free good, and regulatory practice should pay due attention to the relevant costs and trade offs.

6.3 Inadequacy of reasoning

In our judgment, the ERA's Draft Decision appears to be inadequately reasoned in a number of respects, including the following:

- First, the ERA appears to have concluded that because some aspects of the governance and planning *processes* of Western Power were deficient in the first access arrangement period, that this automatically allows for the conclusion that a proportion of the capital expenditure undertaken during this period did not minimise costs and that the *outcome* was therefore inefficient. However, as the report by Wilson Cook & Co correctly (in our view) recognises, a conclusion as to the efficiency of costs does not flow automatically from the assessment of the efficiency of planning and prioritisation process.[22]

  Processes and outcomes are, of course, linked. Speaking generally, better processes lead to better outcomes; but the linkages are neither mechanistic nor one-to-one. Thus, findings of process deficiencies are by no means sufficient to sustain a confident inference that performance (in terms of costs to serve) has been deficient, even against best practice standards.

- Second, the ERA appears at a number of points to substitute presumption for analysis and evidence. Perhaps the most significant of these occurrences is when the ERA appears to jump from a view that it does not have sufficient information to allow it to determine precisely whether or not new facilities investment during the first access arrangement was efficient (in an undefined sense) to a conclusion that the new facilities investment was inefficient by an across-the-board margin of 15%, without anything much in the way of intervening reasoning. As discussed in more detail below, this presumption and the magnitude of assumed inefficiency (i.e. 15%) is, putting it quite simply, unsubstantiated.

- Third, the approach of ERA in the Draft Decision appears to give insufficient weight to Western Power's responsiveness to perceived weaknesses in its business practices. Reasonable conduct does not require that utilities get everything right, but it does require that companies respond when problems are identified (the 'forseeability' point made by Cope, Dismukes and

[22] Wilson Cook & Co. Report page 38, 88.

Yeargain)[23]. We note that each of the consultants' reports commissioned by ERA stated that Western Power's management and board recognised that its governance and cost estimation processes were inadequate in the past, and that, in response Western Power had taken positive steps to address identified inadequacies in ways that could be expected to lead to improvements in these processes.[24]

- Finally, no attempt is made in the draft decision to distinguish between the different potential drivers of cost variances and to examine how this might impact on, and complicate, Western Power's governance and planning decisions. In particular, both consultants' reports recognise that the first access arrangement period was a time of significant and unprecedented change for Western Power and for the Western Australian economy more generally. The reports go on to note that a significant proportion of the observed variance between forecast and actual capital costs in the first access arrangement period could be explained by unexpected increases in demand as a result of the 'booming' Western Australian economy. However, this factor appears to be largely ignored in the draft decision, or at least given relatively little weight.

6.4 Consistency with the Code

As noted above, the ERA concludes, at paragraph 597 of the draft decision, that it is not satisfied that the entire amount of new facilities investment satisfies the efficiency test of section 6.52(a) of the Access Code.

This conclusion raises two immediate questions:

- Is the standard (the acceptable level of 'efficiency' for the NFIT to be passed) being applied in the draft decision consistent with that contained in the Access Code?

- Is the evidence or analysis adduced in support of this conclusion consistent with the types/forms of evidence that would be necessary in order to draw such a conclusion?

For reasons set out below, we are of the view that the answer to each of these questions is in the negative.

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[23] Op.cit.

[24] The Geoff Brown & Associates report, upon which the ERA relies heavily, notes for example: '*We consider that over the AA1 regulatory period the Western Power Board and management have aggressively tried to improve the governance within the organisation and have made commendable progress in this effort. This has been done in an environment where the organisation has faced many challenges including an unprecedented demand for new connections, rapidly rising equipment and labour costs and a legacy of underinvestment in the distribution network that persisted for at least a decade..... We have not seen anything in this review that would indicate that the progress made in the management of capital and operations expenditure during the AA1 period will not continue during the AA2 regulatory period and are confident that where weaknesses in Western Power's management and governance processes are identified they will be proactively addressed.* Page 53.

As regards the standard to be applied, we have already noted that the wording of section 6.52(a) of the Access Code refers to a standard of a 'service provider efficiently minimising costs', and that this is suggestive to us that the relevant standard refers to a process of seeking available cost efficiencies, rather than to a specific cost 'outcome' (such as the minimum possible cost). In any event the provisions of the sections of the Code dealing with the NFIT must be interpreted consistently with the higher level Code objective to promote efficient investment in networks. As already explained, an approach to *ex post* assessment which disallows any capex that cannot be shown to be the least cost of the alternatives available, estimated on a narrow, project by project basis, could be expected, in conditions of uncertainty, to have the effect of discouraging investment, such that investment in networks in aggregate would be at inefficiently low levels.

The draft decision is unclear about the ERA's view of the relevant standard. However, the evidence adduced in the Draft Decision does not, in our view, support the ERA's conclusions, even in the event that an inappropriately high standard were applied.

Two sources of inefficiency are cited in the Draft Decision:

- deficiencies in the planning and governance processes for capital works; and
- the systematic over-engineering of projects.

As discussed earlier, the identification of deficiencies in the planning and governance processes for capital works does not necessarily imply anything definitive about whether the service provider is achieving efficient cost outcomes. If findings of inefficiencies are made, and if capex is to be disallowed from the regulatory asset base, those conclusions should properly be supported by clearly identified inefficiencies in actual project outcomes. However, no supporting analysis and evidence on the point is offered by the ERA.

In relation to the evidence adduced to show systematic over-engineering of projects in the draft decision, which is used as the basis for a presumption of the existence of across-the-board cost inefficiency in new facilities investment, we note the following:

- The ERA concludes, in a relatively tentative way (indicated by the word "suggests") at para 603 of the draft decision that the over-engineering of capital projects was 'systematic'. This conclusion appears to differ in scope and to be much stronger than statements made earlier in the decision, which refer only to 'instances' of over-engineering of projects,[25] and which refer to material in two consultant reports, and to the ERA's own determination in its review of a proposed Medical Centre expansion.
- More importantly, the conclusion that there is a 'systematic' over engineering of NFIT projects across the entire asset base does not appear to be consistent with the evidence referenced in support, particularly the two consultant reports of Geoff Brown & Associates. For example, one of these reports states that it

[25] Para 351 of the Draft Decision

was '*unable to form a view on the exact amount of the expenditure on any project or program that meets the requirements of the NFIT.*'[26] The uncertainties surrounding the estimates would therefore seem to us to preclude any clear conclusion of systematic over engineering (which would imply systematic cost inefficiency). Similarly, while the other of the two reports does identify some instances of where capital costs for specific projects could, in the view of the consultant, have been controlled more effectively, the report does not appear to us to reach any very definite conclusion to the effect that there was *systematic* over-engineering of projects by Western Power.

- The ERA's determination to not approve Medical Centre investment involved a difference in expected costs of $2.5 million ($28.4 million versus $25.9 million), or just under 9% of the expected project cost. Given normal uncertainties concerning the option value of incremental capacity installed (over and above the capacity that might be required in the immediate term), such a level of difference is arguably within the range that might be ascribed to normal and reasonable differences of view among experts. We do not, therefore, find this evidence at all convincing as substantiating material in support of a proposition that there was systematic over engineering of projects.

The claim at paragraph 603 of the Draft Decision that the ERA has project-specific information suggesting that there has been systematic over-engineering of capital projects resulting in inefficiencies in the design of network assets is therefore unsupported. No convincing evidence is offered in support of the claim, and the flimsiness of the information that is referenced indicates that the claim is speculative at best.

6.5 The reasoning underlying the 15% reduction

Finally, we note that the reasoning presented in the Draft Decision as to the magnitude of the alleged inefficiencies associated with new facilities investment in the first access arrangement period is extremely thin, and it is unsupported by any substantive analysis or other evidence. Given the absence of clarity about the relevant efficiency benchmark – i.e. about the zero point from which any 'inefficiency' in costs is to be measured – it is difficult to see how things could be any different.

The only reasoning that we could find in the Decision for the specific level of disallowance of new facilities investment (i.e. the 15% reduction) is that contained in the following two paragraphs:

> *"605. Taking the above factors into account, the Authority considers that the extent of inefficiency is likely to be more than a nominal amount, but less than 25 per cent of the total value of new facilities investment.*
>
> *606. Taking into account the lack of information for this determination (refer to paragraph 345 and following) and the significant commercial effect that the*

[26] Geoff Brown & Associates Ltd 'Review of New Facilities Investment Test Compliance Western Power AA1 Projects' 14 July 2009, page 15

> *determination will have on Western Power's business, the Authority considers that the extent of inefficiency to be taken into account in determining the value of new facilities investment to be added to the capital base should not be at the maximum of the possible range. On this basis, and having regard to the Code objective, the Authority has determined that the extent of inefficiency amounts to 15 per cent of the total amount of new facilities investment other than that amount of new facilities investment comprising assets constructed by other parties and gifted to Western Power."*

The relevant judgments here are, self-evidently, arbitrary. There is no basis for the 25% figure, whose only function seems to be to make a 15% figure look reasonable (because it might have been higher). The lower bound estimate of 'inefficiency' is not quantified, and is simply referred to as being (in the judgment of the ERA, but in the absence of supporting evidence) more than a nominal amount. No reason is given for the particular choice of weighted average calculation that appears to lead to 15%. And, to put matters beyond doubt, that the determination lacks substantial, supporting information/evidence is explicitly recognised by the ERA in the first sentence of paragraph 606.

This approach is inconsistent with the careful and more cautious approach adopted by other regulators - such as the AER/ACCC and Ofgem in the UK - when determining the appropriate amount of capital expenditure that should be disallowed. In these cases, the regulator has presented in some detail the reasoning that underlies the estimate of the alleged inefficiency associated with a particular/specific capital investment.

6.6 Comparison with practice in other, comparable regulatory regimes

It will be apparent from what has been said in the discussion of practice in other jurisdictions regarding capex disallowances (in section 5 above) that the ERA's approach in the Draft Decision is out of line with approaches elsewhere. Four points stand out in this respect:

- The normal standard against which actual performance is compared is based on notions of reasonableness rather than best possible practice (or 'frontier' efficiency). The ERA reasoning appears to us to tend to rely on the latter notion, although it is impossible to be definite because the relevant standard is not actually discussed and specified (which is itself a significant fault in the reasoning).

- When they occur, disallowances in other jurisdictions tend to be based on findings of substantial failures relating to specific projects. They are not based on sweeping, across-the-board judgments about the efficiency of capex programmes as a whole.

- With the exception of US disallowances of investments in electricity power plant, particularly nuclear power plant, *ex post* adjustments to regulatory asset bases have tended to be much smaller, in proportionate terms, than the adjustment indicated by the ERA.

- It is generally recognised that *ex post* disallowances made in regulatory contexts where there is no source of compensatory payments in the regulatory system (such as a higher allowable return on capital, or capex incentive schemes that provide for the possibility of supernormal returns) are liable to lead to deficient investment incentives and hence to inefficiently low levels of investment. The ERA Draft Decision does not address the compensation issue.

7. OVERALL CONCLUSIONS

In response to the two questions asked, and on the basis of the reasoning above, we conclude the ERA's application of the NFIT provisions (sections 6.51A to 6.55 of the Electricity Networks Access Code 2004) and its reasoning for the proposed asset write down of 15 per cent is:

(a) not consistent with the Code objectives.

(b) not consistent with good regulatory principles and practice in other, comparable jurisdictions.

About the Authors

Professor George Yarrow

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George Yarrow is currently Chairman of the Regulatory Policy Institute, Oxford; Emeritus Fellow of Hertford College, Oxford University; Visiting Professor at the Newcastle Business School; an adviser to the UK Civil Aviation Authority; a member of the UK National Audit Office's academic panel on regulatory impact assessment; and an adviser to the New Zealand Commerce Commission.

Until April 2009 Professor Yarrow was a Board Member of the Gas and Electricity Markets Authority (GEMA, www.ofgem.gov.uk), the GB energy regulator and a body responsible for the enforcement of UK and European Competition Law in the energy sector. He also recently served on the Republic of Ireland's Aviation Appeals Panel.

After graduating from Cambridge University, he held appointments at the Universities of Warwick and Newcastle before moving to Oxford, where he spent most of his academic career. He has also had visiting affiliations with Harvard University, the University of California at San Diego, the University of Urbino, and Queen Mary and Westfield College, University of London.

His principal work has been on the economics of competition, regulation and privatization, although he has also written on: energy and environmental policies; corporate objectives and the market for corporate control; aspects of industrial organization theory; monetary theory; health economics; and the reform of social security. His best known works are "Privatization in theory and practice", *Economic Policy*, 1986, variously reprinted and translated, and, with Professor Sir John Vickers, *Privatization: An Economic Analysis*, published by MIT Press in 1988, and subsequently in Spanish and Chinese editions.

Among other things, during his period as a full time academic Professor Yarrow served as a nominator for the Nobel Prize in Economics, and was a member of the editorial boards of *Economic Policy, the Oxford Review of Economic Policy, the Journal of Industrial Economics*, and *Applied Economics*.

In the energy sector, Professor Yarrow has experience of virtually every major aspect of policy development over the past twenty years. He was economic adviser to the National Grid for the initial design of the transmission use-of-system charges for high voltage electricity grid, and later to British Gas for the development of similar entry/exit arrangements for gas pipeline capacity. Later, first as economic adviser to the energy regulator and then as a board member, he was involved in the full range of regulatory reforms introduced in the UK from the mid-1990s on, including: retail market opening, retail market deregulation, gas storage deregulation, the new electricity trading arrangements (NETA), the new gas trading arrangements (NGTA), the establishment of the first energy exchanges, the integration of the Scottish and England & Wales electric systems; and the enforcement of the Competition Act in the energy sector.

In telecoms he was been a member of expert panels set up to assist UK ministers in the development of the Communications Act 2003 and to assist EU Commissioners in the development of policy responses to technological convergence in the audiovisual and communications sectors. A theme of this work was the desirability of reducing, through improved policy strategies, the tension between the bureaucratic cultures typical of administrative agencies responsible for market supervision and the entrepreneurial cultures required for successful discovery and innovation in conditions of rapid change of knowledge.

Professor Yarrow has a longstanding interest in competition law and policy. Over the years, he has written reports and given evidence in a large number of competition cases considered by the Competition Commission, the Office of Fair Trading, the High Court and the Competition Appeals Tribunal in the UK, and the European Commission, the CFI/ECJ at EU level. Together with Peter Freeman, currently Chairman of the Competition Commission, he founded the Regulatory Policy Institute (in 1991) as a response to weaknesses and failures in the economic assessments of the UK competition agencies of the time. He has consistently argued for the importance of strong appeals mechanisms as the only effective vehicle for putting pressure on administrative agencies to improve their assessment procedures and performance.

Although he gave up university teaching in 1997, Professor Yarrow has continued to give lectures on competition and regulation. Examples include: The Enterprise Act: Pluses and Minuses for Competition Policy (London, Beesley Lecture), Electricity Market Reform (Sorbonne, Paris), The Changing Dynamics of Europe's Liberalizing Energy Markets (Amsterdam), Economic Assessment and the Modernization of EU Competition Law (London, for the Judicial Studies Board; and Stockholm), Economic Assessment in Competition Law Cases (Berlin, to the Association of European Competition Law Judges), EU Energy Policy (keynote address for the annual conferences of the Australian Competition and Consumer Commission (ACCC)), Energy Policy: A Time to Stop Pretending? (London, Beesley Lecture), Discovering the Value of Water (London, Beesley Lecture), Current Challenges in Regulatory Policy (keynote address, ACCC), and Environmental Aspects of Energy Regulation (ACCC).

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Christopher Decker is Research Director at the Regulatory Policy Institute, Oxford; an Associate Research Fellow at the Centre for Socio-Legal Studies, Oxford University; and a Research Member of Wolfson College, Oxford University. He currently acts as an economic advisor to the Australian Competition and Consumer Commission (ACCC), the UK energy regulator (Ofgem) and is a member of the panel of economic experts for the Commission for Energy Regulation (Ireland). Previously, Christopher was Principal Economic Advisor at the ACCC.

Chris's work is focused on economic regulation, competition economics and public policy. He has been involved in a range of research and consulting projects for both the public and private sectors, including for: the OECD; the European Commission

(DG Transport & Energy); the Australian Competition and Consumer Commission; the Australian Energy Markets Commission; ENARGAS (Argentina); the South African Competition Tribunal; and in the UK, the Office of Fair Trading, the Competition Commission, Department of Trade and Industry, Cabinet Office and Office of Gas and Electricity Markets.

Recent policy studies include: the review of RPI-X@20 (Ofgem); an assessment of the Intelligent Energy-Europe II Programme (for the European Commission); a review of International approaches to transmission access for renewable energy (Ofgem); the economic issues associated with the use of resets for regulating communications and energy networks (ACCC); a report on the impact of maintaining price regulation (AEMC); a study of next-generation access networks in communications (submitted to the Australian Department of Broadband, Communications of the Digital Economy); an assessment of the competitive and economic impacts of the introduction of the Single European Payments Area (submitted to the European Central Bank); and a study on the development of implementation rules of economic regulation within the Single European Sky initiative (for the European Commission).

In addition, he has recently presented papers on: 'Ideas on how to stimulate more energy network related innovation' at Ofgem's RPI-x@20 workshop (Imperial College, London); '100 years of government control over public utilities: An Australian perspective' at the ACCC Regulatory Conference 2009; and a paper on 'Regulation of Economic Infrastructure in the UK: Developments and Challenges'.

Christopher's academic research is focused on the application of economic techniques in competition law enforcement and in regulatory processes. His book on this issue, *Economics and the Enforcement of European Competition Law* is forthcoming in September 2009. He holds a first class honours degree in economics from the University of Melbourne (Australia) and a PhD from the University of Oxford.

Attachment F2

Opinion by Sinclair Knight Merz

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9 September 2009 *WP03785*

Dear Mr Peter Mattner,

Review of the Application of the New Facilities Investment Test in the Economic Regulation Authority's Draft Decision for the Second Access Arrangement

Sinclair Knight Merz (SKM) is pleased to present its findings on Western Power's application of the new facilities investment test on Western Power's capital expenditure during period from 1 July 2006 to 30 June 2009 (AA#1). In doing so, we have undertaken a comprehensive review of the systems, processes, assumptions and information provided by Western Power in its revenue and expenditure proposals submitted to the Economic Regulation Authority (the Authority) for the Second Access Arrangement.

In undertaking our review, we have considered the Authority's Draft Decision - "*Proposed Revisions to the Access Arrangement for the South West Interconnected Network*", dated 18 July 2009, and the reports prepared by the Authority's consultants (Geoff Brown & Associates Ltd and Wilson Cook & Co).

Over the 3 years period, Western Power has spent a total capital expenditure of approximately $1,004 million on new transmission and $1,445 million on new distribution facilities, a total of $2,449 million. The Authority's Draft Decision proposes to exclude an amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) amounting to $343.8 million to reflect perceived inefficiencies in the undertaking of capital projects over the AA#1 period. This is in addition to the proposed exclusion of $63.5 million of investment in transmission, comprising of an overstatement of costs and $65 million in the distribution network that is not appropriately considered in the new facilities investment.

The primary focus of SKM's review has been the exclusion of 15 per cent of the new facilities investment. In summary, the key issues and conclusions from our review are as follows:

In terms of Western Power's processes of planning and procurement SKM has found that:

a) Western Power's distribution design standards used during the AA#1 period are generally consistent with good industry practice and the requirements of the Western Australian Electricity Networks Access Code. In particular, we found that requirements for economic efficiency in investment and cost of operations are embodied within the design standards.

SKM

b) While Western Power's cost estimating processes did not meet what was considered to be good industry practice in 2006, these have improved considerably to a standard in 2008 whereby they are now considered to be good industry practice.

c) Western Power's load forecasting, planning polices and standards represent good industry practice and are typical of other Network Service Providers in Australia.

The areas where SKM's findings and conclusions differ from those of the Authority's Consultants include:

a) SKM considers that the drivers for the NCR wind-back program are appropriate. These drivers include addressing the utilisation of the transformer assets that are clearly above good industry practice.

b) SKM agrees with Western Power's practice of auditing 10% of the pole-inspections undertaken by contractors until a confidence level is reached, at which time the percentage of inspections is decreased.

c) SKM considers that the timing of Western Power's move to using aluminium cables in 2007 was appropriate and is consistent with other utilities in Australia.

d) SKM notes that Western Power had integrated temperature into its distribution feeder forecasting in 2008 and implemented temperature correlation and correction for zone substations and transmission level forecasts in 2009.

e) In SKM's experience, Western Power's policy to underground distribution systems that pass under transmission lines under construction is a cost effective approach to transmission line construction.

SKM's detailed project review of 7 material projects confirmed the findings discussed above with two minor concerns identified, (the first regarding the efficiency of cost estimating on several projects, and the second a failure to implement a $1 million change in the approved budget for a project).

In analysing the efficiency of Western Power's capital expenditure, SKM applied external benchmarking comparisons on procurement costs and also provided independent cost estimates of 10 of the 30 projects reviewed by the Authority's consultants to test the overall efficiency of the capital expenditure. The findings were:

- The preliminary results of SKM's survey of the market prices for distribution equipment identified no efficiency concerns in Western Power's procurement and installation of distribution equipment.
- There was an average 5% variation between actual costs over the 10 selected projects, compared to SKM's cost estimates. This benchmarking process reflected no systemic variation of Western Power's expenditure to that considered reasonable and prudent.
- The cost over-runs experienced by Western Power on its major projects was found to be better than that experienced by major resource projects in Western Australia during the same period.

Overall, SKM found that Western Power has solid planning, engineering and execution policies and processes generally consistent with good industry practice. However, it is understood that it is taking time for Western Power to adjust to the requirements of regulation.

SKM did not find any evidence to suggest "systemic over engineering" within Western Power's network, or that there are significant inefficiencies arising from poor options analysis, cost control and contract management for capital programs.

SKM identified the following areas that may have impacted on the ability of projects implemented during the AA#1 period to meet the efficiency test of the New Facilities Investment Test:

- Cost estimating: it is recognised that the quality of cost estimates at the beginning of the AA#1 period was poor. As a result of an initiative implemented by Western Power, its cost estimating has significantly improved and is now considered good industry practice.
- Contractor overcharging: there is evidence to show that there was overcharging by contractors at the beginning of the AA#1 period on some projects. Procedures for procurement and management of contractors are now considered sufficiently robust to detect and address any contractor overcharging.

As an outcome of our review of the capital expenditure incurred by Western Power during the AA#1 period, SKM considers all of Western Power's revised capital expenditure to be prudent and the amount of 'inefficiency' in the new facilities investment undertaken by Western Power was in the order of $27 million.

Yours faithfully,

G. Glazier
Sinclair Knight Merz

S. Wightman
Sinclair Knight Merz

Application of the New Facilities Investment Test in the Economic Regulation Authority's Draft Decision on AA#2

- WP03785
- Rev 2
- 9 September 2009

Application of the New Facilities Investment Test in the ERA's Draft Decision on AA#2

REPORT

- Rev 2
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Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
Rev 0	27.08.2009	S Wightman	C Parlongo	26.08.2009	For issue to client
Rev 1	03.09.2009	S Wightman	C Parlongo	03.09.2009	For issue to client
Rev 2	09.09.2009	S Wightman	C Parlongo	09.09.2009	Minor editorial changes

Distribution of copies

Revision	Copy no	Quantity	Issued to
Rev 0	Electronic	1	Western Power
Rev 0	Electronic	1	SKM File
Rev 1	Electronic	1	Western Power
Rev 1	Electronic	1	SKM File
Rev 2	Electronic	1	Western Power
Rev 2	Electronic	1	SKM File

Printed:	15 September 2009
Last saved:	15 September 2009 10:04 AM
File name:	I:\WPIN\Projects\WP03785\Deliverables\Reports\Final Report\WP03785-EE-RP-0001 Rev 2final.docx
Author:	Geoff Glazier
Project manager:	Geoff Glazier
Name of organisation:	Western Power
Name of project:	Application of New Facilities Investment Test in ERA Draft Decision on AA#2
Name of document:	WP03785-EE-RP-001
Document version:	Rev 2
Project number:	WP03785

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1. Introduction

1.1. Background

Sinclair Knight Merz (SKM) has been engaged by the Electricity Networks Corporation (Western Power) to undertake an independent review of the application of the New Facilities Investment Test (NFIT) on Western Power's capital expenditure in the Access Arrangement 1 (AA#1) period, as detailed in the Draft Decision[1]. Of particular relevance is the test detailed in section 6.52(a) of the Electricity Network Access Code 2004 (the Code), referred to in this review as the "efficiency test".

Western Power is regulated by the Economic Regulation Authority (the Authority) in accordance with the Code. The Code contains a New Facilities Investment Test (NFIT), which imposes a discipline on Western Power to deliver capital expenditure efficiently. The NFIT applies:

- Retrospectively – in relation to capital expenditure incurred during the period (from 1 July 2006 up to 30 June 2009); and
- Prospectively – in relation to forecast capital expenditure expected to be incurred during the next access arrangement period (from 1 July 2009 to 30 June 2012).

Western Power submitted its revenue and expenditure proposal[2] for its second access arrangement period (AA#2) in October 2008.

In January 2009, the Authority informed Western Power that insufficient information had been provided to demonstrate that actual and forecast capital expenditure satisfies or is expected to satisfy the NFIT and on 5 February 2009, the Authority issued a notice (pursuant to section 51 of the Economic Regulation Authority Act 2003) requiring Western Power to provide additional information to enable the Authority to undertake its NFIT review.

Western Power subsequently provided the compliance summaries on all new facilities investment projects on which expenditure was incurred during the AA#1 regulatory period.

Through this process, the Authority engaged consultants Geoff Brown & Associates (GBA) and Wilson Cook & Co (Wilson Cook) to, amongst other things, review Western Power's actual and forecast capital expenditure, including application of the NFIT provisions.

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[1] Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network – ERA 13 August 2009.

[2] Reference to Western Power Access Arrangement Submission.

1.2. The Authority's Draft Decision

The Draft Decision by the Authority was issued on 16 July 2009. Contained within the Draft Decision is 'Required Amendment 26', requiring the following revisions:

- exclude investment to the value of \$63.5 million (nominal) for the transmission network in 2008/09 that comprises an overstatement of costs for 2008/09;
- exclude investment to the value of \$65 million (nominal in 2007/08 dollar values) for the distribution network that comprises an amount of costs that is not appropriately considered as new facilities investment; and
- exclude a further amount of 15 per cent of the new facilities investment (other than that comprising gifted assets) to reflect likely inefficiencies in the undertaking of investment.

The primary focus of this report is the third point above, namely the exclusion of a further amount of 15 per cent of the new facilities investment. For the purposes of this report, it will be referred to as 'the 15 per cent reduction'. SKM has also commented on the first two items (above) of Required Amendment 26 where it found, through the process of its review, that the assumptions that underpin these assessments have changed.

1.3. SKM's Scope

The scope of SKM's review included:

- consideration of the impact of the Authority's consultants' reports referenced in the Draft Decision;
- an independent review of Western Power policies, procedures and standards that are relevant to the application of the NFIT to Western Power AA#1 expenditure;
- a review of the implementation documentation for selected projects;
- benchmarking of key items reflective of the efficiency of Western Power's expenditure; and
- a comparison of the processes and decisions on approving capital expenditure (capex) for transmission and distribution services under the National Electricity Rules (NER).

During the course of its analysis, SKM identified issues that, in its opinion, impact on the ability of particular projects implemented during the AA#1 regulatory period to meet the NFIT. SKM identified the projects within the AA#1 capital expenditure to which the issues apply and quantified the potential impact on the efficiency of the relevant projects.

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1.4. Project Team

SKM is a broadly skilled engineering consultancy providing services to major utilities and regulators within Australia and internationally. Through its work with utilities and regulators, SKM has a well developed understanding of the processes and systems required for the efficient development of network facilities. The work in this report was carried out for and on behalf of SKM by a core team comprising:

- Mr. Geoff Glazier, Manager Strategic Consulting WA/NT;
- Mr. Greg Jones, Strategic Consultant;
- Mr. Steve Wightman, Manager Strategic Consulting Asia Pacific;
- Mr. Terry Krieg, Senior Executive Electrical Engineer;
- Mr. Keith Frearson, Executive Power Systems Engineer;
- Mr. Jeff Butler, Executive Networks Consultant;
- Mr. Carl Parlongo, Project Director;
- Mr Alex Lambe, Business Analyst; and
- Mr Mike Farr, Queensland Manager Networks.

1.5. Data Used

Unless noted otherwise, our report is based on the information that SKM understands was made available to the Authority and its consultants for the purpose of assessing Western Power's revised Access Application. In addition, SKM requested further information from Western Power as considered necessary to complete the analysis in this report. This data is specifically listed in Appendix A.

1.6. Structure of the Report

This report summarises SKM's analysis, general observations and conclusions.

Sections 2 and 3 of the report provide the context in which the analysis within the report has been undertaken, discussing the relevant sections of the Authority's draft decision and SKM's approach to the application of the NFIT.

Section 4 comprises a critique of the reports referenced within the Draft Decision.

Section 5 sets out SKM's analysis of relevant Western Power design standards, specifications, and planning policies.

Section 6 provides the results of three approaches to benchmarking Western Power's network and economic performance.

Section 7 provides a summary of the detailed review of selected projects.

Section 8 provides information from comparable regulatory reviews.

Section 9 summarises the findings of the report.

Section 10 quantifies the impact that the issues raised by SKM (through its analysis) may have on the ability of projects in the AA#1 period to meet the NFIT. This is followed by SKM's conclusions.

2. The Draft Decision

2.1. Draft Decision – 15 per cent Reduction

In its Draft Decision, the Authority gave two main factors for the required amendment to exclude 15 per cent of the new facilities investment in the AA#1 regulatory period from the Regulated Asset Base (RAB).[3]

1) *"Project-specific information available to the Authority suggests that there has been systematic over-engineering of capital projects resulting in inefficiencies in the design of network assets".*

2) "Secondly, the Authority considers that there have been deficiencies in the planning and governance of capital works, including inadequate consideration of options when planning network augmentations, and poor cost-control and contract management for capital projects and programs. The Authority, however, does not have sufficient information to place a precise value on the extent of such inefficiencies. The Authority accepts that the vast majority of capital projects and programs undertaken during the first access arrangement period are likely to have been necessary and appropriate and that the extent of inefficiency is likely to have resulted mainly from deficiencies of governance rather than the choice of capital projects".

The Authority references two reports prepared by GBA and one by Wilson Cook in its Draft Decision. In reviewing Western Power's supporting data relating to the NFIT, SKM has considered the Authority's consultants' technical reports; in particular the interpretations used in reviewing Western Power's proposed additions to its capital base with respect to application of the NFIT. SKM has also carefully examined the relevant clauses of the Code and, where applicable, commented on precedents in other jurisdictions. SKM notes that the Authority has indicated it has placed more weight on the GBA reports.[4]

Observation 1

The two main factors provided in the Draft Decision for the 15% reduction are:

- The presence of systemic over-engineering within Western Power.
- Poor options analysis, cost control and contract management.

These factors were established largely with reference to the reports provided by GBA.

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[3] Clauses 603 and 604 of the Draft Decision.

[4] Clause 565 of the Draft Decision.

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2.2. Draft Decision – Impact of the 15 per cent Reduction

The Authority's Draft Decision is that the new facilities investment amounts calculated for the AA#1 period[5] should be further reduced by a factor of 15%, encompassing both transmission and distribution capex (excluding investment comprising assets constructed by other parties and gifted to Western Power). The application of the proposed 15% 'inefficiency' factor would have the effect of reducing Western Power's total opening Capital Base for AA#2 by $343.76M (real as at 30 June 2009), as calculated in the table below. [6]

	2006/07 $ million	**2007/08** $ million	**2008/09** $ million	**Total** $ million
Transmission				
Revised total new facilities investment	306.86	317.00	380.14	1,004.00
15% further reduction	(46.03)	(47.55)	(57.02)	(150.60)
Value to be added to the capital base	260.83	269.45	323.12	853.40
Distribution				
Revised total new facilities investment	425.72	458.98	560.60	1,445.31
Gifted assets	(23.68)	(39.60)	(94.30)	(157.58)
Revised total new facilities investment net of gifted assets	402.04	419.39	466.30	1,287.73
15% further reduction	(60.31)	(62.91)	(69.94)	(193.16)
Value to be added to the capital base (including gifted assets)	365.41	396.47	490.65	1,252.53

[5] Due to issues on recovery of shortfall in contracted works and delay in Margaret River 132kV transmission line upgrade (ref p150 of Draft Decision).

[6] Based on calculations in table 60, page 167 of Draft Decision.

3. New Facilities Investment Test Provisions

3.1. NFIT Criteria

The NFIT is described in section 6.52 of the Code and SKM makes the following observations:

3.1.1. Test for adding new facilities investment to the capital base

The Code requires that only capex that meets the NFIT can be added to the capital base.

In reviewing Western Power's capital expenditure in AA#1, we needed to satisfy ourselves that, from a technical standpoint, Western Power's capex in AA#1 met the first limb (the efficiency limb) of the NFIT, section 6.52 of the Code:

"New facilities investment satisfies the new facilities investment test if: (a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to: (i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and (ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales."

3.1.2. "Efficiency Limb" of NFIT

The efficiency limb refers to investments made by a "*service provider efficiently minimising costs*." While the Code does not provide specific guidance on how the efficiency limb will be applied, section 1.3 of the Code includes the following definition:

"Efficiently minimising costs"*, in relation to a service provider, is defined as "the service provider incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services."*

3.1.3. "Safety and Reliability Limb" of NFIT

The NFIT requires both the efficiency limb and one or more of the net benefit, incremental revenue or safety and reliability limbs to be met.

SKM notes that there are some circumstances where new investment may require a certain level of expenditure to comply with required safety, environmental and/or reliability regulations, standards or statutory requirements.

3.2. Comparison with interpretation and application of NFIT by GBA and Wilson Cook

GBA, in its GBA AA#1 Projects report[7], did not comment specifically on the interpretation of the efficiency limb (test), although there is a reference in GBA's report[8] that "*...the application of the efficiency test is discussed in section 2.5.5...*", however there appears to be no such actual section in their report.

When taking into account efficiency for the purpose of its review, Wilson Cook[9] states: "*We considered efficiency in terms of the nature and the timing of expenditure and looked for evidence that as far as practicable the expenditure reflected optimal planning and design and competitive costs taking account of local factors, 'good electricity industry practice' and the defined security of supply and service standards of the network business concerned – in this case, Western Power.*"

Wilson Cook limited its opinion on efficiency to the scope and timing of capital projects and stated that it was unable to determine the efficiency of capex in the AA#1 period in terms of cost-effectiveness due to insufficient information.

3.3. SKM's approach to compliance with the Efficiency Limb

In reviewing Western Power's AA#1 projects, SKM has undertaken an independent assessment of the projects previously reviewed by GBA and Wilson Cook. Specifically, SKM has also considered the Authority's identified concerns on i) systemic over-engineering of capital projects resulting in inefficiencies in the design of network assets ii) deficiencies in the planning and governance of capital works, including inadequate consideration of options when planning network augmentations, and poor cost-control and contract management for capital projects and programs. (In arriving at these concerns, SKM notes that the Authority placed greater weight on the review of governance and planning processes undertaken by GBA than advice from Wilson Cook, (Clause 565 of the Authority's Draft Decision.))

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[7] Geoff Brown & Associates Ltd: Review of new facilities investment test compliance Western Power AA#1 projects. 14 July 2009.

[8] Ref GBA report on NFIT compliance, page 2

[9] Wilson Cook & Co. Review of Western Power's expenditures for second access arrangement: Final report. May 2009, page 10.

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For the purposes of our review, the assessment of capital projects and the requirements of NFIT are little different to the normal tests of efficiency and prudence that would be applied in reviewing past and future capex put forward by a network business in other States.[10]

The key processes that SKM considered in assessing whether the new facilities investment met the efficiency limb of the NFIT were:

1) Cost estimating:

SKM reviewed information provided by Western Power on its cost estimating processes and the procedures that it has put in place.

2) Options analysis:

SKM reviewed Western Power's load forecasting methodology, network planning and the integration between transmission and distribution and the way in which Western Power treats investment in new facilities investment and NFIT.

3) Governance / approvals of capital spend:

Western Power's governance practices for approving capital expenditure did not form part of SKM's review[11]. However, SKM has commented on general governance issues where these were believed to relate to "efficiently minimising costs".

4) Efficiency of engineering solutions:

SKM reviewed Western Power's standards for establishing engineering designs across distribution and transmission projects and reviewed the application of these standards on particular projects.

5) Procurement:

SKM reviewed a number of relevant Western Power's technical specifications and compared these to good electricity industry practice. SKM also reviewed Western Power's procurement processes including a detailed review of major procurement processes where the cheapest tenderer was not

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[10] SKM notes that the use of a test such as NFIT to review past expenditure for transmission and distribution utilities is not generally practised in other jurisdictions in Australia. The key focus for the regulation of utilities in the National Energy Market (NEM) is on forecasts of capex and opex for the future regulatory period.

[11] Western Power's business processes and governance relating to approving expenditure is covered in a report prepared by PB "Assessment of AA1 capex – NFIT submission" which is included in Western Power's submission to the Authority "Revised Access Arrangement Information for the Network of the South West Interconnected System".

selected on technical or commercial grounds. In addition, SKM included Western Power in a 2009 market survey of equipment costs to provide a comparison with other service providers establishing similar network assets in other jurisdictions in Australia.

6) Project or works management:

SKM independently estimated the costs for 10 completed projects and compared these against Western Power's actual costs.

In SKM's opinion, a high degree of sound engineering judgement and robust planning and design processes are required for efficient network development outcomes. Therefore, it is appropriate that significant weight is given to the network service provider (NSP) being able to demonstrate this engineering capability and the effectiveness of business processes in the context of "good electricity industry practice"[12] under comparable conditions and circumstances[13].

Observation 2

The "Efficiency Limb" of NFIT refers to investments made by a "service provider efficiently minimising costs".

For assessing the "efficiency" of planned network developments, significant weight should be given to the service provider being able to demonstrate sound engineering capability and judgement, as well as the effectiveness of business processes in the context of "good electricity industry practice" under comparable conditions and circumstances.

[12] Refer to definition of "good electricity industry practice" in Section 1.3 of the Access Code.

[13] The reviewers in this report are experienced practitioners within the Australian electricity industry in Australia and are familiar with the definition of good electricity industry practice and its "practical application".

4. Critique of Reports Referenced in the Authority's Draft Decision

4.1. Introduction

The Authority was assisted in arriving at its Draft Decision by reviews of Western Power's expenditure contained in three reports, one by Wilson Cook and two from GBA. SKM has studied the reports and, where appropriate, has provided additional guidance on the application of the efficiency test.

4.2. GBA Report: Review of New Facilities Investment Test Compliance Western Power AA#1 Projects

4.2.1. Scope and Application of the Report

The GBA AA#1 Projects report[14] was commissioned by the Authority to assist with the application of the NFIT to the AA#1 expenditure. The report outlines the reviews of 30 projects, from AA#1 selected by the Authority. These 30 projects represented approximately 50 per cent of the value of new facilities established during the AA#1 period.

4.2.2. Resources Utilised in developing the Report

The GBA AA#1 Projects report does not indicate the resources from GBA who were involved in the review. The report does state that, in its assessment of the NFIT, it did not request supporting information in addition to that originally supplied by Western Power due to time and budget issues.

4.2.3. Interpretation of the NFIT

Section 2 of the GBA AA#1 Projects report provides an overview of the NFIT described in Section 6.52 of the Code. The efficiency test is outlined with a reference to a section 2.5.5 for further information on the application of the test. As noted previously, SKM could not identify a section 2.5.5 in GBA's report or any further guidance on how GBA had applied the efficiency test.

A discussion of the tests outlined in 6.52(b) of the Code is provided with Section 2.1.2, 2.1.3 and 2.1.4 of the GBA AA#1 Project report. While SKM does not disagree with most of the commentary on these tests, the position that the reliability test should only be applied to non-growth projects appears to be based on concern with the wording "*its ability to provide covered services*". As SKM understands it, the position taken by GBA is that all growth-related new

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[14] Geoff Brown & Associates Ltd: Review of new facilities investment test compliance Western Power AA#1 projects. 14 July 2009.

facilities would meet this test and therefore this test should only apply to non growth-related projects. This position appears to ignore the impact that organic[15] growth may have on the network's ability to meet security criteria and hence maintain the level of reliability that forms the basis of the covered services. At certain stages of network development[16], a new facility may be required that is the most efficient investment to maintain reliability, but due to the step change in cost does not meet the incremental revenue test over the medium term. Further, the net benefit test would not be met as the new facility is only required to maintain reliability of supply (and not necessarily provide a net benefit). In this conceivable case, the efficiency test and the reliability test would form a valid test for the appropriateness of a new facility driven by organic growth.

4.2.4. Commentary on Conclusions within the Report

The key findings of the GBA AA#1 Project report were:

a) *Much more care should have been taken to ensure the accuracy of claimed expected costs.*

SKM reviewed the documents provided to GBA and noted the discrepancies between the compliance summaries[17] and the analysis spreadsheets. SKM is of the opinion that, given the criticality of these documents, more care should have been placed by Western Power in identifying and explaining any discrepancies.

b) *Capital Contributions have not been reviewed for reasonableness or accuracy and shortfalls between received capital contributions and expenditure have been claimed for the inclusion in NFIT.*

The appropriate accounting for capital contributions is necessary in any access regime to avoid double counting. In the information provided to GBA, there are anomalies which have not been explained in the documentation. In the subdivision example quoted by GBA, Western Power needs to specifically identify how the shortfall expenditure met the NFIT before this expenditure can be included in the Regulated Asset Base (RAB).

c) *Given the lack of confidence in the underlying data provided, GBA could not form a view on the exact amount of expenditure on any project or program that met the requirements of NFIT.*

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[15] In this context, organic growth refers to growth load through small customer connections that are not able to be directly attributed to (and therefore charged for) upstream network investment.

[16] A conceivable example of this is the introduction of new bulk transmission infrastructure required to maintain reliability that in the medium term has a higher cost than the additional forecast revenue generation under the existing tariffs.

[17] Pro-forma NFIT Compliance Summary provided by Western Power for all 30 projects from the AA#1 selected by the Authority.

Based on the level of detail of the supporting information provided to GBA and the apparent budget and time restrictions limiting GBA's access to the additional information that was available to enable a comprehensive analysis to be undertaken; SKM understands it would indeed be difficult for GBA to form a reliable view on the amount of expenditure that met the requirements of NFIT.

4.2.5. Commentary on Key Findings

Although GBA could not specifically assess the application of the NFIT on the projects due to a lack of supporting information, GBA identified specific expenditures that it believed did not meet the NFIT. GBA also noted that if more detailed information was identified, additional inefficiencies may have been identified.

a) Demand Forecasting and Temperature Sensitivity

GBA[18] remarked that Western Power should consider applying temperature corrections to historic peak demands before they are trended for forecasting purposes. While GBA does conclude that any temperature adjustment would be expected to have little impact on the short term requirement for growth related capital expenditure, it suggests that it may defer the need for some expenditure that is currently forecast to be required towards the end of the AA#2 regulatory period.

SKM notes that Western Power had already undertaken a review of temperature correction and this had been integrated into the distribution feeder forecasting software by June 2008. SKM also notes that temperature correlation and correction had been implemented for zone substations and transmission-level forecasts by June 2009. SKM therefore does not hold the same concerns that GBA has raised.

Western Power's 'System Forecasting: Operating Manual', dated March 2008 and other manuals provide formal and well documented procedures to support its demand forecasting systems. In addition, Western Power had its forecasting processes audited by SKM and ROAM Consulting in March 2007, followed up by a review in June 2008[19] of the progress being made on implementing the recommendations. Further, SKM notes that KPMG[20] undertook a specific review of Western Power's Opal in-house forecasting tool earlier in 2009.

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[18] Geoff Brown & Associates Ltd: Review of new facilities investment test compliance Western Power AA#1 projects. 14 July 2009. Section 4.3.

[19] Sinclair Knight Merz: Demand forecast enhancements review: Review of progress on demand enhancements. 30 June 2008.

[20] Summary of Western Power's forecasting process: System forecasting. 4 August 2009.

Over the past two years, Western Power has been working more closely with the Independent Market Operator (IMO) in preparing forecasts for the SWIS and there is now close alignment between the IMO and Western Power aggregate forecasts[17].

SKM considers Western Power's demand forecasting systems are in accordance with good electricity industry practice in Australia.

b) Undergrounding of Distribution Systems Under Transmission Lines

Western Power's policy is to underground distribution systems that pass under transmission lines under construction[21]. In SKM's experience, this is a cost effective approach to transmission line construction that is routinely undertaken in other jurisdictions[22]. This position is discussed further in section 5.2.7.

c) Use of Standard Transformer at Wells Substation for Boddington Gold Mine Connection

The key issue identified by GBA relates to the decision made by Western Power, in endeavouring to meet the timeframe required for the customer connection, to procure 'standard' 490 MVA transformers under a standing preferred vendor contract, rather than choosing to procure 300 MVA transformers (which would have met the required loadings). Procuring 300 MVA transformers would have required a new specification to be developed and tenders issued and assessed, resulting in a significantly longer lead time.

It is understood that Western Power agreed to meet the customer's deadline. Presumably as part of negotiations on a lower capital contribution by the customer, Western Power also agreed to contribute to the additional cost of the higher capacity transformers, which was originally estimated at $2 million. Western Power considered there to be benefits in having "standard spare" transformers in the event that the Gold Mine ceased operations and the additional capacity could cater for future load growth in the SWIS. SKM notes that the use of standard, non project optimised equipment to meet timetable restrictions is used widely across industry. Further, the use of standardised equipment has some benefit to the broader network through allowing simple interchange in the event of a failure (although SKM notes that it is possible to achieve interchange with smaller units as raised by GBA in the report.

In summary, SKM believes the economic decision to utilise a larger standard item to meet a timeline is based on the question: "*Does the profit generated in the period for which the project schedule is accelerated outweigh the additional cost?*" For the customer to make this decision, the

[21] Western Power: Lines Team Instruction 68 – ABC/Undergrounding Distribution Services. 15 May 2007.

[22] ETSA Utilities and Ergon Energy have similar approaches.

economic cost must be passed through to them. As this cost largely only benefited one customer, SKM believes that this should have been passed through to the customer as a capital contribution.

SKM believes that, consistent with the discussion above, it has not been satisfactorily demonstrated that the extra expenditure on the large transformer would meet the requirements of the NFIT.

SKM accepts that Western Power delivered the required service to the customer (including the required commissioning date) in the most efficient manner, and that the failure appears to be within the application of the capital contribution policy. SKM notes that this is a project specific issue and therefore should not necessarily be assumed to apply to other projects undertaken by Western Power. SKM has not quantified this issue in section 9 of this report as it believes it should be addressed separately, as an issue related to the application of the capital contribution policy (not as an issue related to the efficiency of project delivery).

d) Pinjarra - Wanneroo Transmission Line

With reference to the review comments by GBA relating to the Pinjarra-Wanneroo transmission line, SKM notes the difficulties encountered by Western Power during project implementation, in being required to accommodate late changes in the transmission line route and managing the associated legal challenges etc, resulting in cost increases.

SKM also notes the issues around tendering and the delays in getting agreement to a line route. All of the above issues appear to have been outside the reasonable control of Western Power and resulted in a significant cost increase above the original business case.

GBA also raised concern that only one constructor responded to tender due to a perception that one bidder held IP rights to a tower design relevant to the project. SKM has reviewed documentation that demonstrates that Western Power retains the design IP through the line tender process[23]. This fact does not remove the impact of a single tenderer but does clarify that Western Power's internal processes on the retention of IP did not factually contribute to this outcome (not withstanding any perception management issues).

SKM reached similar conclusions to GBA in recommending that the final project cost satisfied the NFIT and should be added to the Capital Base.

e) Alinta Gas-Fired Generation

On purely technical grounds without any commercial limitations, for the connection project alone, it is recognised that it may not have been necessary to construct the Landwehr terminal station.

[23] DMS#6317420

However, in reviewing the situation more closely, SKM acknowledges that there would have been significant disadvantages, including security issues, in having part of Western Power's shared network deviated into the Alinta site. In addition, there were also benefits of increased flexibility in locating the terminal station close to other existing 330 kV lines. Based on this information, SKM believes Western Power's planning decision to be appropriate.

SKM also believes that the need for substation supply and undergrounding of distribution assets should have been identified earlier. However, as discussed in section 5.2.7, SKM does not share GBA's concerns over the allocation of the $1.33 million for undergrounding the distribution assets along the route of the transmission line. This decision was made in accordance with a Western Power policy that SKM considers to be efficient and in line with good electricity industry practice.

f) Joel Terrace

The prime issue of concern raised by GBA for this project relates to Western Power's planning decision to provide a transitional development path for the conversion of Joel Terrace from 66 kV to 132 kV.

With reference to Western Power's "*East Perth Load Area – Long Term Development Study Notes 2005-2025 (DMS#1828316)*", the Joel Terrace 132 kV conversion project is part of a long term plan for the East Perth load area over the 20 year period covered in the development study notes, which includes a plan for progressive conversion of East Perth's 66 kV subsystem from 66 kV to 132 kV, in order to cater for anticipated load growth and ensure that the system continues to supply loads in accordance with the Transmission Planning Criteria.

SKM notes that GBA states in section 3.1.3, page 8 " *However, as we have not seen this development plan and have not had the opportunity to assess the reasonableness of the assumptions on which it is based, we are unable to assess whether this project meets the requirements of the NFIT."*

SKM assumes that this comment is referring to the development study notes referred to earlier in this section, which is referenced in the business case document for Joel Terrace, which SKM understand GBA has reviewed.

SKM also notes another comment by GBA (section A5.3, page A14, second para.) that "*However we have not seen the analysis...*" and refers to an Excel spreadsheet 'East Perth Load Area – Financial Comparison of Options' (DMS#1828316) which is also referenced in the business case document.

With regard to the GBA comment that "*...the age of the existing 66 kV assets at Joel Terrace is not stated.*", SKM notes that Western Power states in their development study notes document (section

9.3 page 60) that "*Approximately 90% of the equipment at Joel Terrace is in excess of 40 years old and therefore likely to require replacement within the 20 year period of this study.*"

From our review of the business case and development study notes, it appears to us that Western Power's planning approach was sound and reasonable. Further, section 5.1.6 of this report concludes that the 132/66 kV conversion policy is consistent with good electricity industry practice. However, SKM does consider that Western Power should provide information on the comparative costs between the recommended options and the alternatives and also provide a sensitivity analysis for different forecast rates of demand growth, to confirm that the recommended option (and/or the overall development plan), is consistent with the NFIT requirements, (particularly as this is just the first part of a much larger development).

g) Margaret River 132 kV Upgrade

Consistent with the AASB 116 Accounting Standards, expenditure on a project that does not meet the Asset Recognition Test cannot be capitalised[24]. SKM expects that any works completed to date, that do not contribute to Western Power's provision of service, on a project that is suspended until 2018, would struggle to pass the Asset Recognition Test and therefore cannot continue to be carried as Work in Progress (WIP)[25]. Further, any physical works completed that contribute to Western Power providing its service, must then meet the NFIT to be included in the RAB. Through discussions with Western Power, SKM understands some minor physical works may have been completed on this project. Although these works may have been undertaken "efficiently", SKM believes it is unlikely that these "partial works" in isolation from the broader project (that may continue in 2018) would be provide enough value on their own to meet any of the remaining legs of the NFIT. As such, SKM does not consider that expenditure on this project would meet the requirements of the NFIT at this time.

h) Mid West 330 kV Upgrades

As discussed it item (g) above, a project that does not pass the Asset Recognition Test cannot be capitalised. SKM notes the government has recently (after GBA's AA#1 Projects report had been prepared) provided statements to the effect that the funding of the Mid West 330 kV Upgrade (to Eneabba) has been approved. Therefore, it is more likely than not that the expenditure on this project will directly contribute to the establishment of an asset required for Western Power to deliver its services. Further, SKM understands the Authority has previously approved a Regulatory Test Submission and a pre-approval of an NFIT application on this project and allowed it to

[24] Relevant accounting standard and test established in discussions with Western Power.

[25] This comment is based on the previous operational experience of SKM staff and is not the result of a review by a qualified accountant.

proceed based on the information supplied. As such, SKM believes it would be reasonable to re-visit the status of this project and reconsider the appropriateness of including the development costs of this project in the RAB at this time. This position impacts on the $63.5 million reduction detailed in Required Amendment 26 of the Draft Decision.

i) Newgen Neerabup, Perth-Mandurah Rail Connection and Southern Terminal SVC

SKM notes the issues raised by GBA with these projects are not issues stemming from "systemic over-engineering" or other inefficiencies but a result of Western Power's poor management of and accounting for capital contributions. SKM understands the Authority has captured these impacts in the separate $63.5 million and $65 million write downs in item 1 and item 2 of Required Amendment 26 in the Draft Decision.

j) Rural Power Improvement Program

SKM cannot identify any reason that the source of funding for a project, outside that of a customer contribution[26], would impact on the application of the NFIT to a project. SKM does not believe a provision of funds from an entities' owner would be characterised as a customer contribution. As such, based on the information reviewed, SKM would argue that the Rural Power Improvement Program appears to meet the requirements of the NFIT.

k) State Underground Power Project (SUPP)

GBA indicated that the program is 75% subsidised and therefore 25% of expenditure on the State Underground Power Project (SUPP) is available to meet the requirements of the NFIT. GBA does not identify that of the 75%, 50% is a customer contribution from local government and 25% is an equity contribution through Western Power's owner's representative, the Office of Energy. As in the Regional Power Improvement Program, SKM does not consider that the source of funding, (outside of a customer contribution), should necessarily impact on the application of the NFIT. As such, SKM considers that 50% of expenditure on the SUPP project is available to meet the requirements of the NFIT.

In assessing this 50% portion of expenditure, SKM refers to the original basis of the funding arrangements that pre-dates AA#1. SKM's understanding of the basis of the funding arrangements at the time was that Western Power could not justify more than 25% expenditure on the project[27]. This justification was based on the alternative of replacing aging overhead assets with new overhead assets. It was recognised that the rate payers (local government) and the State benefited

[26] Process must be in place to confirm capital contributions do not result in "double counting".

[27] This position is based on prior knowledge of SKM staff.

from the retrospective undergrounding of the overhead distribution assets and therefore these entities made a contribution for the undergrounding option to be implemented.

On this basis, SKM would consider that Western Power, through its previous actions, has set the maximum result of any NFIT assessment of the State Underground Power Project at 25% of expenditure. SKM believes there may be scope for the net benefit test to be applied to this project resulting in a higher proportion of the project expenditure meeting the NFIT. However, Western Power would need to specifically justify this position.

l) Subdivisions

SKM has not commented on GBA's position on subdivisions as this was not within the scope of this review.

m) Vested Assets

SKM has not commented on GBA's position on vested assets as this was not within the scope of this review.

4.2.6. Conclusions

In its critique of the GBA AA#1 Projects report, including a review of the data utilised in the report, SKM makes the following observations.

a) Western Power's accounting for and management of capital contributions has resulted in anomalies and expenditure that may not satisfy the NFIT where they have been the subject of a capital contribution. SKM understands that these issues have been captured in the $63.5 million and $65 million reductions in Required Amendment 26 of the Draft Decision and have not been considered further in this report.

b) SKM does not share the following concerns identified in the GBA AA#1 Projects report:

- Demand Forecasting and Temperature Sensitivity.
- Undergrounding of Distribution Systems Under Transmission Lines.
- Failure of Western Power to retain IP.
- 132 kV Conversion instead of the lower cost 66 kV option (notwithstanding the need to seek specific endorsement from the Authority on the 66 kV to 132 kV policy).

