Amended proposed access arrangement information for the Western Power Network

Date: 26 November 2012

Contents

1 Background and context

This document has been prepared in response to the *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, published by the Economic Regulation Authority (the Authority) on 5 September 2012.

The Authority's final decision is to not approve Western Power's revised proposed revisions to the access arrangement. The Authority requires 58 amendments to the access arrangement that Western Power proposed on 29 May 2012.

This submission explains how Western Power has either implemented or adequately addressed the matters that prompted the Authority to require the amendments detailed in its final decision. This amended proposed access arrangement information should be read in conjunction with the access arrangement information documents submitted by Western Power on 30 September 2011 and on 29 May 2012.

1.1 Access Code provisions

Section 4.23 of the Access Code outlines the requirements for approving the amended proposed revisions to the access arrangement.

4.23 If the Authority's final decision is to not approve a proposed access arrangement and the service provider submits an amended proposed access arrangement and either:

(a) the amended proposed access arrangement implements the amendments required under section 4.17(b); or

(b) the amended proposed access arrangement does not implement the amendments required under section 4.17(b) but otherwise (in the Authority's view) adequately addresses the matters which prompted the Authority to require the amendments,

then the Authority's further final decision must be to approve the amended proposed access arrangement unless:

(c) approving the amended proposed access arrangement would be inconsistent with the Code objective; and

(d) the Authority determines that the advantages of not approving the amended proposed access arrangement outweigh the disadvantages, in particular the disadvantages associated with decreased regulatory certainty and increased regulatory cost and delay.

1.2 Structure of this document

Chapter 2 of this amended proposed access arrangement information provides an executive summary of Western Power's overall response to the Authority's final decision. Chapter 3 provides a description of how Western Power has either accepted or adequately addressed the matters that prompted the Authority to require the amendments. Chapter 4 provides further discussion on specific amendments where required.

Drafting changes to the access arrangement or its associated policies and contracts are incorporated in the amended proposed revisions to the access arrangement, which accompanies this submission.

1.3 Explanatory notes

All monetary amounts presented in this document are expressed in real **30 June 2012 dollars** and apply to 1 July to 30 June financial years **unless otherwise stated**. Some tables may not add due to rounding.

2 Executive summary

On 5 September 2012 the Economic Regulation Authority (the Authority) released its *Final Decision on the Proposed Revisions to the Access Arrangement for the Western Power Network*. The Authority requires 58 amendments to Western Power's proposal to approve the access arrangement. Western Power has implemented or addressed all 58 required amendments and submits amended proposed revisions to the access arrangement.

In preparing this submission, Western Power adequately addressed the matters that prompted the Authority to make a number of required amendments. These matters include the finalisation of the Application & Queuing Policy, standard access contract and service standard adjustment mechanism. Western Power has also addressed the Authority's requirement to appropriately remove the tax liabilities arising from capital contributions and gifted assets from its tax asset base. Western Power considers the Authority can approve the amended proposed revisions to the access arrangement in its further final decision.

Amendments that have been implemented

Western Power has implemented 47 of the Authority's amendments exactly as required. In summary, Western Power has implemented:

- a return on investment of 3.60% post tax
- a forecast of operating expenditure that is $299 million lower than Western Power proposed
- a 6.8% reduction in forecast capital expenditure compared to that forecast by Western Power
- an increase in the number of service measure obligations and targets to assess service performance
- an improvement in the service level required to be delivered across service measures
- removal of the tax liability arising from Western Power's receipt of gifted assets or capital contributions from the target revenue
- several amendments to the standard access contract that Western Power uses for retailers and generators wanting to connect to the Western Power Network. The amendments improve the clarity of obligations and responsibilities between Western Power and contract-holders
- the removal of battery storage and electric vehicle applications from the bidirectional reference service tariff
- refinements to the Application & Queuing Policy that will improve the clarity and process for customers seeking access to the network

The amended proposed revisions to the access arrangement and associated policies and contracts have been updated to reflect all of these amendments.

Amendments that have been addressed

Western Power has addressed 11 of the Authority's required amendments. A key amendment is the calculation of Western Power's tax asset base in order to estimate Western Power's tax liabilities under the post-tax modelling approach required by the Authority. Western Power considers it has addressed the Authority's concerns by implementing an approach to calculating Western Power's tax asset base that appropriately removes capital contributions and gifted assets.

In its final decision the Authority proposes using the regulated asset base as a substitute for the tax asset base used to estimate the tax liability. Western Power considers that the regulated asset base is not a good substitute for the tax asset base. This is because the regulated asset base is escalated for inflation each year and incorporates different asset lives and classes than those used for tax purposes, which would overstate the value of the assets. The Authority's approach would result in a significant variation between the estimate of the tax liability and the actual tax incurred over time.

The Authority has stated that it *'…would not object to Western Power utilising its proposed TAB (tax asset base), provided that capital contributions were appropriately removed…'*[1]. Western Power has therefore undertaken the work required to properly remove capital contributions from its opening and forecast tax asset register. The outcome is a tax asset base founded on the tax asset register rather than the regulated asset base. This adjustment effectively removes capital contributions from the tax asset base without compromising the adoption of a post-tax modelling approach. Western Power considers that this adequately addresses the concerns that led to the Authority's required amendment.

The Applications & Queuing Policy (AQP) is another issue Western Power has addressed. The Authority proposed a number of changes to the AQP that were designed to give further clarity to customers on how the new application process will operate. Western Power has made several variations to the AQP to address the Authority's concerns.

All other required amendments that have been addressed (rather than implemented) are either minor wording changes or are due to the application of finalised 2011/12 information that results in a slightly different revenue outcome. Western Power considers these adjustments can be accepted by the Authority.

Rate of return on investment

The Authority proposes a real post-tax weighted average cost of capital (WACC) of 3.60%. Western Power has implemented this amendment. However, Western Power maintains its view that the Authority's outcome is not consistent with the objectives of the Access Code.

Section 6.4 of the Access Code provides *that the price control in an access arrangement must have the objective of giving the service provider the opportunity to earn revenue for the access arrangement period which includes 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****.*

Western Power's Board is of the view that the return on investment allowed is not commensurate with the commercial risks involved.

As Western Power's owner, the Government has the authority to direct Western Power not to appeal. A Ministerial direction under section 111 of the *Electricity Corporations Act 2005* instructing Western Power not to appeal was received on 18 September 2012.

When compared with other decisions by the Australian Energy Regulator and the Authority's recent gas decisions[2], the Authority's decision on the WACC for Western Power is

[1] Paragraph 1161, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.
[2] *Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011 and Final Decision on proposed *Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011.

unprecedentedly low. Relative to other network investment opportunities, Western Power will be significantly less attractive to investors.

Taking this in to account, Western Power's Board is of the view that the opportunity to pursue alternative sources of capital is severely hampered and the case for the Government to invest in Western Power has been diminished. Consequently, there is a greater risk that Western Power will not be able to service the capital required to deliver the outcomes described in the access arrangement.