Observation 3

SKM does not share GBA's concerns pertaining to:

- Demand Forecasting and Temperature Sensitivity.
- Undergrounding of Distribution Systems Under Transmission Lines.
- Failure of Western Power to retain IP.
- 132 kV Conversion instead of the lower cost 66 kV option.

4.3. GBA Report: Review of Expenditure Governance Western Power

4.3.1. Scope and Application of the Report

The primary scope of the GBA Governance report[28] was to undertake a review of a cross section of Western Power's representative projects and programs. This was to assist the Authority in understanding the extent to which it can rely on Western Power's governance arrangements to determine whether Western Power's access arrangement forward work program and forecasts of capital and operating expenditure are prudent and efficient. To achieve this objective, GBA undertook a review of the governance and management of projects and programs undertaken during the AA#1 regulatory period from 1 July 2006 to 30 June 2009. It is this information that is relevant to the discussion in this report and to the 15 per cent reduction recommended in the Authority's Draft Decision.

4.3.2. Resources Utilised in the Report

There is no indication of the resources committed by GBA in developing the findings in the GBA Governance report. The list of documentation available to GBA is not specifically listed in the GBA Governance report. However, SKM understands that it is the same documentation initially provided by Western Power to SKM. SKM understands GBA undertook a reasonably extensive interview process within Western Power for the purposes of the GBA Governance report.

[28] Review of expenditure governance: Western Power, Geoff Brown & Associates Ltd, Western Power, 14 July 2009.

SKM

4.3.3. Commentary on Key Findings of the Report

a) Cost Estimating

The GBA Governance report identifies the 10 recommendations of the Tellis Chase[29] report in September 2007 and tracks the implementation of these recommendations. Through this process, GBA concludes:

"Should this change process be successful, and we have seen no evidence to indicate that it won't be, we are confident that Western Power's cost estimating processes will be commensurate with industry best practice".

This conclusion is consistent with SKM's benchmarking of Western Power's estimating process undertaken in June 2008[30].

SKM agrees with the conclusions of the Tellis Chase Report and GBA. Thus, we recognise that Western Power's estimating process was below good electricity industry practice in 2006/07 but that it improved to meet good electricity industry practice by 2008/09.

Issue 1 The Western Power estimating process was behind good electricity industry practice at the beginning of the AA#1 period but it has now improved to being considered good electricity industry practice.

b) Materials and Equipment Procurement

SKM notes that GBA believes that Western Power's tendering processes appear thorough and robust. The GBA report also raises the perception that Western Power may specify requirements over and above industry norms; this is discussed further in section 5.4 of this report that undertakes a specific review of major plant items.

c) One Step Ahead

GBA's review of the One Step Ahead (OSA) program concludes by noting that the focus on efficiency and business improvement, which had its genesis in the OSA program, is still strong in Western Power. Relevant to SKM's analysis (although it was not the primary scope of the GBA

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[29] Geoff Brown & Associates Ltd: Review of expenditure governance: Western Power, 14 July 2009, Section 3 reference to Tellis Chase Report.

[30] Sinclair Knight Merz: Transmission Asset Cost Benchmarking, 20 June 2008.

Governance report), is the identification of contractor over-charging issues by the OSA documentation in the years 2006 and 2007. These overcharging issues related to contractor charges in the distribution works area and in the 2004/05 year this was found to be 3.5% of total internally funded distribution capital expenditure, (figure derived using a sampling process). SKM has confirmed this overcharging was related to items such as[31]:

- Contractors assigning more workers than necessary to a job;
- Other behaviours causing overcharging including:
    - Contractors charging more hours per worker than required;
    - Cases identified where contractors have been slow;
    - Cases identified where hours for vehicles drivers were particularly high;
    - Cases identified where contractors have resourced jobs with trainees/ inadequately skilled staff – who take significantly longer to complete work; and
- Duplication of invoices and payments (i.e. Paying invoices twice).

SKM concludes that any robust contractor management process should have identified many of these inefficiencies.

The GBA Governance report concludes that at the beginning of the AA#1 regulatory period it would be reasonable to assume that contractor overcharging was still occurring. The GBA Governance report also concludes the current processes are sufficiently robust to address any contractor overcharging. Given the information provided, GBA's conclusion appears reasonable to SKM.

Issue 2

At the beginning of the AA#1 regulatory period it is reasonable to assume the contractor overcharging for distribution works, identified at 3.5% of internally funded distribution works, was still occurring. Procedures are now considered sufficiently robust to detect and address any contractor overcharging.

[31] Western Power: Presentation on Distribution Contractor Management – DMS# 3172105, July 2006.

SKM

d) Works Program Management

The review of works program management, as it is discussed in the GBA Governance report, is not within the scope of this report as it does not directly contribute to the issues of systemic over engineering or deficiencies, inefficiencies in project delivery or options analysis outlined in Section 5.1. However, through the reviews undertaken in this report, SKM has found nothing that would counter the conclusion of the GBA Governance report that these procedures are generally robust.

e) Zone Substation Planning Criteria

The results of the review that SKM has undertaken on Western Power's planning criteria are provided in Section 5.1 of this report. SKM does not share the concerns raised by GBA in its discussion on the effectiveness of the NCR wind-back program for the reasons discussed further below:

- The process that GBA refers to as "shuffling" is referred by Western Power as 'distribution transfer capacity' (DTC). DTC is integral to the NCR planning criteria[32] and, as such, the capability to "shuffle" load is taken into account in the planning process.
- SKM understands the driver for "headroom capacity", such as that generated by the NCR wind back process, is the same as that described in the GBA Governance report, being to facilitate the management of emergency situations that the network is not designed to handle. In SKM's opinion, this includes load events beyond the forecasting criteria (as experienced by Western Power and Energex in 2004) and the loss of plant beyond that covered by the security criteria.
- GBA's position that the NCR wind back will not eliminate the initial loss of load is correct. This position is fundamental to the fault levels and bus configurations in the existing network. Changing this arrangement is not a viable position for Western Power. Given this, SKM understands that the NCR wind back process will increase the quantity of load that can be met within minutes by the remote reconfiguration within the substation.
- GBA's position appears to be that *"the capacity released by the NCR wind back program would be of little benefit if the spare capacity could not be accessed because of high distribution network loadings."* SKM's experience would lead us to comment that the events in which DTC would be required to realise the value of spare capacity in a substation are a smaller subset of emergency events. As such, SKM does not believe, even with no DTC, the capacity released by the NCR wind back program to be of little benefit.
- SKM has reviewed the Western Power Loads and Forecast Report[33] and identified that the DTC in the majority of substations appears to be decreasing over time. This is consistent with

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[32] Western Power: Transmission Planning Criteria, March 2009, Section 5 Substations Planning Criteria.

a distribution system with increasing utilisation. For a few substations, the DTC has increased (or is forecast to increase) over time. SKM understands this to be a result of reinforcement in the distribution system.

- It should be noted that feeder loading in many utilities is often kept to less than 66% to allow load transfer in the event of a feeder outage (50% to each of two adjacent feeders). This transfer capability is enshrined in the Technical Rules for Urban Distribution Feeders constructed after the Rules Commencement Date. However, there are numerous exceptions and SKM would consider the 66% loading figure as a guide for good practice rather than a rigid figure. SKM understands Energex and Energy Australia use 80% of maximum feeder ratings, however, SKM recognises that both of these utilities feel these levels are too high, and are trying to reduce them.
- GBA's position appears to be that the full capacity lost by the failure of a transformer should be able to be met by implementing DTC and transferring load to other substations to avoid load shedding until the Rapid Response Transformer (RRT) is installed. SKM notes Western Power's current NCR planning criteria incorporates DTC and, as such, the RRT would not be required at these substations if this position was implemented. SKM accepts Western Power's planning policy that allows for a short outage period after a transformer outage while alternative supply arrangements are made. In SKM's view, this approach provides an acceptable compromise between reliability and installed capacity.

In summary, SKM considers that the drivers for the NCR wind-back program are appropriate. These drivers include addressing the utilisation of the transformer assets that are clearly above[34] identified good electricity industry practice. While SKM agrees the a lack of DTC could impact on the ability of the "head-room" generated by the NCR wind back program to assist in a subset of "emergency events", SKM believes this does not materially impact the consistency of the program with good electricity industry practice. SKM has seen evidence that Western Power considers the capacity in the distribution system when undertaking planning activates for zone substations although this has not been uniformly applied[35]; specifically, an allowance for expenditure on

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[33] Western Power: Summer Load Trends Report 2009 – 2028 Substation & System Peaks for the SWIS, December 2008.

[34] Section 6.1 demonstrates that Western Powers substation utilisation is well in excess of other utilities for which SKM has this data.

[35]Examples include Western Power: Establishment of new Cottesloe 132/11kV substation and Western Power: Establish new Wembley Downs substation – Discussion of Options to Increase Substation's Capacity, 6 January 2006.

distribution system upgrades to allow for DTC enhancement. As such, SKM does not share GBA's concerns with the efficiency of the NCR wind back program.

f) Projects and Programs

In the majority of cases, SKM agrees with GBA's general conclusions on the projects reviewed. However, SKM does raise one concern with the information provided by GBA.

GBA[36] states "…..*we are surprised that Western Power finds it necessary to audit 10% of the poles inspected since statistical theory suggest that a much smaller sample should be adequate to monitor the performance of a good contractor with a high level of confidence. If these audits are showing that a significant numbers of serious defects are missed by a contractor, then Western Power needs to take action to improve the situation; otherwise we think the level of audit could be reduced significantly without comprising the integrity of the process.*"

This commentary by GBA on Western Power's practice on auditing contractors responsible for inspecting poles is incorrect and is misleading in the context on how Western Power manages its external contractors.

Western Power's practice is to audit 10% of contractors' work until a confidence level is reached, at which time the percentage of inspections is decreased. The 10% is not random, nor applied uniformly to all contractors. It is undertaken on the basis of the results of previous audits such that if a particular contractor has no defect reports over a certain period of time, then the frequency and number of audits is reduced. If there is a history of defects, the same level of audits is maintained or increased[37]. Given that an extremely high standard of safety is required for the integrity of the poles in Western Power's network, SKM agrees with the practice adopted by Western Power for auditing its contractors' inspection of poles.

g) Summary

SKM's analyses have some points of agreement with the summary conclusions made by GBA including:

- That at disaggregation Western Power had an asset that was the result of the legacy of under spending.

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[36] Geoff Brown & Associates Ltd: Review of expenditure governance: Western Power, 14 July 2009, Section 4.7.1.

[37] Email from Western Power on the Audit of Contractor Inspections DMS#6328913.

- As discussed in Section 4.2, Western Power has not met the reporting requirements of the NFIT as would be expected of a utility that had been operating under a regulatory regime for some time.
- SKM notes that GBA concedes it is unwise to draw conclusions on the basis of the five incidents discussed by GBA in section 5.7 of the GBA governance report. This is particularly the case because of the following issues:
  - As discussed in Section 4.3.3e of this report, SKM does not share GBA's concerns on the NCR wind back program.
  - In SKM's opinion, the incidents of Western Power's assets creating bushfires have a root cause in legacy design issues and under spending previously mentioned.
  - GBA makes the comment in reference to the use of aluminium cable for underground distribution; "*we think Western Power has been very slow to adopt this technology*". SKM notes that Western Power has changed over to using aluminium cable and has being doing so since 2007[38]. This was in response to the large increase in the price of copper which had escalated considerably during the period 2002 to 2006. In SKM's experience, DNSPs in Australia continue to use different combinations of copper and aluminium for overhead and underground services, depending on the voltage levels and conductor sizes required. SKM does not agree with GBA's contention that Western Power has been "very slow" to adopt the use of aluminium over copper.
  - Of the remaining three issues, only one is related to NFIT and the other two represented issues in inspection processes. SKM notes that wood pole inspection through the dig and drill method (although the most satisfactory method identified by Western Power at time), is an inexact process. It is somewhat dependent on operator skill and will not necessarily identify 100% of unsafe poles. SKM has not reviewed in any detail the electrical incident report into the incident on 22 April 2009.
  - In light of the discussion above, SKM believes the incidents listed in section 5.7 of the GBA report provide very limited insight into the effectiveness of Western Power's new facility investment in the AA#1 regulatory period.

[38] Western Power OSA Program Project Closure Report: Cu to Al Cable Project, July 2007

h) Conclusion

- Consistent with the discussion above, SKM does not share the concerns of GBA based on the 5 issues raised in section 5.7 of the GBA Governance report.
- The example of the Wells substation is discussed in Section 4.2.4 of this report, with SKM concluding that the approach to meeting the customer's requirements was consistent with good electricity industry practice. However, Western Power failed to appropriately recover the extra expenditure as a customer contribution.
- SKM's review of Western Power's options analysis is provided in Section 5.1 and concludes Western Power's options analysis is generally consistent with good electricity industry practice.
- SKM concurs with the identified weakness in delivery of large capital projects driven by poor estimating, particularly at the beginning of the AA#1 regulatory period.
- SKM also has concerns regarding the identified contractor overcharging.
- SKM concurs that the asset failures, outlined in the GBA Governance report, are likely to have a root cause in the poor condition of the asset resulting from the legacy of under spending on the network.

Observation 4

SKM has verified that Western Power has improved its systems and processes throughout the AA#1 regulatory period in response to regulatory and economic pressures. This is consistent with the conclusions of the GBA Governance Report.

SKM confirmed the basis of the issues identified as Issue 1 and Issue 2 in previous discussions of this report.

SKM does not, however, share a range of GBA's concerns surrounding options analysis, the NCR wind back program and the timing of the decision to move to aluminium cables.

4.4. Wilson and Cook Report: Review of Western Power's Expenditure for Second Access Arrangement

4.4.1. Scope and Application

The Authority's terms of reference for the Wilson Cook report[39] included advice in relation to Western Power's capital expenditure in the AA#1 regulatory period 2007-2009. The scope to provide this advice included review of existing consultants' reports, benchmarking, a review of asset registers and advice on any discrepancies or areas that warranted further investigation. Of note, Wilson Cook's review was limited to investigating the efficiency test alone in the tests under the NFIT of the Access Code definitions of: "efficiently minimising cost", "Reasonable and prudent person" and "Good electricity industry practice". SKM believes the use of these definitions to define how compliance with the efficiency test is assessed is consistent with SKM's position on the application of the efficiency test outlined in Section 3 of this report.

4.4.2. Resources Utilised in the Report

Wilson Cook outlines the five member team that were involved in undertaking the review. SKM is familiar with most of the team members and aware of their significant experience in supporting regulators in their decision making processes. SKM understands Wilson Cook had access to similar documentation to GBA, as outlined in Annexure A of this report. Wilson Cook also outlines an extensive list of personnel from the Authority and Western Power interviewed for the report.

4.4.3. Interpretation of the NFIT

The Wilson Cook report concludes the efficiency test "*is little different to the normal tests of efficiency and prudence that we would apply in reviewing past and future Capex put forward by a network business*". Wilson Cook also discusses the application of the efficiency and prudency in terms of the test.

4.4.4. Commentary on Key Findings of the Report

The primary conclusion drawn in the Wilson Cook report is that "The scope and prudence of Western Power's capital expenditure for (FY 2007 to FY 2009) is accepted. However, no opinion

[39] Wilson Cook & Co: Review of Western Power's expenditures for second access arrangement final report. May 2009.

is formed regarding the cost effectiveness as a result of a "lack of information provided." This is consistent with SKM's findings outlined in this report with the exception of specific issues that have been quantified in Section 6.1 of this report.

The Wilson Cook report identifies the following issues that are relevant to the application of the NFIT to expenditure in the AA#1 period for the consideration of the Authority:

- There was a lack of information available to review Western Power's capital expenditure.
- There was a lack of information available to support additions to capital base.

As previously discussed, on the basis of the information that Wilson Cook was provided, SKM agrees with these issues.

Observation 5

SKM generally agrees with the findings of the Wilson Cook report and notes that Wilson Cook concluded that "*The scope and prudence of Western Power's capital expenditure for (FY 2007 to FY 2009) is accepted. However, no opinion is formed regarding the cost effectiveness as there was a lack of information provided.*"

5. Assessment of Relevant Western Power Policies, Procedures and Design Standards

5.1. Review of Planning Policies and Practices

5.1.1. Introduction

SKM was requested to review the Transmission and Distribution planning standards and processes from a "good electricity industry practice" perspective.

5.1.2. Approach to Review

Relevant documents were reviewed for comparison with national practices. Note that the comparison was not against any identified 'best practice' approach, but broadly compared to the range of practices undertaken in the industry at this period in time. Through this process, five questions were addressed:

1. Are Western Power's T&D Policies and Standards consistent with meeting requirements of the Code Objective and particular requirements to comply with the Technical Rules and Quality and Reliability Standard?
2. How do Western Power's Planning Policies and Standards compare with good electricity industry practice?
3. Have the Planning Criteria been consistently applied?
4. What aspects have been identified that could potentially lead to inefficiencies in network asset establishment?
5. If possible, what impacts on efficiency do the above aspects have in terms of percentage additional cost (e.g. per substation, per transformer etc)?

5.1.3. Scope of the Review

The scope of the review was to review Western Power's transmission and distribution planning standards and processes and provide an independent opinion as per the above.

5.1.4. Documents Reviewed

The list of documents is included in Appendix B.

5.1.5. Findings

Are Western Power's T&D Policies and Standards consistent with meeting requirements of the Code Objective and particular requirements to comply with the Technical Rules and Quality and Reliability Standard?

The Western Power planning policies have been reviewed for consistency with the Access Code Objective.

The Code objective is defined in Section 2.1 as:

"*2.1 The objective of this Code* **("Code objective")** *is to promote the economically efficient:*

(a) investment in; and
(b) operation of and use of,

networks *and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the* networks."

In the introduction to Western Power's document "Transmission Planning Criteria", the planning criteria as used by Western Power are listed as follows:

"…the planning criteria used by Western Power to ensure Western Power's transmission systems:

- *provide acceptable quality of electricity supply;*
- *provide an acceptably reliable electricity supply;*
- *provide adequate security of electricity supply;*
- *maintain safety standards;*
- *satisfy environmental standards; and*
- *are developed at the lowest cost possible whilst meeting the constraints imposed by all of the above."*

As clearly demonstrated in the last dot point, there is a conflict between the Code objective and the Planning Criteria. In the Planning Criteria, there are a number of technical aspects that are placed in priority ahead of the minimum cost. Conversely, the Code objective places economic efficiency as the first priority. If the technical aspects are taken as a "given", this difference may be purely semantic in nature. On the other hand, the differences in prioritisation may point to fundamental differences in philosophy between the Access Code and Western Power's Planning Criteria. It should be noted that the Planning Criteria makes no mention of the market or of the need to promote competition within the market. SKM notes that use of the Planning Criteria as a guiding document by Western Power is being phased out with a preference to refer directly to the Technical Rules for planning guidance, (however the Planning Criteria was in use during the AA#1 period).

How do Western Power's Planning Policies and Standards compare with good electricity industry practice?

SKM finds that Western Power's Planning Criteria represent good electricity industry practice and would be typical of NSPs across Australia. For example:

- The National Electricity Rules (NER), as they relate to NSPs, place great weight on the technical standards for Quality of Supply (see Section S5.1 of the latest version of the NER).
- The security standards in NSW are mandated by Ministerial decree.
- The reliability standards are prescribed in Victoria and embedded in the "S Factor" reliability performance reward/penalty regime.

However, it would be beneficial if the Planning Criteria could be better aligned with the Code Objective - perhaps by a statement that the meeting of the various technical criteria at least cost ensures that the investment is economically efficient. In this way, the technical criteria can be integrated into a broader definition of "economically efficient" and lead to a more transparent and better understood approach.

Have these planning polices and standards been consistently applied?

SKM has seen evidence of consistent application of the Planning Policies in the planning reports for various projects as discussed in section 7.2.2 of this report.

What aspects have been identified that could potentially lead to inefficiencies in network asset establishment?

As discussed above, the planning documentation reviewed represent good electricity industry practice. The alignment with the Code would provide better clarity for planning staff. However, SKM has identified no evidence that this has resulted in inefficient planning outcomes.

5.1.6. Specific Planning Issues Reviewed

66 kV to 132 kV Conversion

The Western Power Asset Strategy document refers to a long term strategy for conversion to 132 kV from 66 kV but does not provide any further details. There are study notes we have seen on Western and East Perth Terminal load areas, which provide some more specifics on the long term plans of Western Power. SKM have also reviewed a number of specific projects (e.g. Cottesloe, Wembley Downs, Medical Centre and Joe Terrace) where a transitional development for conversion from 66 kV to 132 kV is envisaged. It appears that the Authority remains to be convinced of the "efficiency" of these type of projects, with the common element of choosing to upgrade to 132 kV rather that replace ageing 66 kV equipment.

The strategy of converting the 66 kV system to 132 kV over time is likely to lead to inefficiencies in particular projects from time to time if those projects are considered in isolation. For example, the Medical Centre project was reviewed by GBA. GBA recommended a reduction in allowable project costs on the basis that proposed 132 kV cable and switchgear costs were higher than 66 kV costs (by 5-10%) and could therefore not be justified. It should be noted that from a technical perspective, the use of components rated for 66 kV or 132 kV would have no impact on safety, quality or reliability issues.

It may well be true that the 66 kV components would be cheaper than 132 kV components, and that use of 132 kV components could be seen as economically inefficient. However, it seems to SKM that the adoption of such an approach would be "Penny wise and Pound Foolish". The reason being that if this approach were to be universally adopted it would lead to substantial cost increases for ultimate conversion to 132 kV.

It seems that the Western Power policy of converting the 66 kV network to 132 kV over time has not been subject to Regulatory and Stakeholder scrutiny and/or approval. This is evidenced by the fact that the Regulator has accepted the comments by GBA in this regard. SKM would argue that the 132 kV conversion policy is both prudent and consistent with good electricity industry practice. The practice of conversion to a higher voltage is common and there are sound technical and economic reasons for doing so.

SKM understands that the policy must have Regulatory approval and support. With such approval and support, a significant number of the projects that have been adversely reviewed would be seen as cost-efficient.

SKM recommends that Western Power engage with the Authority in this matter and develop an agreed policy outcome. Such agreement could include:

- agreement regarding the rules for upgrading the 66 kV network to 132 kV; and
- an acknowledgement that development of the 132 kV network will support the operation of the market and promote competition.

SKM is not clear on which documents Western Power has in the public domain, and, if so, what consultation Western Power has had or continues to have with the Authority and other key stakeholders on longer term network strategies. Rather than deal with each project on a case by case basis, SKM believes it is imperative to have effective stake-holder buy-in to longer term network strategies, otherwise it will be a constant re-visiting of the same issues of projects on this nature.

Western Power needs to be able to articulate and promote its network strategies and plans in a clear and transparent manner, with sufficient analysis and details to provide solid justification for its plans in terms of good electricity industry practice, regulatory test and NFIT.

> Observation 6
>
> SKM has identified some inconsistency in the priority of drivers between Western Power's Planning Criteria and the Code. However, SKM contends that the processes outlined in the planning documentation reviewed are consistent with good electricity industry practice. Further, SKM would argue that the 66 kV to 132 kV conversion policy is consistent with good electricity industry practice and would recommend more engagement with the Authority and other stakeholders around such specific planning

5.2. Review of Design Standards

5.2.1. Introduction

SKM was requested to review the Transmission and Distribution design standards applied to capital projects within Western Power. The review undertaken for this project involved the majority of the key design standards forming the basis of designs for new substations, lines and related network infrastructure. The design standards adopted by Western Power are one of the key drivers for cost of infrastructure together with the cost of labour and materials.

5.2.2. Approach to Review

The scope of the review was limited to design standards only. No actual designs for substations or infrastructure were inspected in the field or detailed drawings reviewed for comparison with standards. It is assumed that actual detailed designs are consistent with design standards.

Relevant documents were reviewed for comparison with national practices. Note that the comparison was not against any identified 'best practice' approach but broadly compared to the range of practices undertaken in the industry at this period in time. The review consisted of separate (by SKM staff with the relevant experience) reviews of the following three subsets of design standards:

- transmission substation standards;
- transmission line standards; and
- distribution design standards.

The review consisted of addressing the following questions:

- Are Western Power Design Policies and Standards consistent with meeting requirements of the Code Objective and particular requirements to comply with the Technical Rules and Quality and Reliability Standard?
- How do the Western Power Design Standards compare with good electricity industry practice?
- What aspects have been identified that could potentially lead to inefficiencies in the establishment of new facilities?
- Are there any of the above aspects related to addressing specific safety, quality or reliability issues?
- If possible, what impacts on efficiency do the above aspects have in terms of percentage additional cost (e.g. per substation, per transformer etc)?

The review did not review all of the versions of design standard versions used throughout the AA#1 period in detail but a range of design standards were sampled. Through its review SKM found no evidence in step changes in design standards throughout the AA#1 period.

5.2.3. Documents Reviewed

The design standard documents reviewed are listed in Appendix B.

5.2.4. Design Standards

Power system infrastructure used in transmission and distribution systems is generally long-life, up to 60 or 70 years. During this lifetime, national and international standards and guidelines evolve together with regulatory and legislative requirements on asset owners. The availability of equipment types changes with new developments in materials and products. For example, in the last 30 years (well within the economic life of current electrical infrastructure), significant changes have been seen in primary insulation and switchgear as well as secondary systems and communications. Design standards evolve to meet the demands of new regulatory requirements and to take advantage of new technology.

One of the other influences for change is the risk environment relating to community expectations. While some years ago, particular risk levels or service standards may have been acceptable, that is not the case today. Finally, there are the shareholder expectations that, regardless of whether those shareholders are public or private, have changed with time, demanding a return on investment for infrastructure development.

All of these factors influence the design standards adopted by network service providers, regardless of the ownership model. All of these factors impact on the cost of infrastructure to maintain the level of reliability required to meet service standards.

SKM

5.2.5. Substation Design Standard Review

Are Western Power Design Policies and Standards consistent with meeting the requirements of the Code Objective and particular requirements to comply with the Technical Rules and Quality and Reliability Standard?

> *The Code objective is to promote the economically efficient investment in; and operations of, and use of networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

Western Power's design standards cover the range of electrical infrastructure that comprises the electricity network. The design standards define the level of investment required to meet Code objectives.

The design standards appear to provide a level of network performance that would be consistent with meeting industry standards, Australian Standards or relevant international standards and these practices are referred to and form the basis of Western Power design standards. In addition, there are a number of aspects where design standards have been applied in a manner indicating that investment is based on meeting appropriate levels of risk (rather than a "one size fits all" approach) indicated by the following selected examples:

1) Primary designs include the use of single CB configurations for 132 kV and 1.5 breaker arrangements for 330 kV and above[40]. This is consistent with national practice and indicates that appropriate analysis has been undertaken to determine the relative economy of configuration for different circuit criticality levels.
2) Creepage distances for insulation systems are selected on the basis of location for the appropriate pollution risk. Creepage distances impact the cost of insulation for lines and substations.
3) Protection design philosophies adopted in Western Power, and as defined in various Design Standard documents reviewed by SKM, indicate appropriate levels of design and redundancy for different voltage and criticality levels. Duplication of protection is only specified for voltage levels of 66 kV and above. This approach indicates broad agreement with good electricity industry practice and also prudency in investment decisions in line with Code objectives.

[40] Western Power: Transmission Standard Design Part 2 – Functional Specification – 132/22 kV Zone Substation, 31 January 2009 and Western Power: Transmission Standard Design Part 2 – Functional Specification 330/132 kV Terminal Yard, 30 June 2009.

4) The AC and DC supply system design standard for substations considers the level of criticality of the substation location in the network including voltage and function. A comment is made later in this document that the battery reserve times adopted in WA are generally longer than some other States of Australia, however this is consistent with the larger distances between centres and the ability for field crews to respond with corrective maintenance in the event of loss power supply problems requiring DC power to be maintained[41].

5) Concept Designs and Functional Specifications for 132 kV/22 kV and 330 kV/132 kV show staged development dependent on needs but allowing for future growth. This indicates prudency in investment with minimised initial cost but allowance for future augmentation if required. SKM is aware of similar approaches being adopted in other jurisdictions.[42]

6) Brownfield development is carried out under an assessment framework that includes a risk assessment. This provides a prudent economic and risk based decision framework rather than blind application of new standards[43].

7) Fencing and Security measures and designs in substations are defined according to the risk attached to the relevant site.

Observation 7
The review of substation design standards for Western Power indicates that the Code objectives for economic efficiency in investment and cost of operations are embodied in design standards.

[41] Western Power: Engineering Design Standard J1.1 – DC Power Design Practices, 28 May 1996.

[42] Ergon Energy is an early adopter of this process.

[43] Western Power: Framework for the Application of New or Modified Standards to Brownfield Sites, April 2009.

How do Western Power Design Standards compare with good electricity industry practice?

A broad range of representative standards for transmission and distribution substations were reviewed for comparison with standards used in other regions. This review was not a "line-by-line" comparison and was focused on broad design philosophies and policies evident or defined in the design standards. The focus of comparison was not on determining the historical or legacy preferences that are always a part of organisations' corporate memory but rather on those aspects of design that appear to be different and that would materially affect the cost of Western Power's infrastructure. This review resulted in the following comments.

1) Western Power considers it is legally required to comply with Australian Standards. This is evident in design standards in various locations and also included in the Corporate presentations[44]. This is often a vexing issue for utilities to decide how to deal with legacy issues.
2) The design standards reviewed provide a comprehensive coverage of designs for future infrastructure design. The format of design standards varies due to corporate and organisational changes. A traditional "standards" approach is supplemented by a "standard design" approach used now more frequently in a number of utilities. There did not appear to be missing design standards.
3) Insulation Coordination – it was noted that creepage distances were defined according to the relative location of the substation or site to pollution sources in line with good electricity industry practice.
4) Electrical Clearances for substation design were defined according to AS2067: 1984. It should be noted that AS2067 was updated in 2008 which may have a minor impact on design clearances (not material to costs).
5) Transformer Fire Protection and Bunding design standards appear to be risk based in alignment with good electricity industry practice.
6) Engineering Design Standards – Primary design includes ratings and other criteria in line with Australian standards and good electricity industry practice.
7) Protection Standards provide for a design that is appropriate to the level of risk as defined by circuit criticality and fault and voltage level and appears to be consistent with good electricity industry practice.
8) Engineering Design Standards - DC Power defines designs that are appropriate for criticality of the site (major or minor), and distance from maintenance support. It was noted that battery reserve standards for transmission substations appear to be generally longer than some other States of Australia, resulting in larger and more costly battery systems. However, this is consistent with Western Power's network geography and distances from support.

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[44] Western Power: Primary Plant, Technical Specifications, Preferred Vendor Arrangements & the recent RMU Tender Process Presentation, November 2008.

9) Lightning protection practices are consistent with good electricity industry practice and the WA lightning risk.
10) Functional Specifications for 330 kV/132 kV and 132 kV/22 kV substations define a standard design for future Western Power substations. These standards define a staged development path that as stated previously indicates economic prudency in line with Code objectives. The use of standard designs of this type are used in Queensland and in parts of Victoria and have been adopted to provide an alternative to traditional standards by more closely defining the design standards for commonly used substation designs. A review of these designs indicates that Western Power has adopted a risk based design approach and economic prudency in design. Other elements noted include allowance for future design augmentation in the initial design rather than as an "after-thought". The following several comments relate to consultations drawn from the functional specifications.
11) Security Criteria for CBD zone substations are comparable to other jurisdictions.
12) Voltage Regulation criteria is similar to other jurisdictions. Use of hard wired control system is conservative compared to other states where software and RTU designs are used. This is not likely to be material for costing.
13) Protection systems for 330 kV and 132 kV zone substations appear to be consistent with good electricity industry practice.
14) Substation Land Acquisition guidelines are provided in Functional Specifications and these appear to provide for a risk analysis decision framework aimed at balancing capital cost and minimising hazards associated with site location.
15) Design of roadways in zone substations are specified larger than the minimum required to allow access for a RRT (mobile transformer). While this will increase cost for substations, the cost is offset by the deferred investment in additional main transformers that would otherwise be required if an available spare was not able to be connected temporarily.
16) Security Fencing is designed based on a risk assessment according to the level of threat and risk at a site.
17) Substation design includes provision for EMF compliance with Australian Standards and industry guidelines.
18) Design ambient temperature range (max 50°C) is higher than that used by some jurisdictions but consistent for the region. This factor has cost implications but is justified by network location.
19) Substation building designs incorporate use of transportable buildings rather than traditional brick. This is generally believed to deliver faster delivery times and lower establishment costs.
20) Oil bunding for transformers with 330 kV substation is specified to retain 100% of oil spillage (some designs specify lower percentage retention). This represents a low risk design outcome and is consistent or lower than the standard in other States of Australia.

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Observation 8

SKM's review of Western Power's substation design standards showed that the standards were broad and covered the majority of electrical infrastructure in the Western Power network. The standards were compared to practices used in other jurisdictions in Australia and found to be generally consistent with no material differences that would significantly affect the cost of Western Power infrastructure. Some minor regional differences were noted.

What aspects have been identified that could potentially lead to inefficiencies in the establishment of new facilities?

There are a number of apparent issues identified during the review of standards that could potentially result in higher costs and these may be (incorrectly) considered as indicators of inefficiencies in network asset establishment. These are listed below:

- Soil properties in the south west region appear to be consistently such that footing designs for substations and lines may be more expensive than for comparable regions. This does have cost implications but does not indicate inefficiencies in network assert establishment.
- Auxiliary supply standards for zone substations specify battery survival times up to 24 hours. This is longer than the survival times for some other jurisdictions. The calculation for survival time relates to the risk of maintenance staff not being mobilised to the site to take remedial action in the event of a failure of AC auxiliary supply causing the requirement to operate the station from DC supplies without recharge. This design requirement increases costs but it appears to be related to the distances of typical sites from maintenance depots. These same survival times are used in other jurisdictions for remote sites. The increased costs are considered to be marginal but justified due to the topography of the network in WA.
- The adoption of a standard design approach for some transmission substation design standards has been shown to result in increased initial establishment cost. However, in other jurisdictions where this approach has been used, it has been shown that the approach provides a superior integrated design that is matched to the risks associated with the site and the criticality of function required. The design is more robust, resulting in lower maintenance costs, an easier development path for future expansions and staged implementation where investment is made only when required. Cost benchmarking carried out by SKM in 2008[45] indicated good cost comparison between designs carried out using the standard design approach and those

[45] Sinclair Knight Merz, Transmission Asset Cost Benchmarking, version 4, 20 June 2008.

completed using traditional design approaches. As expenditure and capital costs are directly linked to risk, the approach is considered to be good electricity industry practice and consistent with the Code objectives defined in earlier sections of this report.

- Land acquisition costs for large zone substations may be higher than minimal as land is purchased for Western Power substations according to an assessment of risks. Thus, undesirable land with potentially lower cost may be considered unsuitable due to identified future ownership risks. In addition, the standard design approach described previously may result in the acquisition of land for future expansion but larger than might be considered the minimal requirement for first stage of development. The approach may result in apparent higher costs of land acquisition but would not be considered to result in inefficiencies.
- Design of roadways in zone substations are specified larger than the minimum required to allow access for RRST (spare mobile transformer). While this will increase cost for substations, the cost is offset by the deferred investment in additional main transformers that would otherwise be required if an available spare was not able to be connected temporarily.

Observation 9

A number of issues have been identified in Western Power's substation design standards that may marginally increase the initial capital cost of establishing new facilities. In all identified cases, SKM considers this additional investment to be part of an efficient process to establish new facilities.

Are there any of the above aspects related to addressing specific safety, quality or reliability issues?

None additional to the items mentioned above.

If possible, what impacts on efficiency do the above aspects have in terms of % additional cost (eg per substation, per transformer etc)?

The review identified minimal to no impact on cost of infrastructure.

5.2.6. Transmission Line Design Standard Review

Are Western Power Design Policies and Standards consistent with meeting requirements of the Code Objective and particular requirements to comply with the Technical Rules and Quality and Reliability Standard?

Western Power utilises a combination of standard designs and specifications and customer designs and specifications depending on the size and voltage of the transmission lines required. Standard designs and specifications are used for short 132 kV transmission lines in urban areas with custom designs used for longer rural 132 kV lines and higher voltage lines. SKM is of the opinion that this approach is appropriate.

Western Power's policy is to underground distribution systems that pass under transmission lines under construction[46]. In SKM's experience, this is a cost effective approach to transmission line construction that is routinely undertaken in other jurisdictions[47]. The savings generated by this policy include avoiding the construction and maintenance of scaffolds above the distribution line and a reduction in the tower height of the transmission lines. SKM's experience is that these savings and other construction efficiencies typically outweigh the cost of the undergrounding with the resulting new distribution facility providing a superior quality and safety outcome. SKM considers this policy a good example of efficient development, satisfying both the efficiency test and the reliability and safety test.

The design standards appear to provide a level of network performance that would be consistent with meeting industry standards. Australian Standards or relevant international standards and practices are referred to and form the basis of Western Power design standards.

How do Western Power Design Standards compare with good electricity industry practice?

Western Power's procedures for transmission line design and specification are based on a traditional approach, historically used by many utilities in Australia and throughout the world.

What aspects have been identified that could potentially lead to inefficiencies in the establishment of new facilities

In the past 10 years, analytical software packages have developed that facilitate more effective economic optimisation of transmission line design. An example of this is the PLS CADD

[46] Western Power: Lines Team Instruction 68 – ABC/Undergrounding Distribution Services,, 15 May 2007.

[47] ETSA Utilities and Ergon Energy have similar approaches

structural analysis method 4. This method 4 links the electrical and structural design processes in one package to allow design to be economically optimised. Western Power has not at this time incorporated tools and processes such as method 4 and still follow a traditional design approach of having electrical and structural components designed separately, which can result in a less than optimal design. In SKM's opinion, this is considered more an area for improvement than a deviation from good electricity industry practice at this time. This area for improvement may be able to generate saving of up to 10% on the total cost of transmission line projects.

Are there any of the above aspects related to addressing specific safety, quality or reliability issues?

No issues have specifically been identified.

If possible, what impacts on efficiency do the above aspects have in terms of % additional cost?

None at this time.

> Observation 10
>
> SKM's review of Western Power's transmission substation design standards in the AA#1 period has concluded they are consistent with good electricity industry practice and the requirements of the Code. SKM notes an area for improvement that Western Power should incorporate into its transmission line design processes in the near future.

5.2.7. Distribution Design Standard Review

Are Western Power Design Policies and Standards consistent with meeting requirements of the Code Objective and particular requirements to comply with the Technical Rules and the Quality and Reliability Standard?

Western Power's design policies and standards are aligned with achieving the technical performance requirements stated in the codes, technical rules and standards.

How do the Western Power Design Standards compare with good electricity industry practice?

Western Power's design policies and standards are aligned with achieving the technical performance requirements stated in the codes, technical rules and standards. SKM note the following variations with other approaches in industry:

1) Industry practice generally plans and designs a power system to accommodate future foreseeable load growth with a specific planning horizon (e.g. 5 years or 10 years). Western Power do not appear to design to a planning horizon; and
2) the Technical Rules seek to improve network performance by limiting the number of customers (860) per switchable section on radial feeders and increasing the number of feeders (split outside substation).

Item 1 above is an implementation of section 2.6 (a) of the Technical Rules that states:

"*All distribution systems must be designed to supply the maximum reasonably foreseeable load anticipated for the area served*"

and as such is consistent with the regulatory approved approach to planning. Item 2 is a specific requirement of the Technical Rules (item 2.5.4.4). Within the context of Western Power's very high average feeder loads, it is SKM's position that the variation from the practices of other utilities detailed in 1 and 2 above is appropriate.

What aspects have been identified that could potentially lead to inefficiencies in the establishment of new facilities

SKM finds that although Western Power's design policies and standards are well defined and robust, there is a lack of standard designs for suppliers to work to. Whilst Western Power was undertaking this design process in-house, the lack of standard design drawings was likely not a large issue as SKM would expect "informal" standard drawings would have been utilised along with informal guidelines for design details such as spare underground ducts, duct sizes, cable pit designs and requirements, overhead earth wire installation requirements, sag and tension, pole footing and strength calculation guidelines. In the last two years, Western Power has increasingly used external service providers to undertake distribution designs to meet growing workloads. As a provider of distribution designs to Western Power, SKM expects the introduction of a range of standard design drawings and guidelines would result in a more consistent output from design providers and assist providers in decreasing design costs.

- ***Are there any of the above aspects related to addressing specific safety, quality or reliability issues?***

During the AA#1 period, Western Power has had to address legacy design issues that are now considered unsafe. The main safety design issues are understood by SKM to be:

- The use of long distribution bays;
- The use of underslung earthwires on distribution poles, with different materials and design characteristics to the phase conductors;

- Distribution substation clearance issues;
- Use of metal "twisty" connections for house services; and
- RMU fuses catching fire[48].

SKM understands that these issues were not considered or present in the distribution standard designs at the time of the assets being put in service. However, the legacy of these design issues was being addressed in the capital spend during the AA#1 regulatory period. The impact of these design issues also provides a context to Western Power's focus on safety in plant specification discussed in Section 5.3 of this report.

If possible, what impacts on efficiency do the above aspects have in terms of % additional cost (e.g. per substation, per transformer etc)?

SKM does not believe the introduction of standard design drawings for distribution would have a discernable impact on the expenditure on new facilities in the AA#1 period (as design costs make up a small portion of the overall capital expenditure).

Observation 11 SKM's review of Western Power's distribution design standards in the AA#1 period has concluded they are consistent with good electricity industry practice and the requirements of the Code. SKM notes the impact of historic design standards on expenditure in the AA#1 period and the impact the resulting issues may have on Western Power's risk strategy in this area.

[48] These issues have been identified through SKM industry knowledge and public reporting on these issues, no specific reference to these issues was provided to SKM.

5.3. Review of Plant Specifications

5.3.1. Introduction

In addition to the review of designs standards, SKM was requested to review the Transmission and Distribution purchasing specifications for the purchase of plant items for capital projects. The review undertaken for this aspect of the project involved a number of key plant items and associated documentation. Together with the design standards, equipment specifications adopted by Western Power are some of the key drivers for cost of infrastructure together with the cost of labour.

5.3.2. Approach to Review

Relevant documents were reviewed for comparison with similar documents from a range of other utilities to determine differences with national practices. Note that the comparison was not against any identified 'best practice' approach but broadly compared to the range of approaches undertaken in the industry at this period in time.

5.3.3. Scope of the Review

The scope of the review was a number of selected plant specifications.

5.3.4. Documents Reviewed

The plant specifications reviewed are listed in Appendix E.

Procurement specifications are prepared to document the user requirements for plant purchases. These documents are usually developed over a number of years and evolve with input based on operational experience of utilities. Often the specification is first developed based on a particular type of equipment and is adapted as technology changes. One of the dangers of plant specification is to over-prescribe, forcing the supplier market to maintain a certain product line or worse, to reduce the number of suppliers who are able to tender for the overly prescriptive specification.

However, specifications are seen as a risk reduction approach by the purchasing utility and a brief, performance-based approach is considered too much of a risk. From the supplier perspective, this is frustrating as new innovations are difficult to introduce to the market, but from the purchaser perspective, spares-holdings and operations / maintenance practice changes are minimised.

Suppliers accuse purchasers of a lack of innovation but also do not have the responsibility to introduce new plant to the operations and maintenance staff within that organisation and also do not have the responsibility to manage the new equipment over its long life. These factors impact on the cost of infrastructure to maintain the level of reliability required to meet service standards.

5.3.5. Findings

These specific findings of the review of selected plant specifications are provided in Appendix E. In summary, specifications appear to be conservative and robust and in line with good electricity industry practice. Overall, the specifications reviewed appear to be industry standard and, with minor exceptions, are similar to many used in other utilities in Australia.

Observation 12 SKM's position is that the Western Power plant specifications reviewed appear to be robust and in line with good electricity industry practice.

5.4. Procurement Processes

The high level process documentation SKM has reviewed reflects that Western Power has robust procurement processes with the appropriate levels of probity. This conclusion is supported by findings in the GBA Governance report[49] and the Wilson Cook report[50].

5.4.1. Areas Considered in Detail

During our review, SKM identified some internal communications relating to the letting of a preferred vendor (PV) tender for the supply of RMUs in 2008. Through the review of this internal document[51], SKM identified the following areas of concern:

- Western Power reported that it had introduced a "much more rigorous process" for the establishment of distribution equipment, including establishment of a cross boundary team. This is considered good electricity industry practice and is used by many utilities in Australia to reduce the risk that a product is purchased that meets resistance for O&M staff. However, SKM believes that there are risks in not making a fully commercially-based decision as a first priority and the cross boundary team may need to be reviewed to ensure that there is a balance of operational and commercial scrutiny.

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[49] Geoff Brown & Associates Ltd: Review of expenditure governance: Western Power, 14 July 2009, pp 11.

[50] Wilson Cook & Co: Review of Western Power's Expenditures for Second Access Arrangement Final Report, May 2009, pp 66.

[51] [*confidential text removed*].

- [*Confidential text removed*]. Other utilities have accepted the change as minor and have judged that the new series of RMU were in fact superior. The supplier disagrees that the new model is inferior and actually maintains it has more features.
- One of the reasons Western Power listed as a reason for the contract change was the revision to AS 62271-2005 (switchgear standard), which was not reflected in the previous technical specification, and which the (then) current product did not meet. [*Confidential text removed*]. Other utilities have in fact noted the change in standard but have not seen reason to change their current supplier.
- Only three suppliers tendered [*Confidential text removed*] - This is not unusual in Australia. The Western Australian market would be considered an important but reasonably small market.
- [*Confidential text removed*]. SKM has made enquiries after a review of the specification and disagree with this comment in the key safety areas listed.
- The internal presentation indicates that Western Power did not choose the lowest price tenderer. The main criteria listed in the selection criteria was safety compliance.
- [*Confidential text removed*].
- One of the questions raised in the internal presentation was "Why doesn't Western Power use industry standard specs?" SKM believes the Western Power specification to be well within industry standard range.

As a result of the concerns raised by the review of this internal presentation, SKM requested and received from Western Power the following information:

- More detail on the RMU procurement process including extracts from the assessment criteria[52].
- A summary of the major tender processes undertaken during the AA#1 period including the number of complying tenderers and an indication if the lowest tender was selected. This summary is provided in Appendix F.

Based on its review of the additional information requested on the RMU tender process, SKM has determined that a robust procurement process was used and has no outstanding concerns with the establishment of the RMU contract. Western Power used appropriate levels of probity and a robust value-based procurement process was evidenced. Indeed, SKM found that the internal presentation did not accurately reflect the decision-making process associated with the RMU contract decision.

[52] [*Confidential text removed*].

SKM notes that a significant amount of time was consumed in analysing this process that could have been avoided with the provision of appropriate information on the RMU procurement process in the first instance.

With reference to the summary of other major tender processes provided in Appendix F, SKM notes of the 14 major tender processes, only three were not awarded to the lowest tenderers. This position is not indicative of systemic over specification.

Of the three tenders that were not awarded to the cheapest tenderers, one was not awarded to the lowest tender on the grounds of the commercial and technical performance[53]. SKM notes that commercial performance of a major supplier can have a significant impact on the efficiency of a NSP's business processes, particularly the impact of the supply chain on efficient project delivery. The decision regarding commercial performance appears to be based on information procured from other clients and on local experience. The technical performance issue related to the noise performance of the plant and has been justified on the basis of avoided noise mitigation expenditure at the first installation. As part of a probity audited process, SKM is comfortable that this decision has been appropriately justified.

Further, SKM notes that as part of this procurement decision, Western Power capitalised the impact of energy losses to produce an "Assessed Cost". In this significant item of plant, SKM considers this to be a prudent initiative to maximise the "net benefit" to Western Power's customers.

Of the remaining two tenders, the cheapest submission for part of the tender requirements was excluded due to "technical non-compliance". The Tender Recommendations on the contract T50.2004[54] note that the items with the lowest price that were not selected were done so because they did not meet the following specifications:

- The total operate time was 15 ms slower than required.
- The capability of the circuit breaker to successfully interrupt the DC component of the fault current due to poor X/R ratios.

SKM notes that the circuit breaker operation time directly impacts Western Power's ability to meet the Critical Fault Clearing Times (CFCTs) in the Technical Rules. SKM considers that non compliance with the above technical issues was an appropriate basis for removing the circuit breaker tender from further consideration.

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[53] [*Confidential text removed*].

[54] Western Power: Memo- Supply & Delivery of Outdoor Circuit Breakers 1-2D, 21 April 2005 and Western Power: Memo- Supply & Delivery of Outdoor Circuit Breakers, 5 November 2004.

5.4.2. Conclusions from Detailed Consideration of Major Procurement Processes

As a result of some preliminary concerns surrounding the manner in which Western Power applied is specifications in tender processes; SKM has undertaken a detailed review of major Western Power procurement processes where the lowest tenderers were not selected. The results of these reviews confirm the position established by SKM through its broader review of procurement processes, this being that the Western Power procurement processes are robust, with appropriate technical / commercial balance, and a high level of probity. This conclusion is consistent with the findings in the GBA Governance report[55] and the Wilson Cook report[56].

Observation 13 SKM's position is that the Western Power procurement processes are robust, with appropriate technical / commercial balance, and a high level of probity. This is consistent with the findings in the GBA Governance report[53] and the Wilson Cook report[54].

[55] Geoff Brown & Associates Ltd: Review of expenditure governance: Western Power, 14 July 2009, pp 11.

[56] Wilson Cook & Co: Review of Western Power's Expenditures for Second Access Arrangement Final Report, May 2009, pp 66.

6. Benchmarking

6.1. Network Performance Benchmarking

Western Power's service performance is monitored and reported annually in accordance with the Electricity Networks Access Code 2004[57]. SKM has compared the Reliability Performance, in particular the SAIDI and SAIFI of Western Power with all of the DNSPs in the NEM:

Victoria

- Alinta AE
- Citipower
- PowerCor
- SP AusNet
- United Energy

New South Wales

- Energy Australia
- Integral
- Country Energy

Tasmania

- Aurora

South Australia

- ETSA

ACT

- ActewAGL

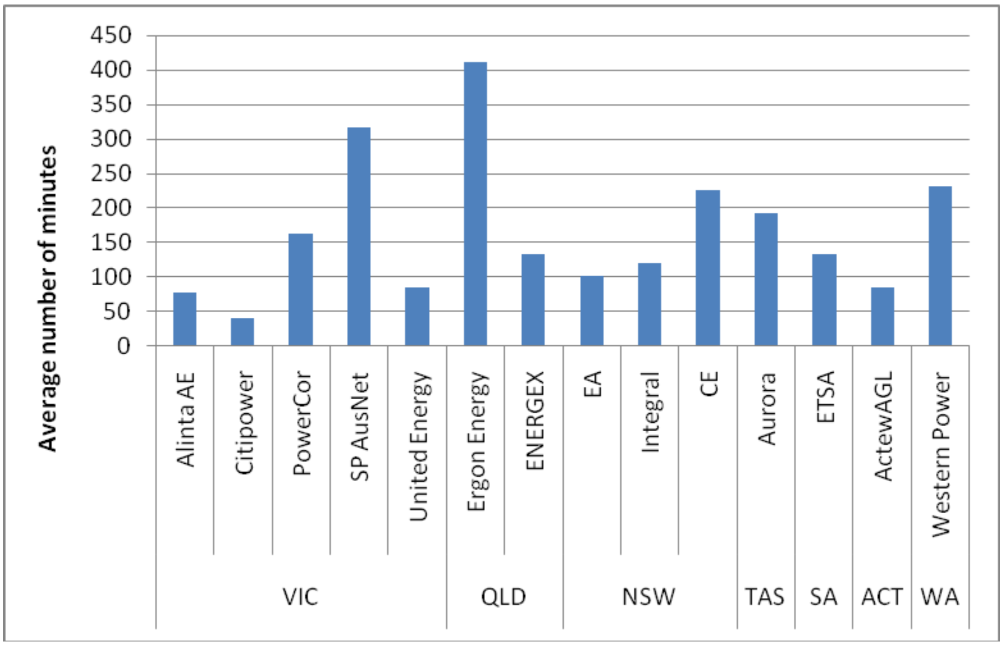
Queensland

- Ergon
- ENERGEX

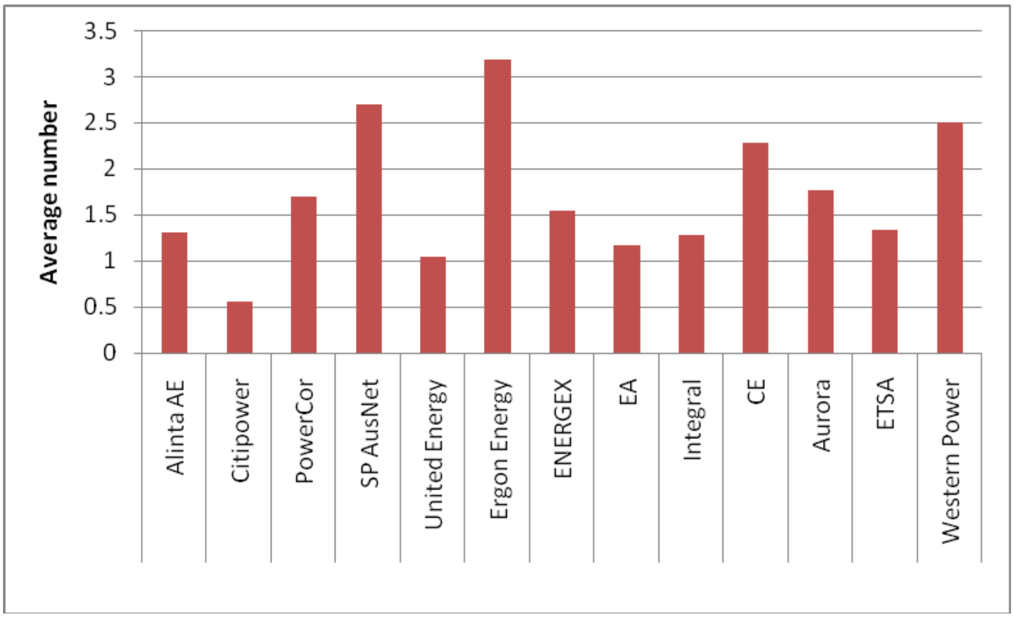
The results of the comparative analysis of the service performance for Australian Distributors for 2007/08 are shown in Figure 1 and Figure 2 (overleaf).

Western Power's SAIDI was 230 minutes for 2007/08 compared to a numerical average of 159.6 minutes and its SAIFI was 2.50 compared to an average of 1.65 for the DNSPs in the NEM. Its performance is better than SP AusNet (316.0 SAIDI, 2.69 SAIFI) and Ergon Energy (411.0 SAIDI, 3.18) and comparable to Country Energy (225 SAIDI, 2.28 SAIFI) and Aurora (192 SAIDI, 1.76 SAIFI) for the same year.

[57] Western Power: Access arrangement service standard report: financial year ending June 2008, 28 October 2008.



- **Figure 1: SAIDI Statistics for Australian Distributors**



- **Figure 2: SAIFI Statistics for Australian Distributors**

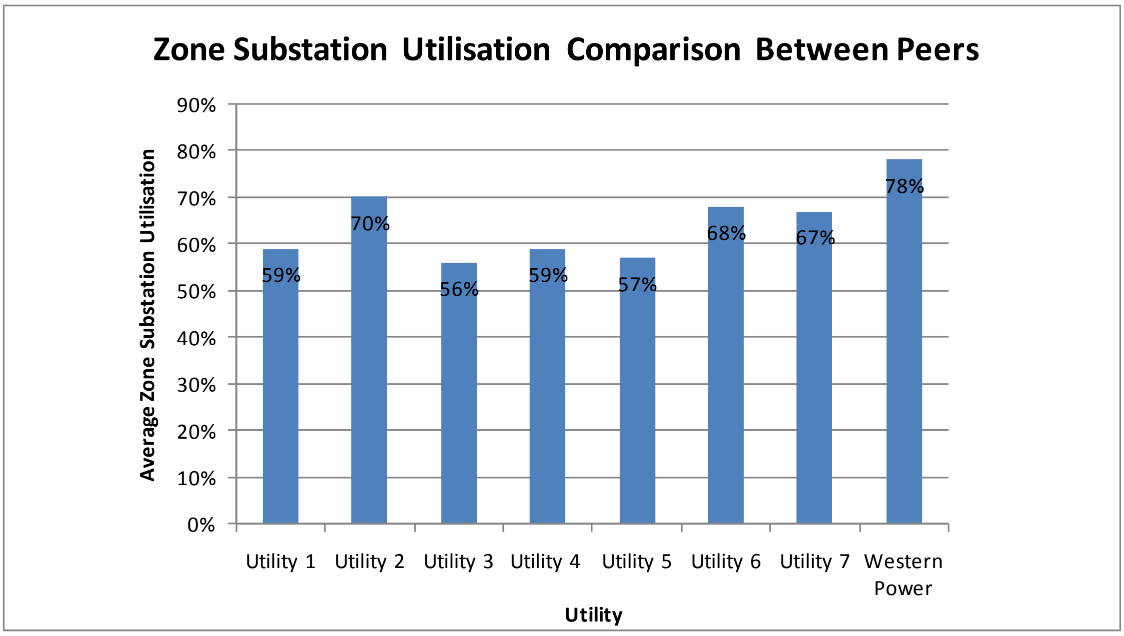
Western Power has a large rural and metropolitan network in addition to servicing the Perth CBD and the network is larger than the average size for the DNSPs in the NEM in terms of energy delivered (GWh), customer numbers and network length. Its mixture of urban and rural coverage, combined with a relatively low density (customer per kilometre) provides particular challenges for achieving reliability and service quality targets.

SKM also notes that Western Power has a below average proportion of underground cable as a proportion of total network kilometres (i.e. of underground plus overhead circuit kilometres) compared to the other DNSPs. Generally speaking, a higher share of underground cable will improve reliability and maintenance costs but adds to capital cost per kilometre.

When the above are taken into consideration in terms of service performance, Western Power is performing as well as, and in some cases better than, its peers in the NEM.

6.2. Comparative Utilisation of DNSPs

Figure 3 demonstrates Western Power's zone substation utilisation at the beginning of the AA#1 period in contrast to seven other Australian utilities.[58] Western Power's utilisation is above that of other comparable utilities.



- **Figure 3 Zone Substation Utilisation Comparison between Peer Utilities in the NEM**

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[58] Due to confidentiality requirements, the names of the utilities and the source of this data have been withheld from this report.

> Observation 14
>
> Western Power's network performance appears appropriate given its areas of operation. However, the utilisation of the Western Power network is likely above that considered good electricity industry practice. This situation will require on-going investment to rectify.

6.3. Performance of Other Capital Intensive Projects

Figure 4 shows the magnitude of cost overruns on resource projects during the period 2006 to 2008 and demonstrates the challenges experienced by other capital intensive projects during the AA#1 period. Figure 5 provides a similar presentation for Western Power projects with a value in excess of $10 million approved in a similar period. A comparison of these two figures demonstrates that Western Power's performance during this period of high project cost escalation is better than that in the broader industry.

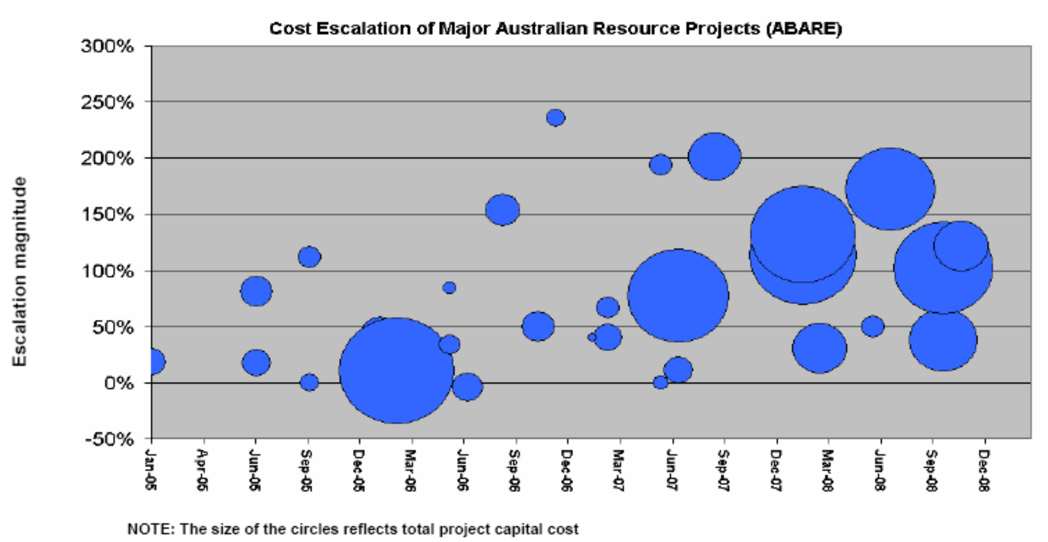

Figure 4: Cost Overruns in Resource Projects in WA during the AA#1 Period[59]

[59] Source ABARE Economics

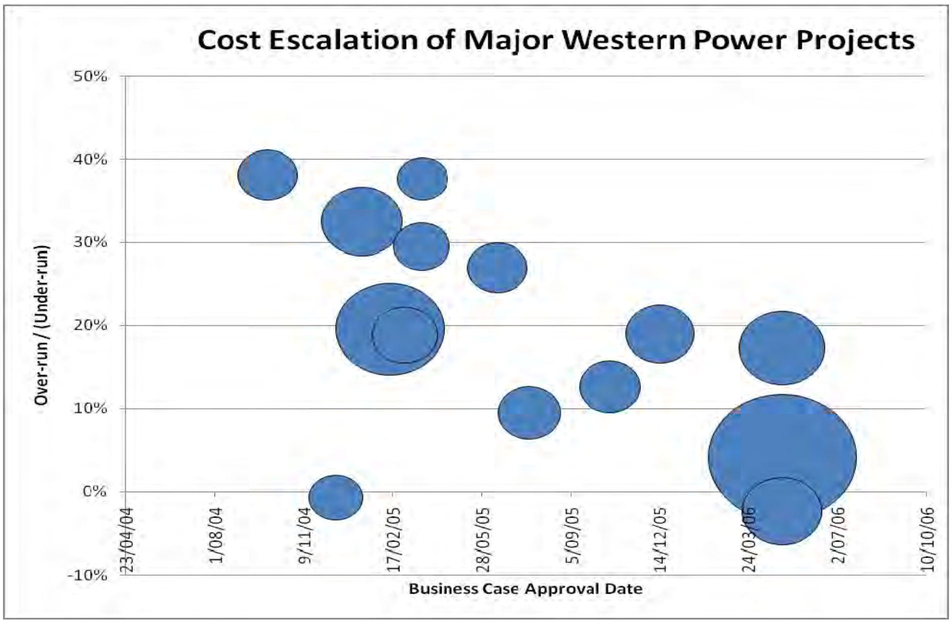

Figure 5: Cost Overruns in large Western Power Projects (greater than $10 million expenditure) during the AA#1 Period[60,61]

> Observation 15
>
> The cost overruns on Western Power's major projects during the AA#1 period are better than that in the broader industry for the same period.

6.4. Distribution Market Price Survey

Western Power participated in the Distribution Market Price Survey No. 4 undertaken by SKM. At the time of issue of this report only preliminary results from this survey were available for review and the following discussion is based on these preliminary results of this study.

6.4.1. Introduction to the Distribution Market Price Survey

SKM conducted previous Distribution Market Price Surveys, in 2001, 2002 and 2003, and in 2006 undertook a multi-utility procurement study designed to understand and assess the impact of

[60] For the purpose of this chart cost over-run is defined as (Delivered Cost - Original Approved Estimate) / Delivered Cost.

[61] Projects that underwent significant scope change subsequent to the original approval have been excluded from the chat.

commodity prices on the contract prices for finished goods such as power transformers, conductor, cable, poles, etc.

The Distribution Market Price Survey typically provides insights regarding:

- The participants own internal costing procedures;
- Differences in design, construction practices, and equipment specifications that result in different pricing outcomes;
- How their estimated unit rate costs compared with general industry costs for capex and opex unit rates;
- How their actual equipment and material contract prices paid compared with the general industry cost curve for that item of equipment / material;
- The trends in costs over time, particularly during, what was at the time thought to be the peak of the boom in commodity prices from 2002 to 2006; and
- The impact that contract types, contract conditions, volumes and technical / commercial specification requirements may have on the prices paid for strategic items of network equipment.

6.4.2. Scope of the Distribution Market Price Study

The study consisted of separate parts.

PART 1: Contract Prices for Equipment / Material

In this part of the survey, SKM collected actual contract price information that the participants paid for the supply and delivery of their most commonly used range of equipment / materials. SKM sought prices paid over the period 2005/06 to 2007/08, which will provide a continuous price trend over the period 2002 to 2008.

PART 2: Estimated / Actual Unit Rate Prices for a Range of Capital Works

In this part of the survey, SKM collected information about the market prices for a sample range of capital works unit rates such as 1 km of HV/LV overhead network, 1 km of HV/LV underground network, distribution transformers, etc. These market prices included all material, labour, transport and overhead costs and are prepared against a brief standard specification.

PART 3: Estimated / Actual Unit Rate Prices for a Range of O&M Activities

In this part of the survey, SKM collected information about the market prices for a sample range of typical O&M activities such as pole inspection, pole replacement, service replacement, etc. Different prices have been obtained for urban and rural situations. These market prices included all material, labour, transport and overhead costs and were prepared against a brief standard specification.

6.4.3. Observations from Preliminary Results of the Distribution Market Price Survey

Comparing the raw data received through the Distribution Market Price Survey for items that allow direct comparison has yielded the following observations:

- The price paid by Western Power for 6 kN wood poles, 22 kV voltage regulators and ground mount transformers is materially higher than the one point of comparison available at this time. It is likely that this difference is a function of the remoteness of the Perth market and associated transport costs but these impacts have not yet been quantified.
- The price paid by Western Power for circuit breakers (11 kV / 22 kV), bare conductor (19/3.25 Neptune), and 24 kV gas reclosers is within 3% of a single point of comparison between that of other respondents where multiple comparisons were available.
- The price paid by Western Power for air break switches is materially lower than that of the two points of comparison. Initial analysis suggests this is a function of the volume purchased by Western Power and the country of purchase (Australian purchase by Western Power).
- Western Power had the lowest installed cost of cable in urban areas and the second lowest installed cost of 22 kV transformers in urban areas of the 4 comparable respondents.
- The cost to Western Power of installing overhead and underground infrastructure in regional areas was materially higher than the two other comparable respondents.
- Any detailed conclusions from the Distribution Market Price Survey will require further data normalisation. However, analysis of the preliminary results has not identified any systemic issues with the Western Power procurement or construction processes. This is consistent with the detailed reviews of specifications and procurement processes in sections 5.3 and 5.4 of this report.

Observation 16
The analysis of the preliminary results of the distribution market price survey has not identified any systemic issues with the Western Power procurement or construction processes.

6.5. Benchmarking of Selected AA#1 Projects against SKM Regulatory Valuation Database

6.5.1. Introduction

As part of this review, SKM has undertaken a Benchmarking of ten (10) projects. The complete report on this benchmarking process is provided in Appendix C. This section of this report seeks to summarise the finding of this benchmarking process.

6.5.2. Summary of Findings

Based on the information available, SKM has been able to conduct a high level assessment only. The accuracy, or reasonable, range for variance between the two estimates was nominated by SKM as ±20%. Whilst this level of accuracy generally relates to budgets, and this review related to completed projects, the information and time available allowed for the level of confidence. The result of the Benchmarking process for the 10 projects is provided below.

Project	Western Power Actual Costs ($M)	SKM Estimate ($M)	Variance[62]
[*Confidential text removed*]	25.9	21.9	-18.3%
Bibra Lake Zone Substation	10.9	9.7	-11.01%
[*Confidential text removed*]	92.2	89.1	-3.4%
Joel Terrace Conversion	9.9	10.8	8.4%
[*Confidential text removed*]	8.6	8.6	0.0%
Wembley Downs Substation Upgrade	4.7	3.9	-19.5%
Advanced Metering Infrastructure Pilot*	5.8	6.0	3.4%
Meter Asset Replacement	8.2	10.1	18.7%
Overhead Customer Service Replacements	35.1	29.5	-19.0%
Overloaded Distribution Transformer Replacements	17.9	18.3	2.3%
TOTAL	**219.2**	**207.9**	**-5.16%**

For the projects reviewed, SKM found that the aggregated comparative estimates produced by SKM were 5% less than the Western Power expenditure, which was well within the range nominated for reasonable accuracy. In some instances, SKM considered that there may have been additional costs involved in the actual expenditure which were either unclear in the scope of works

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[62] Variance calculated as (SKM Estimate – Western Power Actual) / Western Power Actual.

(such as undefined lengths of line) or potential costs associated with environmental issues. Through the benchmarking process, SKM cannot identify any apparent systemic issues that would contribute to consistent sub-economic project outcomes. From discussions with representatives from Western Power, SKM is satisfied that the underlying causes behind the variations between the SKM comparative estimate and the actual expenditure incurred can be sufficiently identified.

Observation 17

For the projects reviewed, SKM found that the aggregated comparative estimates produced by SKM were 5% less than the Western Power expenditure, which was well within the range nominated for reasonable accuracy. Through the benchmarking process, SKM cannot identify any apparent systemic issues that would contribute to consistent sub-economic project outcomes.

7. Detailed Review of Selected Projects

A separate report on the detailed review of 7 selected projects is provided in Appendix D, this section provides a summary of the scope and findings of this report.

7.1. Scope of Detailed Review of Selected Projects

The detailed review focussed on the following 7 projects, these projects were selected as a cross section of projects considered by the GBA AA#1 Project Report and the GBA Governance Report.

- [*Confidential text deleted*]
- Pinjar to Wanneroo 132kV Line
- SHO – KEM 91 Stringing 2nd side
- Distribution Transformer Replacement & LV Network Reinforcement 07/08
- North Country 330kV Reinforcement
- Establishment of Waikiki Substation
- Establishment of Bibra Lake Substation

The scope was to review information provided on these selected projects to determine whether the projects had been delivered in an efficient manner, consistent with the key processes identified in section 3.3 of this report being:

- Cost estimating;
- Options Analysis;
- Approvals processes;
- Efficiency of Engineering Solutions;
- Procurement; and
- Project or Works Management.

7.2. Summary of Findings of the Detailed Review of Selected Projects

The summary of the findings of the detailed review of selected projects is provided under each of the key processes reviewed.

7.2.1. Cost Estimating

SKM found that the cost estimating process was appropriate in four of the seven projects reviewed. For two projects, SKM concluded insufficient information was provided to form a view on the effectiveness of the cost estimating process. For two projects, SKM concluded the cost estimating process was not optimally implemented.

7.2.2. Options Analysis

For all the projects reviewed multiple options were considered and of the options considered the most appropriate appears to have been selected. SKM has identified there is room for improvement in the presentation and discussion of options in the approvals documentation.

For the Bibra Lake substation, SKM had some concern with the way the forecast that underpinned the project was presented in the Business Case. This concern resulted in further investigation into the forecasting process. This investigation identified that block loads had been separately considered in the load forecast although SKM could not identify the process that was followed to achieve this. SKM confirmed that the load forecasts that underpinned the project were conservative in comparison to the actual resulting loads in the area.

SKM notes that with the exception of the North Country 330 kV reinforcement t, the consideration of a demand side management option has not been included on most projects. However, SKM notes many of these projects were designed before the current thinking in the electricity industry to consider the viability of demand side management.

7.2.3. Governance / Approvals Processes

SKM found that appropriate approvals processes were followed for all of the projects reviewed with the exception of:

- the establishment of Waikiki substation for which there was a lack of appropriate information to reach a position on this issue; and
- the Bibra Lake substation for which a $1 million change order did not get reflected in the approved expenditure for the project and the original project approval documentation poorly reflected the options considered. The resulting reduction in the CPA value would have resulted in this project being delivered with a 10% over-run.

7.2.4. Efficiency of Engineering Solutions

There was limited information to make detailed conclusions on the effectiveness of the engineering solutions employed. However, the major and visible engineering decisions appear consistent with good electricity industry practice.

7.2.5. Procurement

No material issues were identified in the projects reviewed that indicated the procurement processes undertaken by Western Power would result in sub economic project outcomes.

7.2.6. Project or Works Management

SKM has identified no significant concerns with the application of Project and Works Management processes to the projects reviewed that have proceeded to a stage that Project or Works Management processes are relevant. The major exception to this is the transformer replacement project, for which SKM could not identify any details on the project management processes employed on the project.

7.3. Comments on Quality of Information

SKM has identified a range of issues on the suitability of the project specific data provided by Western Power as the basis for external review. This is consistent with the findings of GBA and Wilson Cook. The impact of the issues with data quality is difficulty in arriving at an accurate position in the key areas that adequately demonstrate efficiency in capital investment delivery. ERA Governance Review presentations summarising each project were found to be quite helpful but without a complete set of relevant and accurate supporting documentation, it is often difficult to identify the processes and decisions made to justify and efficiently deliver the new facilities investment for each project. The issues raised with the project specific data apply only to the data outlined in Attachment A of Appendix D of this report.

> Observation 18
>
> The detailed review of specific projects confirms that Western Power has been implementing key processes in an appropriate manner with the exception of cost estimating. SKM found that four of the seven projects reviewed did not have effective cost estimating processes and a $1 million dollar change order for Bibra Lake that was not reflected in the approved capital expenditure. Through its detailed review of the selected projects, SKM has raised concerns with the form of the data available from Western Power for application to external review.

8. Comparison to the Regulatory Regimes in the NEM

8.1. Discussion on Regulatory Process in the NEM

The Regulatory Test under the National Electricity Rules (NER) has 2 limbs:

1) the augmentation limb; and

2) the reliability limb.

Under the augmentation limb, projects above $10 million must be submitted for a regulatory test and public consultation process, and must include an assessment of cost of options and market benefits. Other projects, including projects required to meet all their regulatory and statutory obligations (including licence conditions, safety, environmental, etc) do not require a market benefits test. Up until the present, this has mainly affected the TNSPs and a handful of the larger projects for the DNSPs.

The Australian Energy Market Commission (AEMC) is planning on implementing a standardised national framework for the DNSPs, covering Annual Reporting of Planning Processes and Projects, and the introduction of a Regulatory Investment Test for Distribution (RIT-D). The threshold cost for projects requiring them to undergo the RIT-D is expected to be $2.0 million.

8.1.1. Safety and reliability obligations under NER

The Regulatory Test under the NER excludes any mandated security/ safety / reliability obligations and also excludes refurbishment / replacement projects from the market benefits test. The reason for this is that the Net Present Value (NPV) analysis for such projects will always be negative, and there is no potential for non-network solutions to be found that will solve the problem of ageing assets.

South Australia and Victoria presently have bonus / penalty schemes in place based on the reliability of their networks; the Service Incentive Scheme and S-factor regime respectively. NSW has a "paper" trial for DNSPs which has a target to be achieved by 2012 but does not impact on their revenues at present.

8.1.2. Information requirements

While it is not uncommon for regulators to be concerned that they have not been provided with sufficient information to support a regulatory proposal, the Australian Energy Regulator (AER) and the ACCC "coach" the TNSPs and the DNSPs with regard to their informational requirements often up to the 12 months leading up to a determination. They achieve this by preparing and

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issuing pro-forma spreadsheets for the data they require from the TNSPs and the DNSPs, issuing discussion papers, asking for and facilitating comments from the parties. In this way there is a clear understanding on what information is required in the regulatory proposal and any revised proposals are prepared on the basis of new information which may not have been available when the original proposal was submitted.

8.2. Regulatory Outcomes under the NER

8.2.1. New South Wales distribution determination (capex)

The AER recently published[63] its determinations on the distribution services for the period 1 July 2009 to 30 June 2014 provided by the New South Wales (NSW) distribution service providers (DNSPs):

- Country Energy;
- Energy Australia; and
- Integral Energy.

In making its determination, the AER was assisted by Wilson Cook who reviewed the performance and operating requirements of the NSW DNSPs.

In its draft decision, the AER confirmed the need for substantial increases in capital works for each of the NSW DNSPs over the next regulatory control period. The AER further found in its draft determination that:

- Country Energy's proposed capex was $163 million[64] greater than an efficient level. The AER's draft determination amounts to a 4.1 per cent reduction in the proposed capex. In its revised submission Country Energy provided revised non–system land and buildings capex and updated material and labour cost escalators to reflect the latest available information, which was accepted by the AER.
- Energy Australia's proposed capex was $465 million greater than an efficient level. The AER's draft determination amounts to a 5.6 per cent reduction in the proposed capital expenditure. After considering the information in the revised regulatory proposals, the AER approved Energy Australia's revised zone substation capex.

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[63] Australian Energy Regulator New South Wales distribution determination 2009-10 to 2013-14: Final decision, 28 April 2009.

[64] $2008-09

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- Integral Energy's proposed capex was $13 million greater than an efficient level. The AER's draft determination amounts to a 0.5 per cent reduction in the proposed capex. This was accepted by Integral Energy.

The AER's final determination approved a capex allowance of $14.4 billion for the NSW DNSPs, which was 6.0 per cent less than that provided for in the draft decision. The reduction in the approved capex allowance in part reflected the impact of slower economic growth and an expected slowing in the growth of maximum demand.

8.2.2. Actew AGL distribution determination (capex)

The Australian Energy Regulator (AER) recently published its determination[65] on the distribution services for the period 1 July 2009 to 30 June 2014 provided by ActewAGL.

The AER had engaged Wilson Cook to undertake the technical assessment and to advise it on a number of aspects of ActewAGL's regulatory proposal.

The AER confirmed its draft decision that all of ActewAGL's capex in the current regulatory control period was prudent and that the projects and programs undertaken were required, efficient and consistent with ActewAGL's policies and good electricity industry practice. The AER also considered the total amount of $156.2 million in past capex was prudent and should be included in the opening RAB.

This final decision approved a capex allowance of $275 million. Updated material and labour cost escalators, to reflect the latest available information, were also included in the AER's final decision. After considerations to the revised labour and materials cost escalators, the capex allowance was 0.7 per cent lower than that approved in AER's draft decision.

8.2.3. ElectraNet's SA determination (capex)

The Australian Energy Regulator's (AER's) final determination [66] on the transmission services for the period 1 July 2008 to 30 June 2013 provided by ElectraNet SA was given on the 11 April 2008.

The AER engaged SKM as a technical specialist to advise the AER on a number of key aspects of ElectraNet SA's original revenue proposal. In terms of the capex, the AER asked SKM to provide its opinion on:

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[65] Australian Energy Regulator. Australian Capital Territory distribution determination 2009-10 to 2013-14. 28 April 2009.

[66] Australian Energy Regulator: ElectraNet transmission determination 2008-09 to 20112-13, 11 April 2008.

- whether the investment processes and procedures adopted by ElectraNet SA for capex were likely to result in efficient outcomes;
- the prudence of capex undertaken by ElectraNet SA during the current regulatory period;
- the adequacy, efficiency and appropriateness of the capex projects planned by ElectraNet SA to meet its present and future service requirements; and
- the effectiveness of ElectraNet SA's operating practices and procedures and asset management system.

In its May 2007 (original) revenue proposal, ElectraNet SA's forecast capex proposal was $778 million[67]. In the draft decision, the AER reduced this to $606 million. In the draft decision, the AER considered that ElectraNet SA's expenditure over the current regulatory period was prudent and within the approved level of expenditure. However, ElectraNet SA's capital expenditure (capex) assessment and project governance processes—particularly in the early years of the current regulatory period—did not represent best practice, although they were considered to be adequate for the modest capital works program that existed at the time. ElectraNet SA recognised the problem with the management of its capital works program and subsequently introduced improved processes, which have led to ElectraNet SA identifying the need for significant refurbishment of its network. As a consequence, ElectraNet SA undertook a greater level of refurbishment during the latter part of the current regulatory period than was anticipated when its current revenue cap decision was made in 2002.

Following the AER draft decision, ElectraNet SA revised its forecast capex proposal to $719 million. This represented a reduction of around 11 per cent of ElectraNet SA's revised forecast Capex allowance. While this revised forecast reflected some of the adjustments made in the AER's draft decision, ElectraNet SA also included revised forecasts for specific projects where the AER had concluded in the draft decision that it was not satisfied with the project scope and estimates. Taking into consideration the additional information provided by ElectraNet SA in its revised revenue proposal, the AER has approved a forecast capex allowance of $650 million for ElectraNet SA over the next regulatory control period. In addition, the AER has provided an indicative contingent project allowance of $894 million. In reality the actual reduction in capex was less than 1% with one major project in ElectraNet SA's proposal removed from the approved capex and added to the contingent project allowance.

This amended allowance represents the AER's estimate of the total capex that a prudent operator in the circumstances of ElectraNet SA would require to achieve the capex objectives.

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[67] $2007/08

8.2.4. Comments on precedents for regulatory write-down of Capex in the NEM

In recent years, including the latest AER determination in NSW, the AER tends in the final analysis to accept most project related capex expenditure proposed by DNSPs, and any reduction is normally accounted for under several categories or headings (e.g. reduced escalation factors, reduced growth assumptions, efficiency of project costs, IT capex, etc). Wilson Cook report[68] into its review of the proposed expenditure of ACT & NSW Electricity DNSPs is an example of how the AER analyse and account for reductions. In the examples that have been reviewed, the amount of the reduced capex has been small.

The majority of DNSPs in the NEM outsource a significant percentage of their capital projects, and where they do not, they obtain independent estimates from engineering consultancies. This means that if DNSPs don't have competitive prices for project work, they at least have independent cost estimates and are able to demonstrate that the projects meet the "efficient" criteria under the NER.

Since taking over the regulatory role in the electricity sector from the ACCC, the AER has not challenged to date either the prudency or efficiency of past capital projects when they are included in the DNSPs asset base. The only case that SKM is aware of where the actual cost of a DNSP project was challenged by the regulator (then the ACCC) in the NEM, (and the full cost not allowed to be included in the asset base), was the Haymarket 330/132 kV substation upgrade project (a joint TransGrid / Energy Australia project). The main contributing factor for this decision by the ACCC was that there had been significant changes to the project scope resulting in an increase in costs and that the revised project had not been submitted to the regulatory test. The ACCC reasoned that as a result of the way in which the project had developed, it had been subject to poor governance practices and not been developed in an efficient manner.

8.3. Victorian Experience

The Office of the Regulator-General (ORG), Victoria released its price determination for the 5 Victorian DNSPs on 26 September 2000. The then new price controls regulated the charges to be levied by the 5 Victorian DNSPs for electricity distribution services from 1 January 2001 to 30 December 2005.

This Price Determination represented the first electricity distribution price determination made under the legal and regulatory framework established by the Victorian Government prior to the privatisation of the distributors in 1995.

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[68] Wilson Cook & Co. Re: Review of proposed expenditure of ACT & NSW Electricity DNSPs: Energy Australia's submission of January and February 2009. Letter to the Australian Energy Regulator dated 31 March 2009.

In reaching its determination, the ORG undertook an extensive consultation process which commenced in June 1998. There were appeals on the Price Determination by the ORG from 4 of the 5 DNSPs and also a court challenge in 2001 by one of DNSPs.

Mindful that this decision also represented the first determination of its type made under a price based regulatory regime in Australia, the ORG approached the price review with careful attention to the Victorian legislative framework. The ORG also made some high-level observations about the implications of this Determination for future regulation. The following extract was written by the ORG and is quoted from its executive summary[69] on the electricity distribution price determination:

..."Whilst any regulatory framework can be expected to evolve over time as circumstances change, and as the experience and insight of both businesses and regulators matures, a vitally important function of this Price Review has been to lay the groundwork for future regulation. By setting out clearly the principles it has applied and the reasons for them, the Office intends to provide greater certainty and stability about the future regulatory environment. The Office's decisions made in the course of this Price Review cannot pre-empt future regulatory decisions. Nevertheless, the elaboration of regulatory principles, approaches and incentive mechanisms that has occurred in the context of this review and Determination provides a more certain framework for the future investment, operating and financial decisions of the distributors, and for the commercial and consumption decisions of customers"...

From this, the ORG recognised that with its first price determination it was expected that there would be a degree of uncertainty in how the regulatory framework would be applied and that the experience gained would benefit both the regulator and the DNSPs in future price determinations by providing a greater level of confidence for future investment decisions.

[69]Office of the Regulator-General, Victoria: Electricity distribution price determination 2001-05: Highlights and executive summary, September 2000.

Observation 19

For DNSPs and TNSPs operating in the NEM and now entering their second and third round of price determinations, procedures have been developed so that there is a clear understanding on the information that is required to support their capex proposals.

Wilson Cook has undertaken four regulatory reviews of NSPs for the AER over the past 18 months and these reports show how capex is assessed for prudency and efficiency under the NER.

Capex submissions made by NSPs under the NER are ex ante with reductions arising from price determinations in approved capex being less than 5%. There has been no challenge on either the prudency or efficiency of past capital projects.

9. Summary

Throughout SKM's assessment whether the capital projects subject to review would be expected to meet the criteria of "efficiently minimising costs" under the NFIT, SKM has made a number of observations on Western Power's key processes of cost estimating, options analysis, governance / approvals processes, efficiency in design, procurement, and project / works management processes employed by Western Power to deliver its projects. These observations have been listed in our analysis contained in this report and have been used in reaching the conclusions and quantifying the amount of expenditure which SKM believes was "inefficient" during the AA#1 period.

The "Efficiency Limb" of NFIT refers to investments made by a "service provider efficiently minimising costs". For assessing the "efficiency" of planned network developments, SKM believes that significant weight should be given to the service provider being able to demonstrate sound engineering capability and judgement as well as the effectiveness of business processes in the context of "good electricity industry practice" under comparable conditions and circumstances.

In SKM's view, the "Efficiency Limb" of the NFIT is not designed to find the minimum cost solution for each new facility at every stage of every project to develop and construct or otherwise acquire the new facility. Rather, it ensures that an NSP is engaging in a process to efficiently minimise the costs in its business operations, and through a process of continuous improvements, brings about efficient investments. In the electricity industry, business practices must adapt to changes in the external environment including the commercial and technical practices of the broader industry and changes in technology, particularly in the context of an NSP operating and maturing in a relatively new regulatory environment.

The two main factors for the proposed 15% "inefficiency factor" in the Draft Decision are:

- the presence of "systemic over-engineering of capital projects"[70] within Western Power; and
- deficiencies in the planning and governance of capital work, including inadequate consideration of options, and poor control and contract management for capital management programs.

The basis of the proposed 15% reduction was based largely on the reports provided by GBA to the Authority.

[70] Clause 603 of the Draft Decision.

In this report, SKM has focussed on key processes relevant to the factors identified by the Authority as contributing to the 15% "inefficiency factor" and the information that the Draft Decision refers to in establishing these factors.

Our review has been based around four of Western Power's policies, information and processes, being:

- Western Power's design standards;
- Western Power's planning policies;
- key Western Power's plant specifications;
- Western Power's procurement processes; and

a critique of the finding of the reports referenced in the Draft Decision.

To determine the effectiveness of Western Power's application of key processes, SKM has undertaken the following analysis:

- A benchmarking of Western Power's network performance and comparative utilisation against that of other DNSPs.
- A benchmarking of the cost escalation of Western Power's major projects against that experienced by other projects during the same period.
- A benchmarking of the prices paid by Western Power for distribution related products and services against other DNSPs.
- A benchmarking of selected AA#1 projects against SKM's regulatory valuation database.
- A detailed review of the efficiency of the key processes in selected projects.

Finally, to provide context to the Western Power AA#2 Access Arrangement submission, SKM undertook a review of recent regulatory decisions relating to TNSPs and DNSPs in the WEM.

This summary draws together the observations from the above analysis under each of the key processes identified by SKM to be considered whether the new facilities investment meets the efficiency limb of the NFIT and discussed in section 3.3.

Cost Estimating

SKM has found that the Western Power estimating process was behind good electricity industry practice at the beginning of the AA#1 period but it has now improved to being considered good electricity industry practice. This is consistent with the findings of the GBA Governance report.

SKM does however note that cost overruns on Western Power's major projects during the AA#1 period are consistent with, or better than, that in the broader industry in Western Australia for the same period.

The detailed project review identified concerns with the cost estimating of one out of the seven projects reviewed and could not identify sufficient data to provide a position on another two.

Options Analysis:

SKM noted the conclusions of the Wilson Cook report that "*The scope and prudence of Western Power's capital expenditure for (FY 2007 to FY 2009) is accepted. However, no opinion is formed regarding the cost effectiveness as there was a lack of information provided.*"

SKM does not share the concerns raised in the two GBA reports referenced in the Draft Decision pertaining to:

- Demand Forecasting and Temperature Sensitivity.
- 132 kV Conversion instead of the lower cost 66 kV option.
- The NCR windback program.

Through its review of Western Power's planning processes, SKM has identified some minor inconsistency in the priority of drivers between internally referenced planning criteria and the Code. However, SKM would contend that the processes outlined in Western Power's planning documentation that SKM reviewed are consistent with good electricity industry practice. Further, SKM would make the case that the 66 kV to 132 kV conversion policy is consistent with good electricity industry practice but would recommend that there is more engagement by Western Power with the Authority and other stakeholders around such specific planning policies.

In the detailed review of selected projects' Options Analysis, SKM noted multiple options were considered for each option and the most efficient of these options appears to have been selected.

Governance / Approvals of Capital Spend

SKM did not undertake any specific reviews of the approval processes within Western Power. In its detailed review of the implementation of selected projects during the AA#1 period SKM found that appropriate approvals processes were followed in the majority of projects reviewed with the exception of:

- the establishment of Waikiki substation for which there was a lack of appropriate information to reach a position on this issue; and
- the Bibra Lake substation for which a $1 million change order did not get reflected in the approved expenditure for the project and the original project approval documentation poorly reflected the options considered. The resulting reduction in the CPA value would have resulted in this project being delivered with a 10% over-run.
- On the basis of the information provided, the reconciliation process for the Transformer replacement program appeared lacking given the approvals process employed. Specifically, this project was in effect three separately approved programs over three consecutive years. However, these programs were reconciled collectively and this reconciliation illustrated a significant overrun.

Efficiency of Engineering Solutions

SKM does not share the concern raised in the GBA AA#1 projects reports pertaining to Undergrounding of Distribution Systems under Transmission Lines. SKM maintains this policy is consistent with good electricity industry practice.

The review of the transmission and distribution design standards within Western Power observed:

- The review of substation design standards for Western Power indicates that the Code objectives for economic efficiency in investment and cost of operations are embodied in design standards.
- Substation design standards were broad and covered the majority of electrical infrastructure in the Western Power network. The standards were compared to practices used in other jurisdictions in Australia and found to be generally consistent with no material differences that would significantly affect cost of infrastructure in WA. Some minor regional differences were noted.
- A number of issues have been identified in Western Power's substation design standards that may marginally increase the initial capital cost of establishing new facilities. For all of the issues identified, SKM considers this additional investment to be part of an efficient process to establish new facilities.
- SKM's review of Western Power's transmission design standards in the AA#1 period has concluded that they are consistent with good electricity industry practice and the requirements

of the Code. SKM notes an area for improvement that Western Power should incorporate into its transmission line design processes in the near future.

- SKM's review of Western Power's distribution design standards in the AA#1 period has concluded they are consistent with good electricity industry practice and the requirements of the Code. SKM notes the impact of historic design standards on expenditure in the AA#1 period and the impact the resulting issues may have on Western Power's risk strategy in this area.

These observations are supported by the detailed project reviews that concluded that the engineering solutions implemented appeared to be consistent with good electricity industry practice at the time the projects were designed.

Procurement

SKM's position is that Western Power's current procurement processes are robust, with appropriate technical / commercial balance, and a high level of probity. This is consistent with the findings in the GBA Governance report[53] and the Wilson Cook report[54]. Further, the Western Power specifications appear to be conservative and robust and in line with good electricity industry practice. This is supported by the preliminary results of the Distribution Market Price Survey that has not identified any systemic issues within the Western Power procurement processes.

The detailed review of specific projects found that, for the projects reviewed, the procurement processes applied were generally consistent with good electricity industry practice.

Project or Works Management

SKM does not share, nor could it confirm, a factual basis of the concern raised in the GBA AA#1 Projects report pertaining to failure of Western Power to hold IP of the required transmission design solutions.

SKM observes that at the beginning of the AA#1 regulatory period it is reasonable to assume the contractor overcharging for distribution works, identified at 3.5% of internally funded distribution works, was still occurring. Procedures are now considered sufficiently robust to detect and address any contractor overcharging. This is consistent with conclusions in the GBA Governance report.

Overall Project Performance

In addition to the observations above, the benchmarking processes undertaken by SKM found the following.

For the selected AA#1 projects benchmarked against SKM's regulatory ODRC database, SKM found that the aggregated comparative cost estimates produced by SKM were 5% less than the Western Power actual expenditure, which is within the range nominated for reasonable accuracy.

Through the benchmarking process, SKM did not identify any apparent systemic issues that would contribute to consistent sub-economic project outcomes.

The cost overruns incurred on Western Power's major projects during the AA#1 period are consistent with, or better than, the increases in project costs that were experienced by the broader industry in Western Australia over the same period.

Overall Performance

During a period of very high growth, the Western Power network performance appears appropriate given its areas of operation. However, the utilisation of the Western Power network is higher than that which is considered` good electricity industry practice. This situation will require ongoing investment to rectify.

Regulatory Context

For NSPs operating in the NEM and now entering their second and third round of price determinations, procedures have been developed so that there is a clear understanding on the information that is required by NSPs to support their capex proposals.

The largest reduction imposed by the AER on ex ante capex submissions made by NSPs under the NER is 5%. The only challenge on either the prudency or efficiency of past capital projects by DNSPs under the NER that SKM is aware of relates to the Haymarket 330/132 kV substation upgrade.

SKM has noted issues with the suitability of the data provided by Western Power for external review.

10. Conclusions

10.1. Identified Issues Impacting on "Efficiency"

SKM is of the opinion that Western Power is an NSP with solid planning, engineering and execution policies and processes, generally consistent with good electricity industry practice. It is acknowledged that Western Power has worked hard over the past 2 to 3 years to meet the challenges of the new regulatory regime, particularly in the provision of data in a format supportive of an independent review. This extended process of adjusting to the requirements of regulation is not without precedence in Australia.

SKM did not find that the specific process issues raised by GBA in GBA's Governance and AA#1 Project reports could be quantified to support the level of the proposed 15% "inefficiency factor" in the Draft Decision.

Through its review and analysis, SKM found two processes which are expected to have impacted on the ability of particular projects undertaken in the AA#1 period to fully meet the NFIT. These were:

- The poor quality of cost estimates at the beginning of the AA#1 period. As a result of an initiative implemented by Western Power, its cost estimating has significantly improved to being and is now considered good electricity industry practice.
- Overcharging by contractors: an internal review by Western Power at the beginning of AA#1 identified contractor overcharging for distribution works of 3.5% of works. Procedures for procurement and management of contractors are now considered sufficiently robust to detect and address any contractor overcharging.

SKM has endeavoured to quantify the impact of the identified inefficiencies on Western Power's new facility expenditure in the AA#1 regulatory period.

10.2. Quantification of Estimating Issues

In quantifying the potential impact of poor cost estimating on the efficient delivery of a project SKM has considered project development in two distinct phases, as follows:

- Phase 1: Planning and Approval, (Feasibility, design concept and options analysis, cost estimation, business case development, project approval); and
- Phase 2: Project Implementation (Design and Procurement, Construction, Commissioning).

The potential impact of poor cost estimating is different in each of these stages. As an example, it is quite possible that an initial estimate used as the basis for a project approval could be very inaccurate. However, after the project is approved a separate process of project implementation takes place, which is most often managed by a different person (or team) to the person who prepared the initial cost estimate. In this particular example, the project manager could (and should) undertake a review of scope and estimated cost at the commencement of the project and also after receiving tenders etc, which will contain market prices. Provided that the project manager controls the project scope and costs efficiently, the project can still be delivered with an efficient cost outcome.

However, notwithstanding the above, poor cost estimating can potentially impact adversely on the costs of delivering the project. The impacts are generally different on whether the poor estimating process results in an estimate that is too high or too low.

In the case of low estimates, it is likely the approvals process would be adversely affected if the low estimate resulted in the requirement for further approvals. This process in itself can be costly but it can also create delays that have consequential effects on availability of resources, equipment, materials, and seasonal impacts on work etc., which cause additional costs.

Alternatively, a cost estimate that was higher than the actual requirements of the project would not add any additional costs associated with the approvals process but may result in more relaxed cost control on the project. This may increase the opportunity for scope creep to meet the approved costs where procurement and project management practices are poor.

In either case, a substantial error in initial estimate could also change the business case recommended option or even render it unviable in the worst case. SKM has not found any evidence of this in its project specific reviews, as the majority of the options considered by Western Power utilised similar network-based technologies and cost estimating errors tend to have a uniform effect on all options that were being considered.

With regard to Western Power's performance on cost estimating, SKM notes that there appeared to be some significant deficiencies at the beginning of the AA#1 period. However, SKM understands that this has improved significantly after Western Power adopted the recommendations of the Tellis Chase report on cost estimation improvement.

SKM notes that most of the projects delivered within the AA#1 period would have been approved and estimated at the beginning of the period and may have been impacted by poor estimating processes. For the purpose of quantifying the impact on the efficient delivery of projects of poor cost estimating, SKM considers that if an original project estimate is within 20% of the efficient delivered price, normal project governance mechanisms are unlikely to be undermined by the estimate.

In the AA#1 period, SKM has identified:

- 32 significant projects[71], with a total AA#1 period expenditure of $198 million, had original approved cost estimates in excess of 10%[72] below the final delivered cost;
- 20 significant projects, with a total AA#1 period expenditure of $77 million, had original approved cost estimates in excess of 20% above the final delivered cost; and
- 13 significant projects, with a total value of $76 million, that SKM has not been able to identify a record of the original cost estimate.

The projects above are listed in Appendix G.

As discussed above, a poor cost estimate does not necessarily result in an inefficient project. However, it does affect the effectiveness of the governance frameworks around the project increasing the risk of poor project outcomes. For the purpose of making a judgement on Western Power's ability to deliver a project efficiently in the case of a poor initial cost estimate, SKM has taken the view that over a large sample of projects with poor cost estimates being delivered by a company with otherwise robust governance frameworks, an appropriate inefficiency factor to be applied to the total project value is 5%.

SKM's assessment is that any inefficiencies resulting in a factor above 5% would have been specifically identified by the suite of reviews undertaken in this report, particularly the benchmarking and specific reviews of major projects. As such, SKM believes the 5% inefficiency factor on total expenditure across all projects identified as being impacted by poor estimating is appropriate.

10.3. Contractor Overcharging

The contractor overcharging, understood to be taking place at the beginning of the AA#1 period, was quantified by the audits undertaken under the OSA program to be in the order of 3.5% of the

[71] For the purposes of this analysis a significant project has been defined as having a AA #1 period expenditure in excess of $2 million. This figure is set as the boundary between projects that have governance processes directly imbedded the process of delivery (i.e. limited room for variation in the form of project delivery) and projects that are delivered through the application of project delivery governance frameworks on a project by project basis.

[72] A cut of 10% was used for under-runs to identify any projects that may have been had an "efficient delivered price" within the 20% threshold plus Bibra Lake Substation.

total internally funded expenditure on distribution reinforcements. SKM notes that GBA[73] found no evidence of overcharging at the end of the AA#1 period by contractors due to the improvements in contractor management processes implemented by Western Power.

SKM therefore proposes to apply an "inefficiency factor" to internally funded distribution projects of:

- 3.5% in year one;
- 1.75% in year; 2 and
- 0% in year 3.

Applying these inefficiency factors to the projects outlined in the Distribution Analysis Spreadsheet gives the results in Table 1 below.[74]

- **Table 1 : Internally Funded Distribution Works by period with inefficiency factors applied**

	06/07	07/08	08/09	Total
Total Expenditure	$165 million	$193 million	$250 million	$639 million
Related Inefficiency	$5.8 million	$3.4 million	$0	$9.2 million

10.4. Quantification of Impact of Identified Issues

The quantification based on the above discussion is provided below.

- **Table 2: Summary of the Impact of Identified Issues**

Issue	Value of Projects /Purchases Effected	% applied	Value of identified inefficiency
Estimating	$351 million	5%	$18 million
Contractor Overcharging	$639 million	3.5-0%	$9.2 million
Total			**$27 million**

[73] Geoff Brown & Associates Ltd: Review of expenditure governance: Western Power, 14 July 2009, pp 13.

[74] Data in this table has sourced from Western Power DM#5458562v6, Actual Reg Cat pivot table. The SUPP project, Customer Driven works, Gifted Assets and Corporate costs have been excluded from the totals.

11. Abbreviations

AA	Access Arrangement
AASB	Australian Accounting Standards Board
AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AS	Australian Standard
AWP	Annual Work Plan
CB	Circuit Breaker
CBD	Central Business District
CFCT	Critical Fault Clearing Time
CPA	Capital Project Approval
DC	Direct Current
DMS	Document Management System
DNSP	Distribution Network Service Provider
DTC	Distribution Transfer Capacity
EMF	Electromagnetic Frequency
ERA	Economic Regulation Authority
FY	Financial Year
GBA	Geoff Brown and Associates
HV/LV	High Voltage/Low Voltage
IMO	Independent Market Operator
IP	Intellectual Property
NCR	North Country Region
NEM	National Electricity Market
NER	National Electricity Rules
NFI	New facilities investment has the meaning defined in the Electricity Networks Access Code 2004
NFIT	New facilities investment test has the meaning defined in the Electricity Networks Access Code 2004

NPV	Net Present Value
NSP	Network Service Provider
O&M	Operations & Maintenance
ODRC	Optimised Depreciated Replacement Cost
ORG	Office of Regulator-General
OSA	One Step Ahead
PB	Parson Brinckerhoff
PLSCADD	Power Line Systems Computer Aided Design and Drafting
RAB	Regulated Asset Base
RIT-D	Regulatory Investment Test for Distribution
RMU	Ring Main Unit
RRT	Rapid Response Transformer
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SKM	Sinclair Knight Merz
SUPP	State Underground Power Project
SWIN	South West Interconnected Network
SWIS	South West Interconnected System
T&D	Transmission and Distribution
TNSP	Transmission Network Service Provider
WIP	Work in Progress
WP	Western Power

Appendix A: List of Additional Documents Requested

DMS#	Document Title
1148541v2	Cable History Types and Design
1325182v3	Eng Design Std B4
1325214v2	Eng Design Std C1.2
1326068v1	Eng Design Std C1.4
3089633v1	Eng Design Std C1.9
1326157v2	Eng Design Std C1.11
1326165v2	Eng Design Std C1.12
1326176v1	Eng Design Std C2.1
1326190v4	Eng Design Std C2.8
2478157v1	Tx Eng Design Standard J1.1
2478702v1	Tx Eng Design Standard J2.3
1382463v 1	Substation Clearances AS2067
1639158v1	Yellow Paper - S&CS Earthing Std
1983593v1	Yellow Paper - TPS Design & Selection Guideline
1788481v2	Transmission Lines Design Guidelines
3045692v1	Maunsell Telecomms Network Design Review Report
3559462v8	Dx Stds Policies & Technical Docs
417227v3	Tx Assets Std - Conductors & Connectors
4480739v3	Design Flowchart - Substation
4504167v1E	Country Stds - Country Capacity Expansion Projects
4710673v1	Nwk Asset Design Std Tx Prim Eng Insulation Coord
4718488v2	Nwk Asset Design Std Tx Prim Eng Site Utilisation
4721281v1	Nwk Asset Design Std Tx Prim Eng Ratings
4721378v1	Nwk Asset Design Std Tx Prim Eng Power Cabs & Terms
4729404v1	Nwk Asset Design Std Tx Prim Eng Structure Loads
4791857v3	Asset Mgmt Policy Tx Tech Policies & Standards
5101520v2	Tx Lines Design Guidelines
526105v4	Tx Assets Std - Transformer Bunds
5313916v1a	Tech Operational Principles for Dev of Tech Specs
538146v2	Tx Assets STd - Electrical Clearances
6173713v1a	Dev of Stds & Research of New Tech
6173739v1a	Dev of Stds & Research of New Tech
6303613v1	CSES - AA#1 Stds Adopted By Civil & Structural Eng
8692603v3	Tx Assets Standard - HV Power Cables & Terminations
879976v6	HV Extruded Cables - Design & Installation Guidelines
3773264v1	Lines Team Instruc 68 - ABC Ugrounding Dx Services
6056639v5	AM-P0201-07 24kV -362kV Surge Arresters Bus Case

DMS#	Document Title
4075708v2	TX Std Designs Part 2 - 132kV Underground Cable
3749361v3	Tx Std Design Part 2 Func Spec 132kV Urban Wood Pole
419145v3	Tx Eng Std Protection - Backup Protect App
397092v3	Tx Production & Implementation of Stds & Process
418803v4	Tx Eng Std Protection - Trans Protection App
419140v4	Tx Eng Std Protection - Line & Cable Protect App
523195v7	Tx Assets Std - Protection Performance Criteria
371337v1	Protection Design Philosophy (superseded by 523195)
418362v2	Capacitor Bank Protection - Application (Draft)
-	Distribution Construction Standards Handbook
-	Distribution Design Catalogue
3898690v1	OSA Project Handover/Closure Report – Cu to Al Cable Project
3144792v1	Maunsell Cable&Conductor Specification Review – 400mm2 Al Cable
3900711v11	Cu to Al Cable Project Benefits Tracker
3340078v1	Underground Cable Data Sheet Schedule K
	EE2551 - Prysmian Technical Specification
3021171v2	Investigation Report – LV Frame Explosion and Fire
3470476v7a	Part 2 Func Specs132 22kV Zone Subs
3493930v5a	Part 3 Concept Design Specs132 22kV Zone Subs
3619979v3	Part 2 Func Specs 330kV Terminal
3619983v3	Part 3 Concept Deisgn Specs 330 132kV
1212135v1	SO-P0021-02 145kV Transs - Sec G
121238v1	SO-P0021-02 145kV Transs - Sec K
1592939v1	SO-P0098-03 Indoor Metal-Clad Sboards Spec Sec G
1593111v1	SO-P0098-03 Indoor Metal-Clad Sboards Spec Sec K
1839184v1	SO-P0055-04 Outdoor Circuit Breakers Sec G
1839196v1	SO-P0055-04 Outdoor Circuit Breakers Sec K
4234589v4	Tech Spec - AM-P0222-07 Sec E Ring Main Switchgear
5238175v3	Primary Plant - Spec Contract & Ordering Issues
6351540v1	Review Summary – DX & TX Plant Specification Tenders
2249896v1	Memo – Supply & Delivery of Outdoor Circuit Breakers 1-2D
2087145v1	Memo – Supply & Delivery of Outdoor Circuit Breakers
2063271v1	Tender Rec & Memo – 362 Power Trans
1316268v1	Tender Rec & Memo – Supply & Delivery of 132kV Power Trans
2325143v1	Tender Rec – Supply & Deliver Outdoor Circuit Breakers 1-2D
2087154v1	Tender Rec – Supply & Deliver Outdoor Circuit Breakers 3A-8B
400296v2	Reliability Availability & Survivability Critria
3501244v1	HV Nwk Reinforcement Planning volume1 Manual
1538257v5	Procedure Manual for Performing System Studies
4822200v1	Processes & Guidelines in Associated Processes
4880519v6c	Rural Distribution Planning Criteria
5476001v2	NFIT Test Project List - Distribution
4634817v1	AA2 Risk Analysis for Dx Capex

DMS#	Document Title
3062499v2	PJR-WNO 81 Line Submission to the Board June 2006
6260344v2	Summary of Western Power Forecasting Proce
-	Final Determination on the New Facilities Investment Test for a 66-11kV Medical Centre zone Substation Expansion and Voltage Conversion of the Distribution
-	20090219 Notice - New Facilities Investment Test for Western Powers 6611kV Medical Centre Zone Substation - Final Determination
-	20090219 Geoff Brown and Associates Ltd - New Facilities Investment Test - Medical Centre Substation
-	20081211 New Facilities Investment Test for Western Power Medical Centre Zone Substation - Technical Review
-	20080926 Issues Paper - New Facilities Investment Test for a 6611kV Medical Centre Zone Substation Expansion
-	20090108 Public Submission - Draft Decision - Western Power
-	20090108 Public Submission - Draft Decision - Alinta Sales Pty Ltd
-	20090108 D200900326 Public Submission - Draft Decision - Department of Health
-	20081022 Public Submission - Western Power
-	20081014 Public Submission - Alinta Sales Pty Ltd
-	20080926 Notice - New Facilities Investment Test for Western Power 6611kV Medical Centre Zone Substation - Invitation for Submissions
-	20080415 Notice - Western Power 66-11kV Medical Centre Zone Substation Augmentation - Request to Waive the Regulatory Test
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Submission
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Appendix2
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Covering Letter
-	20080415 Determination on an Application from Western Power to Waive the Regulatory Test
-	20080926 Major Augmentation Proposal - Western Power - Submission
-	20080926 Major Augmentation Proposal - Western Power - Covering Letter to Authority
2568070v1	Cottesloe Sub Project Approval
2723694v1	Wembley Sub Discussion of Options
3243805v1	Western Terminal Load Area report
1853853v2	Eperth Load Area Long Term Dev Study Notes 2005-25
1828316v1a	East Perth Load Area – Financial Comparison of Options – Long Term Development Study 2004
2429441v1	Cottesloe Sub CPA Request
1230426v2	Sir Charles Gairdner Hospital Med Centre Zone Sub