The Board notes that the Authority's sampling period results in a risk free rate that is relatively low compared to most other periods. The Board also notes that the Authority has discretion to ensure that the outcome of a particular methodology is consistent with ensuring the return on investment is commensurate with the commercial risks involved. The Board invites the Authority to properly use its discretion in selecting the sampling period for the further final decision.

Conclusion of access arrangement review process

Consistent with section 4.23 of the Access Code, Western Power has implemented or adequately addressed the matters that prompted the Authority to require the amendments prescribed in its draft decision.

Western Power considers the *Amended Proposed Revisions to the Access Arrangement* that accompanies this *Amended Proposed Access Arrangement Information* can be approved by the Authority.

Western Power anticipates that the access arrangement revisions will commence on 1 February 2013.

3 Responses to the Authority's required amendments

This section states Western Power's response to each of the required amendments. The table below briefly describes where Western Power has implemented or adequately addressed the matters which prompted the Authority to require the amendments. Where further discussion is required on specific amendments, this is provided in chapter 4 of this document.

The table also includes a reference to the relevant section of the amended proposed revisions to the access arrangement or associated document where Western Power has made the required amendment.

Table 1: Western Power's response to the required amendments

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 1 Western Power must remove criteria 4) a) from its proposed eligibility criteria for each reference service.	**Western Power has implemented this amendment.**	Refer to the reference services, attached at Appendix E of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 2 The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems.	**Western Power has implemented this amendment.**	Refer to the reference services, attached at Appendix E of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 3 The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in second last row of Table 6 and Table 7).	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** The Authority requires Western Power to amend its transmission and distribution target revenue to reflect the amount it has determined in its final decision, specifically the values in Tables 6 and 7 of its final decision document. The transmission and distribution target revenue will differ slightly from the values in Tables 6 and 7 to account for correction of modelling errors and adjustments resulting from other required amendments. These adjustments are described in section 4.1 of this document.	Refer to sections 5.6.6 and 5.7.6 of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 4 Network control services must be excluded from operating cost forecasts for the purposes of determining target revenue and the D-factor scheme must be modified to include network control services.	**Western Power has implemented this amendment.** An overview of the D-factor modifications that allow for inclusion of network control services is provided in the response to required amendment 42.	Refer to sections 7.4.2 and 7.6.3 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 5 The revised proposed access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 43 and Table 44	**Western Power has implemented this amendment.**	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 6 The revised proposed access arrangement must be amended to reflect a forecast of operating expenditure as indicated by the Final Decision values in Table 52.	**Western Power has implemented this amendment.**	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 7 The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to the cancelled or deferred projects identified in the statutory account audit.	**Western Power has implemented this amendment.**	Refer to section 5.2.1 (Tables 20 & 21) of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 8 The proposed revised access arrangement must be amended to reflect the values shown in Table 57 above.	**Western Power has implemented this amendment.**	Refer to section 5.2.1 (Tables 20 & 21) of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 9 Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.	**Western Power has implemented this amendment.**	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 10 The opening capital base for 1 July 2012 in the proposed revised access arrangement must be inflated using the same methodology as the current access arrangement and must not include the additional half year inflation in relation to expenditure during the second access arrangement proposed by Western Power.	**Western Power has implemented this amendment.**	Refer to section 5.2 (Tables 20 and 21) of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 11 The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 64 and Table 65 above.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** The Authority requires the opening capital base to reflect the values in Table 64 and Table 65 of its final decision. However, the values in Table 64 and 65 must be updated to reflect 2011/12 actual data (rather than forecast). The Authority's calculation of the capital base reflects a forecast of asset disposals during 2011/12, as the audited regulatory financial statements were not available at the time. The audited 2011/12 regulatory financial statements are now available, therefore Western Power has updated the opening capital base to reflect actual asset disposal. This results in a downward adjustment to the opening capital base. The revised opening capital base is provided in Tables 20 and 21 of the *Amended Proposed Revisions to the Access Arrangement*.	Refer to section 5.2 (Tables 20 and 21) of the *Amended Proposed Access Revisions to the Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 12 The revised proposed access arrangement revisions must be amended to remove all stay wire programs from the investment adjustment mechanism.	**Western Power has implemented this amendment.**	Refer to the pro forma forecast statements at Appendix A of this *Amended Proposed Access Arrangement Information*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*. Refer to section 7.3.7(f) of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 13 The revised proposed access arrangement revisions must be amended to include the investment adjustment mechanism values as indicated in Table 99. Western Power's revenue model must also be amended to include a separate regulatory category for wood pole management.	**Western Power has implemented this amendment.**	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*. Refer to section 7.3.7 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 14 The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as set out in Table 119 above.	**Western Power has implemented this amendment.**	Refer to the pro forma forecast statements at Appendix A of this *Amended Proposed Access Arrangement Information*.
Required Amendment 15 In relation to Rate of Return, Table 63 of the Amended Access Arrangement Information must be amended to reflect the relevant values of CAPM and WACC parameters in Table 126 and Table 127 of this Final Decision.	**Western Power has implemented this amendment.** A WACC of 3.60% real post-tax does not satisfy the requirements of section 6.4 of the Access Code. This is discussed in section 4.2 of this document.	Refer to section 5.4 of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 16 No amounts in relation to tax on capital contributions may be included in Target Revenue.	**Western Power has implemented this amendment.** As a consequence of accepting required amendment 16, and for the avoidance of doubt, Western Power has amended the Contributions Policy to include the forecast tax liability as part of the calculation of a contribution.	Refer to clauses 4.4, 5.2 and 5.5 of the Contributions Policy, attached at Appendix C of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 17 The amounts included in target revenue for working capital must be amended to the values in Table 137 and Table 138.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** The Authority requires working capital to be amended to reflect Tables 137 and 138 of its final decision. Western Power notes that the working capital amounts are located in Tables 134 and 135 of the Authority's final decision. Western Power has made several adjustments to target revenue (as described in the response to required amendment 3), which have resulted in corresponding adjustments to the values in Tables 134 and 135. This includes recalculation of the cost of working capital based on the revised revenue caps for AA3. The calculation method remains unchanged from the Authority's final decision. The revised working capital amounts are in section 4.3 of this document.	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 18 The Authority requires that Western Power adopt a tax asset base derived from the regulatory accounts for the purposes of determining its forecast tax liabilities and its maximum annual revenue requirement.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Western Power has amended the tax asset base to remove the value of tax liabilities arising from capital contributions and gifted assets. This amendment is discussed in detail in section 4.4 of this document.	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 19 The correction factor for under-recovery or-over recovery of revenue in the 2012/13 Price List must be based on the actual revenue for 2011/12.	**Western Power has implemented this amendment.**	Refer to the Price List Information, attached at Appendix F.2 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 20 Western Power's amendments for corrections to the real value of the TEC must be removed from the distribution revenue correction factor set out in section 5.7.7 of the revised proposed revisions to the access arrangement.	**Western Power has implemented this amendment.**	Refer to section 5.7.7 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 21 The reward in relation to the service standard adjustment mechanism must be amended to use the Authority's approved post tax WACC of 3.6 per cent.	**Western Power has implemented this amendment.**	Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 22 The service standard adjustment mechanism in target revenue must be updated to reflect actual service standard performance for 2011/12.	**Western Power has implemented this amendment.**	Refer to section 7.5 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 23 The minimum standard Circuit Availability SSB should be set at 97.7 per cent. This is the estimated 97.5 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per	**Western Power has implemented this amendment.**	Refer to section 4.3 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access*

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
cent reduction to reflect forecast impacts of additional transmission network capital works during the third access arrangement period. Table 184 below provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).		*Arrangement Information*.
Required Amendment 24 The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for: • transmission circuit System Minutes Interrupted – for meshed and radial circuits; • 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 0.1 to 1 minute duration and greater than 1 minute duration; and • Average Outage Duration, measured in minutes. Table 184 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power (see Appendix 3 for detail).	**Western Power has implemented this amendment.** The definitions of these service standard benchmarks used during the AA2 period have been retained. This is because the service standard benchmark and service standard adjustment mechanism (SSAM) targets for AA3 are set using the historical data based on the application of the AA2 definitions. Using the AA2 definitions also ensures consistency with how the measures have been reported in the annual Service Standard Performance Report to the Authority. For clarity, Western Power has corrected the following inconsistencies in the benchmark definitions that have been used during the AA3 review process: Planned outages and momentary interruptions were excluded from system minutes interrupted during AA2 and will continue to be so in AA3. The Final Decision incorrectly stated that planned outages are included in the system minutes interrupted measures[3], Loss of supply event frequency was measured for >0.1 system minutes interrupted events and >1 system minutes interrupted events during AA2 and will continue to be so during AA3. The Final Decision and Western Power's	Refer to section 4.3 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.

[3] Paragraph 1852 of the *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
	response to the Draft Decision incorrectly refers to events of 0.1 to 1 minute (including in this Required Amendment 24). This should refer to events of > 0.1 system minutes interrupted.	
Required Amendment 25 The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.	**Western Power has implemented this amendment.**	Refer to section 4.2.3 and 4.2.5 of the *Amended Proposed Revisions to the Access Arrangement*
Required Amendment 26 Western Power is required to adopt the SAIDI and SAIFI service standard benchmark measures estimated by the Authority from the most recent three years of data (Table 185 provides the Authority's estimates – see Appendix 3 for detail).	**Western Power has implemented this amendment.**	Refer to sections 4.2.4 and 4.2.6 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 27 Western Power is required to adopt the Call Centre Performance service standard benchmark measure estimated by the Authority from the most recent five years of data (Table 186 provides the Authority's estimates – see Appendix 3 for detail).	**Western Power has implemented this amendment.**	Refer to sections 4.2.9 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 28 The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Western Power has amended the Price List and Price List Information to reflect the transmission and distribution network	Refer to the Price List and Price List Information, attached at Appendix F of the *Amended Proposed Revisions to the*

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
and distribution network revenue cap approved by the Authority in this Final Decision.	revenue caps that result from the necessary adjustments described in the response to required amendment 3.	*Access Arrangement*.
Required Amendment 29 Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended as follows: 5.6.1 The transmission system revenue cap for revenue cap services ~~determines~~ is used to determine the maximum transmission revenue cap service revenue (MTRt) for Western Power's transmission system for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement,~~ Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ transmission revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t. 5.7.1 The distribution system revenue cap for revenue cap services ~~determines~~ is used to determine the maximum distribution revenue cap service revenue (MDRt) for Western Power's distribution system for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement~~, Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Existing clause 6.5.3, which was included in the 29 May revised proposed access arrangement has the same effect as the Authority's proposed wording that relates to 'Western Power using reasonable endeavours…'. Clause 6.5.3 has been retained instead of adopting the Authority's wording in clauses 5.6.1 and 5.7.1. The reasons for this approach are discussed in more detail in section 4.5 of this document.	Refer to sections 5.6.1, 5.7.1 and 6.5.3 of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 30 The Price List Information must set out details of rebalancing between reference services and the reasons for it with supporting information.	**Western Power has implemented this amendment.**	Refer to the Price List Information, attached at Appendix F.2 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 31 The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Final Decision. Western Power should include sufficient information to enable a comparison with the estimate of incremental and stand-alone costs in the current 2011/12 Price List Information, and to explain any material variations.	**Western Power has implemented this amendment.**	Refer to the Price List Information, attached at Appendix F.2 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 32 All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.	**Western Power has implemented this amendment.**	Refer to the Price List Information, attached at Appendix F.2 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 33 Western Power must amend the gain sharing mechanism methodology and values to use the scaling factors, including economy of scale factors, and operating costs approved by the Authority in this Final Decision. The actual values used for scaling factors must be independently audited. The audit must be carried out by an independent auditor approved by the	**Western Power has implemented this amendment.** The revised forecast efficiency and innovation benchmarks for each financial year are set out in Table 12 in section 4.6 of this document.	Refer to sections 7.4.8 and 7.4.9 of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Authority, with Western Power managing and funding the audit. The scope of the audit will be determined by the Authority.		
Required Amendment 34 Western Power must amend its revised proposed revisions to the access arrangement to include the process for how it will be determined and to what extent there is a relationship between costs savings and the underperformance on service standards as set out in Western Power's amended access arrangement information.	**Western Power has implemented this amendment.**	Refer to section 7.4.4 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 35 Western Power must amend Table 27 of the access arrangement to be consistent with the Authority's determination of efficient operating costs as set out in this Final Decision.	**Western Power has implemented this amendment.**	Refer to section 7.4 (table 33) of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 36 The Circuit Availability SST should be set at 98.1 per cent. This is the estimated 50 per cent PoE level derived from the application of a Smallest extreme value distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.	**Western Power has implemented this amendment.**	Refer to section 7.5.11 of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 37 The System Minutes interrupted (radial networks) measure must be retained as a SSAM incentive measure. The SSAM SST for this measure should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 184 for the Authority's estimates).	**Western Power has implemented this amendment.**	Refer to sections 7.5.3, 7.5.4, 7.5.6 and 7.5.11 of the *Amended Proposed Revisions to the Access Arrangement* Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 38 The Loss of Supply Event Frequency (0.1 to 1 system minutes and greater than 1 system minutes) and the Average Outage Duration measures must be included as SSAM incentive measures. The SSAM SSTs must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 184 for the Authority's estimates).	**Western Power has implemented this amendment.** The loss of supply event frequency service standard benchmark measure is applied for events >0.1 system minutes interrupted (not 0.1 to 1 system minutes interrupted) and events >1 system minutes interrupted, consistent with the AA2 definition This is discussed in the response to required amendment 24.	Refer to sections 7.5.3, 7.5.4 and 7.5.6 of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 39 Western Power must: • increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue; • adopt the weightings set out in Table 4 to allocate the revenue at risk across the various measures • take account of the revisions to allowable transmission revenue set out in this Final Decision to calculate the reward and incentive penalty rates.	**Western Power has addressed the matters which prompted the Authority to require this amendment** In summary, Western Power has: applied the 1% to the annual transmission revenue implemented adoption of the weightings specified by the Authority but notes that this is presented in Table 191, not in Table 4 of the Authority's Final Decision calculated the reward and penalty incentive rates to reflect the revised allowable transmission revenue that results from removing asset disposal from the opening capital base. The revised opening capital base is discussed in response to required amendment 11	Refer to section 7.5.8 and 7.5.11 of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 40 Western Power must adopt revised SAIDI and SAIFI SSAM SSTs that remove the transmission network events from the estimates. The SSAM SSTs must be set at the 50 per cent PoE level based on the best fit statistical distribution applied to the most recent three years of historic data (see Table 185 for the Authority's estimates).	**Western Power has implemented this amendment.**	Refer to sections 7.5.6 and 7.5.11 of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 41 Western Power must adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Final Decision.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Western Power has calculated the reward and penalty incentive rates to reflect the revised allowable distribution revenue that results from removing asset disposal from the opening capital base. The revised opening capital base is discussed in Western Power's response to required amendment 11.	Refer to section 7.5.11 of the *Amended Proposed Revisions to the Access Arrangement*. Refer to the revenue model attached at Appendix B of this *Amended Proposed Access Arrangement Information*.
Required Amendment 42 The D-factor scheme must be amended as set out in paragraph 2273 above.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Paragraphs 2270 to 2273 of the final decision describe that the intent of required amendment 42 is: to exclude new facilities investment from the D-factor	Refer to sections 7.6.1, 7.6.2, 7.6.3, 7.6.4 and 7.6.5 of the *Amended Proposed Revisions to the Access Arrangement.*