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DMS#	Document Title
4110853v2B	Hazelmere Zone Sub Proposed Dx Feeders
3946712v1A	Business Case - Establishment of Hazelmere Sub
3476509v6A	Business Case Muchea Sub Installation
3275740v2	Muchea 3rd Transformer - Scope of Work
3447332v1	Business Case - Wangara Establish New 132-22kV Sub
3145263v4	Wangara - Substation Integration - Scope of Work
2759359v3	Kewdale Establish New Sub - CPA Submission
	Email: ERA Draft Decision - Integrated TransDist Solutions - NCR Windback - 9 Aug 09 from C. Parrotte
5360882v2	Summer Load Trends Report 2009-2028
	Transmission and Distribution Annual Planning Report 2006
	Transmission and Distribution Annual Planning Report 2007
	Transmission and Distribution Annual Planning Report 2008
5274669v1	Tx Asset Management Plan.pdf (VERSION 1)
5274669v2	Tx Asset Management Plan.pdf (VERSION 2)
5274655v2	Dx Asset Management Plan.pdf (VERSION 2)
2362422v5	2006-2009 Strategic Asset Management Plan.doc (VERSION 5)
2362422v6	2006-2009 Strategic Asset Management Plan.doc (VERSION 6)
3195500v7	Business Case Template - Detailed.doc (VERSION 7)
3198881v1	Business Case Guidelines.doc (VERSION 1)
-	20081104 Access Arrangement Service Standard Report Financial Year Ending June 202008
3248073v1	Business Case Template - Shortform.doc (VERSION 1)
3248073v6	Business Case Template - Shortform.doc (VERSION 6)
4958778v1	2.1.02 - Business Case Policy
3195500v2	Business Case Template - Detailed.doc (VERSION 2)
5455834v6	NFIT Test Project List – TX
5458562v6c	NFIT Test Project List – DX
6328913v1	Audit Contractor Inspections
	[*Confidential text deleted*]
4074174v7	Fault History Pivot Tables
	[*Confidential text deleted*]
1758677v1	DAI Project CPA Estimate for Waikiki Zone Sub
5591440v1	Request Quotation for Waikiki Sub
5591444v1	Underground Tender Close & Quote Comparison
5591465v1	Underground Construction Award Confirmation
5592206v1	PO Authorisation Request – Cambridge Cres Cooloongup
5598511v1	Strategic Meet Delivering Summer Required Works Program
5608459v2	Gantt Chart Waikiki Sub – DX Reinforcement Works
6024924v2	Waikiki Scope Change – Sample 1
6024928v2	Waikiki Scope Change – Sample 2
6024931v2	Waikiki Scope Change – Sample 3
2096248v1	WNO-PJR 81 Establish 132kV TX Line SVA Analysis
2149771v1	WNO-PJR 81 Request for Capital Project Approval
3069829v3	PJR-WNO 132kV Double Circuit Line – Revised CPA
	[*Confidential text deleted*]

DMS#	Document Title
	[*Confidential text deleted*]
	[*Confidential text deleted*]
	[*Confidential text deleted*]
2021374v1	Pro Planning Definition Report Establish Bibra Lake Sub
2288490v2	Pro Management Plan Establish Bibra Lake Sub Project
2286762v6	Schedule Establish Bibra Lake Sub Project
3488403v1	PPD Joel Terrace Sub – Install 60MVA 132-11-11kV Trans
3518486v4	Joel Terrace Conversion to 132kV Stage 1 PMP
4555039v17	Joel Terrace Conversion to 132kV – Stage 1 Schedule
	[*Confidential text deleted*]
	[*Confidential text deleted*]
	[*Confidential text deleted*]
3483755v11	OCSC Project Monthly Stats
4069710v3	Twisties Project Management Plan Stage 3
6096389v3	Business Case OCSC Replacement AA2 Period 14 May 09
701888v1	Project Creation Form – APM Substation
1075277v6	Transmission Customer Service Possible Future Block Loads – Summary Report December 2002
1031195v1	Transmission Customer Service Possible Future Block Loads – Summary Report November 2001
1443241v4	Network Customer Service Possible Future Block Loads & Business Development – Summary Report November 2003
2183377v1	SWIS Substation Summer Load Trends (System Peak) 2005 – 2024 Report NBU30
2183510v1	SWIS Substation Summer Load Trends (System Peak) 2005 – 2024 Report NBU31

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Appendix B: Documents Used in Process Reviews

List of Documents for Design Review

DMS#	Document Title	ERA Data / Additional
3605551v5	Western PowerC Technical Rules 2007	ERA
-	Electricity Industry Network Quality and Reliability of Supply Code	Additional
5072213v3	Distribution Standards & Policy Technical Documents Register	ERA
-	Underground Distribution Schemes Manual	ERA
4678720v24	Distribution Design Engineering Design Information Manual	ERA
-	Guidelines for Design & Maintenance of Overhead Distribution & Transmission Lines ENA C(b)1	ERA
-	Electricity Networks Access Code 2004	Additional
-	20081008 Revised Access Arrangement Information for the Network of the SWIS	Additional
1148541v2	Cable History Types and Design	Additional
1325182v3	Eng Design Std B4	Additional
1325214v2	Eng Design Std C1.2	Additional
1326068v1	Eng Design Std C1.4	Additional
3089633v1	Eng Design Std C1.9	Additional
1326157v2	Eng Design Std C1.11	Additional
1326165v2	Eng Design Std C1.12	Additional
1326176v1	Eng Design Std C2.1	Additional
1326190v4	Eng Design Std C2.8	Additional
2478157v1	Tx Eng Design Standard J1.1	Additional
2478702v1	Tx Eng Design Standard J2.3	Additional
1382463v 1	Substation Clearances AS2067	Additional
1639158v1	Yellow Paper - S&CS Earthing Std	Additional
1983593v1	Yellow Paper - TPS Design & Selection Guideline	Additional
1788481v2	Transmission Lines Design Guidelines	Additional
3045692v1	Maunsell Telecomms Network Design Review Report	Additional
3559462v8	Dx Stds Policies & Technical Docs	Additional
417227v3	Tx Assets Std - Conductors & Connectors	Additional
4480739v3	Design Flowchart - Substation	Additional
4504167v1E	Country Stds - Country Capacity Expansion Projects	Additional
4710673v1	Nwk Asset Design Std Tx Prim Eng Insulation Coord	Additional
4718488v2	Nwk Asset Design Std Tx Prim Eng Site Utilisation	Additional
4721281v1	Nwk Asset Design Std Tx Prim Eng Ratings	Additional
4721378v1	Nwk Asset Design Std Tx Prim Eng Power Cabs & Terms	Additional
4729404v1	Nwk Asset Design Std Tx Prim Eng Structure Loads	Additional
4791857v3	Asset Mgmt Policy Tx Tech Policies & Standards	Additional
5101520v2	Tx Lines Design Guidelines	Additional
526105v4	Tx Assets Std - Transformer Bunds	Additional
5313916v1a	Tech Operational Principles for Dev of Tech Specs	Additional
538146v2	Tx Assets STd - Electrical Clearances	Additional
6173713v1a	Dev of Stds & Research of New Tech	Additional

DMS#	Document Title	ERA Data / Additional
6173739v1a	Dev of Stds & Research of New Tech	Additional
6303613v1	CSES - AA#1 Stds Adopted By Civil & Structural Eng	Additional
8692603v3	Tx Assets Standard - HV Power Cables & Terminations	Additional
879976v6	HV Extruded Cables - Design & Installation Guidelines	Additional
3773264v1	Lines Team Instruc 68 - ABC Ugrounding Dx Services	Additional
6056639v5	AM-P0201-07 24kV-362kV Surge Arresters Bus Case	Additional
4075708v2	TX Std Designs Part 2 - 132kV Underground Cable	Additional
3749361v3	Tx Std Design Part 2 Func Spec 132kV Urban Wood Pole	Additional
419145v3	Tx Eng Std Protection - Backup Protect App	Additional
397092v3	Tx Production & Implementation of Stds & Process	Additional
418803v4	Tx Eng Std Protection - Trans Protection App	Additional
419140v4	Tx Eng Std Protection - Line & Cable Protect App	Additional
523195v7	Tx Assets Std - Protection Performance Criteria	Additional
371337v1	Protection Design Philosophy (superseded by 523195)	Additional
418362v2	Capacitor Bank Protection - Application (Draft)	Additional
-	Distribution Construction Standards Handbook	Additional
-	Distribution Design Catalogue	Additional
3898690v1	OSA Project Handover/Closure Report – Cu to Al Cable Project	Additional
3144792v1	Maunsell Cable & Conductor Specification Review – 400mm2 Al Cable	Additional
3900711v11	Cu to Al Cable Project Benefits Tracker	Additonal
3340078v1	Underground Cable Data Sheet Schedule K	Additional
	EE2551 - Prysmian Technical Specification	Additional
3021171v2	Investigation Report – LV Frame Explosion and Fire	Additional

SKM

List of Documents for Planning Review

DMS#	Document Title	ERA Data / Additional
3605551v5	Western PowerC Technical Rules 2007	ERA
-	Electricity Industry Network Quality and Reliability of Supply Code	Additional
400296v2	Reliability Availability & Survivability Critria	Additional
3501244v1	HV Nwk Reinforcement Planning volume1 Manual	Additional
1538257v5	Procedure Manual for Performing System Studies	Additional
1195855	Transmission Planning Criteria Report No. TDWestern Power78-97	ERA
4822200v1	Processes & Guidelines in Associated Processes	Additional
4880519v6c	Rural Distribution Planning Criteria	Additional
5476001v2	NFIT Test Project List - Distribution	Additional
4634817v1	AA2 Risk Analysis for Dx Capex	Additional
	[*Confidential text deleted*]	Additional
6260344v2	Summary of Western Power Forecasting Proce	Additional
-	Final Determination on the New Facilities Investment Test for a 66-11kV Medical Centre zone Substation Expansion and Voltage Conversion of the Distribution	Additional
-	20090219 Notice - New Facilities Investment Test for Western Powers 6611kV Medical Centre Zone Substation - Final Determination	Additional
-	20090219 Geoff Brown and Associates Ltd - New Facilities Investment Test - Medical Centre Substation	Additional
-	20081211 New Facilities Investment Test for Western Power Medical Centre Zone Substation - Technical Review	Additional
-	20080926 Issues Paper - New Facilities Investment Test for a 6611kV Medical Centre Zone Substation Expansion	Additional
-	20090108 Public Submission - Draft Decision - Western Power	Additional
-	20090108 Public Submission - Draft Decision - Alinta Sales Pty Ltd	Additional
-	20090108 D200900326 Public Submission - Draft Decision - Department of Health	Additional
-	20081022 Public Submission - Western Power	Additional
-	20081014 Public Submission - Alinta Sales Pty Ltd	Additional
-	20080926 Notice - New Facilities Investment Test for Western Power 6611kV Medical Centre Zone Substation - Invitation for Submissions	Additional
-	20080415 Notice - Western Power 66-11kV Medical Centre Zone Substation Augmentation - Request to Waive the Regulatory Test	Additional
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Submission	Additional
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Appendix2	Additional
-	20080415 Major Augmentation Proposal - Western Power - Request to Waive Regulatory Test - Covering Letter	Additional
-	20080415 Determination on an Application from Western Power to Waive the Regulatory Test	Additional

DMS#	Document Title	ERA Data / Additional
-	20080926 Major Augmentation Proposal - Western Power - Submission	Additional
-	20080926 Major Augmentation Proposal - Western Power - Covering Letter to Authority	Additional
6019335v1	NCR Presentation to ERA – 15 April 2009	ERA
2568070v1	Cottesloe Sub Project Approval	Additional
2723694v1	Wembley Sub Discussion of Options	Additional
3243805v1	Western Terminal Load Area report	Additional
1853853v2	Eperth Load Area Long Term Dev Study Notes 2005-25	Additional
1828316v1a	East Perth Load Area – Financial Comparison of Options – Long Term Development Study 2004	Additional
2429441v1	Cottesloe Sub CPA Request	Additional
1230426v2	Sir Charles Gairdner Hospital Med Centre Zone Sub	Additional
4110853v2B	Hazelmere Zone Sub Proposed Dx Feeders	Additional
3946712v1A	Business Case - Establishment of Hazelmere Sub	Additional
3476509v6A	Business Case Muchea Sub Installation	Additional
3275740v2	Muchea 3rd Transformer - Scope of Work	Additional
3447332v1	Business Case - Wangara Establish New 132-22kV Sub	Additional
3145263v4	Wangara - Substation Integration - Scope of Work	Additional
2759359v3	Kewdale Establish New Sub - CPA Submission	Additional
2131554v5	Bulk Transmission Network Strategic Plan 2007-20	ERA
	Email: ERA Draft Decision - Integrated TransDist Solutions - NCR Windback - 9 Aug 09 from C. Parrotte	Additional
5360882v2	Summer Load Trends Report 2009-2028	Additional
	Transmission and Distribution Annual Planning Report 2006	Additional
	Transmission and Distribution Annual Planning Report 2007	Additional
	Transmission and Distribution Annual Planning Report 2008	Additional
5274669v1	Tx Asset Management Plan.pdf (VERSION 1)	Additional
5274669v2	Tx Asset Management Plan.pdf (VERSION 2)	Additional
5274655v2	Dx Asset Management Plan.pdf (VERSION 2)	Additional
2362422v5	2006-2009 Strategic Asset Management Plan.doc (VERSION 5)	Additional
2362422v6	2006-2009 Strategic Asset Management Plan.doc (VERSION 6)	Additional

List of Documents for Plant Specifications Review

DMS#	Document Title	ERA Data / Additional
3470476v7a	Part 2 Func Specs132 22kV Zone Subs	Additional
3493930v5a	Part 3 Concept Design Specs132 22kV Zone Subs	Additional
3619979v3	Part 2 Func Specs 330kV Terminal	Additional
3619983v3	Part 3 Concept Deisgn Specs 330 132kV	Additional
1212135v1	SO-P0021-02 145kV Transs - Sec G	Additional
121238v1	SO-P0021-02 145kV Transs - Sec K	Additional
1592939v1	SO-P0098-03 Indoor Metal-Clad Sboards Spec Sec G	Additional
1593111v1	SO-P0098-03 Indoor Metal-Clad Sboards Spec Sec K	Additional

DMS#	Document Title	ERA Data / Additional
1839184v1	SO-P0055-04 Outdoor Circuit Breakers Sec G	Additional
1839196v1	SO-P0055-04 Outdoor Circuit Breakers Sec K	Additional
4234589v4	Tech Spec - AM-P0222-07 Sec E Ring Main Switchgear	Additional
5238175v3	Primary Plant - Spec Contract & Ordering Issues	Additional
6351540v1	Review Summary – DX & TX Plant Specification Tenders	Additional
2249896v1	Memo – Supply & Delivery of Outdoor Circuit Breakers 1-2D	Additional
2087145v1	Memo – Supply & Delivery of Outdoor Circuit Breakers	Additional
2063271v1	Tender Rec & Memo – 362 Power Trans	Additional
1316268v1	Tender Rec & Memo – Supply & Delivery of 132kV Power Trans	Additional
2325143v1	Tender Rec – Supply & Deliver Outdoor Circuit Breakers 1-2D	Additional
2087154v1	Tender Rec – Supply & Deliver Outdoor Circuit Breakers 3A-8B	Additional

Appendix C: SKM AA#1 Projects Benchmarking Report

Contents

Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
A	14.08.2009	J Butler	B Kearney	14.08.2009	For comment
B	20.08.2009	J Butler	G Glazier	20.08.2009	For review
0	26.08.2009	J Butler	G Glazier	26.08.2009	For release
1	02.09.2009	S Wightman	C Parlongo	02.09.2009	For release in main report
2	09.09.2009	S Wightman	C Parlongo	02.09.2009	Minor editorial changes

Distribution of copies

Revision	Copy no	Quantity	Issued to
A	Electronic	1	SKM Perth
B	Electronic	1	SKM Perth
0	Electronic	1	Western Power
1	Electronic	1	Western Power
2	Electronic	1	Western Power

Printed:	15 September 2009
Last saved:	15 September 2009 04:40 PM
File name:	I:\WPIN\Projects\WP03785\Deliverables\Reports\Final Report\WP03785-EE-RP-
Author:	Jeff Butler
Project manager:	Geoff Glazier
Name of organisation:	Western Power
Name of project:	Application of New Facilities Investment Test in Authority Draft Decision on AA#2
Name of document:	Review of Capex Project Estimates
Document version:	Rev 2
Project number:	WP03785

1. Executive Summary

Sinclair Knight Merz (SKM) has been engaged by the Electricity Networks Corporation (Western Power) to undertake an independent review of the application of the New Facilities Investment Test (NFIT) on Western Power's capital expenditure in the Access Arrangement 1 (AA#1) period, as detailed in the Draft Decision.

As a part of the regulatory review undertaken by the Authority, 30 transmission and distribution projects were included in the assessment against the efficiency test. SKM determined it was necessary undertake a review of the capital costs incurred by Western Power in completing these projects to assess the reasonableness of the expenditure.

In generating the comparative estimates, SKM used asset building blocks similar to those used in asset valuations, and cost escalation factors to reflect the changing costs year-on-year during the period 2006 to 2009. These escalation factors take into account movements in commodity prices and labour, and the influence that these cost drivers may have had on the asset costs.

SKM relied upon information originally provided by Western Power for the Authority regulatory review, and supplementary information such as more detailed project scoping documents and single line diagrams. The additional information allowed for comparative estimates to be prepared for ten (10) projects, covering a range of transmission and distribution network augmentations.

Based on the information available, SKM has been able to conduct a high level assessment only. The accuracy, or reasonable range for variance between the two estimates, was nominated by SKM as ±20%. Whilst this level of accuracy generally relates to budgets, and this review related to completed projects, the information and time available allowed for this level of confidence.

For the projects reviewed, SKM found that the aggregated comparative estimates produced by SKM were 5% less than the Western Power expenditure, which was well within the range nominated for reasonable accuracy. In some instances, SKM considered that there may have been additional costs involved in the actual expenditure, which were either unclear in the scope of works (such as undefined lengths of line) or potential costs associated with environmental issues. However, SKM cannot identify any apparent systemic issues that would contribute to a consistent over-estimation of the value of a capital project. From discussions with representatives from Western Power, SKM is satisfied that the underlying causes behind the variations between the SKM comparative estimates and the actual expenditure incurred can be sufficiently identified.

2. Introduction

Sinclair Knight Merz (SKM) has been engaged by the Electricity Networks Corporation (Western Power) to undertake an independent review of the application of the New Facilities Investment Test (NFIT) on Western Power's capital expenditure in the Access Arrangement 1 (AA#1) period, as detailed in the Draft Decision. Of particular relevance is the test detailed in section 6.52(a) of the Electricity Network Access Code 2004 (the Code).

This report provides the results of a benchmarking process undertaken by SKM on 10 projects delivered by Western Power during the AA #1 regulatory period.

3. Approach and Methodology

SKM used typical asset building blocks, similar to those used in asset valuations, as the basis for the comparative estimates. These building blocks are based on reference assets, and are considered appropriate for assessing the reasonableness of the costs incurred by Western Power in undertaking its capital projects.

SKM acknowledges that these building blocks do not capture any project specific costs that may have been incurred, such as transmission lines built in rugged terrain or with an increased number of strain towers, construction undertaken outside normal hours or excessive switching required for substation augmentation. These costs may qualify, at least in part, any difference between the SKM comparative estimate and Western Power expenditure.

3.1. Reference Assets

In developing the building block unit rates, SKM adopted reference assets for substation switchbays and transmission lines based on a number of stated inclusions/exclusions and assumptions.

3.1.1. Substation Switchbays

For each substation asset, the unit rate is based on a replacement asset, which assumes that the substation is constructed as a full and complete installation from inception, and provides for average conditions in construction difficulty associated with installation of the asset, and a significant scale of construction. The standard replacement costs are considered to be realistically achievable by an efficient new entrant that is not constrained by past practices and that proactively manages capital works projects with the objective of minimising total cost.

3.1.2. Transmission Lines

The transmission line building blocks are built up allowing for the following costs and factors:

- Survey;
- Terrain;
- Wind loading design;
- Foundations;
- Structures;
- Conductor;
- Overhead ground wire; and
- Insulators/fittings.

Cost items not included are:

- Route selection, easement survey, acquisition, planning and regulatory approvals;
- Tower design, prototyping, and testing; and
- Easement cost.

3.2. Accuracy

In establishing a criterion for assessing the reasonableness of the Western Power estimates and actual expenditures, SKM is of the opinion that consideration must be given to the level of accuracy that can be achieved.

The graph shown in Attachment A indicates the levels of accuracy that can be expected for estimates prepared for capital works at various stages of a project development. Due to the different levels of engineering input, and completeness in the design, there are various levels of accuracy that can be reasonably expected in high level comparative estimates. It shows that for budgeting where the asset is reasonably well defined an accuracy of ± 20% can be expected.

SKM has also reviewed an international recommended practice for cost estimating[1], and found that:

- There are 5 classes of estimate, with class 5 based upon the lowest level of project definition, and class 1 closest to full project definition;
- A budget or authorisation level forecast is categorised as a class 3 estimate, which is considered to have 10-40% project definition, and a range of accuracy of approximately +20%/-10%;
- The level of project definition roughly corresponds to the percentage complete of engineering, and includes project scope definition, requirements documents, specifications, plans, environmental considerations and other information that must be developed to define the project.[2]

Based on these analyses, SKM has adopted a criterion of ± 20% as the first pass for comparing the Western Power estimates with the SKM reference estimates. For those Western Power estimates

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[1] AACE International, *Recommended Practice No. 17R-97: Cost Estimating Classification System (TCM Framework: 7.3 – Cost Estimating and Budgeting)*, 12 August 1997

[2] Refer Appendix A of this report for table of generic estimate classifications

where the variation is outside this range, SKM has reviewed the underpinning assumptions to identify the potential reasons.

4. Asset Cost Benchmarking

SKM has previously benchmarked costs associated with a selection of zone and terminal substations, and transmission lines of different voltages.[3]

The benchmarking exercise was conducted during a time when Western Australia was experiencing cost increases in excess of the Consumer Price Index (CPI), and there was considerable pressure on available resources to undertake project work. In addition, Western Australia had a larger regional cost variation than many of the eastern States. The challenge this environment presented was for utilities to develop and maintain rigorous estimating processes.

SKM was engaged to provide an independent assessment and comparison of a number of selected cost estimates derived from the Western Power estimating system with similar utilities in other Australian States. The range of assets reviewed included:

- 132/33 kV zone substation;
- 132 kV terminal yard;
- 330 kV terminal yard;
- 132 kV wood pole line;
- 132 kV single circuit steel pole line;
- 132 kV double circuit steel pole lie; and
- 330 kV double circuit steel tower line.

The study concluded that the cost estimates produced by Western Power were considered reasonable (within ±20%) and closely aligned with those in other States. There was a higher degree of variability in costs associated with overhead line construction, with the report highlighting a different approach adopted by Western Power in assuming worst case soil conditions. This factor was considered to have a significant effect on the estimated cost per km, and contributed to a much lower ratio of costs between double circuit and single circuit lines (typically found for other utilities to be 1.5, whilst for Western Power is 1.25).

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[3] SKM, *Transmission Asset Cost Benchmarking*, version 4, 20 June 2008

5. Cost Escalation

Historically, TNSPs have made use of expected movements in the Consumer Price Index (CPI) in order to allow for likely movements in the costs of capital works. However, in more recent times, the rapid increase in commodity prices have, *inter alia*, caused many of the underlying costs of infrastructure projects to rise far more rapidly than corresponding movements in the Australian national CPI.

SKM has held for some time the belief that movements in the CPI do not accurately reflect the movements in costs associated with infrastructure projects, and therefore the CPI index is inappropriate for use as a basis upon which to develop cost escalation factors for use in forecasting movements in the costs of capital works programs. As a result, SKM has used cost escalation factors based on movements in commodity prices and labour in the generation of the comparative estimates.

Research into movements in the costs of electrical equipment experienced by utilities around Australia identified a number of key cost drivers (in no particular order):

- Metals such as copper, aluminium, and steel;
- Labour;
- Construction costs;
- Oil;
- Foreign exchange rates;
- The Trade Weighted index;
- Wood Poles; and
- other cost components which include e.g. supplier's transport costs and profit margins sought in the supply chain.

SKM examined each of the main items of plant equipment and materials within its database, in order to establish a suitable percentage contribution, or weighting, by which each of these underlying components of cost were considered to contribute to the total price of the completed item.

In its determination and application of final weightings for each network asset, SKM used information gathered during its interviews with equipment suppliers and manufacturers, and knowledge available within its internal pool of estimators, procurement specialists, financiers, economists, engineers and operational personnel.

SKM's cost escalation modelling involves mapping the movements of individual items of plant and equipment (based on forecast movements of each of their own underlying cost drivers), to movements in the cost of asset classes.

In developing these cost escalation factors, SKM has relied upon data that is publicly available from independent Australian and international authorities such as:

- Australian Bureau of Statistics (ABS);
- London Metal Exchange (LME);
- Reserve Bank of Australia:
- CRU Group: and
- Consensus Economics.

6. Projects Assessed

SKM has assessed a selection of capital expenditure projects from the past regulatory period, by generating a comparative estimate of costs for comparison against the actual costs incurred by Western Power. For this assessment, SKM has relied upon high level descriptions of the scope of works and/or single line diagrams that have been made available by Western Power, together with NFIT compliance summaries and business cases. The summary of the findings shown in Table 1 represent those projects that SKM was satisfied that the additional information provided by Western Power described the scope of work in sufficient detail for a comparative estimate to be done. No allocations have been made in the SKM estimates for any costs associated with land or easements.

Table 1 Comparison of SKM Comparative Estimates and Western Power Costs

Project	Western Power Actual Costs ($M)	SKM Estimate ($M)	Variance[4]
[Confidential text deleted]	25.9	21.9	-18.3%
Bibra Lake Zone Substation	10.9	9.7	-11.01%
[Confidential text deleted]	92.2	89.1	-3.4%
Joel Terrace Conversion	9.9	10.8	8.4%
[Confidential text deleted]	8.6	8.6	0.0%
Wembley Downs Substation Upgrade	4.7	3.9	-19.5%
Advanced Metering Infrastructure Pilot*	5.8	6.0	3.4%
Meter Asset Replacement	8.2	10.1	18.7%
Overhead Customer Service Replacements	35.1	29.5	-19.0%
Overloaded Distribution Transformer Replacements	17.9	18.3	2.3%
TOTAL	**219.2**	**207.9**	**-5.16%**

* Western Power value shown is NFIT estimated costs as project still in progress

[4] Variance calculated as (SKM Estimate - WP Actual) / WP Actual

SKM noted that the review of the NFIT Compliance conducted for the Authority sought to assess each of the 30 projects and programs, but found " ... *it very difficult to make a meaningful assessment of the investment against requirements of the efficiency test* ... [as] *very little information on cost breakdowns was provided* ... [and] *equipment and labour costs were rising very rapidly*."[5] The review suggested that "... *an efficient project cost that was incurred at the end of the regulatory period would have been inefficient had the same cost been incurred on the same project at the beginning of the period.*"

SKM would concur that the information provided by Western Power limited any comparison of estimates to a high level assessment, although the additional information that was available for the projects shown in Table 1 was sufficient for SKM to generate a comparative estimate with some level of confidence.

With regards to rapidly escalating costs, SKM agrees with the suggestion offered by Geoff Brown & Associates that any direct comparison between costs incurred at the end of a project commenced during the period 2006-2009 and the original estimate prepared in 2005 would be inappropriate. With reference to section 4, in the comparative estimates SKM has applied cost escalation for each asset category relevant to the year of completion of each project.

The reference assets used in the SKM comparative estimates have been based on standard building blocks derived from costs relevant to the eastern States. SKM notes that there are cost differences, particularly in relation to overhead line construction, which may have contributed to the results.

6.1. Individual Project Assessments

The following is a brief assessment of the level of information that was available for the project, and any issues that SKM considered may influence the variation calculated.

A common point of difference between the SKM comparative estimate and the actual expenditure incurred by Western Power will be the allocation included for transport, and any regional cost influences. As highlighted in section 4, SKM has previously identified in a benchmarking study that Western Australia has a larger regional cost variation than many eastern States. The building block costs used by SKM in these comparative estimates are based on typical costs for transmission utilities in the eastern States of Australia, and as such are likely to be conservative compared with costs found in certain parts of WA.

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5 Geoff Brown & Associates, *Review of New Facilities Investment Test Compliance - Western Power AA1 Projects*, 14 July 2009, section 2.3, pp 6

SKM

6.1.1. [Confidential text deleted]

The SKM comparative estimate had a variation of -18% to actual expenditure. There are some activities in the scope of works that SKM considers may not have been completely captured in the comparative estimate that may contribute to this variation:

- The project is categorised as Greenfield, and includes the construction of a new 330 kV terminal substation, and a new 330 kV double circuit overhead line on steel towers. Verbal advice received from Western Power project staff was that the project was under extreme time pressures that are considered to have contributed an additional $2-3M to the equipment purchase costs;
- Other activities listed in the scope of work that have not been included in the SKM estimate are the geo-technical survey and earth potential rise testing of the terminal substation site;
- SKM has included an approximate allocation for design, procurement, project management construction and commissioning which may or may not adequately reflect the actual expenditure incurred on this project due to any project specific requirements that remain undefined.

Overall, SKM is satisfied that the actual expenditure incurred appears reasonable. The comparative estimate is within the nominated accuracy range, and the additional aspects of the work scope would potentially narrow this variation to approximately -7%.

6.1.2. Bibra Lake Zone Substation

The SKM comparative estimate had a variation of -11.01% to actual expenditure. The high level scope of works described in the business case and NFIT compliance summary included:

- Establishment of a new transformer substation;
- Cutting into an existing 132 kV overhead line; and

The project is located in an industrial estate south-east of Fremantle.

There is no allocation in the SKM estimate for any costs that may have been incurred related to land or easements. SKM considers that such costs may apply, as the project has been categorised as Greenfield.

6.1.3. *[Confidential text deleted]*

The SKM comparative estimate had a variation of -3% to actual expenditure, which is well within the nominated ±20% range of accuracy.

The project was categorised as Greenfield, although SKM noted that the NFIT compliance summary referred to the “expansion business case, suggesting it may be a brownfield project. The work involved construction of new 330 kV transmission substation and line assets, as well as integration into the existing network.

Verbal advice received from Western Power project staff highlighted a number of key environmental issues which had a significant effect on project costs:

- The 330 kV transmission line passed along an existing easement through a State forest. It was necessary to limit span lengths, and no additional clearing along the easement was possible;
- The line passes through a dieback infested forest, and as a consequence considerable precautions were required, such as washdowns and disinfecting between sections. This was considered to add approximately $2-3M to costs;
- There were environmental issues associated with the work extending the *[Confidential text deleted]*, which contributed $2.5M to the costs; and
- The 132 kV work to interconnect the new *[Confidential text deleted]* customer owned substation totalled approximately $1.8M.

The comparison of SKM estimate and actual costs for each aspect of the work produced the following results:

- 330 kV line actual costs were approximately $51M compared with the SKM estimate of $46M (including the environmental costs discussed above);
- *[Confidential text deleted]* actual costs of approximately $30M compared with the SKM estimate of $32M; and
- An estimated $3.5M for *[Confidential text deleted]* compared with approximately $2.5M actual costs.

6.1.4. Joel Terrace Conversion

The SKM comparative estimate has a variation of +8% to actual expenditure, and is highly comparable to the original estimate of $11.1M included in the business case.

SKM is satisfied that scope has been fully captured in comparative estimate, and that the actual expenditure was reasonable and efficient.

6.1.5. *[Confidential text deleted]*

The SKM comparative estimate reflects the total actual expenditure incurred. SKM is satisfied that the comparative estimate has fully captured the work scope as defined by Western Power.

6.1.6. Wembley Downs Substation Upgrade

The SKM comparative estimate had a variation of -19% to actual expenditure. The scope of work included decommissioning and removal of 66/6.6 kV assets to allow room for the new assets in the switchyard together with existing low voltage switchboards, which has not been included in the SKM estimate as the extent of work is not clear.

In addition, SKM noted that the project required statutory, regulatory and environmental approvals to extend the substation north of the current site. These costs have not been captured by the SKM estimate.

6.1.7. Advanced Metering Infrastructure Pilot

This project is currently in progress. The SKM estimate had a variation of +3% to the NFIT estimate.

The scope of works includes the installation of 12,000 smart meters and SCADA/communications infrastructure to provide advanced metering infrastructure for future load control and energy efficiency programs. The work is scheduled over two financial years 2008/09 and 2009/10.

SKM is satisfied that the estimated amount for this work is reasonable.

6.1.8. Meter Asset Replacement

There was a variation of +19% between the SKM comparative estimate and actual expenditure. This project required the replacement of 101,000 single phase meters between 2005/06 and 2008/09. These meters were identified for replacement as they were found to be non-compliant with error requirements of the Electricity Act 1945.

The SKM estimate of $10.1M was comparable with the revised NFIT estimate prepared by Western Power, so the actual expenditure is considered efficient.

6.1.9. Overhead Customer Service Replacements

Actual expenditure incurred was +19% higher than the SKM comparative estimate. The project entailed the replacement of overhead customer service connections that were considered to represent serious health and safety risks to Western Power staff and the general public. The work was completed between 2006/07 and 2008/09.

The project was conducted in three stages - 45,000 services in the first, 24,000 in the second, and 28,000 in the third. These replacements involved the replacement of cable and clamps in accordance with current Western Power practice. SKM considers that the variation between the comparative estimate and the actual expenditure is due to the difference in assumptions made by SKM concerning the cable and clamping used.

Based on this consideration, SKM is satisfied that the actual expenditure appears reasonable.

6.1.10. Overloaded Distribution Transformer Replacements

This project involved the replacement of overloaded distribution transformers and unspecified underground low voltage work. The SKM comparative estimate was limited to costs associated with distribution transformers, and was compared with original NFIT estimate, based on the same scope of works.

It was not possible for SKM to do a comparison between the full project expenditure and a comparative estimate, as the extent of the low voltage underground cable works was not fully quantified in the information provided.

For the component of work related to distribution transformers, SKM found a variation of 2% between the comparative estimate and the cost of works. This is considered to represent a reasonable expenditure.

7. SKM Conclusions

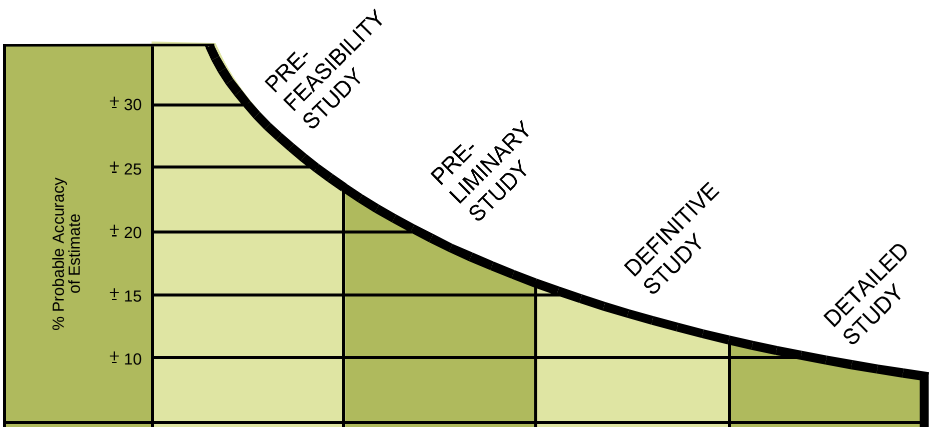
As a part of the regulatory review undertaken by the Authority, 30 transmission and distribution projects were included in the assessment against the efficiency test. SKM was requested to undertake a review of the capital costs incurred by Western Power in completing these projects and assess the reasonableness of the expenditure.

Following this review, SKM has the following conclusions:

- The original information provided for this assessment by SKM is similar to that provided to the Authority and its consultants during the regulatory review. SKM concurred with the observation made by Geoff Brown and Associates that the information provided contained insufficient detail for an assessment to be made. Information subsequently provided by Western Power was sufficient to allow for a high level assessment to be made of the expenditure relevant to 10 projects.
- The 10 projects reviewed were considered to be a reasonable sample, and included a mix of both transmission and distribution projects.
- SKM agrees with the observation offered by Geoff Brown and Associates regarding the dynamic environment that these projects were undertaken in, with sharply increasing costs for both material and labour that were experienced in the Western Australian market being typical of the cost influences seen throughout the Australian electricity industry. It was a fair conclusion that these market conditions strongly impacted on the final costs of the projects.
- SKM found that the comparative estimates prepared using reference building blocks were within the nominated ±20% accuracy range for reasonableness. There was a mix of positive and negative variances, with an aggregated variance of -5% that is, the costs incurred by Western Power in total for these 10 projects was 5% higher than that generated by the SKM comparative estimates.
- There were a number of reasons that may qualify this difference:
  - In some projects, it was not clear if there were land acquisition costs involved which were not accounted for in the comparative estimates;
  - In some instances, there remained some parts of the scope that were not clearly specified, such as lengths of line that were not defined.
- From the sample of projects examined, SKM considered the project costs incurred appeared to be reasonable, within the nominated ±20% acceptable variance.
- SKM cannot identify any apparent systemic issues which would contribute to a consistent over-estimation of the value of a capital project. From discussions with representatives from Western Power, SKM is satisfied that the underlying causes behind the variations between the SKM comparative estimate and the actual expenditure incurred can be sufficiently identified.

Attachment A: Definition Chart for Engineering Estimates

▪ Figure 1 Standard Estimate Accuracy Levels



Type of Estimate	Order of Magnitude	Preliminary	Definitive	Detailed
Provided Documentation	• Product capacity and Location • Cost Data on Similar Projects • Major Equipment List	• Preliminary Equipment List • Engineering Line Diagram • Plant Outline General Arrangement • Maps and Surveys • Bench Test Results • Nature of Facilities	• Equipment Specifications and Vendor Quotations • Construction Schedule • Electrical One Lines • Piping and Instrumentation Flow Diagrams • Soil Data and Architect Features • Site Survey and Labour Complete	• Bulk Material Specifications and Vendor Quotes • Construction Specification and Sub Contractor Quotations • Engineering Advanced Approximately 10%
Definition of Scope of Work	Conceptual	Approximate	Clearly Described Essentially Complete	Complete. Well Detailed
Estimating Procedure	Factoring	Combination of Factoring and Quantity Take-Off	Most Quantity Take-Off. Very little Factoring	Complete Quantity Take-Off
Use of Study	Comparison/ Rejection	Final Feasibility	Budget	Funding

SKM

- **Table 2 AACE IRP No. 17R-97 Generic Cost Estimate Classification Matrix**[6]

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	LEVEL OF PROJECT DEFINITION Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE Typical +/- range relative to best index of 1 (a)	PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 (b)
Class 5	0% to 2%	Screening or Feasibility	Stochastic or judgement	4 to 20	1
Class 4	1% to 15%	Concept Study or Feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget, Authorisation or Control	Mixed, but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Primarily deterministic	1 to 3	5 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Deterministic	1	10 to 100

Notes:

(a) If the range index value of 1 represents +10/-5%, then an index value of 10 represents +100/-50%

(b) If the cost index of 1 represents 0.005% of project costs, then an index value of 100 represents 0.5%

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6 AACE International, *Recommended Practice No. 17R-97: Cost Estimating Classification System (TCM Framework: 7.3 – Cost Estimating and Budgeting)*, page 2, 12 August 1997

Appendix D: Detailed Project Review Report

Contents

Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
0	26.08.2009	M Farr	G Glazier	31.08.2009	Internal Review
1	03.09.2009	G Glazier	C Parlongo	03.09.2009	For Issue in main report
2	09.09.2009	G Glazier	C Parlongo	09.09.2009	Minor editorial changes

Distribution of copies

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Printed:	15 September 2009
Last saved:	15 September 2009 04:26 PM
File name:	I:\WPIN\Projects\WP03785\Deliverables\Reports\Final Report\WP03785-EE-RP-003
Author:	Ian Moller
Project manager:	Geoff Glazier
Name of organisation:	Western Power
Name of project:	Application of New Facilities Investment Test in ERA Draft Decision on AA#2
Name of document:	Review of Selected Western Power Capital Works Project
Document version:	Rev 2
Project number:	WP03785

1. Introduction

Sinclair Knight Merz (SKM) has been engaged by the Electricity Networks Corporation (Western Power) to undertake an independent review of the application of the New Facilities Investment Test (NFIT) on Western Power's capital expenditure in the Access Arrangement 1 (AA#1) period, as detailed in the Draft Decision. Of particular relevance is the test detailed in section 6.52(a) of the Electricity Network Access Code 2004 (the Code).

This report provides the results of a detailed review of available information undertaken by SKM on 7 projects delivered by Western Power during the AA #1 regulatory period.

2. Scope of Work

The scope of work was to review information provided on a set of selected projects to determine whether the projects have been delivered in an efficient manner. In particular, the following components of the projects were considered;

- Cost estimating
- Options Analysis
- Governance / Approvals processes
- Efficiency of Engineering Solutions
- Procurement
- Project or Works Management

Documentation was provided for the following Western Power Projects:

- [*Confidential text deleted*]
- Pinjar to Wanneroo 132 kV Line
- SHO – KEM 91 Line - Stringing 2nd side
- Distribution Transformer Replacement & LV Network Reinforcement 07/08
- North Country 330 kV Reinforcement
- Establishment of Waikiki Substation
- Establishment of Bibra Lake Substation

Additional reference documents have also been provided as background. A complete listing of electronic documents received is shown in Attachment A.

3. Review

3.1. [Confidential text deleted]

[*Confidential text deleted*].

3.1.1. Cost Estimating

The final delivered cost for this project was within 3% of the original cost estimate, suggesting an effective cost estimating process. Furthermore in SKM's Review of Capex Estimates[1], it was concluded that the SKM comparative estimate of -3% to actual expenditure is well within the nominated +/-20% range of accuracy.

3.1.2. Options Analysis

[*Confidential text deleted*].

A series of system studies were carried out to assess various aspects of the [*Confidential text deleted*] proposal and updated as improved technical data became available and in the light of changes that occurred in the bulk transmission plan. These studies are quite comprehensive and were conducted taking into account the requirements of the Electricity Transmission Access Technical Code.

The process of identifying and analysing options for this project appeared to be robust and rigorous for the purposes of identifying the best technical and economic option.

3.1.3. Governance / Approval Process

[*Confidential text deleted*].

Western Power produced an NFIT Compliance Summary[2], which summarises the completed project and seeks to demonstrate NFIT compliance.

From the documents reviewed, Western Power appears to have processes in place that indicate appropriate governance and approval mechanisms.

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[1] SKM report August 2009 - Application of New Facilities Investment Test in ERA Draft Decision on AA#2 – Review of Capex Project Estimates

[2] [*Confidential text deleted*]

3.1.4. Efficiency of Engineering Solutions

From the information supplied, the 330 kV single circuit option using double circuit towers is considered a prudent decision considering:

- More efficient use of the available transmission corridor with future growth in mind;
- The move away from dedicated single circuit construction backed up by previous Regulatory decisions; and
- The improved practicality of being able to defer the stringing of a second circuit due to advances in stringing techniques.

[*Confidential text deleted*]

3.1.5. Procurement

The Project Management Plan[3] sets out the resourcing and methods for producing designs, procuring plant, supplying materials and carrying out construction. Standard tendering processes are nominated for contracted-out supply and/or construction except that substation electrical construction was allocated to internal resources. In the latter case, unless there are internal processes in place to regularly benchmark substation electrical construction, it can be difficult to demonstrate that this type of work is being carried out at competitive rates. From the documents reviewed, it is not clear whether regular internal benchmarking for this activity takes place. However, it could be argued that if Western Power is achieving as-constructed project costs that benchmark well in the industry, then project component costs are less of an issue.

3.1.6. Project or Works Management

A comprehensive Project Plan was provided that covered most of the key components. It is noted that the project Gantt chart was provided as a separate Microsoft Project file[4]. It is unclear whether the Risk Management Plan referred to in the Project Plan is contained in a separate document. There appears to be good change control and change management as evidenced by the change control register[5]. The fact that the project was delivered on budget normally demonstrates good project cost control (all other things being equal).

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[3] [*Confidential text deleted*]

[4] [*Confidential text deleted*]

[5] [*Confidential text deleted*]

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3.2. Pinjar to Wanneroo 132kV Line

From the documentation supplied, the following observations are made.

The essentials of this project were:

- To mitigate line overloads and enable system maintenance to be performed without risking the loss of the entire load area.
- To overcome power quality problems – low voltages at Yanchep and Wanneroo.
- To interconnect new substations.
- To interconnect the future Neerabup Terminal.
- To facilitate the connection of Wind farms located to the north of Perth.

This was achieved by:

- the construction of 26 km of 132 kV double circuit transmission line between Pinjar power station and Wanneroo substation with:
  - part of the transmission line having conductor strung on both circuits. This section of line will require the capacity of two conductors once Neerabup terminal is commissioned (mid 2009), and
  - the remainder of the line had conductor strung on one side only.

3.2.1. Cost Estimating

While the project was originally estimated at $22.2M, it is noted that due to delays in getting original agreement on the line route and the lack of line construction bidders, timing and budgeting had to be revised resulting in a revised business case and Board Approval for a project cost of $27.7M. Subsequently, during construction, Western Power experienced difficulties with a land developer and other Utilities resulting in a further revised budget of $40.9M. The project was completed for $32.8M. This is a good illustration of the difficulties of developing accurate estimates, particularly where these types of projects are renowned for encountering issues outside the control of the construction authority and often unforeseen due to the response of stakeholders. This has been acknowledged by GBA[6] and SKM concurs.

[6] Page 27 – Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

3.2.2. Option Analysis

Western Power has applied its standard transmission planning criteria and carried out load forecasting studies. Notwithstanding the “minor concern” mentioned in the GBA Report[7], the Planning process appears quite reasonable. As a comment, it is considered that forecasting is never a precise exercise and it could be argued that a practical limit should always be placed on analysis commensurate with the accuracy of input data and assumptions.

3.2.3. Governance / Approvals Process

The project business case[8] describes the network need and three possible options to meet that need. It is considered that sufficient justification exists for implementing the selected option.

It appears that the Western Power Board was updated at appropriate times and revised project approval was sought where required, accompanied by reasons why a revised budget was necessary.

Western Power has produced an NFIT Compliance Summary which summarises the completed project and seeks to demonstrate NFIT compliance.

From the documents reviewed, Western Power appears to have processes in place that indicate appropriate governance and that approval mechanisms are in place.

3.2.4. Efficiency of Engineering Solutions

Difficulties in establishing a new transmission line are not unusual and the problems encountered as described above had in SKM’s view, no material impact on the efficiency of the engineering solution and outcomes. GBA[9] called into question the fact that Western Power did not have a suitable tower design that all bidders could use. SKM has verbally confirmed that Western Power did in fact have intellectual property (IP) to the previous design used as a basis in the construction of this line. However, SKM also notes that it is not unusual for network owners to produce a tailored design for a given line, for a variety of reasons. These include: conductor size differences, changes in the wind code, and different environmental constraints resulting from the Environmental Impact Assessment. In SKM’s view, it is not possible nor is it prudent, to hold an inventory of suite of designs of transmission lines that will suit all occasions. It is more common to

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[7] Page 25 of Report - Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

[8] Document WEn2061514v2 WNO-PJR 81 – ESTABLISH NEW 132KV LINE –CPA

[9] Page 26 - Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

first seek to apply existing designs, but if uneconomical or technically unsuitable, then a new design must be developed or obtained. Alternatively, if a line contractor has a suitable design which results in a shortened lead time, then this can often be the most appropriate and economic solution given the situation at the time. Again, this is known have been the case with other network owners.

3.2.5. Procurement

The use of period contracts for substation plant procurement is quite a common approach as is the competitive tendering for earthworks, civil works, and substation structures. Some other network owners contract out substation electrical construction. Line construction by contract is almost universally used by most network owners. It is understandable that Western Power encountered problems in obtaining competitive bids from line constructors as it is know that at the time, there was a substantial amount of line construction occurring in North East Australia. Given that there are only 3 major transmission line contractors in Australia, a peak load of work by two or more transmission network operators, can quickly constrain competitive bidding across the nation. In SKM's experience, there appear to be insufficient incentives to attract overseas bidders for line construction in Australia at the present time.

3.2.6. Project or Works Management

While the specific project management plan for this project has not been sighted, based on reviews of other similar projects where project management plans have been produced, we have no reason to believe that the process is different for this project. Difficulties encountered during the construction have already been described above. From the information provided to SKM, the original planned completion date was November 2007 but because of difficulties and delays encountered, the actual in-service date was November 2008.

3.3. Shotts – Kemerton 91 Line - Second Circuit

Following system studies undertaken during 2004, an options analysis was developed, the selected option for the project was scoped, estimated and approval sought. This project entailed the provision of a new 330 kV transmission line of 60 km in length between Shotts and Kemerton. It consisted of stringing a second circuit on existing double circuit towers, which already supported a 330 kV in-service circuit. Provision of the new line was designed to increase the power transfer capacity of the 330 kV bulk transmission network. The project was given financial approval in January 2005.

3.3.1. Cost Estimating

This project was estimated at $16.1M for a completion date of November 2007. The completed project cost was $17.3M or 7% over the original budget, excluding capitalised interest. This is considered to be a satisfactory result.

3.3.2. Option Analysis

The business case[10] discussed two options. One option involved stringing the second circuit on an existing line while the other option involved installing a Static VAr Compensator. Option analysis and risk analysis appeared to be carried out in an appropriate manner.

3.3.3. Governance / Approvals Process

Western Power appears to have followed the appropriate process in obtaining project approval[11] following the production of the business case.

3.3.4. Efficiency of Engineering Solutions

During project implementation, it was found that three lattice towers had been omitted from the business case, which added $1.9M to the cost of the project. Notwithstanding this, the project completion costs came within 7% of approval and the project was delivered (more or less) to schedule. Stringing a second circuit on an in-service line can be problematic with significant issues, not least of which are the safety aspects if the first circuit cannot be temporarily de-energised or disconnected from the network during construction stages. The safety issues that normally need to be addressed can have a significant impact on the project budget and schedule. No documents were sighted to indicate there were significant problems in this respect. In the absence of any information to the contrary, it may be concluded that the staged stringing of double circuit EHV lines to defer significant expenditure (conductor) is an efficient engineering solution.

3.3.5. Procurement

From the information supplied, Western Power adopted normal procedures to source materials and construction services similar to that described above for other projects. Given the special conditions that can exist when carrying out work on a line that has been / or is connected to the network, it is noteworthy to see that three competitive bids were received to carry out the stringing.

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[10] WEn2141191v1 SHO-KEM 91 -STRING 330KV TX LINE -BUSINESS CASE.doc

[11] WEn2146787v1 SHO-KEM 91 –ESTABLISH NEW 330KV TX LINE MEMO.doc

3.3.6. Project or Works Management

While the project management plan has not yet been sighted, from information received, Western Power appears to have adopted their standard project management processes similar to those described above.

3.4. Distribution Transformer Replacement & LV Network Reinforcement 07/08

From the documentation supplied, the following observations are made.

The essentials of this project were:

- To upgrade pole and ground mounted distribution transformers that are forecast to be loaded in excess of their installed capacity in the SWI during the 2007/08 summer; and
- To reconfigure LV underground cable networks that are at risk of multiple protective fuse operations due to overload.

The project was achieved by;

- Replacing approximately 227 metropolitan distribution transformers;
- Replacing approximately 28 country distribution transformers; and
- Reconfiguration or replacement of approximately 85 underground cable circuits.

3.4.1. Cost Estimating

This project was estimated at $7.75M with a completion date of June 2008. The completed project cost cannot be determined from the documentation provided, as the NFIT report is a consolidated report for 3 years of distribution transformer replacement and network reinforcement disbursed over 4 business case face sheets, and does not allow for an analysis of each of the capital projects that comprise the consolidated report.

SKM has not identified sufficient information that would allow us to determine a comparative estimate for this project.

3.4.2. Option Analysis

Western Power has applied their in-house developed standard forecasting tool (DNAT FLM) as an initial data sorting tool to highlight forecast overloaded assets, then claims to apply a number of checks and balances to validate forecast overloaded assets.

3.4.3. Governance / Approvals Process

The project business case[12] describes the network need and two possible options to meet that need, although one of those options is simply a do nothing option.

3.4.4. Efficiency of Engineering Solutions

From the information provided to SKM, it would seem that this project replaced potentially overloaded transformers with new and larger units at the same location, and replacement of LV underground cable with greater capacity cable, again at the same location. Reference is made to possible LV network reconfigurations.
From the information provided, it has not been possible to determine if demand side options have been considered as alternatives to these supply side options.

There was not a credible second alternate solution to this network constraint proposed in the documentation provided.

3.4.5. Procurement

The use of period contracts for distribution transformer plant procurement is quite a common competitive tendering approach used in the electricity supply industry.

3.4.6. Project or Works Management

SKM notes that the project program requires all transformers (227 metropolitan distribution transformers and approximately 28 country distribution transformers) and all underground cable (approximately 85 underground cable circuits) to be replaced or reconfigured by June 2008. SKM further notes that the GBA Governance review for this project[13] advises that all works were completed (100% completion) by June 2008, and that 70% was completed before summer 2007/08.

Form our review of Excel spreadsheet ‘WEn3476427v14 DX TRANSFORMER OVERLOAD UPGRADE PROJECT 07-08.xls’, it would appear that the 70% installation target before the 2007/08 was achieved. However, we also note in this same spreadsheet, that 5 of the transformer projects were not complete by end June 2008. According to this record, the last transformer upgrade was not completed until November 2008. Given the information provided, SKM have not been able to form a view on the effectiveness on the management of this works program.

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[12] Document DMS3457513

[13] Power Point Presentation: WEn5574605v5 ERA GOVERNANCE REVIEW ûDX TRANSFORMER UPGRADE by Syd McDowell

3.5. North Country 330 kV Reinforcement

3.5.1. Background

The project was driven by two key factors:

1) to provide firm supply to Geraldton. The existing capacity will be exceeded by 2010.
2) to provide sufficient capacity to meet the requirements of proposed new mining loads and generators in the region:
   - Gindalbie (2010)
   - Extension Hill (2011/12)
   - Oakajee Port (2011/12)
   - Coolimba Power station (2012)
   - Eneabba Gas power station (2012?)
   - 11 prospective wind farms (2010 on)

The scope of this project is:

- Establishing a new 330/132 kV terminal substation at Moonyoonooka near Geraldton;
- Constructing 380 km of 330 kV double circuit line from Pinjar-Moonyoonooka;
- Installing line circuits at Neerabup Terminal; and
- Associated distribution work.

The target completion dates are:

- the 330 kV line from Neerabup to Eneabba by November 2010; and
- The 330 kV line from Eneabba to Moonyoonooka by October 2011.

3.5.2. Cost Estimating

In October 2007, Western Power Corporation (WPC) submitted to the Authority a proposed major augmentation known as North Country 330 kV Reinforcement. The estimated project cost was $300M. The Authority issued a Regulatory Test determination in December 2007, which allowed Western Power to proceed with the project.

In late 2008, Western Power allocated construction of the project to one of its two alliance partnerships. As a result, a re-estimated cost of $595M was produced which required re-

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submission to the Authority for a new Network Facilities Investment Test (NFIT) approval. This information was obtained from a (draft) copy of a WPC submission to the Authority[14].

A separate document entitled "NFIT Compliance Summary"[15] specifies the New Facilities Investment to be $343M and refers to the Business Case (DMS#4280536). As the business case document has not yet been sighted, it is unclear to what the estimate of $343M refers.

A WPC presentation entitled "ERA Governance Review – North Country 330 kV Reinforcement"[16] set out the project background, drivers, scope, estimates and proposed work allocation. This presentation also described, at length, the justification for using Alliance Partners for this project as this had a substantial bearing on the revised cost estimate. In their report[17], Geoff Brown & Associates (GBA) have identified a number of issues arising from the estimating of this project and the process of seeking NFIT pre-approval. SKM shares the concerns highlighted in the GBA report.

It was not surprising that costs increased quickly, particularly where:

- the project was one of the largest undertaken by WPC and being exposed to substantial cost increases and,
- Alliance partnering was introduced at a time where the economy was surging and there was strong demand for labour and material resources.

Because of insufficient documentation, it is difficult to form definitive views except to say that with such a significant project as this and a very substantial variation in the estimate at the approval stage, warning signs should have been heeded and a separate economic risk assessment undertaken. In addition, it is suspected that previous models for estimating transmission projects may now not fit well with the concept of Alliance Partnering and therefore development of a better model may need to be pursued if Alliance Partnering is to become a more common method of project delivery.

3.5.3. Option Analysis

As would be expected with a project of this significance, the options analysis appeared to be well developed and from the documentation available, there appears to be no significant issues with the

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[14] 5242393v1A MIDWEST 330KV LINE PRE-APPROVAL OF NFIT (REVISED).doc

[15] NFIT Compliance Summary - Nbt-Mnt 330kV Line Project.DOC

[16] WEn5570049v1A NCR PROJECT-PRESENT TO ERA GOVERNANCE AUDITOR.ppt

[17] Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

choice of the recommended network solution. WPC appear to have followed their standard process even though a full suite of documentation covering such things as the business plan, risk analysis, project management plan, had not been sighted. With a project of this size, it was disappointing that a more comprehensive set of supporting documents were not available to validate the above conditional conclusions.

3.5.4. Governance / Approvals Process

The discussion above, relating to cost estimating and revised approvals, shows that WPC followed the required procedures with the Authority. The various submissions to the Authority give evidence to this. It is noted that at the present time, NFIT approval is pending and this has delayed the commencement of the project. Clearly, this is not a desirable situation and may have been avoided if a better understanding of cost pressures in the prevailing economic environment was obtained.

3.5.5. Efficiency of Engineering Solutions

The chosen engineering solution is considered quite straightforward given the lack of a generation or DSM solutions in the Geraldton area. The network solution will give much needed transmission reinforcement to the areas north of Pinjar and, in particular, to the Geraldton area which is the northern extremity of the South West Interconnected System (SWIS). This solution also has a number of benefits for connection of proposed new customers such as mines and wind farms. It is noted that the new assets were considered as part of the strategic infrastructure supporting economic expansion of the State of WA.

Reference was made to a "Transmission Design Report – North Country Reinforcement Project", but this document had not been discovered at the time of producing this report. It was stated in this document[18] that "*Western Power believes that this detailed design report demonstrates that the project is based on prudent engineering practice and is technically efficient...*"

Without access to this document, no comment can be made on the content of such.

3.5.6. Procurement

The significant issue with this project is the introduction of Alliance Partnering as stated above. No document has yet been sighted to explain procurement strategies for other plant and contracts outside of the Alliance Partnering agreement.

[18] 5242393v1A MIDWEST 330KV LINE PRE-APPROVAL OF NFIT (REVISED).doc

3.5.7. Project or Works Management

Due to the status of the project, no comment can be made regarding the efficacy or otherwise of project management other than to share the concerns highlighted in the GBA report relating to the pre-approval stages of the project.

To date, no Project Management Plan has been sighted.

3.6. Establishment of Waikiki Substation

This project was driven by the growth in demand in the Rockingham area, some 10 km south of Perth. The project was approved in April 2005. It is understood the project is now complete. The scope of the work consisted of:

- Establishing a single 132/22 kV 33 MVA transformer substation at Waikiki;
- Cut the Waikiki substation into the Mandurah-Rockingham 132 kV line;
- Establish three 22 kV feeders to integrate the substation into the Rockingham distribution network; and
- Install two 5 MVAr capacitor banks.

A suitable site for Waikiki substation was acquired. It is situated approximately 6 km south of the Rockingham substation.

3.6.1. Cost Estimating

The total estimated cost of the project at time of approval was $8.86M, of which the distribution component was $1.35M. In November 2007, an increase in the project budget of $2.65M was approved, bringing the revised project approval to $4.0M.

While this project is considered to be at the low end of WPC's investment program, the GBA report [19]states that "*this project was included in the review because of the substantial difference between the budgeted and actual costs.*" GBA's report went into some detail on the causes of the cost increases. This revealed that:

- Substantial delays occurred between the estimate preparation and approval submission,(i.e the estimate was not reviewed before seeking approval);

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[19] Page 29 - Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

- Because there was a significant use of 22 kV copper cable, steep copper price rises added substantially to the cost. It was pointed out that had WPC used aluminium cables, cost increases would have been somewhat less. Since this project, WPC have now started using aluminium underground cables;
- Increased labour costs added substantially to the cost increases; and
- Changes in scope added substantially to the cost increases.

When summarising the discussion on the above cost increases, the GBA report[20] made several references to the inability to reach a firm conclusion through lack of detailed information. Notwithstanding the reasons uncovered for the cost increases, for which SKM concurs, the difficulties encountered in accessing accurate and relevant information is one which SKM has also experienced. Some general points are made on this subject later in this report.

In summing up, from the information available, there is every indication that cost estimating was not implemented as well as it could have been.

3.6.2. Option Analysis

The business case for this project described a number of options and selected the option on the basis of an economic analysis. This process was quite straightforward.

3.6.3. Governance / Approvals Process

Apart from difficulties encountered with costs on this project as described above, there is insufficient easily accessible information available at this time to make any further comment.

3.6.4. Procurement

All material was procured under arrangements with standing offers with suppliers.

The use of preferred vendor contracts to install the underground distribution cabling and the overhead works appears to be a satisfactory method of delivery and one that is used by other similar organisations.

[20] Pages 31 and 32 - Geoff Brown & Associates Ltd – Review of Expenditure Governance – Western Power (14 July 2009)

3.6.5. Project or Works Management

In the absence of additional supporting documentation, based on information summarised in the presentation “Waikiki Substation Feeders”[21], standard procedures appear to have been followed in the project management, tracking and reporting.

3.7. Establishment of Bibra Lake Substation

This project provides for the deloading of the APM substation by the establishment of a new 132/22 kV zone substation at Bibra Lake. The substation is to be developed in stages, with stage 1 comprising:

- 1 x 20/25/33 MVA transformer and associated bay;
- 2 x 132 kV feeder bays;
- 2 x 22 kV 5 MVAr capacitor banks and associated bays;
- 1x 22 kV indoor switch board with 4 feeder bays, 1 transformer bay, 2 capacitor bays and 1 bus section bay;
- 2 x 132 kV feeder bays (KW 81 and SF 81);
- Earth works, access roads, site establishment inclusive of a building for control and 22 kV switchgear;
- All line works to cut into the existing KW – SF 81 line; and
- Protection modifications at Kwinana Terminal and South Fremantle Terminal.

3.7.1. Cost Estimating

The project was originally estimated to cost $13.34M[22], inclusive of 10% contingency and escalation. Also included in this budget was a provision of $2.4M for the associate distribution scope of works. This equates to a capital estimate for the substation and associated transmission line works to $10.94M inclusive of 10% contingency and escalation.

There are no references to issues arising during the construction phase of this project that would impact on the final project cost.

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[21] WEn5570390v7 ERA PRESENTATION-WAIKIKI SUBSTATION FEEDERS.ppt

[22] Memorandum: Establishment of Bibra Lake Substation, Request for Capital Project Approval; dated 11 January 2005 by Doug Aberle

In reviewing the NFIT Compliance report, it is noted that the New Facilities Estimate for this project is stated as being $8.5M and not the $13.34M as stated in the before-mentioned Capital Project Approval Memo and attached Business Case DMS#2166390. This difference in the approval amount is a factor of the $2.4 M that was reported as completed prior to the AA #1 regulatory period. However, the $7.9M representing the completed value in the compliance summary plus the $2.4 million completed pre the AA#1 regulatory period results in a total project cost of $10.3 million. This does not reflect the cost in the Project Close out report of $10.6 million. However, both figures are within 6% of the original $10.9 million budget for the transmission work ($13.34 million total CPA approval, minus the $2.4 million for distribution works).

SKM has identified no project management references to the distribution work except for a single comment that it was completed for the originally estimated $2.4 million figure.

We note that the Project Management Plan[23] documents the findings of a risk assessment workshop in which cost reductions of in excess of $1.0 million were identified and approval gained for the associated project variation. This project does not appear to have been reflected in the final estimated cost in any of the documentation reviewed.

3.7.2. Option Analysis

Western Power has claimed that it applied its standard transmission planning criteria and carried out load forecasting studies, and quoted the consistent load growth at the APM substation, and a projection of sustained similar growth in the future in the future, as justifying the need for the network augmentation.

Based solely on the original information provided to SKM, we would challenge this view. Whilst the line of best fit through the annual loads on the APM substation would likely provide the historical load growth concluded by Western Power, it could also be reasonably argued that the load growth is the result of 3 separate step load increases in mid 1997, 2000 and 2003 respectively. As such, they are not reflective of a sustained and steady load increase. SKM cannot ascertain if Western Power treated these step loads as part of a continuously increasing load and if so, on what basis this decision was made.

As a result of the concerns raised above, Western Power provided the 2002 block load report and the 2004 loads and forecast report. From these, SKM can confirm that:

- Western Power is identifying future block loads and is incorporating them in their planning.

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[23] Project Management Plan, Project T0160665, Establishment of Bibra Lakes Substation; by M Milburn dated September 2005 Issue 1, DMS#:2288490v2; File#:AM/119/T0160665(36)V1

- The actual load growth was found to exceed the load forecasts on which the options analysis was undertaken[24]. For 2008, Bibra Lake had a 2004 forecast load of 15 MW vs an actual load of 25 MW and Australian Paper Mills (that was largely unloaded by the creation of Bibra Lake) with a forecast of 35 MW vs an actual load of 33 MW.

SKM believes that the description in the original business case did not effectively describe the basis of the forecast on which the decision to proceed was based. In quantifying these concerns, SKM could not confirm the forecasting approach that was used at the time. However, it has seen evidence that Western Power separately identified block loads and the load forecast was conservative in comparison to the actual load growth.

SKM also notes that the augmentation options considered in the Project Management Plan[25] differed to the options stated as being considered in the Memorandum seeking capital Project approval[26].

3.7.3. Governance / Approvals Process

Based solely on the information available to SKM for this review and without the opportunity to discuss our observations with Western Power, we have some concerns regarding the governance and approval process followed for this project.

Approvals Process:

- SKM notes that the augmentation options considered in the Business Case Summary[27] differ to the options stated as being considered in the Memorandum seeking capital Project approval[28].

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[24] Western Power: Summer Load Trends Report 2009 – 2028 Substation & System Peaks for the SWIS, December 2008. And Western Power: Summer Load Trends Report 2004 – 2024 Substation & System Peaks for the SWIS, December 2004.

[25] Project Management Plan, Project T0160665, Establishment of Bibra Lakes Substation; by M Milburn dated September 2005 Issue 1, DMS#:2288490v2; File#:AM/119/T0160665(36)V1.

[26] Memorandum: Establishment of Bibra Lake Substation, Request for Capital Project Approval; dated 11 January 2005 by Doug Aberle

[27] Business Case Summary, Establishment of Bibra Lake Substation; DMS#: 2166390v2, File#:SDV/77/T120S14T(156)V1

[28] Memorandum: Establishment of Bibra Lake Substation, Request for Capital Project Approval; dated 11 January 2005 by Doug Aberle

- In that Memorandum, whilst it is stated that 3 options were considered, only one is discussed and the reasons for its dismissal discussed.
- In the same Memorandum, the option recommended for approval is not one of the 3 options that were stated as being considered for the augmentation solution.
- Cost efficiencies identified in a risk assessment workshop (and for which a change of project scope were approved) were omitted from the NFIT Compliance Report.

3.7.4. Efficiency of Engineering Solutions

The comments below are made in addition to our comments above regarding the planning process.

It is normal in recent times (but not necessarily at the time of the approval of this project) for regulators to require evidence that demand side as well as supply side options have been extensively pursued in arriving at the optimal network augmentation. The options process followed by Western Power in this augmentation project does not reference any demand side options that were considered.

The associated planning report[29] is a high level précis document which does not provide enough detail to allow commentary regarding the efficiency of engineering solutions.

3.7.5. Procurement

The use of period contracts for substation plant procurement is quite a common approach as is the competitive tendering for earthworks civil works, substation structures. Some other network owners contract out substation electrical construction. Line construction by contract is almost universally used by most network owners.

3.7.6. Project or Works Management

SKM has reviewed the project management plan[30] for this project and considers it to be a sound document that appears to consolidate or otherwise reference a number of other relevant Western Power Documents.

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[29] Western Power Networks Business Unit, Capital Efficiency Branch, Establishment of Bibra Lake Substation Planning Report: Report # NBU-049-2004; DMS#:2021374V1

[30] Western Power Project Management Plan Project T0160665, Establish Bibra Lake Substation; Written by M Milburn, Dated September 2005

We note that this report documents the findings of a risk assessment workshop in which cost reductions of in excess of $1.0 M were identified and approval gained for the associated project variation. This project variation is not referenced in the NFIT Compliance Summary Report.

This project would seem to have been effectively project managed as evidenced by the under spend in the project budget and the project being delivered only 1 month behind schedule.

4. Comment on Quality of Project Information

In the execution of this review, heavy reliance was made on project and related documents sourced from Western Power and disseminated by various means, the following Attachment A provides a list of these documents . All of these documents were supplied by email via zip files over a period of days.

In terms of usefulness, the ERA Governance Review presentations and the NFIT Compliance Summaries were quite helpful (on the assumption that they accurately reflected the project data).

In general, the quality of the information provided to this review of capital works projects, varied significantly from the helpful to the unhelpful and from completed reports to copies of e-mails. The following difficulties were encountered:

- A number of documents were still in draft form and contained blanks in some areas where the missing information might have been helpful;
- A number of documents were undated and quite a few had self updating date fields which made it impossible to trace their history;
- In some instances there were multiple copies of the same document but different versions;
- There were inconsistencies in the type of documents presented, which made it difficult to quickly extract the relevant information; and
- Some documents were missing or not able to be accessed in time. In a minority of the cases under review, this resulted in not being able to form a firm view on some issues as identified in the review of the selected projects.

Attachment A: Documents Referenced in this Review

A.1 [*Confidential text deleted*]

[*Confidential text deleted*]

A.2 Pinjar to Wanneroo Transmission Line

WEn1439578v2 WNO-PJR 81 132KV LINE CONSTRUCTION - PPD.doc

WEn2061514v2 WNO-PJR 81 – ESTABLISH NEW 132KV LINE –CPA.doc

WEn4515509v6 WNO-PJR 132KV DOUBLE CIRCUIT LINE-BOARD SUB.doc

WEn2780985v1 CONSTRUCTION OF WNO-PJR 132KV TX LINE.ppt

WEn5570242v1 WNO-PJR 81 PRES RELATING TO PLANNING APSECTS.ppt

A.3 Waikiki Substation Establishment

WEn1742546v4 WAIKIKI SUBSTATION-SUBMISSION TO THE BOARD.doc

WEn1762249v1 WAIKIKI ZONE ITEM 1 SCOPE OF WORKS.doc

WEn1813638v2 WAIKIKI SUBSTATION ESTABLISHMENT-COST ESTIMATE.doc

NFIT Compliance Summary - Waikiki Substation.DOC

WEn1742546v4 WAIKIKI SUBSTATION-SUBMISSION TO THE BOARD.doc

WEn1762249v1 WAIKIKI ZONE ITEM 1 SCOPE OF WORKS.doc

WEn1813638v2 WAIKIKI SUBSTATION ESTABLISHMENT-COST ESTIMATE.doc

WEn2235643v2 WAIKIKI SUBSTATION-COVER MEMO TO MD RE APPROVAL.doc

WEn3236693v1 DOCUMENT TRANSMITTAL -N0144460 WAIKIKI DX WORKS.doc

WEn3236730v1 COVER LETTER - N0144460 WAIKIKI SS DX.doc

WEn3627141v2 MEMO TO DX PLANNING-FUNDING FOR WAIKIKI DX WORK.doc

WEn3884874v2 CHANGE CONTROL REQUEST FOR WAIKIKI - DX WORKS.doc

WEn4226950v1 DX SUMMER READY STATUS AS AT 7 NOVEMBER 2007.doc

Manifest1249349123.html

1621873 v1 SCOPE OF WORK FOR WAIKIKI ZONE SUBSTATION.pdf

WEn3683941v28 PEAK READY DISTRIBUTION PROJECT STATUS.pdf

WEn6024056v1 SAFETY BAY RD OVERHEAD UPGRADE MATERIALS LIST.pdf

WEn5570390v7 ERA PRESENTATION-WAIKIKI SUBSTATION FEEDERS.ppt

WEn3063816v3 METRO MAINT CAPACITY-CONTRACTOR QUOTE PROGRESS.xls

WEn3242949v86 DX PROJECT MGMT WORK PACKAGE TRACKING SHEET.xls

WEn3518746v2 METRO MAINTENANCE CAPACITY-QUOTE CONTROL U G.xls

WEn4014684v1 WAIKIKI OVERHEAD UPGRADE QUOTE THIESS.xls

1758677v1 DAI PROJECT CPA ESTIMATE FOR WAIKIKI ZONE SUB.doc

6024924v2 Waikiki Scope Change - Sample 1.lne

6024928v2 Waikiki Scope Change - Sample 2.lne

6024931v2 Waikiki Scope Change - Sample 3.lne

5608459v2 GANTT CHART WAIKIKI SUB - DX REINFORCEMENT WORKS.mpp

5591440v1 REQUEST QUOTATION FOR WAIKIKI SUB.rtf

5591444v1 UNDERGROUND TENDER CLOSE & QUOTE COMPARISON.rtf

5591465v1 UNDERGROUND CONSTRUCTION AWARD CONFIRMATION.rtf

5592206v1 PO AUTHORISE REQUEST - CAMBRIDGE CRES COOLOONGUP.rtf

5598511v1 STRAT MEET DELIVERING SUMMER REQUIRED WORKS PROG.rtf

1742546 Waikiki Business Case.pdf

A.4 Shotts – Kemerton Line Second Circuit

WEn1647677v3 NORTHERN TERM–STUDY NOTES FOR LONG TERM DEV.doc

WEn2073778v4 SHO-KEM ESTAB NEW TX LINE- STRING SPARE CIRCUIT.doc

WEn2126270v1 SHO-KEM 91 ESTABLISH NEW 330KV TX LINE-ESTIMATE.doc

WEn2141191v1 SHO-KEM 91 -STRING 330KV TX LINE -BUSINESS CASE.doc

WEn2146787v1 SHO-KEM 91 –ESTABLISH NEW 330KV TX LINE MEMO.doc

WEn2131554v1 BULK TX NETWORK - STRATEGIC PLAN - 2007-2020.doc

WEn5568569v2 PRESENT- PLANNING ASPECTS OF SHO-KEM 91 TX LINE.ppt

WEn2144772v1 SHO-KEM 91 ESTABLISH NEW 330KV TX LINE - SVA.xls

A.5 Other Reference Documents

WEn3298469v10 PROJECT CHANGE CONTROL REQUEST FORM.doc

WEn2097237v1 NORTHERN TERM LOAD AREA LONG TERM DEV PLANS.doc

WEn2103994v10 TX LINES TEAM - A2 COST ESTIMATE TEMPLATE.doc

WEn4226950v1 DX SUMMER READY STATUS AS AT 7 NOVEMBER 2007.doc

WEn4229698v4 TOR FOR WORKS PROGRAM COMMITTEE.doc

WEn4349124v2 TOR FOR PROGRAM PERFORMANCE COMMITTEE.doc

WEn4473602v4 PROGRAM CHANGE CONTROL REQUEST - TEMPLATE.doc

WEn5614255v2 REACTIVE LV NETWORK OVERLOAD MITIGATION PROCESS.doc

WESTERN POWER ANNUAL REPORT 2008.pdf

DMS3457513-replace distribution transformers.pdf

Geoff Brown and Associates Report – Review of Expenditure Governance – Western Power

[*Confidential text deleted*]

STRATEGIC ALLIANCE AGREEMENT.pdf

WE2118517.pdf

WE2834958V1.pdf

WEn3683941v28 PEAK READY DISTRIBUTION PROJECT STATUS.pdf

WEn5043297v1 WESTERN POWERS COMMERCIAL PRINCIPLES POSTER.pdf

WEn6024056v1 SAFETY BAY RD OVERHEAD UPGRADE MATERIALS LIST.pdf

5570049v2 NCR PROJECT - ERA GOVERNANCE AUDITOR.ppt

WEn4074603v2 ESTIMATING PROCESS REVIEW PROJECT FINAL REPORT.ppt

WEn5574605v5 ERA GOVERNANCE REVIEW –DX TRANSFORMER UPGRADE.ppt

WEn5579839v2 ERA GOVERNANCE REVIEW-WORKS PROGRAM MANAGEMENT.ppt

WEn5587814v1 WORKS PROGRAM GOVERNANCE PRESENTATION FOR ERA.ppt

WEn5587820v1 ESTIMATING PRESENTATION FOR ERA CONSULTANT.ppt

WEn6019335v1 NCR PRESENTATION TO ERA - 15 APRIL 2009.ppt

WEn3063816v3 METRO MAINT CAPACITY-CONTRACTOR QUOTE PROGRESS.xls

WEn3242949v86 DX PROJECT MGMT WORK PACKAGE TRACKING SHEET.xls

WEn3476427v14 DX TRANSFORMER OVERLOAD UPGRADE PROJECT 07-08.xls

WEn3518746v2 METRO MAINTENANCE CAPACITY-QUOTE CONTROL U G.xls

WEn4153521v3 TRANSFORMER LOAD FORECAST SUBSTATION INDEX.xls

WEn4997660v2 FIN IMPACT STATEMENT- METRO LV REINFORCEMENT.xls

WEn5373228v1 EVALUATION SPREADSHEET – POWER TRANSFORMERS.xls

DMS5574061v1 NFIT COMPLIANCE SUMMARY - WNO-PJR 132KV TX LINE.DOC

A.6 North Country 330kV Augmentation (Mid West Transmission Augmentation)

WEn5570049v1A NCR PROJECT-PRESENT TO ERA GOVERNANCE AUDITOR.ppt

3289625v4 BOARD SUB - NORTH COUNTRY REGION REINFORCEMENT.doc

3929838v1 REG SUB - NEW 330KV TX LINE TO MID-WEST REGION.doc

5242393v1A MIDWEST 330KV LINE PRE-APPROVAL OF NFIT (REVISED).doc

NFIT Compliance Summary - Nbt-Mnt 330Kv Line Project.DOC

4280536v3 BC- 330KV TX LINE NC DEC07-24 JAN08 BOARD MEETING.pdf

A.7 Bibra Lake Substation Establishment

2021374v1 PRO PLANN DEF REPORT ESTABLISH BIBRALAKE SUB.doc

2288490v2 PRO MGMTPLAN ESTABLISH BIBRALAKE SUB PROJECT.doc

2286762v6 SCHEDULE ESTABLISH BIBRA LAKE SUB PROJECT.mpp

1075277v6 Transmission Customer Services Branch – Possible Future Block Loads – Summary Report

5360882v2 Western Power: Summer Load Trends Report 2009 – 2028

5360882v2 Western Power: Summer Load Trends Report 2009 – 2028

Appendix E: Review of Selected Plant Specifications

1839196v1 SO-P0055-04 - OUTDOOR CIRCUIT BREAKERS SEC K

This specification relates to climatic conditions and specific technical requirements for purchase of outdoor 24 kV, 36 kV, 145 kV, 245 kV and 362 kV live tank and/or dead tank circuit breakers used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment.

1839184v1 SO-P0055-04 - OUTDOOR CIRCUIT BREAKERS SEC G.doc

This specification related to the purchase of outdoor 24 kV, 36 kV, 145 kV, 245 kV and 362 kV live tank and/or dead tank circuit breakers used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment. Some of the notable specification requirements are:

- The specification gives specific and detailed requirements for the design of support stands under static and dynamic loading. SKM do not believe that this level of detail is necessary but also do not see the requirement as added additional cost. A simpler performance based specification would be expected to achieve a similar outcome.
- Bushings are specified as porcelain. Some utilities have adopted more expensive composite or polymer bushings.

1593111v1 SO-P0098-03 - INDOOR METAL-CLAD SBOARDS SPEC SEC K.doc

This specification relates to environmental conditions and specific technical requirements for purchase of indoor metal clad switchboards typically used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment.

1592939v1 SO-P0098-03 - INDOOR METAL-CLAD SBOARDS SPEC SEC G.doc

This specification relates to technical requirements for purchase of indoor metal clad switchboards typically used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment. Some of the notable specification requirements are:

- The specification contains strange requirement to use chrome pintle pin hinges. The design of hinges on doors is a key issue in the design of suitable arc fault containment. A requirement to use a particular type of hinge appears to introduce an unreasonable to high risk.
- The overall specification is detailed and pedantic. A more performance based specification would be preferred by the supplier market and would possibly achieve better procurement outcomes for Western Power.

1212138v1 SO-P0021-02 - 145KV TRANS - SEC K.doc

This specification relates to environmental and technical requirements for purchase of 145kV rated transformers typically used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment.

1212135v1 SO-P0021-02 - 145KV TRANSS - SEC G.doc

This specification refers to the technical requirements for 145kV rated transformers typically used in substations.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment. A number of comments are made on the specification:

- This seems to be an out of date specification with reference made to AS2374 (all parts). A number of parts to this standard are now superseded by AS60076.
- Over-specific and consideration should be given to simplification to a more performance based approach.

4234589v4 TECH SPEC - AM-P0222-07 SEC E RING MAIN SWITCHGEAR

This specification was the basis of the power point presentation listed above and contains specifications for the purchase of 24kV ring main units (RMU) used in kiosks or in dedicated switch rooms for distribution switching and feeder control.

Comment

SKM has reviewed the specification and finds that the document represents industry standard requirements. There are no requirements that would be considered particularly harsh considering the Western Australian environment. Some of the notable specification requirements are:

- Ambient temperature of 55C. This is used in other jurisdictions and is not unusual.
- Compliance with AS62271 – This is a relatively new standard based on IEC requirements. SKM is unable to verify if other jurisdictions have added this requirement but it would be expected as existing period contracts are renewed.
- Use of 24kV rated equipment for 11kV duty – this is not unusual and some manufacturers have rationalised their inventory to this duty. There may be a cost penalty but this would be balanced by reduced spares inventory.
- The specification for a fitted RTU appears to be very specific and detailed. SKM believe that the RTU may be over-specified for distribution level equipment where response speeds may not be critical.

Appendix F: Summary of major Tender Processes with Western Power during AA#1

[Confidential text deleted]

Contract #	Plant Item	Spec	# Manuf Issued to	# Respondees	# Compliant Respondees	Tender Awarded to lowest tenderer?	Comments
T97.2003	12kV - 36kV Indoor Switchboards	1573454					
T54A.2002	145kV Power Transformers	1183463					
T59.2004	362kV Power Transformers	1870178					
T50.2004	12kV - 362kV Circuit Breakers	1813549					
T50.2004	12kV - 362kV Circuit Breakers	1813549					
T0266	COMBINED CURRENT AND VOLTAGE TRANSFORMERS	4225344					
T83.1998	24kV & 12kV Earthing Transformers						
T78.2005	32V DC, 50V DC, 110V DC Batteries And Battery Chargers For Substations	4856123					
T87.2004	12kV, 24kV & 36kV Capacitor Banks and Series Reactors	1922637					
T151.2004	145kV Capacitor Banks and Series Reactors	4857479					
T41.1999	24kV - 362kV Station Class Surge Arrestors	4825631					
L013.99	Drop out fuses, HV Isolators and Sectionalisers	2318449					
T75.2002	Joints, Terminations & Accessories	798948					
T76.2004	High Voltage Equipment and Assemblies for Overhead Line Hardware						

SKM

Appendix G: List of Major Projects identified in Section 10

Projects for which poor estimating is believed to have resulted in inefficiencies

Project	Total AA1 Actuals	Business Case Approval Date	Original	Over-run / (Under-run)	ITD June-09 Act
Muchea S/S: Install The 3Rd Transformer	$ 2,318,536	22-Jun-07	5,270,000	-122%	$ 2,371,779
Asset Repl 66Kv -Primary-Circuit Breaker	$ 2,673,993	17-Aug-07	5,622,000	-103%	$ 2,767,489
Mu-Alb: Acquire Dcct 220Kv Corridor	$ 2,409,755	14-May-07	5,190,000	-97%	$ 2,631,782
Southern River Ss - Cut In St-Wgp/Apj 81	$ 2,746,666	23-Dec-05	4,978,000	-79%	$ 2,778,038
Hazelmere: Establish New Substation	$ 6,104,991		10,676,000	-71%	$ 6,247,260
Confidential text deleted	$ 7,301,303	2-Oct-07	12,400,000	-65%	$ 7,511,860
Wembley Downs Ss: Convert To 11Kv & Repl	$ 3,957,918	6-Nov-06	6,620,000	-55%	$ 4,263,907
Kalamunda S/S: Install 3Rd Transformer	$ 2,089,698	29-Dec-06	3,212,000	-54%	$ 2,091,046
Transmission Lines : River Crossing Work	$ 5,081,487	18-Feb-04	9,135,000	-47%	$ 6,212,782
Reliability Driven -Secondary-Fault Reco	$ 2,162,527	27-Jun-07	3,169,000	-47%	$ 2,162,527
Piccadilly S/S : 3Rd 132 Kv Transformer	$ 3,142,807	22-Sep-06	4,456,000	-41%	$ 3,155,246
Forrestfield S/S : Install 3Rd Tx	$ 2,932,252	24-Aug-07	4,126,000	-41%	$ 2,932,252
Wlo - Bsn 81 Line & Waterloo Sw/Yd	$ 7,211,940	21-Feb-01	25,000,000	-34%	$ 18,668,548
Mu-Btn 82 (Part) : Construct 132Kv Line	$ 2,839,136	19-Feb-03	24,616,000	-31%	$ 18,748,615
Asset Repl -Primary- Curent Transformer	$ 2,086,724	10-Jul-07	2,648,665	-27%	$ 2,086,724
Cottesloe 6Kv To 11Kv Upgrade Cottesloe All Feeders	$ 3,369,670	19-Oct-05	4,183,000	-24%	
Joondalup : Establish New Substation	$ 4,721,452	15-Feb-06	6,240,000	-23%	$ 5,077,760
Joel Terrace - 132Kv Conversion Stage 1	$ 8,781,821	14-Dec-06	11,135,000	-21%	$ 9,170,035
Confidential text deleted	$ 3,002,332	14-Apr-04	19,700,000	-19%	$ 16,500,007
Jam-Mil 81 & 82 : Replace 132Kv Cables	$ 2,758,156	20-Jul-05	5,922,000	-13%	$ 5,237,454
Over Estimate Subtotal	**$ 77,693,166**	20			

Pjr- Ctb- Gtn 330 Kv : Line Route Acquis	$ 5,768,773	2-Dec-04	5,000,000	22%	6,381,769
Yokine S/S : Install 3Rd Transformer	$ 3,936,584	18-Oct-05	3,150,000	23%	4,073,820
Padbury ; Establish New Substation	$ 4,916,061	15-Oct-03	6,028,000	23%	7,845,627
Mason Road S/S : Install 2Nd Transformer	$ 3,630,673	26-Jun-06	2,789,805	25%	3,700,393
Establish Ct-Bel & We-Bel/Rve Lines	$ 9,640,696	23-Nov-06	7,680,000	25%	10,194,510
Reactive Compensation Southern Load Area	$ 3,406,931		3,480,000	25%	4,627,254
Darlington: 3Rd Transformer	$ 5,766,243	28-Feb-07	4,300,000	25%	5,766,243
Replace 6 Cb 330Kv Brown Boveri	$ 2,767,044	7-Feb-07	2,074,000	26%	2,808,630
Confidential text deleted	$ 14,151,160	15-Jun-05	11,300,000	27%	15,471,969
Confidential text deleted	$ 9,843,201	17-Aug-05	8,700,000	29%	12,219,420
Rangeway : Establish New Substation	$ 2,430,412	18-Oct-01	9,358,000	29%	13,258,369
Kw-Sf 81: Convert Line To Double Circuit	$ 12,612,428	22-Mar-05	10,730,000	30%	15,221,614
Clarkson - Establish New Substation	$ 4,715,636	17-Dec-03	6,833,000	30%	9,704,780
Replace 143 Aric Oil & Winding Temperat	$ 2,225,669	3-Apr-06	1,604,600	30%	2,279,543
Sawyers Valley S/S:Stage 2 Network Reinf	$ 2,402,414	3-Feb-06	1,682,000	30%	
Establish New Substation - 4 New Feeders Henley Brook	$ 2,639,220	30-Sep-04	1,800,000	32%	
Reactive Comp - Various Metro Substation	$ 2,788,274	16-Dec-05	1,931,000	32%	2,845,994
Pjr - Wno : Construct New 132Kv Line	$ 26,260,421	13-Jan-05	20,628,000	33%	30,586,198
Reinforcement Of The 22Kv Distribution Network Bunbury Harbour Several Fee	$ 2,521,472	11-Jul-06	1,660,000	34%	
Medium-Term, Second Toodyay Feeder Northam Toodyay	$ 3,495,548	16-Jun-05	2,234,000	36%	
Bibra Lake Fault Upgrades Aust. Paper Mills Spearwood Ave	$ 3,844,087	21-Jan-05	2,400,000	38%	
Waikiki : Establish Zone Substation	$ 10,261,622	23-Mar-05	7,510,000	38%	12,044,582
Henley Brook - Establish New S/S	$ 13,913,062	30-Sep-04	9,300,000	38%	15,030,577
Installation Of New Merlin Rd Feeder At Mandurah Substation - Cpa 0194, N0	$ 2,670,819	13-Jun-05	1,567,000	41%	
Morley S/S : Install 3Rd Tranformer	$ 5,083,693	25-Nov-05	2,750,000	46%	5,137,399
Confidential text deleted	$ 5,793,974	30-Apr-07	2,768,000	52%	5,795,022
Substation Safety Upgrades : Stage 3	$ 5,464,917	11-Sep-06	2,261,051	59%	5,464,917
Distribution Works On Establishment Of Waikiki Substation Waikiki New Fee	$ 3,676,498	23-Mar-05	1,350,000	63%	
Confidential text deleted	$ 2,335,997	19-Dec-06	960,000	67%	2,881,766
Confidential text deleted	$ 8,695,475	8-Dec-06	2,800,000	68%	8,713,029
Comms Network Monitor System Purchase	$ 2,541,875	26-Aug-05	392,000	86%	2,743,734
Under Estimate Subtotal	**$ 190,200,879**	**31**			
Asset Repl - Primary - Circuit Breakers	$ 2,318,201	27-Jun-07	-	100%	2,318,201
Sw Bulk Transmission Reinforcement Stg 1	$ 4,360,636	1-Jun-07	#N/A	#N/A	4,396,097
HIGH WIDE LOAD CORRIDOR 2 (HWLC2)	$ 2,520,357		#N/A	#N/A	
ST-WGP/APJ 81 POLES 405 - 412 ALCOA PINJ	$ 2,372,258		#N/A	#N/A	
PERTH BUNBURY HWAY SOUTH GATEWAY ALLIANC	$ 2,791,110		#N/A	#N/A	
Fremantle	$ 7,804,118		#N/A	#N/A	
Como East	$ 10,650,102		#N/A	#N/A	
Nedlands East	$ 4,033,893		#N/A	#N/A	
Churchlands/Wembley Downs	$ 14,473,680		#N/A	#N/A	
Highgate East	$ 6,320,500		#N/A	#N/A	
Distribution Works On Establishment Of Southern River Substation Southern	$ 3,113,128		#N/A	#N/A	
Mt Pleasant North	$ 5,548,293		#N/A	#N/A	
Customer Information Systems	$ 9,326,237		#N/A	#N/A	
No Estimate Subtotal	**$ 75,632,513**	13			
Grand Total	**343,526,557**				

ATTACHMENT G
Western Power's detailed response to Required Amendment 29

1. Introduction

Required Amendment 29 states:

> "The target revenue should be revised to reflect a pre-tax WACC value of 7.06 percent, subject to revision of the risk free rate and the debt margin at a date to be advised and prior to the Authority's final decision."

Section 2 below sets out Western Power's comments on Required Amendment 29. In light of this discussion, Section 3 presents Western Power's suggested approach for addressing this Required Amendment.

2. Western Power's comments on the Required Amendment

In its Draft Decision, the ERA proposed a real pre-tax WACC of 7.06% subject to revision of the risk free rate and debt margin at the time of the ultimate final decision.

Following the publication of the Draft Decision, Western Power engaged KPMG to provide expert advice on the WACC. A copy of KPMG's report is provided as Attachment H.

The Authority will be aware that in May of this year, the Australian Energy Regulator (AER) completed an extensive review of the WACC parameters to be applied to regulated electricity distribution and transmission businesses in the National Electricity Market. The AER's review concluded that the following WACC parameters are applicable to the regulated electricity network businesses.

Parameter	Value / method for determination[1]
Gearing	60% debt to total assets
Risk free rate	10 year Government bonds
Benchmark credit rating	BBB+
Debt risk premium[2]	Based on the Australian benchmark corporate bond rate for corporate bonds at the benchmark credit rating and for a maturity of 10 years.
Equity market risk premium	6.5%
Beta	0.8
Gamma (franking credit value)	0.65

1 As set out in the AER's May 2009 *Statement of the Revised WACC Parameters (Transmission)* and *Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)* unless otherwise noted.

2 As specified in clauses 6.5.2(e) and 6A.6.2(e) of the National Electricity Rules.

Western Power contends that there are no valid reasons to suppose that the cost of capital faced by a Western Australian electricity network business would be any lower than that determined by the AER as being applicable to similar businesses in the Australian National Electricity Market. On this basis, Western Power considers that the point estimate of the WACC should be no less than the WACC value obtained by applying the parameter values determined by the AER in May 2009.

Western Power also notes that KPMG has indicated that there may be grounds for further upward revision of values for parameters used in the calculation of the WACC. Western Power requests that the Authority also considers these issues in relation to the WACC.

3. Western Power's proposed approach for addressing Required Amendment 29

The pre-tax WACC value of 7.06 percent specified in Required Amendment 29 is materially below the WACC value obtained by adopting the parameters determined by the AER for application in the National Electricity Market. Given the reasoning set out above, Western Power does not agree with Required Amendment 29.

Western Power's position is that the WACC should be no less than the value obtained by applying the WACC parameters determined by the AER. Therefore, for modelling purposes in preparing this submission, Western Power has used a WACC of 7.59% real pre-tax which reflects the AER parameters set out in the table above, and current market conditions (up to 30 June 2009).

ATTACHMENT H

Western Power

The cost of capital

The ERA's Draft Decision on Western Power's Proposed Revisions to the Access Arrangement for the South West Interconnected Network

Government
September 2009
This report contains 37 pages
WPC Draft Decision WACC040909.doc

Contents

Inherent Limitations

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KPMG have indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

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The findings in this report have been formed on the above basis.

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1 Executive summary

1.1 Background and purpose of this report

In Western Power's Proposed Revisions to the Access Arrangement for the South West Interconnected Network ("SWIN"), it proposed a pre-tax real WACC of 8.95%. This proposal was based, in part, on advice KPMG provided to Western Power, as contained in our report dated July 2008.[1] That report made recommendations on the values or value ranges that Western Power should adopt for each of the underlying parameters that make up the WACC, and explained the basis for these recommendations.

On 16 July 2009, the Economic Regulation Authority ("ERA") issued its Draft Decision on Western Power's proposed revisions to the access arrangements for the SWIN. The Draft Decision rejected the WACC proposed by Western Power and required that it further amend its revisions by using pre-tax real WACC of 7.06%.

Western Power has instructed KPMG to consider the ERA's Draft Decision in respect of the cost of capital and comment on the basis for its decision. In doing so, KPMG has examined both the process by which the ERA has arrived at its preferred WACC and the basis upon which the ERA has assessed the values and / or value ranges for the underlying parameters.

1.2 Key findings

1.2.1 Comments on the ERA's process

The ERA has rejected Western Power's proposed WACC of 8.95% on the basis that the value falls outside of the range that the ERA considers to be reasonable. In arriving at its range, the ERA has undertaken the following process:

1 The ERA has made judgments on the estimate of the cost of capital that would "best" or "better" meet the objectives of the Access Code. This is reflected in the ERA's:

- reasons for removing the 10th and 90th percentiles of the range generated using its preferred underlying parameter values; and

- selection of a point value – the midpoint of its range – as the WACC.

This approach is inconsistent with that adopted by the ERA in its last decision for the SWIN, and would appear to be inconsistent with the requirements of the Access Code.

2 The ERA does not appear to have taken into account the likely impact of the Global Financial Crisis in assessing required rates of return (e.g. in assessing the MRP).

[1] KPMG, Weighted Average Cost of Capital: Western Power, July 2008

3 The ERA appears to have relied on the same evidence used by the Australian Energy Regulator ("AER") in its first periodic review of some of the WACC parameters, under the National Electricity Rules ("NER"). However, except for the assumption on the value of imputation credits, it has arrived at different conclusions on the relevant parameter values, these being the:

- market risk premium ("MRP"), with the midpoint of the ERA's range – 6.0% – lower than that used by the AER (6.5%); and
- equity beta, with the midpoint of the ERA's range – 0.65 – also lower than that used by the AER (0.80).[2]

These differences lead to a cost of equity that is about 1.30% lower in real terms (equivalent to over 15 percentage points lower) than that proposed by the AER. The Draft Decision does not explain why it has reached such a different conclusion to the AER on the MRP and the equity beta, nor why it was in agreement with the AER's views on the value of imputation credits, when the evidence considered by the ERA is largely the same as that considered by the AER.

1.2.2 Comments on specific parameter values

Some of the difference between the ERA's and Western Power's WACC proposals can be explained by movements in market-based parameters. However, there are a number of other differences between the parameter values and/or value ranges proposed by the ERA, which reflect midpoint values that are lower than those proposed by Western Power. These are:

1 a larger range for the MRP, for which the midpoint is 6.0% (rather than 6.5% which is the midpoint value implicit in Western Power's proposal);

2 a lower range for the equity beta, with a midpoint of 0.65 (rather than 1.0 which is the midpoint value implicit in Western Power's proposal); and

3 a value for gamma in the range of 57% to 81%, for which the midpoint is 69%, compared with a range of 0% to 50% proposed by Western Power.

Our comments on the ERA's proposals for each of the above parameters are set out below.

Market risk premium

The ERA's proposed range for the MRP does not recognise the impact the Global Financial Crisis has had on levels of risk aversion across investment markets. As the AER has observed, current economic conditions are not stable, and there are, in the AER's view, a range of indicators that suggest the forward-looking MRP has changed from well below 6% to well above 6%.

[2] The ERA's gamma midpoint (69%) is also higher than that used by the AER (65%).

The process by which the ERA has assessed the appropriate value for the MRP is also of concern. As indicated above, the ERA does not appear to have taken into account the Global Financial Crisis, even though the available evidence from another of its recent decisions suggests that the ERA was aware that such considerations were relevant to its assessment.

Equity beta

The ERA has proposed to significantly reduce the cost of equity for investors through a lower equity beta (amongst other things). This decision comes:

- at a time when financial markets indicate that the cost of equity has in fact increased; and
- despite the fact that the SWIN is arguably a more risky asset than its interstate counterparts.

Investors in the SWIN face additional risks associated with the relatively high rate at which investment has been occurring. The risks associated with the regulatory regime under which it operates also expose investors to ex-post assessments of capital expenditure and revenue deferral. Electricity networks in eastern Australia do not face risks associated with investment optimisation as this is specifically prohibited under the National Electricity Rules.

Empirical measurement of the equity beta is an inherently difficult exercise and the resulting estimates frequently suffer from high levels of estimation error. Recognising this, regulators have historically tended to place more weight on other factors and less weight on empirical evidence when assessing the appropriate value for the equity beta. This practice was reinforced in the AER's recent WACC decision. By contrast, the ERA seems to have chosen to place more weight on empirical evidence and less on other factors, for reasons which are not apparent.

Value of imputation credits

The ERA's preferred range of 57% to 81% for gamma is justified principally on the grounds that it is consistent with the conclusions reached by the AER. No explanation has been provided for why the ERA believes that consistency with the findings of the AER is necessary for this parameter, but not in regards to the equity beta and the MRP. The ERA's reliance on the AER's conclusions is also questionable given that (as we highlight in Section 4.8) the AER's assessment would appear to suffer from a number of problems, which we believe weakens the case for the ERA's reliance.

A further issue with the ERA's assessment is that it has issued two decisions since the AER's final decision in May 2009 – one on TPI's rail infrastructure and the other on the SWIN – but has only chosen to be consistent with the AER's final decision in one of these cases, this being for the SWIN. We consider that the inconsistencies in the ERA's process raise questions about its assessment in the case of the SWIN.

1.2.3 Financial adequacy

In addition to our comments on the ERA's assessment process and its views on specific parameters, KPMG believes that there may be some issues with the ERA's target revenue modelling.

Our high level tests of the ERA's target revenue modelling indicate that:

- there are risks that investors may not receive the WACC of 7.06%, which the ERA has proposed due to the lack of certainty that the deferred revenue will eventually be recovered in full; and

- in the distribution business, revenue deferral appears to result in cash flows insufficient to allow the business to repay its debt (to enable it to maintain a constant 60% gearing level each year) and to pay dividends and imputation credits at a rate that ensures that equity investors receive a cash flow return at a rate to allow a pre-tax real WACC of 7.06%.

These concerns raise issues over whether a higher cost of debt should be allowed (given the higher levels of gearing that the business is forced to sustain) and whether a higher equity beta is justified (given the risks associated with the business' ability to repay its debt).

2 The ERA's Draft Decision on the cost of capital

2.1 Overview and comparison with Western Power's proposal

In Western Power's Proposed Revisions to the Access Arrangement for the South West Interconnected Network ("SWIN"), it proposed a pre-tax real WACC of 8.95%. This proposal was based, in part, on advice KPMG provided to Western Power, as contained in our report dated July 2008. That report made recommendations on the values or value ranges that Western Power should adopt for each of the underlying parameters that make up the WACC, and explained the basis for these recommendations.

Western Power's proposal was based, in part, on prevailing market rates at the time its proposed revisions were submitted. The proposal noted these rates would be subject to revision in the lead up to the ERA's Draft and Final Decision to reflect prevailing market conditions at the time. Western Power argued that its proposals were consistent with the principles espoused by the MCE's Expert Panel as codified in the National Electricity Rules, and satisfied the requirements of the Access Code.

Table 1 sets out the values and value ranges for individual parameters put forward in Western Power's proposal, and those adopted by the ERA in its Draft Decision.

Table 1: Western Power's cost of capital proposal and the ERA's Draft Decision

	Western Power proposal October 2008	ERA Draft Decision July 2009
Nominal risk free rate*	6.45%	5.60%
Real risk free rate*	3.62%	3.15%
Inflation rate*	2.73%	2.38%
Debt %	60%	60%
Equity%	40%	40%
Market risk premium	6% – 7%	5% – 7%
Equity beta	0.90-1.10	0.50-0.80
Debt margin*	3.37% - 3.77%	3.11 – 3.17%
Value of imputation credits (gamma)	0% - 50%	57% - 81%
Range – pre-tax real WACC	8.50% - 11.12%	6.21% - 7.91%
ERA's "reasonable" range		6.38%-7.74%
Proposed value	**8.95%**	**7.06%**

* Market based parameters subject to revision

In its Draft Decision, the ERA noted that it had no issues with Western Power's methodology to estimate the WACC. As such, the differences between the WACC in the Draft Decision and

Western Power's proposal relate primarily to differences in the values of the underlying parameters.[3]

The ERA identified values or value ranges for the underlying parameters that make up the WACC. It then used these values or value ranges:

- to establish "the extremes" of the range for the estimate of the WACC;
- reduce that range by excluding values below the 10th and above the 90th percentile, on the basis that this approach would "best" meet the objectives of the Access Code;
- decided that Western Power's proposal did not meet the Access Code objective or the objectives of section 6.64 as it fell outside this range; and
- decided to use the "central value" of its range on the basis that no other value would "better" meet the Access Code.

There have been some significant movements in the value of some of the market-based parameters since Western Power submitted its proposed revisions. Those movements account for approximately 80 basis points of the difference between Western Power's proposal and the ERA's Draft Decision. To the extent that the ERA's proposals on market-based parameters do indeed reflect market movements, these parameters can be expected to continue to change until the ERA issues its Final Decision.

However, there are a number of other changes in parameter values and/or value ranges proposed by the ERA which reflect midpoint values and are lower than those proposed by Western Power. These are:

- a larger range for the MRP, for which the midpoint is 6.0%, rather than 6.5% which is the midpoint value implicit in Western Power's proposal;
- a lower range for the equity beta, with a midpoint of 0.65, rather than 1.0 which is the midpoint value implicit in Western Power's proposal; and
- a value for gamma in the range of 57% to 81%, for which the midpoint is 69%, compared with a range of 0% to 50% proposed by Western Power.

Based on these differences, ERA has rejected Western Power's proposed WACC of 8.95% and has required it to amend its target revenue calculations to reflect a pre-tax real WACC of 7.06%.

2.2 Issues with the Draft Decision

Western Power has instructed KPMG to consider the ERA's Draft Decision in respect of the cost of capital and comment on the basis for its decision. In doing so, KPMG has examined both the process by which the ERA has arrived at its preferred WACC and the basis upon which

[3] Western Power's also proposed a slightly different way to estimate the risk free rate, which the ERA rejected.

the ERA has assessed the values and / or value ranges for the underlying parameters. We also considered the evidence the AER relied upon in its recent review of certain WACC parameters.[4]

The WACC proposed in the ERA's Draft Decision raises concerns that fall into two broad areas. These are the ERA's:

- overall approach to assessing the reasonableness of Western Power's proposed WACC; and
- conclusions on a number of key parameter values, particularly given:
  - market conditions in light of the fallout from the Global Financial Crisis;
  - consistency with, or justified departure from, the recent decision made by the AER;
  - the process by which it has formed its conclusions on these matters; and
  - its consideration of the specific circumstances facing Western Power's network business.

[4] AER, Electricity transmission and distribution network service providers, Review of weighted average cost of capital (WACC) parameters, Final Decision, May 2009.

3 Approach and basis for determining WACC

3.1 Basis for approving or rejecting Western Power's proposals

3.1.1 The ERA's approach

The basis on which the ERA has made its Draft Decision appears to be inconsistent with how the ERA has interpreted the Access Code in the past, and with our understanding of how the Access Code should be interpreted.

This is illustrated by comparing the current Draft Decision to the ERA's Draft and Final Decisions on the first access arrangement for the SWIN.

First SWIN Access Arrangement: Final Decision

In the ERA's Final Decision for the SWIN, it:

- produced a reasonable range for the WACC, this being 5.57% to 6.85%;
- compared Western Power's revised proposed WACC to this range; and
- concluded that Western Power's proposed WACC was acceptable as it fell within the range.

This is evidenced by the following quote from the decision:

> *"The WACC incorporated by Western Power in the revised proposed access arrangement (6.76 per cent pre-tax real) lies within the reasonable range determined by the Authority for the purposes of this Final Decision. Accordingly, the Authority accepts that this value meets the requirements of the Access Code."*[5]

First SWIN Access Arrangement: Draft Decision

In the ERA's Draft Decision for the SWIN, it did not express any views on the merits of a specific point estimate within the reasonable range of values. It stated that:

> *"Taking into account all of the available evidence, the Authority's WACC Determination and the analysis described above, the Authority considers that a point estimate of the pre-tax real WACC that meets the requirements of section 6.64 of the Access Code and the Code objective is 6.0 per cent."*[6]

In the 2006 Draft Decision, the ERA refers to a point estimate that "meets" the requirements of the Access Code, rather than an estimate that "better" meets the requirements.

[5] ERA, Final Decision on the Proposed Access Arrangement for the South West Interconnected Network, 2 March 2007, paragraph 453.
[6] ERA, Draft Decision on the Western Power Networks Business Unit Proposed Access Arrangement for the South West Interconnected Network, 21 March 2006, paragraph 681.

2009 Draft Decision

In the current Draft Decision, the ERA has:

- Proposed adjusting its initial WACC range by removing the values below the 10th and above the 90th percentiles, resulting in a narrower range. This approach was chosen on the basis that it would "best" meet the objectives of the Access Code.

  > *"The Authority has given consideration to defining a reasonable range of estimates of the WACC that would best meet the objectives of the Access Code, which would be narrower than the range that may be derived by the application of the extremes of values for each of the parameters of the WACC."*[7]

  It is important to note that the ERA explicitly acknowledges the arbitrariness of this approach:

  > *"However, while the Authority recognises that no reasonable person would adopt the extremes of this range, the Authority is of the view that there is no apparent rigorous statistical or other method for determining precisely at which point values close to the extreme values of the range do not reflect a reasonable view of the current market for funds."*[8]

- Rejected Western Power's proposed WACC of 8.95% on the basis that it fell outside of the reasonable range of values, this being. 6.38% to 7.74%:

  > *"…the WACC proposed by Western Power of 8.95 per cent falls outside this range of values. Accordingly, the Authority considers that the WACC value proposed by Western Power does not meet the Code objective and the objectives of section 6.4 of the Access Code."*[9]

- Proposed a cost of capital set at the "central value" of its modified range, 7.06%, on the basis that no other value better meets the objectives of the Access Code:

  > *"there are no particular circumstances of the SWIN that would cause a value of the WACC in either the lower or upper part of the range of values indicated in paragraph 774 to **better** meet the relevant objectives of the Access Code".*[10] (emphasis added)

As such, the ERA's approach appears to be inconsistent with the approach it has adopted in the past.

3.2 Possible interpretations of the ERA's approach

The ERA's approach in its 2007 final decision is more consistent with KPMG's understanding of the correct interpretation of the Access Code, this being that the ERA is obliged to accept a proposal unless it is demonstrably inconsistent with the requirements of the Access Code.

As Section 4.28 (b) of the Access Code states:

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7 ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 16 July 2009, paragraph 772
8 Ibid., paragraph 773.
9 Ibid., paragraph 775.
10 Ibid., paragraph 777.

> *" to avoid doubt, if the Authority considers that the Code objective and the Requirements, ..., are satisfied, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements…"*[11]

Another related concern is with the ERA's approach of narrowing its feasible range. Whilst we note that this practice was also employed in the 2007 decision, the ERA's rationale for it appears to be questionable. In particular, applying individual parameter values which are in themselves considered reasonable should not result in a range of outcomes which are "extreme" or unreasonable at the upper and lower bound.[12] Moreover, whilst the ERA argues that narrowing the estimated WACC range is required to arrive at a "***reasonable range of estimates of the WACC that would best meet the objectives of the Access Code***"[13], this process does not appear to have had any impact on the ERA's Draft Decision and required amendments.

It is not entirely clear whether there has been a shift in the ERA's interpretation of the Access Code in the Draft Decision and, if there has, why that shift might have occurred.

[11] *Electricity Networks Access Code,* unofficial consolidated version, 4 November 2008, page 51. The Access Code also contains a note, which states "*The effect of section 4.28 is to make the Authority's decision in relation to a proposed access arrangement a pass or fail assessment."*

[12] Provided those parameters values and ranges are not inversely related, which the ERA does not appear to argue.

[13] ERA Draft Decision, para. 773.

4 Issues with specific parameters

4.1 Overview

KPMG has concerns with the views expressed by the ERA on the parameter values or value ranges, which relate both to the process by which the values were estimated and the resulting values for the:

- market risk premium ("MRP");
- equity beta, including the apparent lack of consideration of the commercial risks associated with Western Power's network business; and
- value of imputation credits (gamma).

These issues are highlighted in part, by the different conclusions drawn by the ERA and AER, even though similar evidence was used in both cases. In addition, these concerns reflect the ERA's apparent lack of consideration of market conditions, particularly in light of the Global Financial Crisis.[14]

4.2 The AER's decision of certain WACC parameters

The AER's decision was made under the National Electricity Law ("NEL") and the National Electricity Rules ("NER") in May 2009.[15]

The NER specifies the values for certain parameters critical to determining the rate of return for electricity transmission businesses, and outlines the process for periodically reviewing the values. The NER also states that, where the values for the above parameters cannot be determined with certainty, the AER must, amongst other things, have regard to:

(i) *the need to achieve an outcome that is consistent with the national electricity objective; and*

(ii) *the need for persuasive evidence before adopting a value for that parameter that differs from the value that has previously been adopted for it.*[16]

[14] References to the decisions made by the AER on certain parameter values which are made in this report by KPMG should not be presumed to reflect KPMG's agreement with the AER's choice of values.