[4] Under section 5.1.1 of the Wholesale Electricity Market Rules the definition of network control service is "A Network Control Service is a service provided by generation or demand side management that can be a substitute for transmission or distribution network upgrades."
[5] Under the Access Code the definition of alternative options is "in relation to a major augmentation, means alternatives to part or all of the major augmentation, including demand-side management and generation solutions (such as distributed generation), either instead of or in combination with network augmentation."

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
	make clear that only costs in excess of amounts approved in the target revenue are allowed allow the inclusion of network control services Western Power has adopted slightly different wording to that provided in paragraph 2273. In summary, Western Power has: Western Power has removed all references to new facilities investment (as required by paragraph 2270 of the final decision). This includes amendments to clause 7.6.1 and 7.6.4 the Authority's proposed wording for 7.6.2 a) did not take into account the effect of the Investment Adjustment Mechanism (IAM). The IAM can result in the amount of costs in the target revenue being adjusted. Western Power has included additional wording to clarify that the impact of the IAM is to be taken into account in determining the amount previously included in target revenue the Authority proposed including network control services within 7.6.2 b). However, the term "network control service" is not defined under the Access Code. For the avoidance of doubt, Western Power has defined the network control services consistent with the definition of network control services under the Wholesale Electricity Market Rules[4] and the definition of alternative options under the Access Code[5]. Western Power has amended clause 7.6.3 to use a simpler form of the wording used in AA2 in line with the Authority's drafting in paragraph 2273 These amendments have the same effect as the Authority's amendment, while properly accounting for the impact of the IAM.	

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 43 The values in relation to the recovery of deferred revenue stated in section 7.7 of the revised proposed revisions to the access arrangement must be amended to: $47.7 million ($ as at 30 June 2012) for transmission services; and $358.3 million ($ as at 30 June 2012) for distribution services.	**Western Power has implemented this amendment.**	Refer to section 7.7 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 44 Clause 3.6(b) and (c) of the ETAC must be amended to clarify that, to the extent the model service level agreement applies, Western Power must comply with any relevant disconnection timeframes in the model service level agreement.	**Western Power has implemented this amendment.**	Refer to clauses 3.6(c), (d) and (e) of the Electricity Transfer Access Contract, attached at Appendix A of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 45 Clause 3.7 of the ETAC must be amended to require Western Power to act “as soon as reasonably practicable” to advise a user of any connections points which have reverted to it as a “default supplier” retailer.	**Western Power has implemented this amendment.**	Refer to clause 3.7(l) in the Electricity Transfer Access Contract, attached at Appendix A of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 46 Clause 6.1 of the ETAC must be amended to include an obligation for Western Power to negotiate in good faith and use reasonable endeavours to negotiate a Connection Contract with the designated controller.	**Western Power has implemented this amendment.**	Refer to clause 6.1(f) in the Electricity Transfer Access Contract, attached at Appendix A of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 47 Each of the sub-clauses in clause 3.7 of the electricity transfer must be amended to require Western Power to act “as soon as reasonably practicable”.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** The words “as soon as reasonably practicable" have been added to each subclause where it is appropriate. Western Power has: added "as soon as reasonably practicable" to (a), (b), (c) Western Power has added "as soon as reasonably practicable" to (d) subject to the Metering Code, or a service level agreement, not specifying a timeframe. “As soon as reasonably practicable" is not required in (e) and (k) as those clauses are not about timing issues. For paragraph (f) "As soon as reasonably practicable" is not required as the Build Pack specifies its own time limits. For example, the Build Pack specifies that a NMI standing data request requires a response by COB on the business day following the request. For paragraph (g) “As soon as reasonably practicable" is not required as it has its own time limits (1 July and 21 July). "As soon as reasonably practicable" was already in (h), (i) and (j) so no further change was required.	Refer to clause 3.7 in the Electricity Transfer Access Contract, attached at Appendix A of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 48 An amendment is required to the ETAC to reflect the amendments set out in paragraph 2461 above.	**Western Power has implemented this amendment.**	Refer to clauses 9 (f), (g) and (h) in the Electricity Transfer Access Contract, attached at Appendix A of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 49 An amendment is required to the ETAC to include a clause requiring Western Power to pay interest on cash	**Western Power has implemented this amendment.**	Refer to clause 9(i) in the Electricity Transfer Access Contract, attached at Appendix

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
security deposits provided by users.		A of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 50 The Applications & Queuing Policy (AQP) must be amended to enable applicants to elect, at the time of application, that they wish the application to be processed as an applicant-specific solution.	**Western Power has implemented this amendment.** Western Power has introduced three new clauses: 16.5, 20.3A and 24.1(b2), which have the effect of enabling applicants to elect to be processed as an applicant specific solution. Clause 16.5 provides that an applicant at the time of making an application may opt-out of the competing applications group (CAG) process. If it does so, it will be treated as an applicant-specific solution. Clause 20.3A clarifies that the applicant can pursue an applicant-specific solution at any time, and where it does it stays in consideration as part of a CAG (unless it has opted out). Clause 24.1(b2) allows applicants to opt out of one or more CAGs at any time. These additional clauses allow applicants to be processed as an applicant-specific solution at the time of application.	Refer to clauses 16.5, 20.3A and 24.1 (b2) of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 51 The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out: • how competing applications in a “competing applications group” will be processed; • how timing of network augmentations will be coordinated with the applications; • how the competing applications group concept will	**Western Power has implemented this amendment.** Section 4.7 of this document describes how Western Power has given effect to the Authority’s amendment.	Refer to clauses 3.15, 24.1, 24.1(b1), 24.6, 24.6A-24.6C of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
operate; and • what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.		
Required Amendment 52 Timelines for applicant-specific solutions must be stated in line with the timelines for competing applications groups.	**Western Power has implemented this amendment.** Western Power has inserted a table in Appendix B to the AQP, which sets out the timeframes for the competing application group process so it can be compared with the applicant-specific solution process. The table indicates that the timeframes for the applicant-specific solution and the competing application group solution are roughly equivalent but the actual outcomes are highly dependent on the time taken for specific steps (e.g. negotiations to change preliminary access offers and objections to applicant-specific solutions). For additional clarity, clause 24.1(b1) has been added to provide that Western Power will notify applicants within 30 business days if they have been included in a competing application group.	Refer to Appendix B and clause 24.1(b1) of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*
Required Amendment 53 Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.	**Western Power has implemented this amendment.**	Refer to clause 18.2A(b) of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*.

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
Required Amendment 54 Sections 17A.3 and 17A.4 of the AQP must be amended as set out in paragraph 2591 above.	**Western Power has adequately addressed the matters which prompted the Authority to require this amendment.** Western Power has updated clause 17A.3 with the Authority's wording and updated clause 17A.4 to address the required amendment. Western Power's amendment to clause 17A.4 is discussed in section 4.8 of this document.	Refer to clauses 17A.3 and 17A.4 of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 55 The applications and queuing policy must be amended to include a specific clause in similar terms to clauses 24.5(b) and (c) of the current access arrangement.	**Western Power has implemented this amendment.**	Refer to clause 24A.5 of the Applications & Queuing Policy, attached at Appendix B of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 56 The proposed revisions to the access arrangement must be amended to reflect the Authority's published Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy and any consequential amendments.	**Western Power has implemented this amendment.**	Refer to the Contributions Policy, attached at Appendix C.1 of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 57 Clause 6.3 of the contribution policy must be amended as follows: ~~A headworks contribution~~ The headworks base charge …	**Western Power has implemented this amendment.**	Refer to clause 6.3 of the Contributions Policy, attached at Appendix C of the *Amended Proposed Revisions to the Access Arrangement*.
Required Amendment 58 Western Power's proposed Appendix D - Current prices and explanation of charges needs to include sufficient detail to enable readers to locate the relevant price	**Western Power has implemented this amendment.** This amendment relates to Appendix D of the Distribution Headworks Methodology. The appropriate reference has been detailed in section 5.4 (a footnote). Appendix's C and D have	Refer to Appendix D of the Distribution Headworks Methodology, attached at Appendix C.2 of the *Amended*

Required amendment	Western Power response	Cross reference to relevant section of access arrangement
tables on Western Power’s website.	been amended to refer to clause 5.4. Western Power has also made a number of additional amendments from documents submitted in response to the Authority’s draft decision: Distribution Headworks Methodology: in section 2.1, the reference to clause 5.17D (b) of the Code has been corrected to reflect the current 4% figure. There is a minor change to the definition of "mixed zone" as a result of changes to the price list information Contribution Policy: in section 1, the definition ‘headworks base charge’ has been renamed ‘distribution headworks base charge’ in accordance with the changes to the mid-period AA2 change. There are also minor changes to the definitions of ‘mixed zone’ and ‘rural zone’ as a result of changes to the price list information.	*Proposed Revisions to the Access Arrangement*.

4 Further discussion of key amendments

This chapter provides further discussion on several required amendments where Western Power has:

- implemented the amendment and explanation is required of how Western Power has given effect to the Authority's required amendment
- addressed the issues that prompted the Authority to make the required amendment

4.1 Required amendment 3 – Revenue

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in second last row of Table 6 and Table 7).

The Authority requires Western Power to amend its transmission and distribution target revenue to reflect the amount it has determined in its final decision, specifically the values in Tables 6 and 7 of its final decision document. The transmission and distribution target revenue differs slightly from the values in Tables 6 and 7 to account for corrections to modelling errors and changes resulting from other required amendments. These adjustments are described below.

- **Investment adjustment mechanism (IAM)** - the revenue model in the final decision provides for a return via the IAM on a small amount of investment that did not meet the new facilities investment test. This is a modelling error. Western Power is not entitled to earn a return on this investment, so the revenue has been adjusted downwards accordingly.
- **Equity raising costs** - the revenue model in the final decision contained an error that double-counted equity raising costs in the cash flow analysis and applied Western Power's inflation adjustment rather than the implied inflation adjustment. This has been corrected.
- **Wood poles –** Western Power has accepted required amendment 13, which requires the introduction of a new regulatory category for wood pole management so that the specific wood pole expenditure is more clearly defined[6]. Having specific dollar amounts results in more accurate application of depreciation, therefore the distribution revenue must be adjusted accordingly.
- **Updated inputs for 2011/12 results –** Western Power has updated all 2011/12 inputs to reflect end of year results rather than forecasts. These include updated revenue, energy and asset disposals.[7]
- **Tax asset base –** Western Power has addressed required amendment 18, which requires tax on capital contributions and gifted assets to be removed from the tax asset base. Western Power's tax asset base varies from the Authority's calculation in its final decision as it is based on Western Power's view of the tax asset register, which more accurately estimates the tax liability. This results in a revised tax liability

[6] Previously, wood pole expenditure was included in the asset replacement category as an assumed ratio of 60%.
[7] Actuals were not available at the time of Western Power's previous revised access arrangement submission (29 May 2012), however the Authority had incorporated actuals for capital expenditure, capital contributions and operating expenditure in its final decision. See audited regulatory financial statements attached at Appendix C of this document.

of $323 million and a $89 million consequential increase in target revenue. The calculation of the tax asset base is discussed in section 4.4 of this document.

Table 2 shows the impact these amendments have on target revenue. Overall these amendments increase Western Power's revenue entitlement over AA3 by $103 million (present value as at 30 June 2012) compared to the final decision.

Table 2: Comparison of present value of revenue cap services revenue for the third access arrangement period

$ million real as at 30 June 2012	Transmission	Distribution	Total
Final decision – revenue present value	1,468.9	4,556.1	6,024.9
Final decision response – revenue present value	1,481.9	4,645.7	6,127.7
Difference	13.0	89.6	102.8

The revised values of target revenue determined by Western Power for its response to the final decision are set out below in Table 3 and Table 4. These tables also show the "smoothed" target revenue that becomes the revenue cap under the price control.