[15] The ERA's decision is under the Access Code, but the differences between the objectives of the two instruments appear to be modest. The objective of the Access Code is to promote the economically efficient: (a) investment in; and (b) operation of and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks. In relation to the rate of return, the Access Code requires that service providers are given an opportunity to earn an amount of revenue that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved. The objective of the National Electricity Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

[16] National Electricity Rules Version 20, Chapter 6A Economic Regulation of Transmission Services, 6A.6.2(j)(4) and Chapter 6, 6.5.4(4).

The NEL therefore explicitly sought to place a high standard for making changes to these parameter values. It is surprising in these circumstances that the ERA has not attached significant weight to the findings of the AER.

4.3 The market risk premium ("MRP")

4.3.1 Issues with the ERA's draft decision

The ERA Draft Decision proposes a range of 5% to 7% for the MRP. It concludes:

> *"Taking the above evidence of realised equity premia over recent decades and market practice, the Authority considers that a reasonable range of estimates for the market risk premium is 5.0-7.0 per cent."*[17]

The Draft Decision also notes that the 2005 WACC Determination does not specify a value for the MRP, although a value of 6.0% is indicated as a "possible value".

It is important to note that the value of the MRP proposed by the ERA in the Draft Decision:

- does not appear to reflect the outcome of a detailed review (i.e. the discussion on the MRP in the Draft Decision is two pages, compared with 64 pages in the AER's review);
- does not appear to reflect consideration of prevailing market conditions and the Global Financial Crisis, which has had a significant impact on the market's views on risk; and
- ignores the outcomes of the AER's final decision.

In the AER's recent review, it decided to increase the value applied to the MRP from 6.0% to 6.5%.[18] The AER's decision was based upon the view that the forward looking MRP is likely to have increased as a result of the Global Financial Crisis and, as such, the AER considered it reasonable to adopt a value for the MRP above the long run historical average.[19]

The AER's decision to increase the value for the MRP is particularly significant because it occurred despite:

- long-standing and widespread regulatory practice of allowing a MRP of 6%;
- extensive debate over the past five years on whether the MRP has declined from historical levels;[20] and
- the strong resistance that the AER, and other regulators, have displayed towards adopting a MRP above 6%.

[17] ERA Draft Decision, paragraph 729.
[18] AER, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, May 2009.
[19] As interpreted by the AER.
[20] Much of this debate is contained the AER's Final Decision, pages 175 to 238.

The following extract from the AER's final decision demonstrates underlying rationale:

> *"The AER considers that prior to the onset of the global financial crisis, an estimate of 6 per cent was the best estimate of a forward looking long term MRP, and accordingly, under relatively stable market conditions – assuming no structural break has occurred in the market – this would remain the AER's view as to the best estimate of the forward looking long term MRP. However, relatively stable market conditions do not currently exist and taking into account the uncertainty surrounding the global economic crisis, the AER considers two possible scenarios may explain current market conditions:*
>
> - *that the prevailing medium term MRP is above the long term MRP, but will return to the long term MTP over time; or*
> - *that there has been a structural break in the MRP and the forward looking long term MRP (and consequently also the prevailing) MRP is above the long term MRP that previously prevailed.*
>
> *Whilst it cannot be known which of these scenarios explain current financial conditions, both are possible, and both suggest a MRP above 6 per cent at this time may be reasonable…"*[21]

As such, it is surprising that in the midst of what has been described at the most significant financial crisis since the Great Depression,[22] the ERA has not sought to examine the potential impact of current market conditions on the market cost of equity. This is despite the fact that other regulatory decisions made by the ERA around this time indicate that the ERA was aware of both the relevance of market conditions on the MRP, and the AER's decision to lift the value for the MRP to 6.5%.

The ERA's June 2009 Determination on TPI's rail assets

The ERA's assessment of the appropriate value for the MRP in the Draft Decision appears to be consistent with its June 2009 determination in relation to TPI's rail assets ("TPI 2009 Final Determination"). In that determination, the ERA used a MRP of 6%, which is consistent with the midpoint of the range for the MRP in the Draft Decision for the SWIN.

However, there are some aspects of the TPI 2009 Final Determination which raise questions about the ERA's assessment process. In that determination, the ERA highlighted submissions that pointed to an increase in the MRP due to market conditions, and also noted that the AER adopted a MRP of 6.5%. In the section on the MRP, 'Authority's Final Determination', the ERA states that it has taken into account the CRA's comments (its WACC adviser) in its final report:

> *"to the effect that there is no clear justification for increasing or decreasing the market risk premium in the current economic climate."*[23]

On this basis, the ERA then concludes that:

[21] AER Final Decision, page 238.
[22] Evans, Bill, Global Head of Economics, Westpac Banking Corporation, "The Credit Crisis and the Australian economy", published in AFMA, 2008 Australian Financial Markets Report, page 6. He described it as *"the most difficult period in the global financial system since the Great Depression of the 1930's"*
[23] ERA, Final Determination on the 2009 Weighted Average Cost of Capital for TPI's Railway Network, 22 June 2009, paragraph 116.

> *"there is insufficient evidence to justify any change to its assumed value of 6 per cent for the market risk premium."*[24]

However, it is worth noting that the ERA also states at the outset of the report that:

> *"CRA was **not** asked to provide the Authority with detailed advice on the CAPM or the **market risk premium**."*[25] (emphasis added)

The points set out above draw into question the basis of the TPI 2009 Final Determination since it would appear that the ERA's conclusion that there was insufficient evidence to move away from an assumed value of 6% for the MRP was made without seeking, "detailed advice" on the impact of the Global Financial Crisis on the market cost of equity, yet its views have been attributed to "comments" made by its adviser "to the effect that" the MRP had not changed.

The questions that we raise over the process for the TPI 2009 Final Determination are important because that decision was made three weeks before the ERA's Draft Decision for the SWIN. It suggests that the ERA Draft Decision for the SWIN on the MRP might have been influenced by views it formed in its Final Determination on TPI's rail assets, without the benefit of detailed advice from its consultant.

4.3.2 Market evidence on the MRP

The appropriate value to adopt for the MRP has been a highly debated issue for some time with regulators, regulated businesses and academics holding highly divergent views. Some of the differences were resolved in the AER's recent review of WACC parameters under the NER. This included agreement on:

- the need for internal consistency between the term of the risk free rate and the term of the MRP;
- the accepted use of arithmetic averages for historical average estimates;
- primary weight being placed on long-term historical averages (as opposed to short-term historical averages);
- the need to "gross-up" historical excess returns for the value of imputation credits distributed, but only for the period since the introduction of imputation tax system in 1987. In the AER's final decision, it was noted that historical excess returns grossed up by an assumed utilisation rate of 0.65 and estimated over a range of periods that the AER considered appropriate (i.e. 1883 – 2008, 1937 – 2008 and 1958 – 2008), all fell close to 6%, with some estimates above and some below. Specifically, these estimates fell within the 5.7% and 6.2% range;[26]

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24 Ibid., paragraph 117
25 Ibid, paragraph 27.
26 AER Final Decision, page 215.

- not explicitly adjusting historical data for potential positive or negative one-off events. The AER noted that recent research by Hathaway (2005)[27] and Hancock (2005)[28] identified a number of one-off events which were likely to have impacted on the measured MRP, but it was unclear whether excluding these events meant that historical estimates were more or less likely to overstate or understate a forward looking MRP;

- the problems associated with cash flow based measures of the MRP. Even though these measures are arguably more forward-looking, they suffer from inherent volatility through small changes in assumptions. It is significant to note that on this particular measure, the AER highlighted that in the past cash flow based measures have consistently produced a forward-looking MRP well below 6 per cent. Taking this into account, regulators considered that there was evidence to lower the MRP below 6%, but in the interests of promoting regulatory stability, maintained an MRP of 6%. However, the AER notes that of late, the values indicated by such measures "*… have changed from well below 6 per cent to well above 6 per cent."*[29]*;* and

- survey-based studies showing that 6% is the most commonly used MRP value adopted by market participants.

However, considerable differences in views remain on the finding in Gray and Hall (2006)[30] that to preserve internal consistency, it is necessary to adopt a value for the MRP of 6% and a value for imputation credits of zero.

Whilst it is generally agreed that 6% is the most commonly adopted value for the MRP (and that there is a large body of evidence to support the reasonableness of this assumption), the impact of the Global Financial Crisis has led to heightened levels of risk aversion across investment markets. For examples, the Boston Consulting Group ("BCG")[31] recently made the following observation:

> *"Investors are asking for hefty risk premiums across all asset classes. In particular, credit spreads have widened and will stay high for the foreseeable future – with significant volatility. Even for companies with good credit, this means a higher borrowing cost (e.g. the discount rate for investment-grade borrowers has spiked to ~600 bps for 60-day maturities). The conditions for longer term borrowing are no better."*

Such considerations have led to the AER to propose an increase in the value of the MRP from 6% to 6.5% in its recent review of WACC parameters. It is worthwhile noting the additional market evidence outlined in Officer and Bishop (2009),[32] which appears to have contributed to the AER's decision to raise the MRP. This includes the argument that whilst there was a large negative stockmarket return in 2008, this did not imply a negative forward looking MRP

[27] N. Hathaway, Australian market risk premium, Capital Research 2005
[28] J. Hancock, The market risk premium for Australian regulatory decisions, South Australian Centre for Economic Studies, 2005.
[29] AER Final Decision, page 220.
[30] Gray, S and J. Hall, Relationship between franking credits and the market risk premium, Accounting and Finance, 46, 2006, pp. 405 – 428.
[31] Rhodes, D., Stelter, D., Saumya, W., and Andre Krominus, Boston Consulting Group, Collateral Damage: What the Crisis in the Credit Markets Means for Everyone Else, October 2008, page 5
[32] B. Officer and S. Bishop, Market risk premium – Further comments- Prepared for ENA, APIA and TransGrid Australia, January 2009.

because there is likely to be an inverse relationship between the realised and forward looking MRP.

In particular, Officer and Bishop expressed the view that a decline in stock market returns arises from either a downgrading of expected cash flows for all stocks and/or an increase in the average discount rate, and under present circumstances, both have most likely occurred. They concluded that since there was a decline in the 10-year Commonwealth Government Bond rate over 2008 and given evidence of increased market volatility, it was likely that the underlying MRP has increased substantially, at least in the short-term.

Whilst the AER was not convinced that this represented persuasive evidence that the forward looking long term MRP would be significantly above the historical long-term average observed excess return, the AER considered that this provided:

> "*persuasive evidence that a structural break has occurred in the MRP (which would cause less weight placed on long term historical estimates) and consequently provide persuasive evidence from a departure from the previously adopted MRP of 6 per cent.*";[33]

In addition, Officer and Bishop highlighted that MRP estimates derived from observed corporate credit spreads for BBB-rated corporate bonds had risen substantially over the 2008 calendar year – 295 basis points for the 2008 calendar year compared with 122 basis points in the period to December 2006. They argued that the rise in corporate credit spreads could be explained by either an increase in the MRP, an increase in the beta or some combination of these factors. In the period to December 2006, an MRP of 6% together with a debt beta of 0.2 was required to explain an average spread of 120 basis points. However, for the 2008 calendar year an average spread of 300 basis points and an unchanged debt beta implied an MRP of 15 per cent. The AER's final decision appears to have placed some reliance on the likely rise in the implied MRP.[34]

The above evidence led Officer and Bishop to conclude that the prevailing short to medium term MRP is well above 6 per cent.

On balance, the AER's decision to increase the value for the MRP from 6% to 6.5% appears to have been driven by:

- primary weight being placed on long-term historical evidence which supports a range of 5.7% to 6.2% after grossing-up for imputation credits. Values indicated by surveys and cash flow based measures were also considered, with the latter strongly indicating that the forward looking MRP was well above 6 per cent; and

- acknowledgment that "relatively stable market conditions do not currently exist" due to the Global Financial Crisis.

[33] AER Final Decision, page 233.
[34] We note that Officer and Bishop also presented evidence to support the MRP implied from forward market contracts but the AER placed limited weight on this data.

4.4 Equity beta

4.4.1 Issues with the ERA's draft decision

The ERA's Draft Decision proposes a range of 0.50 to 0.80 for the equity beta. It concludes that:

> *"Having regard to these matters, but relying primarily on the best estimates of beta values for comparable businesses, the Authority considers that a reasonable range for the equity beta at a gearing level of 60 per cent to assets is 0.50 to 0.80"*[35]

The ERA's examination of the equity beta makes substantial reference to the evidence reviewed by the AER as part of its recent WACC review under the NER. However, the ERA draws a significantly different conclusion (the AER decided on a value of 0.80).

The ERA refers to the conclusions drawn by the AER, but does not explain how it arrived at a different conclusion based largely on the same evidence. The ERA's discussion on regulatory 'precedents', including the AER's decision, makes two key points:

- that regulatory precedents should *"be considered in the proper context"*[36] and be considered together with current capital market evidence. The ERA does not explain what this means, although the discussion appears to imply that there were historical reasons why regulators used higher betas in the past; and
- that in ascribing a value to the equity beta, *"primary reliance should be placed on capital market evidence and statistical estimates of the beta values."*[37]

We note that in the Draft Decision, the ERA highlights the need to set WACC at a value that:

- gives the service provider an opportunity to earn revenue that meets the forward-looking and efficient cost of funds;
- is commensurate with the commercial risks involved in providing covered services; and
- promotes the economically efficient investment in, and operation and use of, the SWIN and the services provided by the SWIN.[38]

We note that, whilst worded somewhat differently, these objectives would appear to be broadly consistent with the National Electricity Objective[39] ("NEO"), with which the AER is required to have regard (i.e. they both focus on economic efficiency over the longer term).

35 ERA Draft Decision, paragraph 743.
36 Ibid., paragraph 735.
37 Ibid., paragraph 737.
38 Ibid., paragraph 743.
39 The national electricity objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

The implication would appear to be that the ERA has arrived at a different conclusion than the AER after reviewing largely the same evidence because they:

- have each given significantly different weights to each of the above factors – this is possible since the ERA's Draft Decision refers to the AER's decision to adopt an equity beta value of 0.8 in its final WACC decision, whilst noting that analysis produced by the AER's consultants provided support for an equity beta around 0.45;[40] or

- each holds significantly different views about the outcomes necessary to promote economic efficiency. We note that the AER's final decision on WACC observes that whilst market data suggests a value for the equity beta that is lower than 0.8, "*…the AER has given consideration to other factors, such as the need to achieve an outcome that is consistent with the NEO (in particular, the need for efficient investment in electricity services for the long term interests of consumers of electricity).*" [41] By contrast, it is not apparent from the ERA's Draft Decision that the broader objectives in setting WACC have had any bearing on its decision on the equity beta value.

Another possible implication of the ERA's Draft Decision is that it believes that the systematic risks associated with Western Power's SWIN are low relative to similar energy network assets elsewhere in Australia. Our response to this argument is addressed at Section 4.5.

Irrespective of the underlying reason for the divergent views of the ERA and AER on the equity beta, the practical implication of the ERA's Draft Decision is that two regulators have formed quite different views about the relative market risks associated with investing in electricity transmission and distribution assets in different parts of Australia, when such differences do not appear to be justified on the basis of the intrinsic risk of the underlying asset.

4.4.2 Market evidence on the equity beta

As noted in KPMG's July 2008 advice to Western Power, empirical measurement of the equity beta is an inherently difficult exercise and the resulting estimates frequently suffer from high levels of estimation error.[42] These problems are compounded by the fact that there is only limited listed company data from which to empirically measure equity betas for energy network businesses in Australia. Whilst the use of comparable international companies is possible, there are significant challenges associated with translating such data into an Australian context given differences in tax regimes, mix of industry sectors and other structural differences between economies.

A value of 1.0 had been adopted for the equity beta in many regulatory decisions on energy network pricing in Australia to date. However, in recent years regulators have started to reduce the value for equity beta on the grounds that observed market data supports a lower value. At the same time, regulators have also acknowledged that measured equity betas may not be robust and hence the case for reducing the value of equity beta may not be as strong as the data alone would suggest.

[40] ERA Draft Decision, paragraph 683.
[41] AER Final Decision, page 343-344.
[42] Refer also to the methodological issues noted in KPMG's original advice to Western Power, Section 8.2.2.

Nevertheless, at the time KPMG provided its advice to Western Power, regulatory precedents pointed to a range of 0.80 to 1.0 for the equity beta of a network business with 60% gearing. Differences in regulatory decisions between jurisdictions have reflected regulators:

- choosing to place different weights on Australian empirical data, overseas empirical data and regulatory precedents in arriving at their specific decisions; and
- taking into account factors such as methodological issues with empirical measurement, data integrity / sample selection and size issues and the importance of regulatory stability in deciding upon the appropriate weights.

The AER has recently decided to adopt a value of 0.80 for the equity beta in its review of WACC parameters. The AER's review was characterised by a lengthy debate on – amongst other things – the methodological issues associated with empirical measurement of equity betas.[43] It would appear that the most contentious issues in this part of the AER's review related to the:

- choice of comparable companies (in particular, whether AGL, Alinta and GasNet should be excluded);
- use of weekly as opposed to monthly return observations. The AER chose to adopt weekly observations but many submissions noted that monthly observations were standard practice;
- importance and relevance of various statistical measures of bias, precision and reliability (in particular, the inferences which may be drawn when a low "R-squared" ratio is observed, and what confidence intervals indicate); and
- the appropriateness of applying Blume and Vasicek adjustments to beta estimates for individual firms to adjust beta estimates towards a 'prior belief' value.

The empirical evidence reviewed by the AER suggested a range of 0.41 to 0.68 for the equity beta. However, the AER's final decision was to adopt a value of 0.80 for the equity beta, after considering other factors such as the need to achieve an outcome consistent with the National Electricity Objective, in particular, the need for efficient investment in electricity services for the long term interests of consumers of electricity.

KPMG considers that the AER's empirical analysis does not necessarily support a conclusion that the forward-looking equity beta is lower now than it has been in the past. It must be noted that the true forward-looking equity beta is unobservable. Moreover, estimates of beta using historical data, which do not incorporate the period at the height of the Global Financial Crisis intensified, this being the last three months of 2008 after the collapse of Lehman Bros., may lead to erroneous conclusions about the appropriate direction of change for equity beta.

Technical and measurement issues aside, KPMG notes that the ERA's draft decision to reduce the equity beta from the previous range of 0.8 to 1.0, to 0.50 to 0.80, represents a 1.2% to 1.8% point reduction in the real CAPM cost of equity. We question whether this is an appropriate or

[43] AER Final Decision, section 8.5.3.1 to 8.5.3 7 pages 264 to 311.

prudent response at a time when capital markets have experienced unprecedented levels of turmoil.

Current market conditions support the view that the cost of equity has in fact increased due to the Global Financial Crisis. For example, data on the trading yields of infrastructure businesses as reported in the Financial Investor Group's submission to the AER's WACC review[44] indicates that there has been a material increase in the prospective yields of the businesses examined. The most likely reason for this movement is an increase in the cost of equity required by investors in such businesses.

This interpretation of the changes in trading yields is consistent with advice recently provided to the AEMC by its adviser on the financing of Australian energy sector investments, in light of the potential effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target. As part of this work, the consultant (S3 Advisory) interviewed financial market participants. On the basis of these interviews it concluded that:

> *"There is a strong view from the Financial Market Participants interviewed as part of this process that the cost of capital has risen and will remain at a higher rate than it has been in recent years. There was agreement that the risk has increased and, as discussed in the report, the corporate cost of debt has increased substantially. Given that the cost of capital represents the opportunity cost for capital and that Australia is a price taker on global capital markets, this would imply a higher opportunity cost to capital allocated to Australia and its energy sector. It is understood that some international investors in the energy sector have already raised their required rates of return."*

In respect of regulated energy networks in particular, it states:[45]

> *"…it is expected that the risk premium required on investments will increase, with those in the regulated energy sector being no exception."*

It also states:[46]

> *"Given a number of international energy Market Participants have recently increased their hurdle rates it is hard to conceive of a reason for them to invest in regulated assets that will potentially have their economic returns reduced by the regulator. Of course there may be other investors who will fill this gap but at this stage it is unclear who they might be given that the cost of funds accessed by corporate investors has increased substantially…*
>
> *..the cost of funds has increased for any providers of capital meaning that a reduction in the regulatory WACC and a significant increase in private funding are in obvious conflict."*

Australian energy businesses that have recently attempted to raise capital in the current market also provide evidence on the extent to which investors have raised their required returns.

Current market conditions do not support the view that the cost of equity has declined. This calls into question the ERA's proposal to reduce the cost of equity through, amongst other things, reducing the equity beta.

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[44] Financial Investor Group, Submission to the AER's WACC Parameter Review, January 2009, page 35
[45] Ibid., page 50
[46] Ibid., page 9-10

4.5 Risks associated with Western Power's network business

The ERA's Draft Decision implies that it believes the systematic risks associated with Western Power's SWIN are low relative to similar energy network assets elsewhere in Australia. KPMG believes there are reasons to suggest that, if anything, the SWIN is a relatively more risky electricity transmission and distribution business. There are two key reasons for this, these being the extent to which it is exposed to:

- development risk; and
- *ex post* asset value optimisation (and revenue deferment).

4.6 Development risk

Western Power is in an unusual business position given the amount of development that is currently occurring in Western Australia. This development has resulted in Western Power investing heavily to meet the needs of its customers, though the company has also experienced considerable volatility its capital expenditure needs. The evidence that we have reviewed in relation to the pace of asset growth within the SWIN indicates that:

- Western Power's investment over the current access arrangement period has been about \$2.5 billion.[47] This is equivalent to approximately 79% of the capital base at the start of the access arrangement period. It is also around 58% higher than was estimated at the start of the access arrangement period. This change was due to the ongoing rapid and unexpectedly strong growth in the Western Australian economy, with the commodities 'super cycle'.
- Western Power's revised proposed capital expenditure over the next access arrangement period is expected to be around \$3.5 billion (subject to further analysis by the ERA) or 66% of the opening value of Western Power's proposed capital base at the start of the next access arrangement period.[48]

  However, this capital expenditure is 17% lower than that estimated by Western Power in October 2008 when it submitted its proposed revisions. The change is due to the quick and unforseen change in economic conditions with the Global Financial Crisis, and the slow-down in growth in Western Australia, albeit from a very high base.
- Notwithstanding the volatility in actual and proposed capital expenditure, the actual annual capital expenditure in the current access arrangement period will be approximately \$860 million per annum compared to \$172 million per annum for regulatory depreciation. Capital expenditure will continue to be disproportionately higher than depreciation in the next access arrangement period.

Those capital investment needs, and the associated uncertainty, are indicative of a business that is not in a 'steady state', but rather one that is undergoing substantial development and asset

[47] Although there is dispute at the moment regarding the extent to which Western Power should be able to incorporate this into its capital base.
[48] Again, subject to the same dispute outlined above.

accumulation. Moreover, the evidence (as Appendix A illustrates) suggests that the rate of development faced by the SWIN is significantly higher than, at least, most of its peers.

It is reasonable to assume that there is more risk attached to this rate of development.

The impact of development risk on equity betas can be understood by looking at companies in the toll road sector, which have a share of their activity in toll road construction / development, as distinct from toll road operations. This data is shown in Table 2.

Table 2: Equity betas of selected toll road companies

Company	Equity beta	Gearing (%)
Transurban	0.77	44
Macquarie Infrastructure Group	0.86	70
Australian Infrastructure Fund	0.75	9
Connecteast Group	1.13	60
Rivercity Motorway	2.00	77

Rivercity Motorway is a single purpose investment vehicle established to finance, design, construct and operate the North-South Bypass Tunnel in Brisbane for a 45 year concession period. Analyst reports suggest that construction of the tunnel was roughly half complete in both works and dollar terms, and the opening of the tunnel is forecast to be ahead of its October 2010 schedule (which implies reduced completion risk). The equity beta for Rivercity Motorway therefore is akin to that of a Greenfield project with some degree of construction risk.

It is therefore likely that Western Power would have a more risky profile relative to many of its peers. These risks are likely to be exacerbated by the ERA's decision to undertake an *ex post* assessment of capital expenditure.

4.6.1 Assessments of historic capital expenditure

The ERA'S Draft Decision reduces Western Power's proposed opening value of the capital base for the second access arrangement period by \$474 million. This reduction has been proposed because the ERA considers there has been:

- *"systematic over-engineering of capital projects resulting in inefficiencies in the design of network assets";*[49] and
- *"deficiencies in the planning and governance of capital works, including inadequate consideration of options when planning network augmentations and poor cost-control and contract management for capital projects and programs".*[50]

As a result, the ERA has reduced the starting capital base value in the following manner:

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[49] ERA Draft Decision, paragraph 603.
[50] Ibid., paragraph 604

- firstly it has reduced the transmission network cost by $63.5 million and the distribution network cost by the same amount, arguing that these should not be considered as new facilities investment or they comprise an overstatement of costs for 2008/09; and

- secondly, it has reduced the new facilities investment (other than that comprising of gifted assets) by 15 per cent reduction (around $345 million), reflect likely inefficiencies in the undertaking of the investment.

The ERA has justified the size of the reduction in the allowed capital expenditure under the efficiency test as follows:

> "*Taking the above factors into account, the Authority considers that the extent of inefficiency is likely to be more than a nominal amount, but less than 25 per cent of the total value of new facilities investment….*
>
> *Taking into account the lack of information for this determination (refer to paragraph 345 and following) and the significant commercial effect that the determination will have on Western Power's business, the Authority considers that the extent of inefficiency to be taken into account in determining the value of new facilities investment to be added to the capital base should not be at the maximum of the possible range. On this basis, and having regard to the Code objective, the Authority has determined that the extent of inefficiency amounts to 15 per cent of the total amount of new facilities investment other than that amount of new facilities investment comprising assets constructed by other parties and gifted to Western Power"*[51]

Implications for risk

It is unlikely that *ex post* optimisation of capital expenditure can occur without imposing additional risk on the business, particularly given the development profile.

In discussing the capital base and new facilities investment, the ERA notes that utility regulators throughout Australia have favoured the roll forward method and this is also the method mandated for National Electricity Market electricity transmission and distribution networks under Chapter 6a and 6 of the NER. However, the ERA has failed to note that under the NER there is no scope for optimisation.

The AER addressed this issue in its Final Decision on various WACC parameters. It stated that:

> *"The AER considered that regulated utilities face a lower degree non-diversifiable business risk, compared to the market, which is primarily driven by the stable cash flows of regulated utilities. This in turn is driven by both the nature of the industry, such as the relatively high demand inelasticity of electricity to price, and by the protection of the regulatory regime.*
>
> *The regulatory regime for electricity transmission and distribution network service providers includes design features such as:"*
>
> …
>
> *"The rolling forward of the service provider's RAB, rather than the re-valuing or re-optimisation of the RAB at each reset. Under the ex-ante regime actual capex is rolled into the RAB, without any ex*

[51] Ibid., paragraph 605-606.

post prudency assessment.[52] *This approach means that at the end of each regulatory period a benchmark efficient NSP's prices and / or revenues are adjusted back to reflect their underlying cost base. This means that any increase in costs from forecast due to changes in GDP (which may effect the growth in peak demand), or from changes in commodity prices are automatically rolled into the RAB. The AER considered this was highly likely to reduce exposure to systematic risk compared with the market in general."*[53]

The ERA's Draft Decision therefore puts forward a lower equity beta than the AER and does so in the context of a regulatory regime that, in the AER's view, is "highly likely" to increase exposure to systematic risk.

4.7 Gamma (value of imputation credits)

4.7.1 Issues with the ERA's draft decision

The ERA's Draft Decision proposes a range of 57% to 81% for gamma. The ERA concludes that this is consistent with a distribution rate of 1.0 and an utilisation rate of 0.57 to 0.81. It also notes that this is consistent with the findings of the AER, which proposed a range of 57% to 74%,[54] and settled on a midpoint estimate of 65%.

The ERA has relied on the conclusion drawn by the AER in relation to gamma. It states:

> *"In considering the value of imputation credits, the Authority has had regard to the detailed consideration given by the AER to this element of the WACC calculation."*[55]

The ERA provides no explanation as to why the AER's views are particularly worthy of consideration in relation to this parameter. Nor has the ERA explained why, in establishing the upper end of its feasible range for gamma, it chose to select the results of a particular sub-period from the same study considered by the AER, rather than the results for the entire period under examination. The effect of the ERA taking into account (and slightly modifying) the AER's views on this parameter is to obtain a lower WACC than would otherwise be the case.

The ERA's position on gamma in the Draft Decision represents a significant shift on its earlier position, which it arrived at after considering the AER's decision. The ERA has issued two decisions since the AER's final decision in May 2009, but has only chosen to be consistent with the AER's final decision in one of these cases:

- on 22 June 2009, the ERA made its Final Determination on the WACC for the TPI's rail infrastructure, in which it used a gamma of 50%; and

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[52] *"In some regimes, such as telecommunications a RAB can potentially be re-optimised at each review, such as under a total service long run incremental cost (TSLRIC) approach, however, this is not the case under the NER."*
[53] AER, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, May 2009, page 248-249.
[54] The higher end of the AER's range reflected a midpoint estimate of a range of estimates from a study by Handley and Maheswaran (2008), whereas the high end of the ERA's range reflects the high end of the estimates in Handley & Maheswaran (2008).
[55] ERA Draft Decision, paragraph 751.

- on 16 July 2009, the ERA made its Draft Decision on the WACC for Western Power, proposing a value for gamma which it regards as being consistent with the AER's decision.

The process by which the ERA arrived at its conclusions on gamma for TPI's rail assets is instructive. The ERA's Final Determination discusses its Draft Determination (made in January 2009). It states:

> *"Australian regulators are faced with varying and conflicting theory and evidence on the value of franking credits. Evidence on the value of the imputation factor (including the impact of changes in taxation law on this value) supports gamma values anywhere in the range of zero to one.*
>
> *The Authority is left with a need to make a determination on the current value of gamma to be applied in TPI's WACC Determination with the major conceptual issues unresolved."*[56]

In the section 'Authority's Final Determination', the ERA then states:

> *"The Authority also notes that the AER has recently adopted a gamma of 0.65 in its final Statement of the Revised WACC Parameters (Transmission) and Statement of Regulatory Intent on the Revised WACC Parameters (Distribution) in May 2009.*
>
> *However, the Authority does not consider that the uncertainty relating to an appropriate value for gamma, as outlined in its draft determination, has significantly changed since this determination was published earlier this year.*
>
> *On this basis, the Authority confirms its position on the value of gamma as set out in its draft determination."*[57]

It would appear that the ERA has made two assessments about the same parameter three weeks apart and formed a different view on the appropriate gamma estimate to adopt, whilst relying on the same evidence. Moreover, in its TPI determination, it explicitly rejected the notion that the AER had removed the uncertainty relating to an appropriate value for gamma.

The ERA's process appears to raise questions about its assessment of gamma not just in its Draft Decision for Western Power, but also in the TPI Final Determination.

4.8 Market evidence on gamma

The value of imputation credits ("gamma" or γ) is equal to the product of the imputation credit payout ratio (also known as the distribution rate) and the utilisation rate, which reflects the market value of each dollar of franking credits in the hands of investors.[58] As noted in KPMG's July 2008 advice to Western Power, many previous regulatory decisions have adopted a value for gamma of 50%. This has typically reflected:

[56] ERA, Final Determination on the 2009 Weighted Average Cost of Capital for the Pilbara Infrastructure ("TPI's") Railway Network, paragraphs 297-298.
[57] Ibid., paragraphs 312-314.
[58] The utilisation rate is also often denoted by "theta" or θ.

- a distribution rate assumption in the range of 0.71 to 0.84. Much of the earlier regulatory decisions relied upon the distribution rate statistics in Officer and Hathaway (1999), which was recently updated in Officer and Hathaway (2004);[59] and

- a utilisation rate assumption in the range of 0.50 to 1.00. This assumption was based on a range of studies using methodologies such as dividend drop-off ratios, analysis of tax statistics, examination of rights issues and inference from trading in other derivative securities.

Up until recently, regulatory decisions on the value of gamma have typically focussed more on the utilisation rate than the distribution rate. The key issues with respect to the utilisation rate have tended to focus on the:

- identity of the marginal investor, including the question of whether foreign investors in the domestic capital market should be recognised;

- time period for estimating the utilisation rate (in particular, whether pre-2000 data should be taken into account); and

- merits of the results of studies which have attempted to estimate the value of the utilisation rate, including Cannavan, Finn and Gray (2004),[60] Beggs and Skeels (2006),[61] Ickiewicz (2007),[62] and Handley and Maheswaran (2008).[63]

The AER's discussion of the issues in its recent Final Decision indicates that substantial disagreement still exists on all of these issues. Nevertheless, the AER's final position was to rely on the utilisation rate estimates in Beggs and Skeels (2006) and Handley and Maheswaran (2008) to establish the range of the utilisation rate of 0.57 to 0.74.

The AER's review has also raised additional issues in relation to the distribution rate assumption. The ESC has only recently adopted a 100% distribution rate assumption in its 2008 Gas Access Arrangements Review, and now the AER has also made this assumption. In the AER's case, this move is based on technical advice provided by its consultant,[64] which indicated that this assumption is consistent with the commonly applied WACC framework adjusted for imputation (as indicated in Officer (1994)). This assumes that all cash flows are perpetuities

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[59] N. Hathaway and B. Officer, The Value of Imputation Tax Credits – Update 2004, Capital Research Pty Ltd, November 2004.
[60] Cannavan, D., F. Finn and S. Gray, 2004, The Value of Dividend Imputation Tax Credits in Australia, Journal of Financial Economics, 73, 167-197.
[61] Beggs, D. J. and Skeels, C.L., (2006), "Market arbitrage of cash dividends and franking credits," *Economic Record*, 82 (258), 239 – 252.
[62] Ickiewicz, J., (2007), "Valuing dividend imputation credits in Australia: An Alternate approach", Honours thesis, University of Queensland Business School (unpublished).
[63] Handley, J., and K. Maheswaran, (2008), "A measure of the efficacy of the Australian imputation system", Economic Record, 84, 264, 82-04.
[64] Handley, J., Further Comments on the Valuation of Imputation Credits, April 2009 http://www.aer.gov.au/content/item.phtml?itemId=728166&nodeId=9c5ddf922380f84d5dc1c17313045358&fn=Attachment%20A%20-%20Handley%20-%20Further%20comments%20on%20the%20value%20of%20imputation%20credits.pdf

and are fully distributed each period.[65] Consequently, whilst market observations provided support for a market average distribution rate of 71% as indicated in Hathaway and Officer (2004), the AER has chosen to adopt a 100% distribution rate for the purposes of estimating gamma.

The AER's final position on the utilisation rate and the distribution rate together establish a range for gamma of 57% to 74%, with a midpoint estimate of 65%.

4.8.1 Issues with the AER's analysis and conclusions

Notwithstanding the apparent thoroughness of the AER's review of the evidence on gamma, in our view, a number of arguments appear to have been either ignored or not satisfactorily addressed by the AER. These are set out below.

Behaviour of Australian stock prices around the time imputation tax credits were introduced

The AER does not appear to have addressed the reason why Australian stock prices did not behave differently to normal expectations when the dividend imputation system was introduced. In a submission to the AER's Issues Paper on the WACC review, the Strategic Finance Group ("SFG") pointed to the likely change in the cost of equity at the time imputation credits were introduced, and noted:

> *"If gamma really is 0.5, the cost of equity capital would have been reduced substantially and stock prices would have risen accordingly – in order of 30% or more."*[66]

SFG also referred to an unpublished study by Ickiewicz (2007) which found no evidence that Australian stocks behaved differently from what would normally be expected over the period imputation credits were introduced.

In rebutting the results of Ickiewicz (2007) and SFG's arguments, the AER noted that Ickiewicz (2007) did not appear to be consistent with another study it had reviewed. However, the AER merely refutes the findings of Ickiewicz (2007) without explaining why it believes that "*the finding from Ickiewicz (2007) that there was no abnormal share price movements … around the time of the introduction of the rebate provision in July 2000 does not imply that imputation credits are not valued by investors."*[67]

The AER claims that interpreting Ickiewicz (2007) as showing that imputation credits have no value is "*inconsistent with the empirical results from dividend drop-off studies*"[68] however, at the same it concluded that there are significant problems with dividend drop-off studies:

> *"That is, the AER considers that:*

[65] Whilst this does represent a departure from the previous "Monkhouse" approach (which assumed that a firm may payout less than 100% of its credits in a period but any retained credits are never paid out and therefore have zero value), the AER's consultant maintains that the Officer approach is more reasonable.
[66] Strategic Finance Group (SFG), 16 September 2008, The impact of franking credits on the cost of capital of Australian firms, Report prepared for ENA, APIA and GridAustralia, page 23.
[67] AER Final Decision, page 446.
[68] Ibid., page 446

- *It is reasonable to exercise caution in interpreting the results of dividend drop off studies, due to the inherent noise in the estimates, the often anomalous results, and the assumptions required for interpretation (e.g. perfect arbitrage, risk, etc.), and*
- *On this basis, taking into account the issues of multi-collinearity when estimating the 'franking credit drop off ratio' , an even greater degree of caution should be exercised in estimating theta from dividend drop off studies.*
- *In summary, once the significant issue of multi-collinearity is taken into account, the AER considers it questionable whether dividend drop-off studies can provide sufficiently reliable and/or useful information on the value of imputation credits."*[69]

Given these views, it is difficult to understand how the AER can benchmark the findings of Ickiewicz (2007) against the findings from studies which it expressly considers unreliable.

Questionable interpretation of Beggs and Skeels (2006)

The AER relied heavily upon the findings from Beggs and Skeels (2006) in forming its view on the appropriate lower bound estimate of the utilisation rate. Yet, Beggs and Skeels (2006) employ the dividend drop-off approach, the merits of which the AER has expressly called into question (as discussed above). The AER itself qualifies the study as follows:

> *"The AER acknowledges that the results from the Beggs and Skeels study need to be treated with caution given the issues associated with inherent noise in the estimates from the dividend drop off methodology, as well as the potential problems of multi-collinearity. One of the key advantages of the Beggs and Skeels study is that the authors attempt to address the difficulties with assigning value to the two components of the total dividend (i.e. the cash and imputation credit components). Beggs and Skeels argue that the results of their study do not suffer from such problems …The AER considers that although this may only mitigate (rather than remove) the issues associated with multi-collinearity, it appears to be a reasonable approach to dealing with the problem."*[70]

Interestingly, while the AER accepted Beggs and Skeels (2006) estimate of the value of the utilisation rate, it appears to have ignored another key finding from the study in relation to the value of cash dividends. In our view, this represents a significant omission on the part of the AER because as previously noted by SFG, the findings of Beggs and Skeels (2006) in relation to the value of the utilisation rate are:

> *"…conditional on dividends being worth only 80 cents in the dollar. …*
>
> *In my view, it would be inconsistent and wrong:*
>
> - *to reduce the required return (and the regulated price) to reflect the estimated value of franking credits, but*
> - *to not then take account of the offsetting effect of dividends being estimated to be worth only 75-80 cents in the dollar,*
> - *especially when these two effects are part of a single estimation exercise in which the first estimate is conditional on the second. If the required return is to be reduced on the basis of these estimates (as in (a) – which is the present regulatory practice) then the effect of dividends being worth less than their face value (as in (b) should be taken into account. Conversely, if the value*

[69] Ibid., page 437.
[70] Ibid., page 445.

or dividends in (b) is not taken into account, then the reduction in the required return should also not be taken into account."[71]

SFG concludes that if the combined value of cash dividends and imputation credits is around $1.00 – which is consistent with the combined results from Beggs and Skeels (2006) – then there is no surplus to be attributed to the franking credit. The AER's WACC review does not consider this issue. This is difficult to understand, given significance of its implications and the high degree of reliance that the AER has chosen to place on the study.

[71] Strategic Finance Group (SFG), 16 September 2008, The impact of franking credits on the cost of capital of Australian firms, Report prepared for ENA, APIA and GridAustralia, page 7 (para. 18).

5 Financial adequacy

Testing for financial adequacy

Ultimately, the ERA's assessment of WACC and the underlying parameters translate into forecast cash flows for the SWIN. If the assumptions that the ERA has used for these parameters are properly applied to estimate allowed revenues, then it should follow that debt and equity investors in the SWIN can expect to receive cash flows which equate to the rates of return that the ERA has assessed as being appropriate. In this regard, it is mathematically possible to test whether the key assumptions of the ERA's draft decision have been applied in an internally consistent manner, such that the resulting cash flows to investors equate with the stated allowed returns.

The issue that such testing typically focuses on is whether the ERA's proposed revenue stream implies a level of cash flow that is sufficient to enable Western Power to distribute dividends and associated franking credits, at the rate the ERA has assumed in its WACC assumptions, given its assumed benchmark level of gearing.

Scope of our review

KPMG has undertaken a high level analysis of the cash flows implied by the ERA's Draft Decision on the SWIN in order to test the internal consistency of this decision. We stress that we were required to undertake our analysis at a "high level" since we did not have access to a soft copy of the ERA's target revenue model.

We undertook the analysis based on the printouts of the public version of the ERA's target revenue calculations, which are contained in Appendix A of its Draft Decision.[72] This means that we were only able to perform a limited analysis of the model. Without access to the electronic copy of the model, we were unable to confirm whether the printouts we have analysed represent the complete model, nor have we been able to drill-down into the underlying calculations and checks that appear to be in the model. It is possible that with access to the electronic copy of the model, we would be able to further analyse whether our *prima facie* concerns are justified.

5.1 Issues identified

KPMG has identified what appear to be a number of potential anomalies in the target revenue modelling, which we are at present unable to resolve. These are described in detail below. Western Power may wish to conduct its own analysis to see if the apparent anomalies can be reconciled.

[72] ERA, Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, Appendix A: Target Revenue Calculation (Revenue Model), 16 July 2009.

Treatment and recovery of deferred revenue

The ERA has proposed to defer \$348.34 million of revenue for the distribution network and \$58.82 million for the transmission network business. The deferral of revenue effectively creates an asset for the business, and the ERA's Draft Decision indicates that it proposes to capitalise the deferred amounts:

> _"… the Authority considers that the access arrangement should, in effect, capitalise the amount of deferred revenue and provide for the recovery of this amount according to a defined schedule. In the absence of other relevant factors, the Authority considers that this schedule should provide for the recovery of the deferred revenue in a similar manner to the straight-line depreciation of physical network assets with a constant amount of recovery in each year subsequent to the second access arrangement period and over a total recovery period equal to the average life of network assets. "_[73]

There are clearly a range of options for recovering this deferred revenue. However, as part of that recovery, it would be appropriate to ensure that a return is factored into the capitalised value of the asset over the deferral period. Without this there is a risk that investors may not receive the WACC of 7.06% which the ERA has proposed.

We also note that the ERA's revenue deferral proposal means that the SWIN may be exposed to additional risks (relative to its interstate counterparts) associated with the future recovery of this revenue, if there is any uncertainty around the full recovery of deferred revenue not (e.g. if there are price shocks in the next access arrangement period).[74]

Ramifications of the revenue deferral

It would appear that the cash flows proposed by the ERA result in tax losses in the distribution business, and to less of an extent, in the transmission business. The proposed deferral of revenue adds to the tax loss.

Tax losses result from timing differences and therefore the less payment today means more payment tomorrow (and vice versa). Since tax losses can be accumulated to offset a business' future tax obligations, they represent an asset to the business. For accounting purposes, tax losses result in the recognition of an asset. However, in the target revenue methodology, there is no ability to value the tax losses as an asset (which would then attract a return).

Adequacy of expected cash flow returns

Our high-level attempt to replicate the ERA's target revenue calculations suggests that there may be a problem with financial adequacy in the distribution business. The proposal to defer a large portion of distribution revenue into the future either causes, or aggravates this problem. The resulting cash flows in the distribution business do not appear to be sufficient to:

- ensure that debt is repaid at a rate which ensures the distribution business maintains a constant gearing of 60% each year. If this scenario prevails, debt as a share of total capital

[73] ERA Draft Decision, para. 1021.
[74] We make this comment on the basis that regulators do change over time and a future regulator may not necessarily be bound by the promises made by his predecessor in the past.

will rise (above 60%) and, on this basis, the business may not receive a sufficient level of revenue to allow it to pay its assumed interest expense (which is calculated assuming debt equals 60% of the regulatory asset base). It also raises the question of whether the cost of debt and the equity beta would increase given the higher levels of gearing that the business would carry and the risks associated with the business' inability to repay its debt; and

- pay dividends and distribute imputation credits at a rate which ensures that equity investors in the distribution business receive part of their allowed return in the form of franking credits, which are valued at 69% of face value. Importantly, this implies that equity investors would not receive a cash flow return at a rate to allow a pre-tax real WACC on 7.06%.

Whilst we have not been able to extend the analysis to the transmission business, we suspect that the transmission business may face similar issues.

Requirement for external equity raising and recovery of equity raising transaction costs

Where issues of financial adequacy arise, they also raise the question of whether the business needs to raise equity funding from external sources. The formula for calculating the required amount of external equity raising required (in nominal dollars) is:

Equity raising required = Equity to be funded – (Internal cash flows – Repayment of debt – Dividends)

Where:

Equity to be funded =	Equity raised to funded CAPEX – Equity returned due to depreciation + Equity raised to fund impact of CPI on the asset base
Internal cash flows =	Revenue requirement less OPEX less interest expense less tax payable

KPMG notes that the AER's recent determination on the revenues for NSW electricity distribution businesses made an allowance for equity raising costs, or the transaction costs associated with required equity raising.[75] The AER considered that this allowance was justified notwithstanding that the NSW electricity businesses are in fact government-owned. This position recognises the fact that from a competitive neutrality standpoint, the AER's benchmark firm is defined as a pure play regulated electricity network operating in Australia without parent ownership.[76] The allowed rate was 2.75% of the capital to be raised.

It is important to note that the ERA has not allowed for equity raising transaction costs, which is something to which consideration should be given.

[75] We note that an allowance for equity raising transaction costs has only recently been allowed by the AER.
[76] AER Final Decision, NSW electricity distribution businesses, page 563.

A Comparison of Western Power's capital expenditure needs

Some indication of the extent to which investment is occurring in electricity transmission and distribution networks in Australian states can be obtained from the AER's 2008 State of the Energy Market report.

The Table below provides that summary. It shows that Western Power is spending relatively less on the basis of this comparison than some businesses (particularly in the NSW and Queensland).

Growth in RAB across all electricity businesses ranges is highly variable ranging from 30% to over 90% in the case of EnergyAustralia. Western Power's counterparts in NSW (except for TransGrid) in general display the most comparable level of investment growth, followed by its counterparts in Queensland. As shown in the table below, the AER has recently issued its final decision for the NSW electricity distribution businesses. Allowed capex for the regulatory period to 2013-14 amounts to $14.4 billion (in 2008/09 dollars) for all of the NSW businesses, which represents a growth of around 88% over the opening RAB for the regulatory period.

It is worth noting, however, that:

- The regulatory period for Western Power is three years, whereas for most of the other businesses (including NSW and Queensland) it is five years.

- Western Power's actual capex spend over the current regulatory period has significantly exceeded the amount which was approved at the last determination, which is indicated in the table below. If actual spend is taken into account, Western Power has increased the size of its RAB by about 79% over the current regulatory period.

TableA1:Rate of growth of asset base

Electricity transmission & distribution businesses	RAB at start of current regulatory period ($m)	Approved investment over current regulatory period ($m)	Approved capex as a % of RAB
Western Power (trans. & dist.)	**2,982**	**1,533**	**51.4%**
ElectraNet	1,251	655	52.4%
ETSA Utilities	2,468	810	32.8%
Transend	604	362	59.9%
TransGrid	3,013	1,184	39.3%
Energy Australia (trans & dist.)	8,235	7,838	94.2%
Integral Energy	3,690	2,721	73.7%
Country Energy	4,319	3,826	88.6%
ActewAGL	510	115	22.5%
SP Ausnet (trans. & dist.)	3,498	1,702	48.7%
Jemena	578	253	43.8%
United Energy	1,220	547	44.8%
CitiPower	991	529	53.4%
Powercor	1,626	1,008	62.0%
Powerlink	3,753	2,418	64.4%
Energex	4,308	3,011	69.9%
Ergon Energy	4,198	2,945	70.2%

KPMG analysis

Source: AER, 2008 State of the Energy Market Report, Regulatory decisions, proposed access arrangement information.

Notes

1 *According to the AER 2008 State of the Energy Market Report, RAB and approved capex data reflects the amounts shown in relevant regulator's final decision.*

2 *The regulatory period is 5 years for all businesses except Western Power which is 3 years*

3 *Opening RAB for NSW transmission & distribution businesses have been updated to reflect the recent AER's final decision for NSW electricity businesses*

ATTACHMENT I

Western Power's Response to Required Amendments 32 and 36

1. Introduction and overview

Required Amendment 36 states:

> “The proposed access arrangement revisions should be amended to provide for the recovery of deferred revenue as a constant amount in each year subsequent to the second access arrangement period and over a total period of recovery equal to the average economic life of network assets.”

This amendment has been proposed in relation to the deferral of revenue arising from Required Amendment 32 which states:

> “The proposed access arrangement revisions should be amended to provide for deferral of revenue from the second to the third and subsequent access arrangement periods in an amount that fully offsets the effect of the change in the treatment of capital contributions in the determination of target revenue.”

The Authority has proposed that the additional revenue arising in the second access arrangement period, as a result of the change in the treatment of capital contributions from the Queensland to the conventional approach, should be deferred and recovered over the average economic life of network assets.

Following publication of the Draft Decision, Western Power has undertaken extensive modelling to ascertain the effect of Required Amendment 36 on the Corporation’s financial performance. In addition, Western Power has engaged NERA Economic Consulting to provide expert opinion on Required Amendments 32 and 36. In light of this further analysis, section 2 below sets out Western Power’s comments on Required Amendments 32 and 36. Section 3 presents Western Power’s suggested approach for addressing this Required Amendment. A copy of NERA’s report is also provided as an Attachment J.

2. Western Power’s comments on the Required Amendments

Paragraph 834 of the Draft Decision states (in relation to Required Amendment 32):

> “As the change in treatment of capital contributions is such as to have no net commercial impact on Western Power in present value terms, the Authority considers that the deferral of revenue should be undertaken in such a manner as to minimise the price-shock effects on network users. The Authority considers that this would be best achieved by deferring an amount of revenue equal to the total effect of the change in treatment of capital contributions.”

Required Amendment 36 eliminates the possibility of Western Power recovering the deferred revenue over a period that is less than the average economic life of network assets.

Western Power has examined the effects of these Required Amendments. On the basis of this examination Western Power considers that there are sound reasons why the period over which deferred revenue is recovered should not be extended to the average life of network assets. These include:

- Financial modelling undertaken by the Corporation indicates that the full recovery of deferred revenue in the third access arrangement period will not result in a price shock in that period. The results of the modelling are set out in the table below:

Scenario	Increase in Average Price[1]				
	2012/13	2013/14	2014/15	2015/16	2016/17
Increase in average price path over the third Access Arrangement	2.4%	2.5%	2.5%	2.5%	2.5%

  The modelling indicates that the rate of change in the average price increases by only 2.4% to 2.5% per annum when deferred revenue is recovered during the third access arrangement period, instead of over the average economic life of network assets.

  Clause 6.4 requires a price control to have, as one of its objectives "avoiding price shocks (that is, sudden material tariff adjustments between succeeding years)." The Authority's interpretation of this provision in paragraph 834 of the Draft Decision (i.e. that "deferral of revenue should be undertaken in such a manner as to minimise the price-shock") is not correct. In this context, it is particularly noteworthy that in paragraph 860, the Draft Decision states:

  > "While the Authority acknowledges that the tariff increases permitted by the side constraint could be seen as contrary to the objective of section 6.4(c) of the Access Code of avoiding price shocks, the Authority considers that, consistent with section 2.3(b) and taking into account the Code objective, the objective in section 6.4(a) of allowing for recovery of efficient costs of provision of services should prevail over the objective of section 6.4(c)."

  Western Power concurs with this reasoning. Moreover, it is noted that the reasoning set out in paragraph 860 of the Draft Decision is equally applicable to a consideration of the length of time over which deferred revenue is recovered.

- Following on from the above point, it is noted that the deferral of revenue introduces a mismatch between the efficient cost of supplying network services and the network tariffs applied to customers. The true cost of present network services is deferred and near term tariffs are understated with any cost shortfalls recovered by an increase in long-term tariffs. This may lead to higher near-term demand for services as a result of inefficient economic decision-taking by network customers that further exacerbates the effects of revenue deferral. The recovery of deferred revenue over the average economic life of network assets will increase the period of subsidy to near-term users of the network in

[1] The average year on year increase in price path is derived from the modeled smoothed regulated revenues.

comparison to the full recovery of deferred revenue during the third access arrangement period. Allocative efficiency considerations therefore favour the recovery of deferred revenue over the shortest possible time-frame.

- Required Amendment 36 does not have a "neutral commercial impact" upon Western Power as claimed in paragraph 834 of the Draft Decision. The Authority has limited its assessment of the impact upon Western Power to a discussion in terms of net present value. This approach does not take into account the timing of revenue and cost cash flows, and the implications of these for the financial sustainability of Western Power. By restricting the recovery of deferred revenue to the average economic life of network assets, the Authority will increase Western Power's borrowings, financing costs and gearing levels in the intervening period. This has negative implications for Western Power's financial performance over the immediate and medium term, and thus, the impact of Required Amendment 36 is not commercially neutral when these factors are taken into consideration.

An extended discussion of other issues arising from Required Amendment 36 is contained in a report prepared by NERA Economic Consulting, a copy of which is provided as Attachment J.

3. Western Power's proposed approach to addressing the Required Amendments

In view of the reasoning and analysis set out above, Western Power proposes that the revenue deferred from the second access arrangement period should be recovered in full over the course of the third access arrangement period.

1 September 2009

Attachment J: ERA Required Amendments 32 and 36: Deferral of Target Revenue from AA2 to AA3 and Beyond

Western Power

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Contents

Executive Summary

Background

Western Power has asked NERA to provide advice in relation to the Economic Regulatory Authority's (ERA) Draft Decision to require Western Power to make the following arrangements to its Revised Access Arrangement for the second Access Arrangement period (AA2):

> **Required Amendment 32:** The proposed access arrangements revisions should be amended to provide for deferral of revenue from the second to the third and subsequent access arrangement periods in an amount that fully offsets the effect of the change in the treatment of capital contributions in the determination of target revenue.
>
> **Required Amendment 36:** The proposed access arrangement revisions should be amended to provide for the recovery of deferred revenue as a constant amount in each year subsequent to the second access arrangement period and over a total period of recovery equal to the average economic life of network assets.

In its Access Arrangement Information, Western Power proposed to defer the recovery of an amount of revenue from AA2 'to the third or subsequent access arrangement periods.' The amount of revenue deferral proposed by Western Power was $191.9m (present value as at 30 June 2009). The deferral of revenue was proposed as an 'extraordinary step' to manage the price impact on customers in the forthcoming access arrangement period arising as a result of Western Power's increased expenditure needs and its change in the treatment of capital contributions.

The impact of the ERA's required amendments 32 and 36 are to defer an amount of Western Power's target revenue which is expected to be more than twice as large (in present value terms) to that proposed by Western Power, and for a period that greatly exceeds that proposed by Western Power.

Impact of the required amendments

By requiring that the entire change in target revenue as a result of the change in capital contribution treatment be deferred from AA2 and then recovered over the average life of network assets, the ERA is in effect perpetuating key aspects of the 'Queensland approach' to capital contributions that occur over AA2.

As a result, many of the benefits associated with the change in the treatment of capital contributions will be lost for AA2, including:

- an improvement in financial sustainability for Western Power;
- an improvement in economic efficiency, by avoiding distortions to current and future tariffs; and
- improved inter-generational equity, as future users are not paying for assets used by current users.

Although the change in the regulatory treatment of capital contributions will have no impact on Western Power in present value terms, it will have a material impact on its financing decisions, due to the implied change in cash flows. Similarly, any deferral of target revenue from AA2 and beyond will reduce Western Power's cashflows, and therefore has the potential to adversely affect its debt ratio and debt costs.

In addition, under the required amendments current users will continue to face prices below the level of the true cost of service, leading to outcomes that are allocatively inefficient. By extending the time period over which revenue is recovered, this distortion in price signals will continue for longer.

The ERA's decision as to the amount of revenue to defer and the length of deferral needs to be cognisant of the impact of revenue deferral on Western Power's financial position and the implications for efficient price signals. It need not be the case that the appropriate amount of deferral from the perspective of achieving desired tariff outcomes exactly equates to the level of capital contributions expected for AA2.

Price control objectives

In the context of revenue deferral, we note that there is a potential conflict between the price control objective in clause 6.4(a) of the Code (which requires target revenue to be set to cover the forward looking and efficient costs of service provision) and that in 6.4(c) (avoidance of price shock). Where target revenue is deferred in order to better meet the objective in 6.4(c), this results in tariffs being below the cost of supply for current users and above the cost of supply for future users (ie, not in line with 6.4(a)).

This distortion in tariffs in turn results in outcomes that will be less allocatively efficient and therefore which do not promote the efficient use of networks, as required by the Code objective. As a result, consideration of economic efficiency would support a view that the objective in 6.4(a) should be given precedence over the objective in 6.4(c), in resolving any conflict.

Uncertainty in relation to recovery of deferred revenue

There are no explicit provisions in the Code for the ERA to bind itself to allowing the inclusion of deferred revenue in determining future target revenue. This is in contrast to the provision in the National Gas Rules that allow for the inclusion of fixed principles in an access arrangement.

There is therefore a degree of uncertainty for Western Power that deferred revenue will ultimately be recovered. This uncertainty is exacerbated by the increase in the amount and length of deferral under the ERA's required amendments.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of Western Power.

Western Power has asked NERA to provide advice in relation to the Economic Regulatory Authority's (ERA) Draft Decision to require Western Power to make the following arrangements to its Revised Access Arrangement for the second Access Arrangement period (AA2):

> **Required Amendment 32:** The proposed access arrangements revisions should be amended to provide for deferral of revenue from the second to the third and subsequent access arrangement periods in an amount that fully offsets the effect of the change in the treatment of capital contributions in the determination of target revenue.
>
> **Required Amendment 36:** The proposed access arrangement revisions should be amended to provide for the recovery of deferred revenue as a constant amount in each year subsequent to the second access arrangement period and over a total period of recovery equal to the average economic life of network assets.

Specifically, NERA has been asked to comment on:

§ the extent to which the required amendments are consistent with the Code provisions, in particular the price control objectives;

§ the reasoning provided by the ERA in its Draft Decision in relation to the required amendments; and

§ the implications of the required amendments from the perspective of economic efficiency.

The remainder of this report is structured as follows:

§ Section 2 sets out Western Power's Proposed Access Arrangement Revisions and contrasts these with the ERA's required amendments;

§ Section 3 discusses the relevant provisions of the Electricity Network Access Code ('the Code');

§ Section 4 considers the reasoning provided by the ERA for the proposed amendments;

§ Section 5 discusses the implications of the proposed revisions in the context of economic efficiency; and

§ Section 6 provides some conclusions.

2. Western Power's Proposal and the ERA's Required Amendments

2.1. The change in approach to the regulatory treatment of capital contributions

Under Western Power's approach to the treatment of capital contributions in the current access arrangement period (AA1) (the so-called 'Queensland approach'), forecast capital contributions were subtracted from Western Power's target revenue and the assets covered by those contributions were incorporated within Western Power's Regulatory Asset Base (RAB). This approach had the impact of reducing current network tariffs, but resulting in future tariffs being higher than they otherwise would have been, as Western Power would earn a return on and return of the value of contributed assets over the expected life of those assets. In effect, under this regulatory treatment of capital contributions current customers defer paying some of the costs associated with assets they are using today, but instead pay the return on and of the deferred amount over subsequent regulatory periods.

Western Power is proposing to change its approach from AA2 going forward, to bring it into line with conventional regulatory treatment. Under the conventional approach, contributed assets and the associated revenue from capital contributions are excluded both from Western Power's RAB and from the determination of target revenue (and therefore the determination of network tariffs).

Western Power commented in its Revised Access Arrangement Information that the proposed change in the regulatory treatment of capital contributions would result in a 'one-off' increase in Western Power's target revenue for AA2.[1] The 'increase' referred to is the impact on network tariffs in AA2 from target revenue no longer being reduced by the amount of capital contributions expected in AA2. That is, it is a notional 'increase' compared to the level of tariffs for AA2 that would have occurred had Western Power retained the Queensland approach to capital contributions. Western Power have not proposed to 'unwind' the deferral of revenue that in effect resulted from the adoption of the Queensland approach for AA1.[2]

2.2. Western Power's proposal to defer revenue

In its Access Arrangement Information, Western Power proposed to defer the recovery of an amount of revenue from AA2 'to the third or subsequent access arrangement periods.'[3] The amount of revenue deferral proposed by Western Power was $191.9m (present value as at 30 June 2009).[4]

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1 Western Power, *Revised Access Arrangement Information for the Network of the South West Interconnected System*, 1 October 2008, p. 110 and p. 146.

2 Specifically, Western Power have not proposed that the value of contributed assets in AA1 should be removed from the RAB and recovered via target revenue in AA2.

3 Western Power, *Revised Access Arrangement Information for the Network of the South West Interconnected System*, 1 October 2008, p. 110 and p. 146.

4 $14.6m for the transmission business (present value as at 30 June 2009) plus $177.3m for the distribution business (present value as at 30 June 2009).

Western Power noted that the deferral of revenue was proposed as an 'extraordinary step' to manage the price impact on customers in the forthcoming access arrangement period. In particular, Western Power commented that the deferral of revenue was proposed in order to effect a transition to the conventional approach to capital contributions (discussed above) and also to manage the price increase in the forthcoming access arrangement period as a result of Western Power's increased expenditure needs. Western Power reiterated the twofold reasoning behind the proposed deferral of revenue in its later submission in response to the ERA's Issues Paper.[5]

Western Power noted that its decision as to the amount of deferral was based on 'optimising the anticipated price increases at the commencement of, and during, the third access arrangement period.'[6] In its December submission Western Power commented that:

> The revenue deferrals have been designed to provide a transition path from present prices to cost reflective prices over a period of 4 years, thereby avoiding a much larger step increase in the first year and reduce [sic] the price shock impact.

Western Power proposed the inclusion of the following clause in its Access Arrangement Revisions to give effect to the proposed revenue deferral for transmission reference service revenue:

> 5.37A To manage the overall price increases in this *access arrangement period*, Western Power has deferred the recovery of some transmission *reference service* revenue from this *access arrangement period* to the third or subsequent access arrangement periods. The deferred amount of revenue is $14.6 million ($ real as at 30 June 2009) expressed in present value terms as at 30 June 2009. An amount must be added to the *target revenue* for the transmission network in the third *access arrangement period* or subsequent *access arrangement periods* such that the present value (at 30 June 2009) of the total amount added to *target revenue* (taking account of inflation and the time value of money) is equal to the present value of the deferred transmission *reference service* revenue (at 30 June 2009). For the avoidance of doubt, the addition to *target revenue* in the third and subsequent *access arrangement periods* must leave Western Power financially neutral compared to a situation where transmission *reference service* revenue deferral had not occurred.

An equivalent clause (5.48A) was proposed by Western Power to facilitate the deferral of distribution reference service revenue.

2.3. The ERA's required amendments

In its Draft Decision, the ERA is requiring Western Power to make the following amendments in relation to its proposal to defer revenue AA2:

> **Required Amendment 32:** The proposed access arrangements revisions should be amended to provide for deferral of revenue from the second to the third and subsequent access arrangement periods in an amount that fully offsets the effect of the change in the treatment of capital contributions in the determination of target revenue.

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5 Letter from Phil Southwell, Western Power to Robert Pullella, ERA, 17 December 2008, p. 6.

6 Western Power, *Revised Access Arrangement Information for the Network of the South West Interconnected System*, 1 October 2008, p. 110 and p. 146.

> **Required Amendment 36:** The proposed access arrangement revisions should be amended to provide for the recovery of deferred revenue as a constant amount in each year subsequent to the second access arrangement period and over a total period of recovery equal to the average economic life of network assets.

Amendment 32 requires Western Power to defer the *entire* amount of the adjustment to target revenue associated with the change in treatment of capital contributions. The ERA's estimate of the impact required amendment 32 is that the amount of revenue Western Power is required to defer is increased to $407.17m (present value as at 30 June 2009)[7], or more than double the $191.9m deferral proposed by Western Power. As discussed in section 2.1, the impact of the change in treatment of capital contributions is to remove the adjustment to target revenue to reflect the level of capital contributions. As a result, the final amount of revenue required to be deferred under required amendment 32 will depend on final forecasts of capital contributions for AA2.

Amendment 36 requires this deferred amount to be recovered over the average remaining life of network assets. NERA understands that the average remaining life for network assets assumed in the Draft Decision is 42 years for distribution assets and 51 years for transmission assets. As discussed above, Western Power had proposed to defer revenue only until the first year of AA3, ie, a period of 4 years.[8]

Taken together, the impact of the ERA's required amendments 32 and 36 are to defer an amount of Western Power's target revenue which is expected to be more than twice as large (in present value terms) to that proposed by Western Power, and for a period that greatly exceeds that proposed by Western Power.

In relation to required amendment 36, the ERA in its Draft Decision comments that:

> 'the access arrangement should, *in effect*, capitalise the amount of deferred revenue and provide for the recovery of this amount according to a defined schedule.' [9] [emphasis added]

From this statement it appears that the ERA is not proposing that the deferred revenue would actually be capitalised and incorporated within Western Power's RAB. Indeed, such an approach may not be consistent with the roll-forward approach adopted for determining the RAB for AA2.[10] As a result, we have assumed that the recovery of the deferred revenue will therefore need to occur via an explicit adjustment to target revenue in each subsequent access arrangement period.

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7 ERA Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, p. 232. The ERA has determined that the change in capital contributions revisions accounts for $58.82 million of target revenue for the transmission network and $348.35 million of target revenue for the distribution network, in present value terms.

8 Although Western Power refers in its Access Arrangement proposal to deferring revenue 'over 3rd AA and subsequent periods', its December submission to the ERA makes clear that the revenue deferral was envisaged to only be until the 1st year of AA3.

9 ERA Draft Decision, p. 275.

10 Clause 6.48 of the Code does not prescribe the manner in which the capital base is to be determined for each access arrangement period, but does require it to be determined in a manner consistent with the Code objective. As a result, capitalisation of the deferred amount may be able to be accommodated under an alternative approach, provided that it meets the Code objective.

3. Code Requirements

In this section we consider the ERA's required amendments in the context of the Code provisions. Specifically we consider:

- § the price control objectives under clause 6.4 and the potential conflict between 6.4(a) and 6.4(c); and
- § the potential for uncertainty in relation to the future recovery of deferred revenue, absent an explicit mechanism in the Code, and the associated risk implied for Western Power.

3.1. Price control objectives

The Code sets out objectives for the price control applying during an access arrangement, in clause 6.4. Specifically, clause 6.4 requires that the price control must have the objectives of:

> (a) giving the *service provider* an opportunity to earn revenue **("target revenue"**) for the *access arrangement period* from the provision of *covered services* as follows:
>
> (i) an amount that meets the forward-looking and efficient costs of providing *covered services*, including a return on investment commensurate with the commercial risks involved;
>
> [..]
>
> (c) avoiding price shocks (that is, sudden material tariff adjustments between succeeding years).

The ERA has pointed to the objective of avoiding price shocks in clause 6.4(c) in justifying its required amendments. The specific arguments put forward by the ERA in relation to avoiding price shocks are considered further in section 4.1. However, we note that in the general context of the deferral of target revenue there is a potential conflict between the two objectives 6.4(a) and 6.4(c). Target revenue is set in relation to the forward-looking and efficient costs of providing covered services. The deferral of target revenue from one access arrangement period to subsequent periods may result in the revenue recovered under the price control being *below* the level required to meet forward-looking and efficient costs, ie, to fall short of the objective in 6.4(a). Similarly, the inclusion of deferred revenue as part of target revenue for future access arrangement periods will result in target revenue for that period being ***above*** the forward-looking and efficient costs of providing covered services.

Under clause 2.3(b)(ii) of the Code, where there is a conflict between specific criteria in the Code in relation to the same thing, the Code objective is to be applied in deciding how the specific criteria can best be reconciled and which of them should prevail. The Code objective is set out in clause 2.1 as:

> The objective of this Code ("Code objective") is to promote the economically efficient:
>
> (a) investment in; and
>
> (b) operation of and use of,
>
> *networks* and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *networks*.

We note that the ERA elsewhere in its Draft Decision has expressed the view that the objective in clause 6.4(a) of allowing for recovery of efficient costs of provision of services should prevail over the objective of 6.4(c).[11]

Economic efficiency generally requires customers to pay the marginal cost associated with providing goods or services to them. Where target revenue is deferred in order to better meet the objective in 6.4(c), this results in tariffs being below the cost of supply for current users and above the cost of supply for future users. Where customers face a price below marginal cost, they will over consume the service compared to a circumstance where the price reflects the true cost of provision, ie, the outcome will be less allocatively efficient. Such an outcome would not promote the efficient use of networks, as required by the Code objective. As a result, consideration of economic efficiency would support a view that the objective in 6.4(a) should be given precedence over the objective in 6.4(c), in resolving any conflict. The implication of revenue deferral for economic efficiency is discussed further in section 5.

3.2. Uncertainty in relation to future recovery of deferred revenue

There is a question as to the extent to which the ERA is able to commit to allowing the future recovery of deferred revenue and therefore the extent of uncertainty faced by Western Power that deferred revenue will ultimately be able to be recovered.

3.2.1. No explicit mechanism in the Code covering deferral of revenue

The National Gas Rules (NGR) make provision for an access arrangement to contain fixed principles.[12] Inclusion of a fixed principle in an access arrangement is binding on both the regulator and the service provider for the period for which the principle is fixed. There are, however, no equivalent provisions under the Code for 'fixed principles' to be incorporated within Western Power's access arrangement. It is therefore unclear as to the status that any provisions in relation to the recovery of deferred revenue in Western Power's Access Arrangement for AA2 may have at the time the ERA considers the third and subsequent access arrangement proposals.

In making decisions under the Code, the ERA is exercising its discretion within the context of the Code provisions and of the ERA's powers under the Economic Regulation Authority Act. Regulators in other jurisdictions have acknowledged that they are not able to make binding commitments that limit their ability to exercise discretion in future regulatory decisions. For example, in Victoria the regulator commented that:

> The current regulatory framework is one within which the Office has the discretion to use judgment in exercising its statutory power. In the absence of an explicit legal power to bind future decision-makers, a decision-maker exercising statutory power now cannot bind future decision-makers in the exercise of that power. Moreover, the Office recognises the importance of not unduly fettering future decision-makers.[13]

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[11] ERA Draft Decision, para 860, p. 240.

[12] National Gas Rules Version 2, Part 9: Price and revenue regulation, Division 10: Fixed Principles.

[13] ORG, *Electricity Distribution Price Determination 2001-2005 Volume 1 Statement of Purpose and Reasons*, p. 87.

As a result, given that there is no explicit provision made in the Code for the ERA to commit to allowing the recovery of deferred revenue, there is therefore a degree of uncertainty for Western Power that target revenue deferred from AA2 will be able to be recovered in future.

This uncertainty is exacerbated by the absence of an explicit provision for the deferral of revenue under the Code. The Code requires 'target revenue' to be determined in accordance with clause 6.4(a). There is no reference in clause 6.4(a) to adjustments to target revenue to recover revenue deferred from a previous access arrangement period. We note that the ERA has previously commented that there is no explicit contemplation in the Code of either the deferral of target revenue or adjustments to target revenue to take account of previously deferred amounts.[14]

3.2.2. ERA's required amendments increase uncertainty

The impact of the ERA's required amendment 32 is to substantially increase the amount of revenue that would be deferred from AA2 compared with that proposed by Western Power. The extent of uncertainty increases the greater the amount of revenue that is deferred, all else equal. This is because the impact of the deferred revenue on future tariffs will be greater, the greater the amount of deferred revenue. When combined with changes in forward looking efficient costs expected at the time of future access arrangement decisions, this may again result in 'price shocks' that are considered unacceptable at that time. As a consequence, the recovery of the deferred revenue may be delayed further, in order to mitigate the impact on prices.

An increase in the period over which revenue is deferred may offset the uncertainty associated with an increase in the amount of deferral. To the extent that the tariff implications of the deferral are reduced for any particular access arrangement period, by being spread over more periods, their incorporation into target revenue is less likely to result in a 'price shock' that would lead to pressure for further deferral. However, counteracting this, the longer the time period of deferral the more review points there are. Under the ERA's required amendment 36, assuming an average remaining life of network assets of 50 years and five year access arrangement periods, the deferred revenue will be considered by the regulator <u>ten times</u>, before it is fully recovered by Western Power. It is possible that the consistency of such revenue deferral with the Code provisions could be challenged at any of those review points.

As a result, there appears to be a greater degree of uncertainty surrounding the ultimate recovery of deferred revenue under the ERA's required amendments than under Western Power's proposal, which limited the extent of deferral (and therefore the uncertainty) to one access arrangement period.

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[14] ERA Draft Decision, p. 274; ERA *Issues Paper on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, November 2008, p. 37.

4. ERA's Reasoning in its Draft Decision

The ERA makes the following points in support of both required amendment 32 and required amendment 36:

- the objective of 6.4(c) of the Code to avoiding price shocks; and
- the neutral commercial effect of the change in treatment of capital contributions on Western Power.

We discuss each of these points below.

4.1. Avoiding price shocks

The ERA points to the Code provision 6.4(c) in relation to the 'avoidance of price shocks' in justifying both its required revision 32 (that the entire amount of revenue associated with the change in treatment of capital contributions should be deferred) and required revision 36 (that the deferral should be over the average life of network assets).[15]

Clause 6.4(c) provides guidance in relation to the interpretation of 'avoiding price shocks' in that such shocks are defined as 'sudden and material tariff adjustments between succeeding years.' In determining the amount of revenue to be deferred in order to better meet this objective, it is therefore necessary to take a view on what is a 'material' increase in tariffs. We note that Western Power's proposed deferral amount of $191.9m was based on its view of the change in prices that was appropriate during the current access arrangement, and that the deferral was proposed in response to the price increases otherwise implied by both the change in capital contributions treatment and Western Power's proposed increase in expenditure in AA2. Furthermore, the extent of the price increase implied for AA2 will already be reduced compared to that proposed by Western Power, as a result of other aspects of the ERA's Draft Decision, including the ERA's proposed reduction in expenditure for AA2.

By definition, the more target revenue is deferred and the longer it is deferred for, the lower the impact on prices in AA2. The ERA's Draft Decision is that the impact on prices of the change in the treatment of capital contributions should be 'minimised'. This goes further than 'avoiding sudden and material tariff adjustments', as it may be possible for some of the price impact of the change in capital contributions approach to be accommodated in price increases for AA2 that are not considered to be 'material' overall. As a result, the objective in 6.4(c) by itself is not sufficient to support the ERA's required amendments. The required amendments also rely on the ERA's further argument that the change in capital contributions treatment is designed to have a neutral commercial impact on Western Power's business (discussed below).

In addition, we note that deferring revenue recovery into future periods may simply 'store up' the difficulty of accommodating future price rises. Changes in future costs and expenditure requirements may well require prices in future access arrangements to rise, and the impact of

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15 ERA Draft Decision, para 1018, p. 274.

also needing to recover deferred revenue will augment those increases. This is especially the case when the deferred revenue is to be recovered in the near term, in order to contain the risk faced by Western Power (as discussed in section 3.2).

4.2. 'Neutral commercial impact'

In its Draft Decision, the ERA refers to the change in capital contribution treatment as being designed to have a 'neutral commercial effect on Western Power's business in present value terms'.[16] The ERA considers that in this context the price-shock effects on network users should be ***minimised***,[17] and therefore that the entire amount of the increment to target revenue that would otherwise arise as a result of the change should be deferred (ie, required amendment 32). In addition, the ERA considers that the context of the 'neutral commercial impact' on Western Power supports its extended deferral of revenue under required amendment 36.[18]

The change in the regulatory treatment of capital contributions will result in Western Power receiving the same amount of revenue in present value terms as it would have under the previous treatment. However, the fact that there is no change in the present value of revenue received does not mean that there is no commercial impact on Western Power. NERA's earlier advice to Western Power in relation to the treatment of capital contributions highlighted the following advantages of changing the approach:

- an improvement in financial sustainability for Western Power;
- an improvement in economic efficiency, by avoiding distortions to current and future tariffs; and
- reduced tariff volatility and improved inter-generational equity, as future users are not paying for assets used by current users.

The improvement in financial sustainability resulting from the change in the approach to capital contributions arises through discontinuing the revenue deferral that occurs under the Queensland approach. Deferral of revenue results in reduced cashflows for the business (as current tariffs are below the level they would otherwise be) and has the potential to adversely affect Western Power's debt position and its debt costs.

In the same way as the previous capital contributions treatment affected Western Power's financial position, the explicit deferral of revenue from one access arrangement period to future periods also affects the business' financial position. The revenue earned under the deferred approach will be equivalent in net present value terms.[19] However, cash flows will be affected and the business may require higher debt levels to fund the current cost of service.

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[16] ERA Draft Decision, para 1020 p. 274.

[17] ERA Draft Decision, para 832, p. 232 and also para 1020, p. 274.

[18] ERA Draft Decision, para 1021 p. 274.

[19] Ignoring the potential uncertainty that deferred revenue will ultimately be able to be recovered, as discussed in section 3.2).

The substantially greater degree of revenue deferral required by the ERA and the significant extension of the timeframe for deferral may therefore have a commercial impact on Western Power and in particular may adversely affect Western Power's cash-flow, debt ratio and cost of debt.[20] [21]

By requiring that the entire change in target revenue as a result of the change in capital contribution treatment be deferred from AA2 and then recovered over the average life of network assets, the ERA is in effect perpetuating key aspects of the 'Queensland approach' to capital contributions that occur over AA2. As a result, the benefits associated with the change in the approach will be lost for AA2, including the benefits associated with improved financial sustainability for Western Power and improved price signals for economic efficiency (discussed in the following section). Moreover, as discussed in section 3.2, the ERA's proposed approach exposes Western Power to a greater degree of uncertainty in relation to the recovery of deferred revenue than under its previous treatment of capital contributions.[22]

As a result, the ERA's decision as to the amount of revenue to defer and the length of deferral needs to be cognisant of the impact of revenue deferral on Western Power's financial position and the implications for efficient price signals (see section 5). It need not be the case that the appropriate amount of deferral from the perspective of achieving desired tariff outcomes exactly equates to the level of capital contributions expected for AA2.

Finally, we note that where the ERA makes a decision to defer revenue from AA2 to subsequent access arrangement periods, Western Power should be kept 'financially neutral' to the impact of this change. This means that any additional financing costs resulting from the ERA's decision for greater revenue deferral (if retained) should be able to be recovered. This is reflected in Western Power's wording of its proposed access arrangement clauses 5.37A and 5.48A.

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[20] In the event that the increase in debt ratio exceeds Western Power's current Treasury debt allowance.

[21] We note that the impact of revenue deferral on a business' cash flow is explicitly acknowledged as a relevant factor in the NGR, in the context of the appropriateness of depreciation schedules. An adjustment to depreciation schedules to 'back-end' depreciation is an alternative means of addressing concerns in relation to price shocks. In order to ensure that any proposed 'back-ending' is appropriate, the NGR requires that the depreciation schedule should be designed: '89(e) So as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs'.

[22] Under the previous treatment of capital contributions the assets subject to contribution were included in Western Power's RAB, whereas the ERA is not proposing to actually capitalise the deferred revenue from AA2.

5. Implications for Economic Efficiency

The deferral of target revenue introduces a mismatch between the cost of supplying network services and the network tariffs applied to customers. This mismatch results in tariffs being below the cost of supply for current users and above the cost of supply for future users.

In principle, economic efficiency requires customers to pay the marginal cost associated with providing goods or services to them. Where customers face a price below marginal cost, they will over consume the service compared to a circumstance where the price reflected the true cost of provision. As a result, prices below the cost of service may drive higher network demand than would be the case if customers faced the true cost of service. Deferral of revenue therefore results in outcomes that are less allocatively efficient.

In addition, the deferral of revenue means that the current cost of providing electricity network services is funded partly by existing users, and partly by future users. While the revenue implications for Western Power are identical, the burden of payment between customers differs. The deferral of revenue does not provide intergenerational equity between current and future customers because it results in future customers subsidising the usage of current customers.

As noted above, NERA's earlier advice to Western Power in relation to changing the treatment of capital contributions highlighted the resulting improvement in economic efficiency, by avoiding distortions to current and future tariffs. This distortion arose as a result of the deferral of revenue from current to future access arrangement periods.

In this context, Western Power's proposal to defer revenue associated with the change in its capital contributions treatment from AA2 into AA3 can be viewed as a balance between:

- managing price shocks to customers (resulting from both the change in capital contributions treatment and the increase in proposed network expenditure in AA2); and
- a continuation of the distortions implied by the deferral of revenue under the previous treatment of capital contributions.

By proposing to defer revenue until AA3, Western Power was effectively prolonging some of the adverse consequences of the previous treatment of capital contributions, including the distortion of efficient tariff signals.

However, the ERA's required amendments further prolong these consequences, both by increasing the amount of revenue deferred but also (more importantly) by extending the timeframe over which revenue is deferred. As a result, the ERA's required amendments mean that the benefits associated with the change in the capital contributions approach will not be fully realised for contributions made during AA2. Current users will continue to face prices below the level of the true cost of service, leading to outcomes that are allocatively inefficient. By extending the time period over which revenue is recovered, this distortion in price signals will continue for longer.

6. Conclusions

The impact of the ERA's required amendments 32 and 36 are to defer an amount of Western Power's target revenue which is expected to be more than twice as large (in present value terms) to that proposed by Western Power, and for a period that greatly exceeds that proposed by Western Power.

By requiring that the entire change in target revenue as a result of the change in capital contribution treatment be deferred from AA2 and then recovered over the average life of network assets, the ERA is in effect perpetuating key aspects of the 'Queensland approach' to capital contributions that occur over AA2. As a result, many of the benefits associated with the change in the treatment of capital contributions will be lost for AA2, including:

§ an improvement in financial sustainability for Western Power;

§ an improvement in economic efficiency, by avoiding distortions to current and future tariffs; and

§ improved inter-generational equity, as future users are not paying for assets used by current users.

Although the change in the treatment of capital contributions will have no impact on Western Power in present value terms, it will have a material impact on its financing decisions, due to the implied change in cash flows. Similarly, any deferral of target revenue from AA2 and beyond will reduce Western Power's cashflows, and therefore has the potential to adversely affect its debt ratio and debt costs.

In the context of revenue deferral, we note that there is a potential conflict between the objective in clause 6.4(a) of the Code (which requires target revenue to be set to cover the forward looking and efficient costs of service provision) and that in 6.4(c) (avoidance of price shock). Where target revenue is deferred in order to better meet the objective in 6.4(c), this results in tariffs being below the cost of supply for current users and above the cost of supply for future users. This in turn results in outcomes that will be less allocatively efficient and therefore which do not promote the efficient use of networks, as required by the Code objective. As a result, consideration of economic efficiency would support a view that the objective in 6.4(a) should be given precedence over the objective in 6.4(c), in resolving any conflict.

Finally, we note that there are no explicit provisions in the Code for the ERA to bind itself to allowing the inclusion of deferred revenue in determining future target revenue. There is therefore a degree of uncertainty for Western Power that deferred revenue will ultimately be recovered. This uncertainty is exacerbated by the increase in the amount and length of deferral under the ERA's required amendments.

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ATTACHMENT K
Western Power's detailed response to Required Amendment 34

1. Introduction

Western Power proposes to address the matters in regard to a gain sharing mechanism raised by the Authority in Required Amendment 34, which states:

> "The proposed access arrangement revisions should be amended to specify a gain sharing mechanism as follows.
>
> a) Subject to paragraph (b) of this required amendment, an above-benchmark surplus is to be calculated for each of the years 2009/10 to 2011/12 as:
>
> ABS2009/10 = EIB2009/10 – A2009/10
>
> ABS2010/11 = (EIB2010/11 – A2010/11) – (EIB2009/10 – A2009/10)
>
> ABS2011/12 = (EIB2011/12 – A2011/12) – (EIB2010/11 – A2010/11),
>
> where
>
> ABSt is the above-benchmark surplus in year t ;
>
> EIBt is the efficiency and innovation benchmark for year t, being the forecast of non-capital cost for year t applied in the determination of target revenue for year t, adjusted for inflation as appropriate and adjusted to include any relevant adjustments for unforeseen events and changes to the Technical Rules as allowed for under sections 6.6 and 6.9 of the Access Code;
>
> At is the actual non-capital costs incurred by Western Power in year t, adjusted for inflation as appropriate, adjusted to include any relevant adjustments for unforeseen events and changes to the Technical Rules as allowed for under sections 6.6 and 6.9 of the Access Code and to exclude any amount of non-capital costs incurred by Western Power in implementing a non-network alternative to a capital project the costs of which are included in target revenue for the access arrangement period.
>
> b) In any year in which Western Power fails to meet service standard benchmarks for that year, the above-benchmark surplus for that year is zero.
>
> c) Subject to paragraph (d) of this required amendment, the following amounts may be added to target revenue for one or more access arrangement periods covering the years 2012/13 to 2016/17:
>
> GSMA2012/13 = ABS2009/10 + ABS20010/11 + ABS2011/12
>
> GSMA2013/14 = ABS2009/10 + ABS20010/11 + ABS2011/12
>
> GSMA2014/15 = ABS2009/10 + ABS20010/11 + ABS2011/12
>
> GSMA2015/16 = ABS20010/11 + ABS2011/12
>
> GSMA2016/17 = ABS2011/12
>
> Where GSMAt is the gain sharing mechanism adjustment to target revenue for year t.
>
> d) In any year where the amount of an adjustment to target revenue determined under clause (d) is a negative value, the amount of the adjustment to target revenue in that year is zero."

Section 2 below sets out Western Power's comments on Required Amendment 34. In light of this discussion, Section 3 presents Western Power's suggested approach for addressing this Required Amendment.

2. Western Power's comments on the Required Amendment

Western Power accepts the Required Amendment in principle. However Western Power does not accept the requirement under paragraph (b) of the Required Amendment, which states that "in any year in which Western Power fails to meet service standard benchmarks for that year, the above benchmark surplus for that year is zero".

This aspect of the Required Amendment reflects a contention that any failure to meet service standard benchmarks in a year is related directly to the level of non-capital expenditure in that year. Such a contention relies on the following two assumptions:

- firstly, that the reasons for perturbations in the service standards from year to year are related to the actual level of total non-capital expenditure; and

- secondly, that there is a direct temporal link between annual total non-capital expenditure and service standards.

For the reasons set out below, both of these assumptions are open to question.

Western Power acknowledges that over time, if network reliability-related non-capital expenditure is sustained at below efficient levels, then this will result in some deterioration in network service performance. However, such deterioration would be unlikely to be immediate (assuming that pre-existing level of expenditure were efficient), and moreover, the deterioration would be manifested as a trend change.

An efficient level of network-related expenditure should have the aim of achieving a defined service standard, having regard to the annual variations in measured performance that are due to factors that are unrelated to the level of expenditure (for example, variations in weather conditions). In this context, it is noteworthy that analysis of the causes of faults shows that weather-related events are the primary cause of approximately 30% of all faults (excluding major event days).

It is also noted that a significant proportion of non-network expenditure is not related to network reliability. The categories of non-capital expenditure can be distinguished between those that impact on network reliability performance and those that do not, as shown in the table below.

Expenditure categories that can impact network reliability	Expenditure categories not related to network reliability
Reliability	SCADA and communications
Maintenance Strategy	Non-reference services
Preventive Condition	Call centre
Preventive Routine	Metering
Corrective Deferred	Business support
Corrective Emergency	Network operations

It is noteworthy that the proportion of total operating expenditure on activities that have a direct bearing on the level of network reliability is:

- approximately 57% in the case of distribution; and
- approximately 40% in the case of transmission[1].

In view of this, and the other considerations set out above, it seems both unnecessary and unreasonable for paragraph (b) of the Required Amendment to require that "in any year in which Western Power fails to meet service standard benchmarks for that year, the above-benchmark surplus for that year is zero".

Western Power contends that any provisions within the gain sharing mechanism that are intended to give effect to the requirements of clause 6.2 of the Code[2] should:

- distinguish between operating expenditure that has a direct bearing on the performance of the network, and operating expenditure that does not;
- recognise that a significant portion of the annual service standard performance is not within the control of the service provider; and
- provide appropriate incentives for Western Power to minimise operating expenditure whilst ensuring that Western Power is incentivised to maintain and improve the performance of the network.

1 Based on 2008/09 actual expenditure.

2 This provision states, in relation to a gain sharing mechanism: "An above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period by failing to comply with section 11.1."

3. Western Power's proposed approach for addressing the Required Amendment

On the basis of the reasoning set out above, Western Power proposes to accept the required amendment, with the following adjustments.

It is proposed to separate the non-capital expenditure budget into two categories, those being:

- Expenditure categories that can impact on network reliability, and
- Expenditure categories not related to network reliability.

The table set out in section 2 above provides the suggested allocation of expenditure categories.

It is further proposed that the "above benchmark surplus" should be separately determined for each category of non-capital expenditure that is classified as having an impact on network performance.

In addition, it is proposed that the requirement under paragraph (b) (namely, that the above benchmark surplus be zero for any year in which the service standard benchmark is not met) apply only to the "above benchmark surplus" related to "expenditure categories that can impact network reliability".

Consequently, the "above benchmark surplus" for "expenditure categories not related to network reliability" would be retained regardless of the service standard achieved in that year.

ATTACHMENT L

Western Power's detailed response to Required Amendment 35

1 Introduction

Western Power proposes to address the matters raised by Required Amendment 35, which states:

> "The proposed access arrangement revisions should be amended to alter the specification of the service standard adjustment mechanism at clauses 5.24A and 5.24B to:
>
> (a) remove the dead-bands and limits around target values of service standards; and
>
> (b) calculate an amount of a difference between target and actual service standards as:
>
> SSD2009/2010 = (SSB2009/10 – SSA2009/10)
>
> SSD2010/2011 = (SSB2010/11 – SSA2010/11) – (SSB2009/10 – SSA2009/10)
>
> SSD2011/2012 = (SSB2011/12 – SSA2011/12) – (SSB2010/11 – SSA2010/11)
>
> Where:
>
> SSDt is the service standard difference in year t
>
> SSBt is the service standard benchmark in year t
>
> SSAt is the actual service standard in year t.
>
> (c) increase the value of incentive rates by a factor of 2.5 for distribution services and 2.5 for transmission services." [Note that the factor of 2.5 for transmission as is in accordance with the corrigenda issued by the Authority on 13 August 2009.]

The architecture of the Required Amendment reflects the Authority's view that under-performance or out-performance against the service standard benchmarks should be calculated as a year-on-year change in performance.

Section 2 below sets out Western Power's comments on Required Amendment 35. In light of this discussion, Section 3 presents Western Power's suggested approach for addressing this Required Amendment.

2 Western Power's comments and approach on Required Amendment 35

There are no Code provisions which would explicitly necessitate this Required Amendment. In addressing this Required Amendment Western Power has therefore considered in particular the approaches adopted in other regulatory regimes.

2.1 Approach applied in the National Electricity Market

Throughout the Draft Decision, the Authority has recognised the importance of maintaining consistency with the National Electricity Rules and the approaches applied by the AER. However, with respect to service standards and the service standard adjustment mechanism, the Authority has also drawn on the approaches applied in other regimes and in particular the ESC Victoria (ESCV).

The AER has recently published its Service Target Performance Incentive Schemes (STPIS). A revised Distribution STPIS was published in May 2009 and the AER's Transmission STPIS was published March 2008. These schemes now apply in all jurisdictions that are subject to the National Electricity Rules (NER).

In making determinations, the NER requires the AER to specify how a Service Target Performance Incentive Scheme (STPIS) will be applied. The scheme is intended to provide incentives that encourage the delivery of an economically efficient and appropriate level of service for customers. To achieve this outcome it is essential to have (among other things) an appropriate incentive rate in the STPIS and appropriate targets and mechanisms by which to apply the rewards and penalties relevant to each particular network. Indicative incentive rates in the AER's STPIS for distribution are based on the 'Value of Customer Reliability' (VCR) which is estimated to be $95,700/MWh for CBD load and $47,850/MWh for all other areas. These rates are intended to drive only investments which are economically efficient for the relevant community.

The transmission determinations which have been completed since the introduction of the AER transmission STPIS are:

- TransGrid Transmission Determination 2009–10 to 2013–14.
- ElectraNet Transmission Determination 2008–09 to 2012–13.
- Transend Transmission Determination 2009–10 to 2013–14.

For each of the above determinations, a total of 1% capped revenue at risk was divided up amongst the various service components (circuit availability etc.) which included collars and caps without deadbands.

Distribution determinations/guidelines since the introduction of the AER distribution STPIS include:

- The ACT and New South Wales distribution determination 2009/10 to 2013/14, which states[1]:

  > "The AER notes ... it must monitor and collect information from any or all of the NSW DNSPs and ActewAGL on matters relevant to be included in the STPIS... Revenue will not be placed at risk under the data collection process during this period."

  It is noted that the ACT and NSW determination was undertaken in accordance with the NER, and the AER's decision regarding the application of the STPIS to ACT and NSW distributors over the 2009/10 to 2013/14 period. That decision stated[2]:

  > "Clause 6.6.2(k) of the transitional Chapter 6 rules precludes the AER from applying a STPIS in the ACT which confers financial rewards or imposes financial penalties for the 2009–14 regulatory control period, without the agreement of the DNSP. ActewAGL has indicated it does not support the application of a financial incentive at the 2009 distribution determination.

[1] AER, *Final decision: New South Wales Distribution Determination 2009/10 to 2013/14*, 28 April 2009, page 244.

[2] AER, *Final decision Service Target Performance Incentive Arrangements for the ACT and NSW 2009 Distribution Determinations*, February 2008, page 7.

> While the AER has more scope under the transitional Chapter 6 rules to introduce a STPIS with financial impact in NSW than the ACT, the AER considers that it should not do so at this time for practical reasons. In particular, there are data and design issues which need to be addressed prior to the introduction of a scheme with potential financial impact."

- Victorian DNSPs are currently operating under the 2006 determination made by the ESCV however they now fall under the regulatory regime of the AER. On 29 May 2009, the AER published the framework and approach paper for its 2011-15 distribution determination for Victorian DNSPs. With respect to the STPIS, the paper states:

  > "The AER's likely approach is that it will apply the reliability of supply, customer service and GSL component of the [AER] STPIS to the Victorian DNSPs in the next regulatory control period."

In order to maintain consistency with the approach that is now applied nationally, Western Power considers that the requirements of other schemes (such as now superseded scheme applied by the ESCV) should not necessarily be adopted in Western Australia. Rather, Western Power believes the Code objective would be best served by taking general guidance where relevant from the STPISs developed in accordance with the National Electricity Rules.

2.2 Western Power's Original Submission

Western Power proposed separate SSAMs for the adjustment of both Transmission and Distribution revenues.

For each SSAM, Western Power proposed that:

- The values of penalty/reward rates were determined so that a maximum of 0.5% of the proposed target revenue was at risk. Rates were calculated such that the maximum potential loss or gain would occur if the actual values for all service standard indicators were at the limits.

- A penalty or reward to be determined for each year of the access arrangement period according to the difference between a service standard benchmark and the actual performance in each year.

- A dead-band range applies such that no adjustment occurs where actual performance is within a specified range of the service standard benchmark. The dead-bands establish a performance tolerance around the service standard benchmarks to cater for expected small variations in performance. The bounds of the dead-band were set, by reference to historical data on system performance, at +/-10% (with variations for some transmission indicators).

- Low and high limits applied to the achieved service standards for each performance indicator that may be taken into account in calculating the adjustments to revenue in order to cap the overall exposure to gains or losses. The performance limits were generally set at +/-20% (transmission circuit availability was set at +/-1% of availability)

2.3 Required Amendment Part (a) - Deadbands and Limits

Distribution

Under the SSAM, Western Power should be incentivised to undertake carefully considered planning of capital and operational work to achieve prudent nominated targets, whilst efficiently minimising costs. Western Power considers if a SSAM is overly punitive it has the potential to drive inefficient behaviour. Actual service standard performance is dominated by weather and Western Power considers that its proposed deadbands and limits for service standard targets are appropriate, as they minimise exposure to extreme random events.

However, Western Power also recognises the importance of consistency with other regulatory regimes and notes that the AER Distribution STPIS does not include deadbands or limits for individual performance indicators but does include a cap on total revenue at risk.

Consequently, to maintain consistency with recent decisions and guidelines by the AER, Western Power agrees to remove the deadbands and limits for individual performance indicators in the SSAM for distribution, but proposes total revenue at risk shall be capped at 1%.

Transmission

The Transmission SSAM proposed by Western Power contains a structure which is consistent with the service component of the AER transmission STPIS in that it includes targets, deadbands, caps and collars on performance indicators with a capped portion of revenue ascribed to each. It is noted that the market impact component of the AER transmission STPIS is not relevant to Western Australia give the design of the wholesale electricity market (WEM)

Unlike distribution indicators, it is not proposed that the definitions for transmission indicators will provide exclusions for major event days (such as in accordance with IEEE1366-2003 definitions). Transmission indicators can consequently be subject to volatility. For example, a new load of 150MW which has recently been connected to the SWIS on a radial transmission line will result in the *system minutes (radial)* indicator being disproportionately at risk of under performance due to a single outage.

Western Power further recognises that given the meshed nature of the SWIN and the design of the WEM it is possible for a SSAM to drive a perverse outcome particularly where exposure to individual performance targets is not capped. In the situation where a significant penalty due to a random event is not capped, the SSAM could encourage the inefficient behaviour to unnecessarily maximise Circuit Availability in order to achieve a gain that offsets an unreasonable loss.

Consequently, Western Power suggests the Authority should reconsider the appropriateness of applying part (a) of the Required Amendment to transmission, in light of recent decisions by the AER. Consistent with other recent decisions, Western Power proposes to remove the deadbands in the SSAM for transmission as required the Authority, but maintain lower and upper limits such that the total revenue at risk shall be capped at 1%.

2.4 Required Amendment Part (b) - Operation

In determining gains and penalties, the Authority has proposed that performance be measured with reference to the year-on-year change in the difference between target and actual performance, rather than as a difference between target and actual service standards for each year. This method introduces the possibility of perverse outcomes, particularly given the volatility of service standards.

While this method of calculating service standard performance has been used previously in other regimes (notably, Victoria), the most recent decision for the AER Distribution STPIS (May 2009) has removed this requirement.

Consequently, Western Power suggests the Authority should reconsider the appropriateness of part (b) of the Required Amendment in light of recent decisions by the AER. Consistent with those decisions, Western Power proposes to determine service standard performance for the SSAM as a difference between target and actual service standards for each year.

2.5 Required Amendment Part (c) - Incentive Rates

Western Power's proposed incentive rates were calculated so that a maximum of 0.5 per cent of the proposed target revenue was at risk. Rates were calculated such that the maximum potential loss or gain would occur if the actual values for all service standards were at the proposed upper or lower limits each year.

However, Western Power understands the Authority determined in its Draft Decision that the amount of revenue at risk was 0.17%, and that incentive rates needed to be increased by factors of 2.5 and 25 for distribution and transmission respectively. To arrive at these figures the Authority made certain assumptions including the following:

- no deadbands apply,
- performance would be at the nominated upper limits,
- the calculation method specified in part (b) of the Required Amendment applies,
- transmission incentive rates would be applied for each 1% of performance whereas Western Power's transmission rates were actually intended to apply to each 0.1% of performance.

The Authority issued corrigenda on 13 August 2009, revising its estimate of revenue at risk from 0.17% to 0.26%. It also revised the required increase in the transmission incentive rates from 25 to 2.5.

Western Power generally accepts that incentive rates should be increased so that 1% of revenue will be at risk under reasonable worst-case scenarios, however in calculating the revised rates certain assumptions need to be amended. It should be noted a final determination of incentive rates will require approved annual revenues to be known, and incentive rates should then be scaled appropriately so the revenue at risk will apply over the relevant performance band.

Further, Western Power proposes that incentive rates should be based on an average of the smoothed annual revenue for distribution and transmission, so that they do not change every year. This would ensure that the rates provide a constant incentive across the access arrangement period. This is consistent with the requirements of the AER where incentive rates are calculated at the commencement of the regulatory control period and these rates apply for the duration of the regulatory control period.

Setting incentive rates for Transmission

The revised incentive rates for transmission should be determined in the basis of the following:

- Deadbands should be removed, but lower and upper limits should be maintained.
- Performance should be calculated as the difference between a service standard benchmark and the actual service standard in each year.
- Transmission incentive rates should be applied to each 0.1% of performance.

For Transmission, Western Power proposes to comply in part with part (c) of the Required Amendment. The incentive rate for Circuit Availability will be increased by a factor of 2.5, however due to the volatility of System Minutes, the existing incentive rate will be maintained. With the removal of deadbands and changes to incentive rates, limits shall be amended accordingly to maintain the existing ratios of maximum reward or penalty in each category to result in 1% revenue at risk at the performance limits.

Setting incentive rates for Distribution

The revised incentive rates for distribution should be determined in the basis of the following:

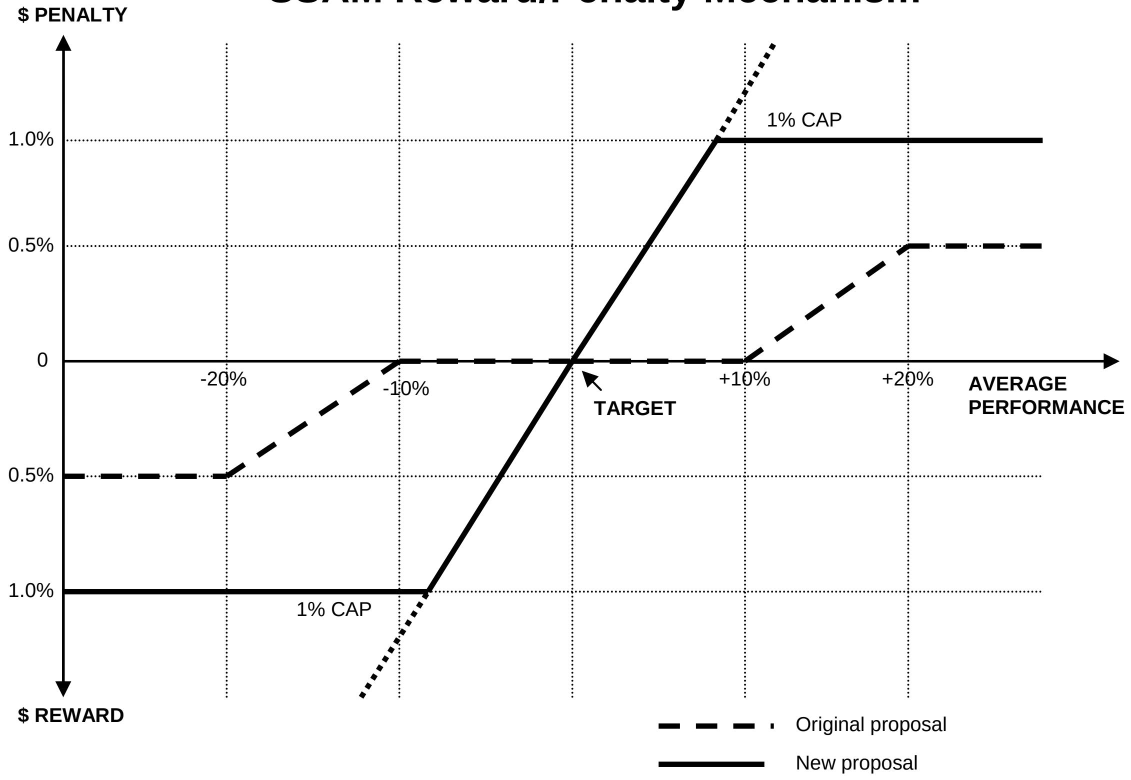
- Deadbands and limits should be removed.
- Performance should be calculated as the difference between a service standard benchmark and the actual service standard in each year.
- Total revenue at risk should be capped at 1%.

For Distribution, Western Power proposes to comply with the part (c) of the Required Amendment. The incentive rates for distribution shall be increased by a factor of 2.5.

It is noted that to achieve 1% of revenue at risk assuming performance at the proposed lower and upper limits, the incentive rates would not have to be increased at all since the deadbands have been removed. However, Western Power accepts that the incentive rates originally proposed are not, in themselves, sufficient to provide signals that would lead to optimal reliability-driven investment in the network. However, as the Authority recognises in its Draft Decision, to determine the true Value of Customer Reliability for the SWIN, an extensive study would be required. Such a study cannot be completed within the required time frame for this access arrangement approval process. Western Power consequently accepts the required amendment to increase the distribution incentive rates generally by a factor of 2.5. Consequently, if performance is at +8% for all feeder categories the penalty will be 1% of revenue.

For illustrative purposes only, the resultant mechanism is shown in the diagram below (for distribution):

SSAM Reward/Penalty Mechanism



2.6 Indicative Revised Incentive Rates and Targets - Transmission

The table below sets out the indicative revised incentive rates and targets for transmission.

		Expected Performance Band						
		Low Limit		Target		**High Limit**	**Incentive Rate** $ per 0.1% CA, and $ per 0.1 SMI	**Maximum Reward or Penalty**
Circuit Availability (%)	2009/10	97.6		98		98.4	$375,000	$1,500,000
	2010/11	97.6		98		98.4	$375,000	$1,500,000
	2011/12	97.6		98		98.4	$375,000	$1,500,000
System Minutes Interrupted (meshed network)	2009/10	7.4		9.3		11.2	$75,000	$1,425,000
	2010/11	7.4		9.3		11.2	$75,000	$1,425,000
	2011/12	7.4		9.3		11.2	$75,000	$1,425,000
System Minutes Interrupted (radial network)	2009/10	1.1		1.4		1.7	$25,000	$75,000
	2010/11	1.1		1.4		1.7	$25,000	$75,000
	2011/12	1.1		1.4		1.7	$25,000	$75,000
Transmission - Total (over 3 years)								$9,000,000

As noted in the table below, the indicative rates shown above are based on an assumed transmission revenue of $300 million per year.

Average Smoothed Transmission Revenue ($M)	**300**
Total Annual Revenue at Risk ($M)	3
Total Revenue at Risk over 3 years capped at 1% of revenue ($M)	9

Note: Dollars are Real 30 June 2009

It is noted that:

- Actual performance is expected to fall between the Low Limits and the High Limits set out in the table above for the Availability measure, however the volatility of the system minutes measures is such that there is a reasonable possibility that the actual performance will be outside the limits.

- The reward/penalty for each indicator is capped.

- If performance is at the High Limit for all indicators, the penalty will be 1% of revenue.

- Individual incentive rates will be recalculated once final revenues have been determined such that approximately 1% of revenue will be at risk over the expected performance band.

2.7 *Indicative Revised Incentive Rates and Targets - Distribution*

The tables below set out the indicative revised incentive rates and targets for SAIDI and SAIFI in relation to the distribution network.

		Expected Performance Band (± 8%)				
		Expected Low	Target	**Expected High**	**Incentive Rate** ($ per SAIDI minute)	**Expected Maximum Reward or Penalty**
SAIDI - CBD (Minutes)	2009/10	35	38	41	$220,000	$660,000
	2010/11	35	38	41	$220,000	$660,000
	2011/12	35	38	41	$220,000	$660,000
SAIDI - Urban (Minutes)	2009/10	152	165	178	$220,000	$2,860,000
	2010/11	149	162	175	$220,000	$2,860,000
	2011/12	141	153	165	$220,000	$2,640,000
SAIDI - Rural Short (Minutes)	2009/10	238	259	280	$8,200	$172,200
	2010/11	233	253	273	$8,200	$164,000
	2011/12	224	244	264	$8,200	$164,000
SAIDI - Rural Long (Minutes)	2009/10	563	612	661	$8,200	$401,800
	2010/11	541	588	635	$8,200	$377,200
	2011/12	512	556	600	$8,200	$328,000
Distribution SAIDI – Expected Maximum Total (over 3 years)						$11,947,200

		Expected Performance Band (± 8%)				
		Expected Low	Target	**Expected High**	**Incentive Rate** ($ per Unit of SAIFI)	**Expected Maximum Reward or Penalty**
SAIFI - CBD	2009/10	0.22	0.24	0.26	$10,300,000	$206,000
	2010/11	0.22	0.24	0.26	$10,300,000	$206,000
	2011/12	0.22	0.24	0.26	$10,300,000	$206,000
SAIFI - Urban	2009/10	1.77	1.92	2.07	$10,300,000	$1,545,000
	2010/11	1.74	1.89	2.04	$10,300,000	$1,545,000
	2011/12	1.68	1.83	1.98	$10,300,000	$1,648,000
SAIFI - Rural Short	2009/10	2.87	3.12	3.37	$450,000	$112,500
	2010/11	2.82	3.06	3.30	$450,000	$108,000
	2011/12	2.74	2.98	3.22	$450,000	$112,500
SAIFI - Rural Long	2009/10	4.60	5.00	5.40	$450,000	$180,000
	2010/11	4.45	4.84	5.23	$450,000	$175,500
	2011/12	4.42	4.80	5.18	$450,000	$175,500
Distribution SAIFI - Total (over 3 years)						$6,220,000

As noted in the table below, the indicative rates shown above are based on an assumed distribution revenue of $600 million per year.

Average Smoothed Distribution Revenue ($M)	**600**
Total Annual Revenue at Risk capped at 1% of revenue ($M)	6
Total Distribution Revenue at Risk over 3 years ($M)	18

Dollars are Real 30 June 2009

It is noted that:

- SAIDI and SAIFI performance is expected to fall within ± 8% of targets.
- The reward/penalty is not capped for any indicator or feeder category, but the overall reward/penalty is capped at 1% of revenue for each year.
- If performance is at +/- 8% for all feeder categories, the reward/penalty will be 1% of revenue.
- Individual incentive rates will be recalculated once final distribution revenues have been determined such that approximately 1% of revenue will be at risk over the expected performance band.