Table 3: Composition of transmission network target revenue

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Operating expenditure	104.0	103.3	103.6	105.7	108.2	472.1
Plus depreciation	85.2	93.8	103.4	110.0	117.4	456.5
Plus redundant assets	0.0	0.0	0.0	0.0	0.0	0.0
Plus return on investment	92.1	99.6	110.1	115.0	120.5	481.4
Plus return on working capital	0.5	1.3	1.0	1.0	0.8	4.1
Plus tax payable	49.5	27.1	8.0	0.0	0.0	80.2
Less value of imputation credits	-12.4	-6.8	-2.0	0.0	0.0	-20.1
Forward-looking efficient costs	**319.0**	**318.3**	**324.1**	**331.6**	**346.9**	**1,474.3**
Plus gain sharing mechanism	0	0	0	0	0	0
Plus unforeseen events adjustment	0					0
Plus Technical Rules change adjustment	0					0
Plus investment adjustment mechanism amount	-47.6					-46.0
Plus service standards adjustment mechanism amount	6.1					5.9
Plus D-factor amount	0					0
Plus recovery of AA2 deferred revenue	10.6	10.6	10.6	10.6	10.6	47.7

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Adjustments in accordance with previous access arrangement	**-30.9**	**10.6**	**10.6**	**10.6**	**10.6**	**7.7**
Less non-revenue cap services revenue	0	0	0	0	0	0
Transmission target revenue for revenue cap services (unsmoothed)	**288.1**	**328.9**	**334.7**	**342.2**	**357.4**	**1,481.9**
Annual revenue cap services revenue (smoothed) – TR_t	**387.3**	**367.1**	**326.7**	**292.5**	**260.7**	**1,481.9**
% change in TR_t		-5.2%	-11.0%	-10.5%	-10.9%	

Table 4: Composition of distribution network target revenue

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Operating expenditure	348.3	351.8	347.8	343.3	352.3	1,569.8
Plus depreciation	194.1	214.2	237.5	241.7	255.3	1,024.2
Plus redundant assets	3.4	0.5	0.0	0.0	0.0	3.8
Plus return on investment	138.9	152.9	168.9	184.0	197.8	753.9
Plus return on working capital	2.1	2.5	3.0	3.2	3.5	12.8
Plus tax payable	52.8	69.7	72.2	79.4	71.6	309.8
Less value of imputation credits	-13.2	-17.4	-18.0	-19.9	-17.9	-77.4
Forward-looking efficient costs	**726.4**	**774.3**	**811.4**	**831.8**	**862.6**	**3,596.8**
Plus gain sharing mechanism	0	0	0	0	0	0
Plus unforeseen events adjustment	0					0
Plus Technical Rules change adjustment	0					0
Plus investment adjustment mechanism amount	1.9					1.9
Plus service standards adjustment mechanism amount	24.5					23.7
Plus D-factor amount	0					0
Plus recovery of AA2 deferred revenue	79.6	79.6	79.6	79.6	79.6	358.3
Adjustments in accordance with previous access arrangement	**106.0**	**79.6**	**79.6**	**79.6**	**79.6**	**383.9**
Tariff equalisation contribution – TECt	150.8	166.0	156.0	134.4	128.9	665.0

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Less non-revenue cap services revenue	0	0	0	0	0	0
Distribution target revenue for revenue cap services (unsmoothed)	**983.3**	**1,019.8**	**1,047.0**	**1,045.8**	**1,071.1**	**4,645.7**
Annual revenue cap services revenue (smoothed)	**836.6**	**1,014.3**	**1,056.6**	**1,112.5**	**1,166.9**	**4,645.7**
Less TEC_t[8]	150.8	166.0	156.0	134.4	128.9	665.0
Distribution revenue cap formula component – DR_t	**685.7**	**848.4**	**900.6**	**978.1**	**1,038.0**	**3,980.7**
% change in DR_t		23.7%	6.2%	8.6%	6.1%	

4.2 Required amendment 15 – WACC

In relation to Rate of Return, Table 63 of the Amended Access Arrangement Information must be amended to reflect the relevant values of CAPM and WACC parameters in Table 126 and Table 127 of this Final Decision

The Authority proposes a real post-tax weighted average cost of capital (WACC) of 3.60%. Western Power has implemented this amendment. However, Western Power maintains its view that the Authority's outcome is not consistent with the objectives of the Access Code.

As Western Power's owner, the Government has the authority to direct Western Power not to appeal. A Ministerial direction under section 111 of the *Electricity Corporations Act 2005* instructing Western Power not to appeal was received on 18 September 2012.

Section 6.4 of the Access Code provides *that the price control in an access arrangement must have the objective of giving the service provider the opportunity to earn revenue for the access arrangement period which includes 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****.*

Western Power's Board is of the view that the return on investment allowed is not commensurate with the commercial risks involved.

When compared with other decisions by the Australian Energy Regulator and the Authority's recent gas decisions[9], the Authority's decision on the WACC for Western Power is unprecedentedly low (see Figure 1). Relative to other network investment opportunities, Western Power will be significantly less attractive to investors.

Taking this in to account, Western Power's Board is of the view that the opportunity to pursue alternative sources of capital is severely hampered and the case for the government to invest in Western Power has been diminished. Consequently, there is a greater risk that Western

[8] The price control formula for the distribution system includes an explicit pass through element for TEC.

[9] *Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011 and Final Decision on proposed *Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011.

Power will not be able to service the capital required to deliver the outcomes described in the access arrangement.

The Board notes that the Authority's sampling period results in a risk free rate that is relatively low compared to most other periods. The Board also notes that the Authority has discretion to ensure that the outcome of a particular methodology is consistent with ensuring the return on investment is commensurate with the commercial risks involved. The Board invites the Authority to properly use its discretion in selecting the sampling period for the further final decision.

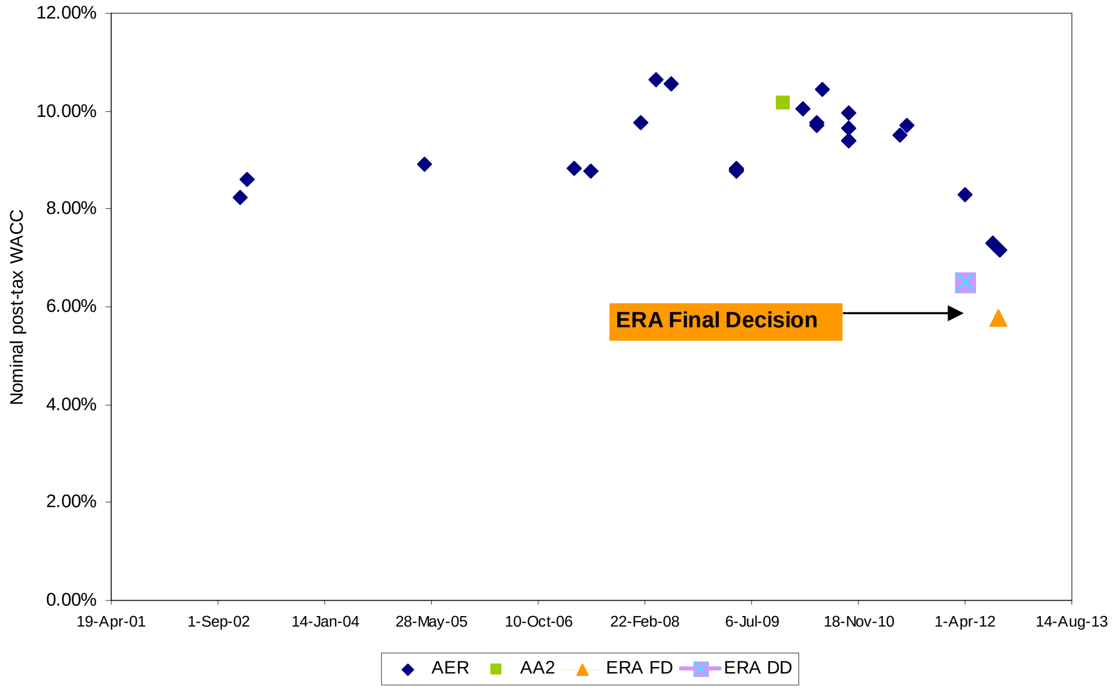

Figure 1: Comparison of recent WACC determinations

4.3 Required amendment 17 – Working capital

The amounts included in target revenue for working capital must be amended to the values in Table 137 and Table 138.

The Authority requires working capital to be amended to reflect the working capital values in its final decision. Western Power has made several adjustments (as described in the response to required amendment 3) to target revenue that have resulted in adjustments to the working capital values the Authority proposed in Tables 134 and 135 of its final decision[10].

Western Power has recalculated the cost of working capital based on the revised revenue caps for AA3. The calculation method remains unchanged from the Authority's final decision.

Table 5 and Table 6 show the impact of this on the working capital requirement over AA3.

[10] Note that while required amendment 17 state the working capital values are in tables 137 and 138, this is an error. The values are located in tables 134 and 135.

Table 5: Transmission working capital requirement

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Final decision – opening value of working capital	13.6	35.6	25.8	25.7	21.6
Final decision response – opening value of working capital	13.6	36.4	28.3	27.1	22.1
Difference	0.0	0.8	2.5	1.4	0.5

Table 6: Distribution working capital requirement

$ million real as at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Final decision – opening value of working capital	57.4	72.4	77.7	83.7	92.9
Final decision response – opening value of working capital	57.4	70.6	84.4	89.9	97.8
Difference	0.0	-1.8	6.7	6.2	4.9

4.4 Required amendment 18 – Tax asset base

The Authority requires that Western Power adopt a tax asset base derived from the regulatory accounts for the purposes of determining its forecast tax liabilities and its maximum annual revenue requirement.

Western Power has addressed this required amendment by removing capital contributions and gifted assets from the tax asset base it proposed in its response to the draft decision.

Required amendment 16 states tax liabilities associated with capital contributions and gifted assets must not be recovered through the target revenue. Western Power has implemented this amendment. As a consequence, capital contributions must be removed from Western Power's tax asset base with the exception of those received during the AA1 period. AA1 liabilities remain in the tax asset base on the basis that they are also incorporated in the regulated asset base.

In its final decision the Authority proposes using the regulated asset base (RAB)[11] as the tax asset base (TAB). The Authority adopted this approach as it recognised the complexities of adjusting Western Power's tax asset register to remove tax on capital contributions and therefore considered the RAB an adequate substitute. Western Power considers that the regulated asset base is not a good substitute for the tax asset base. This is because the regulated asset base is escalated for inflation each year and incorporates different asset lives to those used for tax purposes, which would overstate the value of the assets. As a consequence, the Authority's approach would result in a significant variation between the estimate of the tax liability and the actual tax incurred over time.

[11] Regulated asset base is a synonym for the term 'capital base' in the Access Code. Regulated asset base and capital base can be used interchangeably.

The Authority requires the adoption of a post-tax approach to determine target revenue for the AA3 period. This approach requires the estimation of the tax liability. The tax liability is estimated with reference to the tax asset base and tax depreciation. Western Power considers that utilising the regulatory asset base and applying depreciation with reference to asset lives used for regulatory purposes (that differ to the life used for tax purposes) is not a proper application of this approach and can not provide an accurate estimate of tax liability.

4.4.1 RAB versus tax asset register

The post-tax model adopted by the Authority requires an estimate of the tax liability. The tax liability building block must approximate as closely as practicable the tax liability costs Western Power will incur in AA3, provided those costs do not fail the efficiency test imposed by section 6.40 of the *Electricity Networks Access Code 2004*. The Authority did not find that the actual costs Western Power will incur for its tax liability (net of capital contributions) in AA3 would fail the efficiency test.

Western Power does not consider that the RAB is a reasonable proxy for the TAB for the purposes of estimating the tax liability. This is because the value of the RAB is affected by depreciation using different asset lives to Western Power's tax asset register as presented in Tables 7 and 8. The reasons for this are:

1. the value of the RAB is based on the 2004 Optimised Deprival Value (ODV). This valuation was initiated in order to assist in the determination of the fair values of physical assets to be transferred from Western Power Corporation to the four key successor entities (Synergy, Verve, Western Power and Horizon Power) and the valuation of the network assets to be used for regulatory purposes.[12] The ODV valuation acknowledged that *the access pricing arrangements are based upon, amongst other parameters, application of a real pre-tax weighted average cost of capital to a value ascribed to the regulatory asset base*[13]. This is in contrast to the tax asset register which reflects the written down value of the historic cost of Western Power's capital assets
2. the method used to roll forward the RAB in real terms has the effect of escalating the value of the RAB by inflation. Therefore the RAB-based TAB proposed by the Authority overstates the value of the TAB and therefore overstates depreciation on the TAB. The effect of this overstatement will be to increase the amount of depreciation estimated for the purposes of the tax liability building block. This will reduce the tax building block's value compared with the tax depreciation Western Power will actually be entitled to claim and the tax liability it will actually incur.
3. the asset lives assumed for depreciation purposes in the RAB differ to those used by the Commissioner for Taxation, which are actually applied to Western Power's tax asset register. The use of a different life to calculate the depreciation impact on the TAB does not provide a reliable estimate of Western Power's tax liability over AA3. Table 7 and Table 8 show the differences between the economic lives applied in the RAB-based TAB proposed by the Authority and the Commissioner's lives

The tax asset register would result in a more accurate estimate of the tax liability than using the RAB because the tax asset register only reflects the nominal values of assets and is not escalated for inflation year-on-year.

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[12] Western Power Corporation, Physical Asset Valuation as at 30 June 2004 – Distribution and Transmission Networks – Report to the valuation committee, June 2004, pg 5, Available from: http://www.erawa.com.au/cproot/2642/2/AAI%20-%20Addendum%20-%20Asset%20Valuation%20Report.pdf

[13] Ibid.