3 Western Power's proposed approach for addressing Required Amendment 35

Western Power generally accepts the Required Amendment, but proposes some variations to ensure that the SSAM is consistent with the relevant AER Service Target Performance Incentive Scheme (STPIS). Western Power's proposal is summarised as follows:

<u>Part (a) of Required Amendment 35</u>

For distribution, dead-bands and limits will be removed. For transmission, dead-bands will be removed but the Low Limits and High Limits will be retained consistent with recent AER decisions. For both distribution and transmission, total revenue at risk shall be capped at 1%. For distribution, the 1% cap shall apply to the aggregate of all penalties or rewards, whereas for transmission the portion of revenue at risk shall be limited for each performance indicator in accordance with the Low and High Limits.

<u>Part (b) of Required Amendment 35</u>

This portion of the Required Amendment is not consistent with the AER STPIS, and Western Power requests the Authority to reconsider the need for this particular requirement.

<u>Part (c) of Required Amendment 35</u>

The incentive rates will be increased by a factor of 2.5, with the exception of the rate applied to System Minutes.

Further, Western Power proposes that incentive rates be based on an average of the smoothed annual revenue for the distribution and transmission networks so that the rates do not change every year. Under this proposal, the rates will provide a constant incentive across the access arrangement period.

Individual incentive rates will be recalculated once final revenues have been determined so that approximately 1% of revenue will be at risk over the expected performance bands and limits as outlined in the tables above.

ATTACHMENT M
Western Power's detailed response to Required Amendment 37

1. Introduction

Western Power proposes to address the matters raised by the Authority in Required Amendment 37, which states:

> **“***The proposed access arrangement revisions should be amended to delete the proposed D-factor scheme at clauses 5.54 to 5.57.”*

Section 2 below sets out Western Power’s comments on Required Amendment 37. In light of that discussion, Section 3 then presents Western Power’s suggested approach for addressing this Required Amendment.

2. Western Power’s comments on Required Amendment 37

Paragraphs 1023 and 1024 of the Draft Decision describe Western Power’s proposed D-factor scheme as follows:

> “Under the proposed D-factor scheme, an amount will be added to target revenue in the third access arrangement period in respect of:
>
> - any additional operating expenditure being incurred by Western Power as a result of deferring a capital expenditure project during the second access arrangement period (clause 5.55(a)); and
>
> - any additional operating or capital expenditure incurred by Western Power in relation to demand management initiatives (clause 5.55(b)).
>
> The proposed D-factor scheme is subject to:
>
> - where an adjustment is made in respect of deferral of capital expenditure, the capital expenditure having been included in the forecast of costs taken into account in determination of target revenue for the access arrangement period; and
>
> - Western Power making available to the Authority a business case for the relevant operating or capital expenditure.”

In paragraph 1025 of the Draft Decision, the Authority noted that submissions it had received in relation to the D-factor scheme indicated general support for arrangements that promote efficient expenditure on non-network solutions to address network constraints, including demand management initiatives.

One of the reasons Western Power had proposed the D-factor scheme was to address the following point:

> “A broadly defined Investment Adjustment Mechanism (IAM) adjusts future revenue so that Western Power is financially neutral if actual capital expenditure (excluding

> replacement and IT capital expenditure) is higher or lower than forecast. A similar adjustment mechanism does not apply to operating expenditure. It follows from these regulatory arrangements that Western Power will be financially disadvantaged if it incurs additional operating expenditure during an access arrangement period in order to efficiently defer or avoid capital expenditure."[1]

The adverse efficiency and incentive effects (noted above) that the D-factor scheme is intended to address have been acknowledged by the Authority, at paragraph 1027:

> "In circumstances where opportunities for non-network alternatives are not identified and addressed in cost forecasts for an access arrangement period, the potentially limited incentive to substitute non-capital costs for capital costs may create a barrier to developing and implementing efficient non-network alternatives. This barrier is heightened by efficiency incentive schemes, as any additional non-capital costs incurred by the service provider may only not be recoverable, but may also reduce incentive payments that may otherwise accrue to the service provider from other, unrelated, efficiency gains."

It is also noteworthy that the Draft Decision acknowledges, at paragraph 1029, that Western Power's proposed D-factor scheme would address the incentive barriers to implementing efficient non-network alternatives. Furthermore, in the same paragraph, the Authority rejects the suggestion made in one submission that the D-factor scheme would distort competition in the provision of demand-side management services.

> "The D-factor scheme proposed by Western Power would address the incentive barriers to implementing non-network alternatives to capital projects in resolving network constraints. While it has been submitted that this would alter the competitive position of Western Power in providing services in demand-side management *vis-à-vis* other providers of such services, the Authority does not accept that this would be the case. Rather, the Authority considers that removing disincentives for Western Power to implement non-network alternatives in resolving network constraints would increase the role of demand-side initiatives in the operation of the electricity market and would generally increase demand for services necessary to implement programs of demand management."

Given that the Authority acknowledges the merits of Western Power's D-factor proposal, it is disappointing that the Authority ultimately rejects the proposed scheme. The Authority's reasoning in paragraph 1030 of the Draft Decision is set out below:

> "Despite the potential efficiency benefits of the proposed D-factor scheme, the Authority considers that the Access Code does not allow the scheme to be included in the access arrangement. Section 6.4(a) of the Access Code establishes objectives for a price control that include an objective for target revenue to include certain amounts, including a range of adjustments arising from the previous access arrangement period. An amount in respect of the D-factor scheme as proposed by Western Power does not fall within any of the amounts contemplated by section 6.4(a). Nor does the proposed D-factor scheme address any other objectives for the price control under section 6.4 of the Access Code."

Western Power does not agree with the Authority's reasoning in paragraph 1030 of the Draft Decision, because section 6.4(a)(i) of the Code provides for the recovery of an amount that meets the forward-looking and efficient costs of providing covered services. The proposed D-factor scheme would enable Western Power to recover the efficient

[1] Western Power, *Access Arrangement Information,* 1 October 2008, page 183.

costs of implementing non-network solutions, where a business case can be demonstrated. A D-factor scheme would therefore be consistent with section 6.4(a)(i) of the Code. Furthermore, by requiring Western Power to remove the D-factor scheme, Required Amendment 37 lessens Western Power's ability to recover its efficient costs. In Western Power's view, such an outcome would be inconsistent with the requirements of section 6.4(a)(i) of the Code.

The Draft Decision rejects the proposed D-factor scheme on the grounds that the recovery of the relevant costs in a later access arrangement period is not expressly provided for by section 6.4(a). In Western Power's view, this reasoning is at odds with the Authority's position in relation to deferred revenue (in paragraph 833 of the Draft Decision), where the Authority supports revenue deferral even though it is not expressly provided for in the Code. Western Power also notes a relevant precedent in the first access arrangement period, where the Authority approved Western Power's proposed Capital Contributions Adjustment Mechanism, although this mechanism is also not expressly provided for in the Code.

It should be noted that in paragraph 1026 states:

> "The Authority accepts that a scheme such as the proposed D-factor scheme may have efficiency benefits in the provision of network services. The potential efficiency benefits of the proposed D-factor scheme arise due to the limited incentive that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. For example, a saving of $100 in capital expenditure during an access arrangement period relative to the forecast for that period will give rise to a "reward" to the service provider of an amount equal to the rate of return and depreciation allowance on the amount of $100, say $10 where the rate of return is 6 per cent and where depreciation of the capital asset is at 4 per cent per annum. However, under a conventional scheme of regulation, any (above-forecast) non-capital costs that would be incurred by the service provider in achieving the efficiency gain in capital costs are not recoverable. So, if additional non-capital costs of $20 were required to achieve the $100 saving on capital costs, the service provider would be worse off even though the substitution of non-capital costs for capital costs would have been efficient."

The example cited in paragraph 1026 is applicable only to Western Power in circumstances where the capital expenditure deferred is *not* subject to the Investment Adjustment Mechanism (IAM). Where the capital expenditure is subject to the IAM - and this is highly likely to be the case where there are opportunities to efficiently substitute operating and capital expenditure - Western Power receives *no* "reward" for deferring or avoiding the capital expenditure under the IAM. This underscores the very poor incentive properties of the present arrangements, and highlights the merits of Western Power's D factor proposal.

It should also be noted that the Authority does seek to ameliorate the adverse incentives in the current access arrangements to undertake efficient non-network investment and demand side management initiatives. In particular, in paragraph 1031 of the Draft Decision the Authority proposes an adjustment to the gain sharing mechanism:

> "The Authority considers, however, that the access arrangement should, where possible, foster incentives for adoption of efficient non-network alternatives. For this reason, the Authority considers that the gain sharing mechanism to be included in the access arrangement for the second access arrangement period should include provision to exclude from actual non-capital costs any amount of non-capital costs that were incurred

> as a result of implementing a non-network alternative where such costs were not, and could not reasonably have been, included in the forecast of non-capital costs accounted for in target revenue for the access arrangement period."

Western Power concurs with the Authority that it is appropriate to provide for an adjustment to the gain sharing mechanism because that scheme would otherwise impose an efficiency penalty on Western Power for the costs of undertaking non-network and demand-side management initiatives. However, as noted above, due to the operation of the Investment Adjustment Mechanism there is no gain to Western Power if it defers capital expenditure as suggested by the Authority in paragraph 1026 of the Draft Decision. Moreover, as the Authority's own reasoning in paragraph 1027 points out, the Authority's proposal would reduce - but not eliminate - the barrier to developing and implementing efficient non-network alternatives that exists because of the limited incentive for Western Power to substitute non-capital costs for capital costs.

Consequently, the Authority's rejection of the D-factor scheme will discourage the pursuit of efficient non-network solutions since there would not be any mechanism for Western Power to recover the associated non-capital costs. Such an outcome would be contrary to the Code objective, which is set out in section 2.1 as follows:

> "The objective of this Code is to promote the economically efficient:
>
> (a) investment in; and
>
> (b) operation of and use of,
>
> *networks* and *services* of *networks* in Western Australia in order to promote competition in markets upstream and downstream of the *network*s."

Western Power believes its proposed D factor arrangements are consistent with the promotion of the economically efficient investment in, and operation and use of Western Power's networks and services.

3. Western Power's proposed approach for addressing Required Amendment 37

In light of the discussion in section 2, Western Power invites the Authority to reconsider its approach to the D-factor scheme. In particular, Western Power considers that it would be reasonable for the proposed D-factor scheme to be approved by the Authority given that:

1. the Authority has recognised the merits of the D-factor scheme (in paragraphs 1029 and 1030, for instance);
2. the Authority has previously approved the capital contribution adjustment mechanism, even though the Code does not expressly provided for such a mechanism;
3. the Authority's Required Amendments for the gain sharing mechanism do not fully address the acknowledged barrier to developing and implementing efficient non-network alternatives that exists because of the limited incentive for Western Power to substitute non-capital costs for capital costs; and

4. the proposed D-factor scheme is consistent with the efficiency principles set out in the Code objective.

In the event that the Authority is minded to not approve the proposed D-factor scheme, then Western Power proposes that the Investment Adjustment Mechanism should be amended so that any capital expenditure that is efficiently deferred through the employment of an operating expenditure solution should be excluded from the Investment Adjustment Mechanism. This suggested alternative approach would at least ensure that Western Power is not required to reduce its future revenue requirements (through the Investment Adjustment Mechanism) if capital expenditure is deferred efficiently as a result of Western Power undertaking non-network initiatives.

At this stage, however, Western Power's preference is for the D-factor scheme to be approved by the Authority.

Attachment N

Distribution Headworks Methodology

ELECTRICITY NETWORKS CORPORATION

("WESTERN POWER")

ABN 18 540 492 861

{Note: This methodology has been prepared in accordance with the requirements of the Electricity Networks Access Code 2004.}

CONTENTS

1. Definitions

In this headworks methodology the following terms are used and have the same meaning as given in the contributions policy or the Code (reproduced below for convenience).

“**alternative options**" has the same meaning given to it in the contributions policy.

{Note under the contributions policy “alternative options" means "alternatives to part or all of a network enhancement, including demand-side management and generation solutions (such as distributed generation) either instead of or in combination with a network enhancement.}

“Code” means the *Electricity Networks Access Code 2004* (as amended).

“connection application” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “connection application” means an application lodged with Western Power under the *applications and queuing policy* that has the potential to require a modification to the *network.}*

“connection point” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “connection point” means an *exit point* or an *entry point* identified or to be identified as such in an *access contract*.}

“contributions policy” has the same meaning given to it in the *Code*.

> {Note: Under the *Code* "contributions policy" means “a policy in an *access arrangement* under section 5.1(h) dealing with *contributions* by users”.}

“cpi” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “cpi” means the “all capitals consumer price index” as defined by the Australian Bureau of Statistics.

“customer” has the meaning given to it in the *Act*.

“distribution system” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “distribution system” has the same meaning given to it in the *Code*, but excludes equipment within zone substations used for the transportation of electricity at nominal voltage of less than 66 kV.}

“feeder diversity factor” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “feeder diversity factor” means the factor applied to the *capacity requirement* that reflects the effective contribution of the *connection* capacity to the feeder peak load.}

“forecast costs” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “forecast costs” means any or all of the *forecast new facilities investment* or the forecast *alternative option costs*, as applicable, to be incurred by Western Power with regards to *works*.}

“headworks” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “headworks” means enhancements required to the existing *HV* three-phase *distribution system* that provides for an increase in capacity of that system.}

“headworks charge” has the same meaning given to it in the *Code*.

{Note: Under the *Code* "headworks charge", in respect of a *headworks scheme*, means “the amount payable by a *user* to a *service provider* under the *headworks scheme* in respect of a *connection point*".}

“headworks scheme” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “headworks scheme” means the *scheme* described in clause 6 of the *contributions policy*.}

“mixed zone” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “mixed zone” has the meaning given to it in section 4.3 of the *price list information* in the *access arrangement*.}

“network” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “network” means those parts of the *SWIS* that are owned and operated by Western Power.}

“network assets” has the same meaning given to it in the *Code*.

> {Note: Under the *Code* "network assets", in relation to a *network* means "the apparatus, equipment, plant and buildings used to provide or in connection with providing *covered services* on the *network*, which assets are either *connection assets* or *shared assets*".}

“reasonable time” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “reasonable time” means the time determined in accordance with clause 5.3.}

“relevant area” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “relevant area” with respect to *connection applications* in relation to the *distribution system* means any area where the *relevant connection point* is located at a distance along the line feeder route equal to or greater than 25 km from the *relevant zone substation* within the *network* in the *rural zone* or *mixed zone*.

“relevant connection point” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “relevant connection point” means, with respect to a *connection application*, the appropriate *connection point* as determined under clause 6.5.}

“relevant zone substation” has the same meaning given to it in the contributions policy.

{Note under the contributions policy “relevant zone substation” means the zone substation to which the new or upgraded *connection* will be connected under normal system operating conditions.}

“SWIS” has the meaning given to it in the *Code*.

> {Note: Under the *Code* "SWIS" "the interconnected transmission and distribution systems, generating works and associated works
>
> (a) located in the South West of the State and extending generally between Kalbarri, Albany and Kalgoorlie; and
>
> (b) into which electricity is supplied by

(i) one or more of the electricity generation plants at Kwinana, Muja, Collie and Pinjar; or

(ii) any prescribed electricity generation plant"}

"transmission system" has the same meaning given to it in the Code, but also includes equipment within zone substations used for the transportation of electricity at nominal voltage of less than 66 kV.

"user" has the same meaning given to it in the *Code*.

{Note: Under the *Code* "user" means "a person, including a *generator* or a *consumer*, who is a party to an [*sic*.] contract for services with a *service provider*, and under section 13.4(e) includes another *business* as a party to a *deemed access contract*".}

"works" has the same meaning given to it in the contributions policy.

{Note under the contributions policy "works" includes *headworks* and all works required to be undertaken to provide an *applicant* with the *covered services* sought by the *applicant* in a *connection application*.}

2. Introduction

This document explains Western Power's Distribution Headworks Scheme methodology used to determine the headworks prices that may be applied under the Contributions Policy as provided for in the Code sections 5.17C and 5.17D.

2.1. Code Requirements

The following Code provisions apply to a headworks scheme.

5.17C Despite section 5.14, the Authority may approve a contributions policy that includes a **"headworks scheme"** which requires a user to make a payment to the service provider in respect of the user's capacity at a connection point on a distribution system because the user is a member of a class, whether or not there is any required work in respect of the user.

5.17D A headworks scheme must:

(a) identify the class of works in respect of which the scheme applies, which must not include any works on a transmission system or any works which effect a geographic extension of a network; and

(b) not seek to recover headworks charges in an access arrangement period which in aggregate exceed 1% of the distribution system target revenue for the access arrangement period; and

(c) identify the class of users who must make a payment under the scheme; and

(d) set out the method for calculating the headworks charge, which method:

(i) must have the objective that headworks charges under the headworks scheme will, in the long term, and when applied across all users in the class referred to in section 5.17D(c), recover no more than the service *provider's* costs (such as would be incurred by a *service provider efficiently minimising costs*) of any *headworks*; and

(ii) must have the objective that the *headworks charge* payable by one *user* will differ from that payable by another *user* as a result of material differences in the *users'* capacities and the locations of their *connection points*, unless the *Authority* considers that a different approach would better achieve the *Code objective*; and

(iii) may use estimates and forecasts (including long term estimates and forecasts) of loads and costs; and

(iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs; and

(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

This methodology document explains how the requirements of sections 5.17D (i), (ii) and (iii) have been met in the contributions policy.

Code compliance of the methodology

Section 5.17D

With respect to section 5.17D(i), the proposed headworks scheme is designed to recover the forecast costs of headworks less a forecast allowance for network access revenue from customers connecting to the network and who are forecast to make use of the associated headworks. Headworks prices are to be reviewed regularly to reflect the actual costs of the provision of headworks.

With respect to section 5.17D(ii), the headworks scheme is designed such that the contribution for an applicant depends on their individual required electricity demand, their distance from the relevant zone substation, and the voltage of the network to which they are connecting. Consequently charges for each applicant will differ as a result of material differences in the users' capacities and the locations of their connection points.

With respect to section 5.17D(iii), the headworks scheme prices are based on estimates and forecasts (including long term estimates and forecasts) of loads and costs.

2.2. Overview of Headworks Scheme

(a) Distribution headworks are major enhancements to the existing three-phase distribution system to provide increased electricity capacity to meet growth in customer electricity requirements. Distribution headworks may include major works such as overhead HV power lines, voltage regulators, step-up and step-down transformers, network augmentations, and new distribution feeders.

(b) The headworks scheme and associated prices apply to the provision of distribution infrastructure only, not transmission infrastructure, and in particular applies to those customers seeking to connect to the network in the rural and regional areas of the SWIS. Other areas of the SWIS (such as the CBD and metropolitan Perth) are excluded from the scheme, and charges for increases to network capacity in those areas are determined on a case by case basis.

(c) The headworks scheme includes a headworks charge that allows for an equitable sharing of costs between all new customers, including customers seeking to upgrade existing connections, and one which presents less of a financial barrier to developments triggered by individual customers.

(d) The headworks scheme applies to connection applications in relation to the distribution system where the relevant connection point is located at a distance equal to or greater than 25 kms from the relevant zone substation in either the rural zone or mixed zone within the network.

(e) The headworks charge varies depending on the location and the connection voltage level. It reflects the average cost Western Power incurs in providing additional electricity capacity to the relevant parts of the network. The charge does not include the direct costs of customer connection to the existing network, including reticulation of underground electricity services for new subdivisions, which are determined in addition to the headworks charge.

3. Objectives of the headworks scheme

This section sets out the objectives used in determining the headworks scheme and prices.

(a) The headworks scheme has been designed to meet the high-level objectives described below.

   (i) Comply and be consistent with the regulatory framework;

   (ii) Provide a method for allocating the costs of the provision of network distribution headworks to customers seeking to connect to the network in a fair and equitable manner;

   (iii) Be as cost reflective as is reasonable to reflect the network user’s utilisation of the network headworks capacity;

(iv) Be as simple and straight forward as is reasonable taking into account other objectives; and

(v) Provide price stability and certainty to enable network users to make informed investment decisions.

(b) The methodology must ensure that headworks contributions will, in the long term, recover no more than Western Power's costs of headworks.

4. Methodology Overview

This section provides an overview of the methodology used in determining the headworks price. It is noted that the cost of the provision of electricity capacity at a particular location is a function of:

(i) the amount of capacity sought by a customer,

(ii) the distance along a feeder from the zone substation,

(iii) the voltage level of the feeder line, and the costs of the power line infrastructure itself.

On this basis, the approach taken to develop the headworks prices is as follows.

(a) Western Power has modelled a standard feeder to determine the capacity available at various distances along the feeder and determined the cost to provide that capacity in terms of a fixed cost ($ per kVA) plus a variable cost ($ per kVA) for the provision of that capacity at the various lengths of line. Modelling was carried out separately for 22 kV and 33 kV lines.

(b) The results of the modelling carried out under (b) have then been reduced to a standard mathematical formula that defines the cost of distribution headworks required to deliver capacity at any point along a fully developed feeder. This mathematical approach has been further adjusted to reflect the costs associated with a number of actual studies to ensure the price structure is robust and that it meets the objectives and principles of the headworks scheme.

(c) Price lists have then been produced that enable a headworks charge to be determined for an applicant seeking a new connection to the network or for a load increase at an existing connection. The charge is based on:

(i) the capacity sought,

(ii) the distance to the zone substation, and

(iii) the voltage of the feeder supplying the customer.

5. Methodology

5.1. Modelling of Standard Feeder

(a) As developing and applying locational specific headworks charges in all possible SWIS locations is not a feasible or practicable outcome, Western Power has developed a standard SWIS headworks price based on modelling of standard distribution feeders.

(b) A distribution planning study was conducted and identified:

(i) the optimal (fully developed) standard feeder capacity for line distances in steps from 50 km to 300 km for each of 22 kV and 33 kV voltage levels; and

(ii) the distribution line construction cost estimates from recent representative baskets of actual projects, applied to the line distances in steps from 50 km to 300 km at each voltage level.

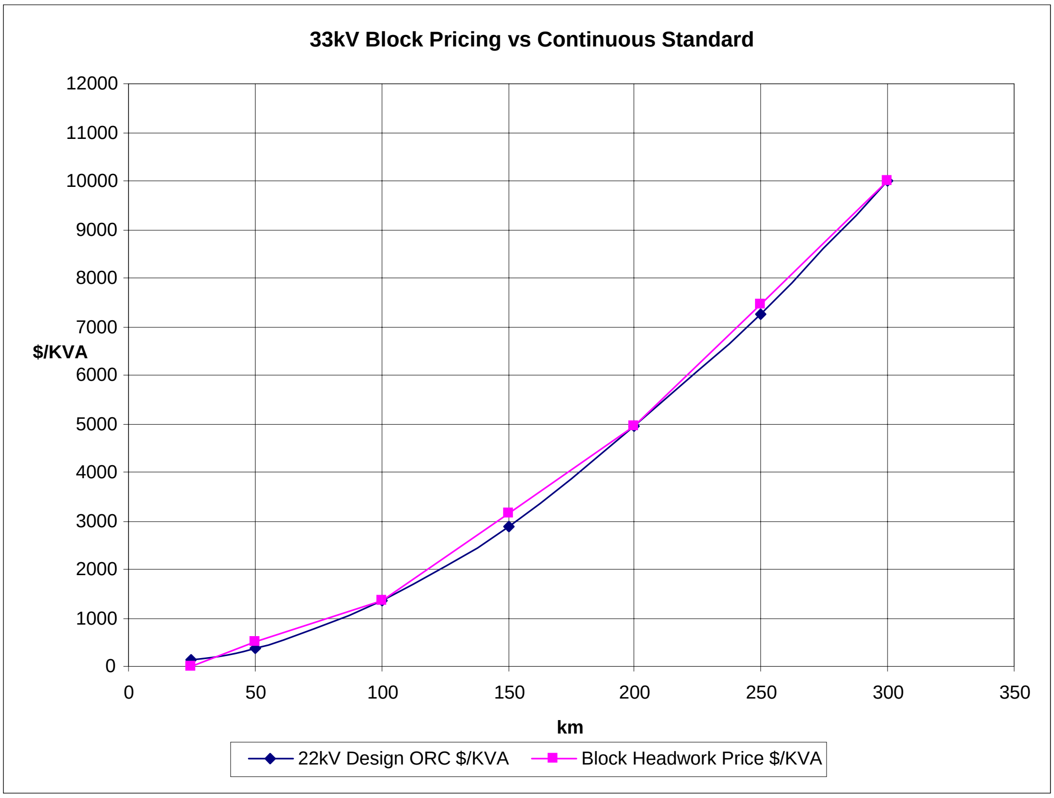
(c) These optimal replacement costs and capacity-distance outcomes were applied to determine a standardised headworks cost-capacity curve. This curve describes the calculation of a standardised headwork cost over each of the 50 km increments as follows:

(i) Standard headworks price = [Fixed cost (FC) plus Variable cost (VC)] / Capacity Delivered expressed in $/kVA.

(Note that the capacity of the feeder at each distance has been determined on the basis of using 19/3.25 all aluminium alloy conductor (AAAC), and installing two voltage regulators to maximise the capacity that could be obtained within the statutory voltage limits. Consequently the fixed cost is representative of the cost of the two regulators and the variable cost reflects the cost of the feeder line per km.)

(d) This capacity-cost curve was then converted mathematically into a headworks price applied in block increments of distance and taking into account the 25 km zero charge distance. Two part block pricing allows for practical application of distance pricing.

(e) The resulting headworks price (in $/kVA) for each block increment referred above is illustrated against the standard capacity-cost curve in the figure below:



5.2. Headworks Modelling at Specific Locations

This section describes the location specific studies that were carried out to determine the actual cost of the provision of additional network capacity in seven locations within the SWIS.

(a) Western Power has conducted extensive modelling to determine the optimal network development pathway for seven representative locations within the SWIS (Walpole-Denmark; Bremer Bay; Ravensthorpe; Dongara; Brookton, Jurien Bay and Kalbarri).

(b) This modelling considered both network augmentation options and alternative network options (embedded generation) to meet the forecast load growth for each location. The key elements of the models developed included:

(i) Load forecasts. Central load forecasts were developed from the current customer application data available to Western Power, the existing customer load profile on each feeder, and from long term historical load growth rates for each region. Land subdivisions were allocated an estimated commencement date, diversified maximum demand and time to maturity. Low and high case load forecast scenarios were developed by considering adjustments to the underlying application data and long term load feeder growth rates.

(ii) Network distribution augmentation costs and/or embedded generation costs. All potential currently available and future network augmentations were considered. A cost estimate of each option was developed and the additional network capacity delivered was modelled by Western Power using load flow analysis. Alternative embedded generation option costs were established from current industry unit cost estimates. Embedded generation options considered included islanding, semi-islanding and peak lopping modes of operation. Peak lopping mode whereby the embedded generation is used to cap the feeder demand (using load distribution curve) proved the lowest cost of these approaches.

(iii) Network distribution revenue was determined using average historical distribution revenue data for each location considered.

(c) The models determined the optimal network development pathway for each location over a long term 30 year study period, being that option that delivered the lowest net present value of meeting the forecast customer loads.

(d) In all locations considered the required investments did not meet the New Facilities Investment Test without customer contributions (by differing quantum). The models were used to develop a locational specific headworks charge that when applied to the forecast customer loads for that location, ensured that the net present value of revenue equalled the net present value of network costs over the period.

5.3. Adjustment of the Standard Headwork Formula

(a) Western Power considered the differences between the locational headwork charge determined by previous modelling and the standard optimal cost approach. Differences were noted in particular locations due to the existence of factors including initial spare feeder capacity; the existence of low cost network enhancement options or high cost options; the potential for deferment of network options by the use of embedded generation; and that typically time staging of network augmentation options under detailed locational modelling better matched costs with capacity requirements over time.

(b) Western Power considered options to minimise the gap between the standard optimal cost approach and the locational specific headworks cost determined from previous modelling along the feeder length. Typically the standard cost approach overstated the outcomes.

(c) The adoption of a 75% adjustment factor applied to the standard cost approach was found to provide close alignment between the actual locational modelled costs and the mathematically derived cost.

5.4. Publishing of Prices

(a) Western Power publishes the headworks prices applicable as a series of price list tables on its website.[1] These price list tables show the headworks price payable by a customer (residential or commercial applicants) seeking connection to the network. Prices are displayed in 5 km distance increments (although actual distances are used when calculating the customer charge). These tables show:

(i) Distribution headworks prices: single commercial applicants (excludes standard revenue offsets);

(ii) Distribution headworks charges: residential subdivision and single residential applicants (includes standard revenue offsets);

(iii) Distribution headworks charges: commercial subdivision applicants (includes standard revenue offsets);;

(b) Published price list tables display pricing for customer connection at both 22 kV and 33 kV voltage levels. Prices currently include the Government rebate subsidy scheme administered by Western Power and described in Appendix D.

5.5. Determining the headworks contribution

(a) The contributions policy sets out the method for determining the headworks contribution. The headworks contribution so determined for a customer connection application depends on three factors:

(i) The capacity sought by the applicant (in kVA),

(ii) The distance from the nearest relevant zone substation (in km), and

(iii) The voltage of the distribution feeder to which the connection is made (either 22 kV or 33 kV).

[1] Contained in Western Power “Distribution Headworks Scheme Policy” document.

6. Headworks Price List Review Process

This section sets out the procedures to be applied when adjusting the published headworks price list tables to ensure that current pricing reflects changes in the underlying construction cost structures.

(a) Western Power will adjust the headworks price lists quarterly based on applying the relevant quarterly CPI index increase to the prevailing price lists, but at a rate not exceeding 100% CPI;

(b) Western Power will reset the headworks price list tables annually based on movements arising from an annual review of the distribution construction cost estimates against those derived in section 5. The price reset shall take account of the quarterly CPI price adjustments made over the previous 12 month period.

Appendix A - Derivation of Distribution Feeder Capacity

This appendix sets out the basis for Western Power's determination of the capacity that can be delivered on a standard fully developed distribution feeder ("standard" feeder).

Standard Feeder Capacity

(c) Western Power conducted load flow studies to determine the capacity of a "standard" distribution feeder at both 22 kV and 33 kV voltages. The capacity delivered along a distribution feeder is determined by the distance from the source and the feeder voltage level (subject to appropriate conductor size and use of voltage regulators etc).

(d) The load flow studies assumed that a fully developed distribution feeder will have two voltage regulators along its length. For simplicity, the study determined the point load that when located at the end of a feeder of varying 50 km increments, would lower the feeder delivered voltage level to the emergency planning limits. Such a load is considered representative of the voltage constrained capacity of the feeder.

(e) The results of these load flow studies are shown in the table below.

Line Length (km)	22kV Capacity (kVA)	33kV Capacity (kVA)
50km	6,500	14,300
100km	3,300	7,300
150km	2,250	5,100
200km	1,750	3,950
250km	-	3,340
300km	-	2,900

Appendix B - Derivation of Distribution Cost Estimate

This section sets out the basis for Western Power's determination of the distribution costs of a standard fully developed distribution feeder ("standard" feeder).

Standard Feeder Cost Estimate

(a) The cost estimates used for determining both the 33 kV and 22 kV "standard" distribution headworks infrastructure cost used in calculating the applicable headworks price lists are derived from the standard cost estimates developed by Western Power Country Planning and Development section. These standard estimation costs are used by Western Power in determining the connection quotations provided to customers.

(b) The following specification assumptions were applied in determining the cost estimates applied by Western Power for a fully developed standard feeder:

(i) Voltage regulator (2 off 250 amp rated);

(ii) Overhead 3 phase line construction cost (19/3.25 AAAC conductor). Distribution line construction costs were based upon wood pole overhead construction type, which is representative of most country distribution lines. Construction type is the same for both 22 kV and 33 kV voltage levels.

(iii) Substation feeder circuit cost is not included as it is normally treated as a transmission development cost item.

(c) Western Power updates these cost estimates on a regular basis to reflect up to date changes in the average standard cost of construction of new distribution infrastructure for use in customer quotations and internal budgeting. Refer to section 6 for details of the headworks price review procedures.

Appendix C - Revenue Offsets

This appendix describes the process for determining revenue offsets that may be applicable to a customer headworks contribution.

Overview of Offsets

(a) Headworks prices are reduced or offset by taking into account the network access revenue expected to arise from the connection over a reasonable period of time (which is assumed up to 15 years).

(b) These offsets will vary depending on whether the connection is for residential or commercial customers. The revenue offset for commercial loads needs to be individually assessed, as every case will be different.

(c) The revenue offset for residential and commercial land subdivisions can be pre-determined based on a set of standard assumptions which are listed in the table below.

Residential Land Subdivisions	Commercial Land Subdivisions
(i) 5 kVA ADMD per lot[2]	(i) 40 kVA ADMD per lot
(ii) 5000 kWh consumption per annum per lot	(ii) 20% load factor with 30% Off Peak energy consumed per annum per lot
(iii) Reference Tariff RT1 applied	(iii) Reference Tariff RT4 applied
(iv) 4 years to full maturity of land uptake	(iv) 4 years to full maturity of land uptake
(v) 15 years reasonable time period for revenue	(v) 15 years reasonable time period for revenue

(d) The price lists for residential and commercial subdivisions take that standard offset into account so that the headworks charge can be readily determined for such developments. Individual assessments may be required where specific land developments vary from these standard assumptions. The standard assumptions underlying the pre-determined revenue offset calculations are:

(e) The headworks price lists and indicative worked examples published by Western Power on its website provide indicative prices for the following three cases namely (i) residential subdivision applications; (ii) commercial subdivision applications, and (iii) single commercial customer applications.

(f) In compiling the customer connection quotation, Western Power applies any network access revenue offsets that are surplus to the quantum of headworks charge applicable, as a further offset to any direct connection charges that may be payable by the customer, noting that revenue offsets are not to be double counted against both contribution requirements.

[2] ADMD is the After Diversity Maximum Demand for the connection

Appendix D - Government Subsidy Scheme

This appendix provides an overview of the Government rebate subsidy scheme that currently applies for all residential and commercial applications impacted by the headworks scheme. Western Power administers this scheme (for ease of application) however Government policy in this area is not an obligation of Western Power's access arrangement, and the following is provided for information only.

Subsidy Overview

(a) The State Government has determined that a rebate subsidy will apply to headworks charges in locations where headworks charges will be greatest. The Government rebate subsidy is structured to cap the customer headworks charge that would otherwise be payable.

(b) As a result there is no requirement for individual customers to apply for the Government rebate as Western Power incorporates the rebate when issuing customer quotations. Western Power separately manages the administration and recovery of subsidy funds with the Government.

(c) The headworks price lists and indicative worked examples published by Western Power on its website have taken the Government rebate into account.

ATTACHMENT O
Western Power's Revenue and Tariff Proposal

1. Introduction

This attachment sets out the revenue and tariff outcomes that would result if Western Power's response to the Draft Decision is accepted.

2. Revenue Outcomes

The composition and derivation of the target revenue for the transmission business for the second access arrangement period is given below.

Table 1: Composition and derivation of transmission network revenue ($ million real as at 30 June 2009)

Financial year ending:	**Present Value**	**30 June 2010**	**30 June 2011**	**30 June 2012**
Operating Costs	237.5	75.9	96.7	103.8
plus Depreciation	199.2	70.7	75.4	85.1
plus Redundant Assets	-	-	-	-
plus Return on Assets	494.5	169.7	185.8	219.5
plus Return on Working Capital	3.1	1.2	1.5	0.8
Forward-looking efficient costs	**934.3**	**317.5**	**359.5**	**409.2**
less Non-Reference Services Revenue	-2.3	-0.9	-0.9	-0.9
Transmission Reference Service Revenue	**931.9**	**316.6**	**358.6**	**408.3**
Deferred Transmission Reference Service Revenue	**64.6**			
Smoothed Reference Services Revenue - TR_t	**867.3**	**273.1**	**338.5**	**399.8**
Unforeseen events revenue adjustment	0.0			
plus technical rule change revenue adjustment	0.0			
plus investment adjustment mechanism amount	13.7			
plus capital contribution adjustment mechanism amount	-42.5			
Adjustments in accordance with previous access arrangement	**-28.8**			
Smoothed adjustments in accordance with previous access arrangement – $AA\#1_t$	**-28.8**	**-9.6**	**-11.1**	**-12.8**
Tariff Equalisation Contribution – TEC_t	**0.0**	**0.0**	**0.0**	**0.0**
Correction factor from 2008/09 – TK_t	**0.0**	**0.0** (Forecast)		
Maximum transmission reference service revenue – MTR_t	**838.5**	**263.4**	**327.4**	**387.0**

The following table gives the composition and derivation of the target revenue for the distribution business for the second access arrangement period.

Table 2: Composition and derivation of distribution network revenue ($ million real as at 30 June 2009)

Financial year ending:	Present Value	30 June 2010	30 June 2011	30 June 2012
Operating Costs	910.4	283.7	360.1	418.0
plus Depreciation	412.1	145.8	158.1	174.4
plus Redundant Assets	9.7	3.8	3.8	3.7
plus Return on Assets	628.6	221.4	240.7	267.6
plus Return on Working Capital	7.1	1.6	3.3	3.5
Forward-looking efficient costs	**1,967.9**	**656.2**	**766.0**	**867.1**
less Non-Reference Services Revenue	-27.9	-10.1	-10.8	-11.4
Distribution Reference Service Revenue	**1,940.0**	**646.1**	**755.2**	**855.7**
Deferred Distribution Reference Service Revenue	**489.3**			
Smoothed Reference Services Revenue - DR_t	**1,450.7**	**427.7**	**562.5**	**706.5**
Unforeseen events revenue adjustment	0.0			
plus technical rule change revenue adjustment	0.0			
plus investment adjustment mechanism amount	28.3			
plus capital contribution adjustment mechanism amount	-143.4			
Adjustments in accordance with previous access arrangement	**-115.1**			
Smoothed adjustments in accordance with previous access arrangement – $AA\#1_t$	**-115.1**	**-37.4**	**-44.3**	**-52.5**
Tariff Equalisation Contribution – TEC_t[1]	**341.4**	**121.1**	**136.5**	**138.1**
Correction factor from 2008/09 – DK_t		**0.0** (Forecast)		
Maximum distribution reference service revenue – MDR_t	**1,677.1**	**511.4**	**654.7**	**792.2**

1 The TEC value for 2009/10 was published on 25 August 2009 in the *Electricity Industry (Tariff Equalisation Contribution) - Notice (No. 1) 2009*. TEC values for 2010/11and 2011/12 shown are indicative only. Department of Treasury and Finance is currently undertaking a review of the appropriate TEC based on updated network tariffs, and will provide formal notice to the ERA accordingly.

3. Price Increases

A further price increase in 2009/10 (on 1 January 2010) is required to manage the average tariff increases in 2010/11 and 2011/12 and to support Western Power's proposed works program.

Western Power requires the income received from network revenues to support its proposed expenditures. Without sufficient revenue, operating and capital expenditure plans will be placed under pressure. Any shortfalls in revenue could lead to an increase in borrowings. However, increased borrowing levels may also create challenges for the financial sustainability and long-term performance of the business.

Western Power has accepted required amendment 32, and deferred a substantial amount of revenue into the next access arrangement period in order to assist with the avoidance of price shock. Western Power is also concerned that the current approved 2009/10 level of pricing may result in price shock during the second access arrangement period. Western Power has calculated that if the current prices are maintained for the full 2009/10 financial year, average tariff increases of CPI+29% would be required in 2010/11 and 2011/12 in order to recover the required revenues over the remaining two years of the regulatory period.

The following section sets out the average price outcomes that minimise price shock and collect the revenue required over the second access arrangement period.

4. Average Price Outcomes

The average price path (including an increase on 1 January 2010) that would result from the acceptance of Western Power's response to the Draft Decision is set out below.

Figure 1 shows the trend in average transmission tariff prices in real dollars from July 2006 to the end of the forthcoming access arrangement period.

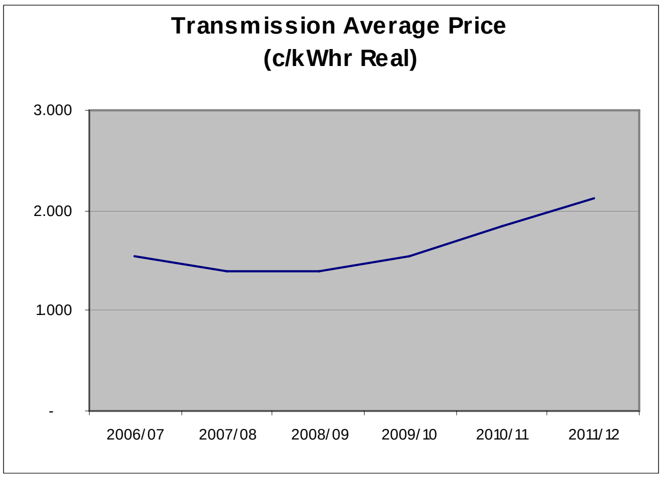


Figure 1: Transmission Average Price (c/kWhr real as at 30 June 2009)

Figure 2 shows the trend in average distribution tariff prices in real dollars from July 2006 to the end of the forthcoming access arrangement period.

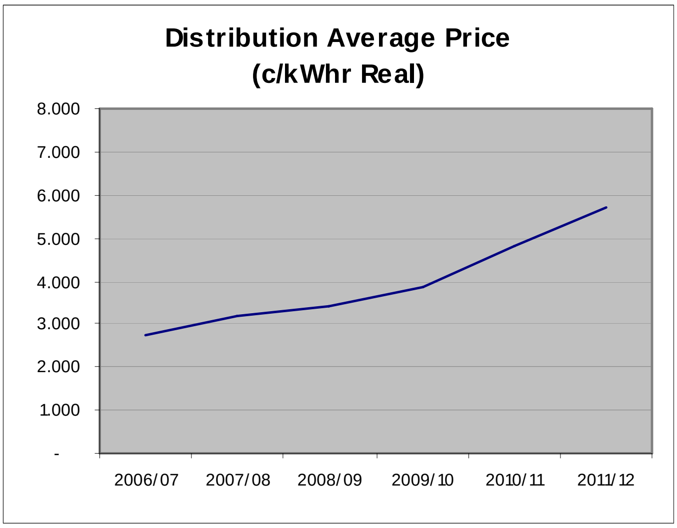


Figure 2: Distribution Average Price (c/kWh real as at 30 June 2009)

Table 3 below sets out the proposed price paths for transmission and distribution for the second access arrangement period. Western Power has set the price path so as to provide for equal price increases over each year of the access arrangement period. In particular the proposed increase on 1 Jan 2010 ensures that the prices at the end of the 2009/10 year would be 15.3% and 18.5% higher than the transmission and distribution prices in 2008/09 respectively. As noted above, this provides a smooth price path for both transmission and distribution over the whole of the second access arrangement period.

Table 3: Average Price Path

Price Year commencing	1 July 2009	1 Jan 2010[2]	1 July 2011	1 July 2012
Transmission Price Path	CPI+5%	CPI+9.0%	CPI+15.3%	CPI+15.3%
Distribution Price Path	CPI+5%	CPI+12.3%	CPI+18.5%	CPI+18.5%

Table 4 below sets out the annual target revenues for transmission and distribution for the second access arrangement period compared with the outcomes in the Draft Decision.

[2] 1 Jan 2010 – assumed start date of the amended proposed access arrangement revisions

Table 4: Revenue Comparison

		2008/09	2009/10	2010/11	2011/12	Total
ERA Draft Decision 16 July 2009	**Annual Revenue (Real)**	$671m	$783m	$914m	$1,067m	$2,764
	Average Revenue[3] Increase		CPI +16.7%	CPI +16.7%	CPI +16.8%	
Western Power Resubmission September 2009	**Annual Revenue (Real)**	$671m	$775m	$982m	$1,179m	$2,936
	Average Revenue[4] Increase		CPI +15.4%	CPI +26.8%	CPI +20.1%	
	Average Price[5] Outcome		CPI +17.6%	CPI +17.6%	CPI +17.6%	

Western Power also intends to adjust the Asset Charge of the Streetlight tariff (RT9) to be cost reflective over the second access arrangement period. The tariff does not currently recover the operating costs of the streetlight business. Any adjustment will avoid price shock to the users of this tariff.

5. Side constraints

Sections 5.35 and 5.46 of the proposed revisions to the Access Arrangement set out matters relevant to the determination of the side constraints to apply to transmission and distribution, respectively. Table 5 below shows the value of Y to be used in the calculation of the side constraints if the price paths shown above were to be applied. Section 3.11 of Western Power's proposed revisions to the Access Arrangement (which provides for an additional margin of 5% to be added to the value of Y) would remain unchanged.

3 The ERA draft Decision bases the average tariff increases on increases in revenue.

4 These figures have been calculated using the approach used by the ERA and represent a comparison to the Average Revenue Increase of CPI +16.7% reported in the Draft Decision. They reflect an increase in price and also an increase in forecast energy sales.

5 These figures represent in real terms, equal year on year increases in average price.

Table 5: Value of Y to be used for calculation of tariff side constraint

	2009/10	2010/11	2011/12
Transmission - Y	n/a	15.3%	15.3%
Distribution - Y	n/a	18.5%	18.5%

Western Power will propose appropriate tariff side constraints in its submission of amended proposed access arrangement revisions following the Authority's Final Decision. That proposal will be commensurate with final tariff outcomes and will incorporate a margin to accommodate appropriate tariff rebalancing in subsequent years.

6. Amendments to definition of Pricing Year

Following the Authority's Final Decision, Western Power intends to include a Price List (as part of its submission of amended proposed access arrangement revisions) that will apply from the start date of the amended proposed access arrangement revisions.

Western Power will give effect to this by amending sections 3.8 to 3.10 of the proposed access arrangement revisions to allow for the access arrangement to set out the start and end dates of each pricing year in the access arrangement period.

Table 6 sets out the proposed start and end dates of each pricing year in the access arrangement period.

Table 6: Pricing Years Definition

Pricing Year	Start Date	End Date
1	Start date of the amended proposed access arrangement revisions	30 June 2010
2	1 July 2010	30 June 2011
3	1 July 2011	30 June 2012

ATTACHMENT P

Western Power's Revised Service Standard Benchmarks (Distribution)

1 Introduction

This attachment explains the relationship between network expenditure and service performance, and concludes that in light of the reduced levels of expenditure now proposed, it is appropriate to adjust downwards the distribution service standard benchmarks that Western Power initially proposed in its submission in October 2008. It is noted that in its letter to the Authority of 25 May 2009 regarding reductions in forecast expenditures, Western Power foreshadowed the need for consequential changes to service standard targets.

Accordingly, Section 2 of this Attachment provides an overview of the main factors that have led to the revision of Western Power's service standard benchmarks, while section 3 provides a more detailed explanation of those factors. Section 4 sets out Western Power's proposed service standard benchmarks for distribution.

2 Overview

Western Power submitted its proposed service standard benchmarks (SSBs) in its Access Arrangement proposal in September 2008. In that original submission, Western Power intended to improve the overall performance of the distribution network by 29 SAIDI minutes.

The Authority's Draft Decision accepted the proposed SSBs but it set out several Required Amendments (principally requiring reductions in Western Power's expenditure forecasts) that have led to the need to revise the proposed SSBs.

The following factors are the main drivers for revising the SSBs:

1. Western Power proposes a reduction in reliability driven capital expenditures, compared to the level of expenditure proposed in the October 2008 submission.

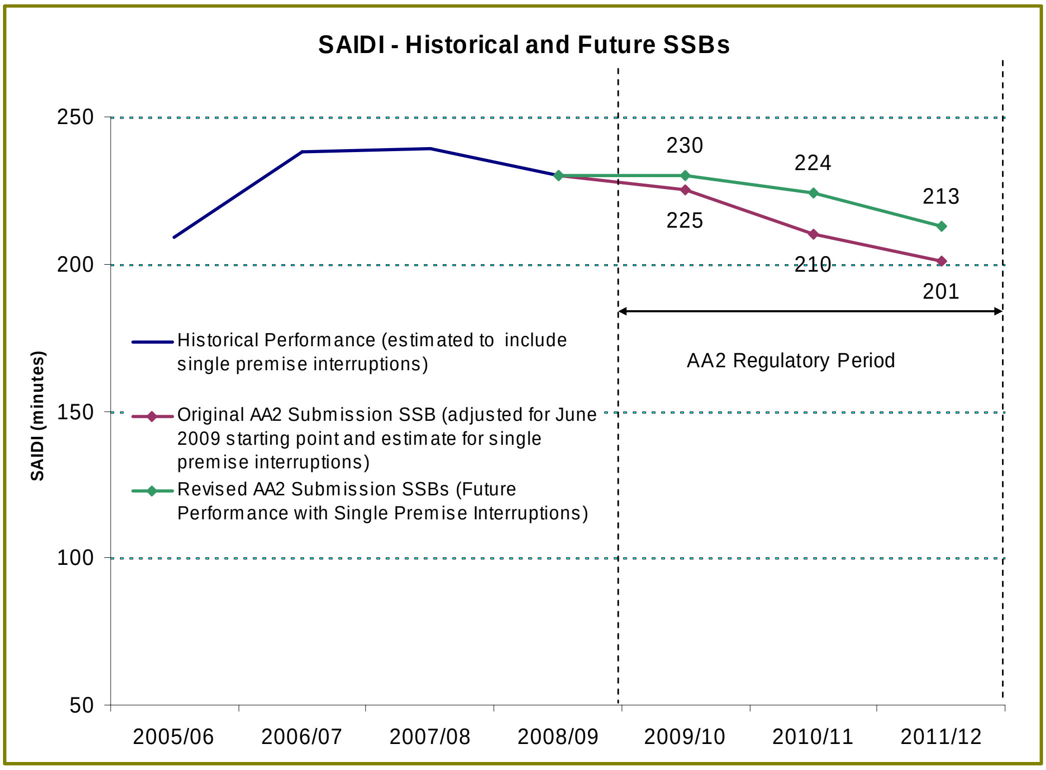
2. Western Power proposes a reduction in operating expenditure compared to the level of expenditure proposed in the October 2008 submission.

3. The SSBs proposed in Western Power's October 2008 submission were based on definitions of SAIDI and SAIFI that made provision for the exclusion of single customer interruptions. Required Amendment 23 of the Draft Decision requires the definition of the SAIDI and SAIFI reliability measures to be amended to include single customer interruptions.

The impact of each of these factors on Western Power's proposed SSBs is explained in further detail in Section 3 below[1]. These factors have resulted in a new forecast of reliability performance improvement over the regulatory period of 17 SWIS SAIDI

[1] Section 2.3.4 of Attachment D (*Supplementary Report: Capital and Operating Expenditure 2009/10 to 2011/12)* also discusses the proposed level of reliability associated with Western Power's revised expenditure forecasts.

minutes. The diagram below shows the original (October 2008) and the revised proposed SAIDI SSBs.



Note: Each of the traces above have been calculated in accordance with the new proposed definition of SAIDI consistent with Required Amendment 23 (which results in an estimated additional 9 minutes of SAIDI due to the inclusion of single premise interruptions).

3 Western Power's reasons for the revising its service standard targets

3.1 Reliability driven capital expenditure

Reliability driven capital expenditure is aimed at selectively maintaining or improving the standard of services delivered by the SWIS network. This category of expenditure involves a range of initiatives including:

- Automation – This initiative aims to maintain or reduce the number of customers affected by supply interruptions, and to maintain or improve supply restoration time, through the targeted use of network automation.
- Re-conductoring – This initiative aims to maintain or improve supply reliability through selective re-conductoring, which improves load transfer capacity under network fault conditions.
- Reinforcement – This initiative aims to maintain or improve supply reliability through selective pole reinforcement, which is a proven cost-effective method for extending pole life and returning poles to a serviceable condition.

As noted in Attachment D of this submission:

- Current economic conditions have necessitated Western Power's re-consideration of the rate at which improvements can be made to network performance so that it accords more closely with the standards set out in the *Electricity Industry (Network Quality and Reliability of Supply) Code* 2005.

- Reliability driven capital expenditure has also been significantly reduced through the State budgeting process for 2009/10.

In view of the foregoing considerations, the revised reliability capital expenditure forecast is presented in Table 1 below.

Distribution - Reliability	**09/10**	**10/11**	**11/12**	**Total**
Reinforcement	6.10	11.00	15.81	32.91
Automation	4.20	12.43	15.97	32.60
Re-conductoring	0.00	5.33	6.86	12.19
Other	0.67	0.28	8.38	9.33
Total ($M)	**10.96**	**29.06**	**47.03**	**87.04**

Table 1 – Distribution Capital Expenditure – Reliability ($M at June 30 June 2009)

The revised reliability driven capital expenditure forecast is significantly lower than that contained in Western Power's original access arrangement revisions submission as shown in Table 2 below:

	AA2 Period ($Million)			
	2009/10	**2010/11**	**2011/12**	**Total**
Original AA2 Submission	$44.4	$54.4	$67.4	$166.2
Revised AA2 Re-submission	$11.0	$29.1	$47.0	$87.0

Table 2 - Reliability Driven distribution capital expenditure ($M at June 30 June 2009)

The reduction in reliability driven capital expenditures has a direct impact on the achievable improvements in network performance over the 3 year term:

3.2 Reductions in operating expenditure

Higher than optimum maintenance work backlogs will continue to exist under the proposed forecast expenditures for the 2009/10 to 2011/12 regulatory period. An effect of high backlogs of work is an increased likelihood of a low probability / high impact events occurring. Despite being exposed recently to severe storms and relatively hot conditions, Western Power's network has (so far) not been subject to the occurrence of such an event. Although the probability of a high impact event occurring in the short term remains low, the on-going existence of the work backlog will contribute to a lower level of network reliability performance than could otherwise be achieved. Western Power recognises that work backlogs must be reduced to provide an acceptable level of long-term network performance.

3.3 Effect of Required Amendment 23

Required Amendment 23 requires the definitions of SAIDI and SAIFI to be altered so that they do not make provision for the exclusion of single customer interruptions.

Single customer interruptions historically have been excluded in SAIDI and SAIFI measures of reliability performance. Their inclusion in these measures will result in a slight deterioration in measured performance, both historically and in the future. This does not mean that actual performance will deteriorate, however the SSB targets for the second access arrangement period need to be increased by an average of 9 SAIDI minutes per annum to adjust for the new definition of SAIDI.

4 Proposed Distribution Performance Targets

The revised distribution reliability performance targets are set out in Table 3 and Table 4 below.

	AA2 Period		
	2009/10	**2010/11**	**2011/12**
CBD	38	38	38
Urban	165	162	153
Rural Short	259	253	244
Rural Long	612	588	556
SWIS	**230**	**224**	**213**

Table 3 - SAIDI Service Standard Benchmarks

	AA2 Period		
	2009/10	**2010/11**	**2011/12**
CBD	0.24	0.24	0.24
Urban	1.92	1.89	1.83
Rural Short	3.12	3.06	2.98
Rural Long	5.00	4.85	4.80
SWIS	**2.50**	**2.46**	**2.41**

Table 4 - SAIFI Service Standard Benchmarks

In relation to the SSB targets, it is noted that:

1. SWIS SAIDI is expected to improve by 17 minutes and SWIS SAIFI by 0.09 over the second access arrangement period (AA2).

2. Targets during the AA2 period are inclusive of Single Premise Interruptions (in accordance with Required Amendment 23), which are estimated to increase the performance measures by an average of 9 SAIDI minutes per annum.

3. Targets for Urban, Rural Short, Rural Long and SWIS for 2010/11 to 2011/12 are based on work that is proposed to be undertaken during the AA2 period.

4. Targets for Urban, Rural Short and Rural Long for 2009/10 are based on the following factors:

    - An estimated 3 minute SWIS SAIDI saving to be achieved as a result of work undertaken in the last year of the current regulatory period; and

    - Higher than optimum maintenance work backlogs as a result of reduced operating expenditure in 2009/10, resulting in deterioration in reliability by an estimated 3 SAIDI minutes.