Table 7: Comparison of distribution economic lives against the Commissioner's tax lives

	Standard Life (AA3) (years)	Tax Life (years)	Difference
Wooden Pole Lines	41	45	4
Underground Cables	60	50	-10
Transformers	35	40	5
Switchgear	35	30	-5
Street lighting	20	15	-5
Meters and Services	25	25	-
IT	6	4	-2
SCADA & Communications	10.16	10	-0.16
Other Distribution Non-Network	10.16	10	-0.16
Distribution Land & Easements	-	-	-
Equity Raising Costs	44	5	-39.0

Table 8: Comparison of transmission economic lives against the Commissioner's tax lives

	Standard Life (AA3) (years)	Tax Life (years)	Difference
Transmission cables	55	47.5	-7.5
Transmission steel towers	60	47.5	-12.5
Transmission wood poles	45	47.5	2.5
Transmission Metering	40	25	-15
Transmission transformers	50	40	-10
Transmission reactors	50	40	-10
Transmission capacitors	40	40	-
Transmission circuit breakers	50	40	-10
SCADA and Communications	11	12.5	1.5
IT	6	4	-2
Other Non-Network Assets	16.85	12.5	-4.35
Land & Easements	-	-	-
Equity Raising Costs	49	5	-44

4.4.2 Western Power's approach

It is generally accepted regulatory practice in Australia to establish the tax asset base based on the following principles:

- the date the business was first subject to tax (or the national tax equivalents regime (NTER))
- the tax value of assets at that date, in sufficient detail to distinguish RAB assets from any non-RAB assets
- the vintage profile of the RAB assets when first subject to tax including any capex that took place prior to the commencement of regulation
- the tax base established when first subject to tax can then be rolled forward to the commencement of the post-tax approach taking account of relevant tax depreciation provisions, actual capex and disposals

Western Power sought expert advice from Ernst & Young to assist with the implementation of the post-tax approach to determining revenue and provided this advice to the Authority for review.

The Authority has stated that it *'…would not object to Western Power utilising its proposed TAB, provided that capital contributions were appropriately removed…'*[14]. Therefore, Western Power has undertaken the work to properly remove capital contributions from its opening and forecast tax asset register relying on the further advice of Ernst & Young, which has also been provided to the Authority. Western Power considers that this advice can be relied upon. The outcome is a TAB based on the tax asset register, which more accurately reflects Western Power's tax liabilities.

Western Power's method to determine the net tax value as at 30 June 2012 is as follows:

1. determine the tax value of assets as at 1 April 2006 (this being the date that Electricity Networks Corporation (trading as Western Power) was established under the *Electricity Corporations Act 2005* distinguishing between regulated assets, System Management (Markets) assets and unregulated assets)
2. roll forward the tax asset base to the commencement of the post-tax approach at 1 July 2012, taking account of relevant tax depreciation provisions, actual capex in AA1 and AA2[15]
3. determine the written-down value of capital contributions as at 1 April 2006
4. roll forward the value of capital contribution to the commencement of the post-tax approach at 1 July 2012, taking account of actual capital contributions in AA2[16]
5. deduct the value of capital contributions at 1 July 2012 from the tax value of asset based on a simple pro-rata allocation

Western Power's method to establish the TAB adopts the straight line depreciation method.[17] Applying straight-line depreciation simplifies the modelling of the tax asset base. Western Power has tested the reasonableness of this assumption by applying diminishing value depreciation method in rolling-forward the TAB to 30 June 2012 to the assets where diminishing value can be applied for tax purposes. This resulted in an opening tax asset base around $260 million **lower** than the proposed tax asset base. This substantial permanent difference would be to the detriment of Western Power's customer base.

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[14] Paragraph 1161, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.
[15] Ernst & Young concluded that the were no disposed assets that should have a tax written down value as at 30 June 2012 - Tax liabilities for regulated revenue purposes – Report of Vaughan Lindfield, 18 May 2012, para 67.
[16] AA1 capital contributions are to be retained in the tax asset base, therefore are not included in the roll forward of the value of capital contributions to be removed from the TAB
[17] Ernst & Young concluded that the straight line (prime cost) method for depreciation is reasonable and consistent with the approach adopted by other regulatory authorities - Tax liabilities for regulated revenue purposes – Report of Vaughan Lindfield, 18 May 2012, para 32.

Western Power proposes that diminishing-value depreciation should be assumed for any assets that are added to the tax asset base during the AA3 period. Diminishing-value depreciation is an option available under the tax regime that can be adopted for network assets. This option reduces the amount of revenue to be recovered from customers and reflects Western Power's forward-looking efficient costs.

Table 9: Comparison of straight-line and diminishing value depreciation applied to TAB

	Straight line depreciation		**Diminishing value depreciation**	
	Opening tax asset base $ millions as at 30 June 2012	Total depreciation over AA3 $ millions nominal	Opening tax asset base $ millions as at 30 June 2012	Total depreciation over AA3 $ millions nominal
Transmission	$2,043.3	$-431.5	$1,980.9	$-484.5
Distribution	$3,127.7	$-663.3	$2,929.9	$-812.8
Total	**$5,171.0**	**$-1,094.8**	**$4,910.8**	**$-1,297.3**

The TAB should reflect the tax profile of assets that are incorporated in the RAB. To align the tax asset register with the RAB, an adjustment needs to be made for capital contributions. The RAB treatment over time for capital contributions is as follows:

- at the commencement of AA1 all accumulated capital contributions were removed from the RAB
- during AA1, capital contributions were incorporated in the RAB
- from AA2 onwards, capital contributions have not been added to the RAB

Therefore capital contributions received during the AA1 period do not need to be removed from the tax asset register.

To establish the TAB it is necessary to map assets from the tax asset register categories into the regulatory asset classes. Judgement is required in this mapping process due to the different asset categories between the tax asset register and regulatory assets. Ernst & Young has detailed its assumptions in this mapping process used to establish the TAB.[18]

The simple pro-rata allocation used to deduct the value of capital contributions at 1 July 2012 from the gross tax value is reasonable given the limited information available on capital contributions by asset class. The method used to determine the net tax value at 1 July 2012 results in the allocation method having no impact on the tax calculation in AA3 or future regulatory periods. The allocation method does not impact on the tax calculation in AA3 as the total amount of capital contributions deducted from the tax value and from the depreciation amounts remains constant irrespective of the allocation method. It is the total net depreciation that impacts on the calculation of the tax building block, rather than how it is allocated across asset categories.

The analysis by Ernst & Young to determine the nature of capital contributions incorporated in the tax asset register was provided to the Authority on 2 August 2012[19]. The analysis has been used to remove all capital contributions from the tax asset register with the exception of those received during AA1.

Western Power notes the complexities of removing the value of capital contributions from the tax asset register. The impact of using different assumptions when mapping assets from

[18] Ernst & Young, Tax liabilities for regulated revenue purposes – Report of Vaughan Lindfield, 18 May 2012
[19] Response to information request FD14.

regulatory categories to tax categories results in a different estimation of asset life for an asset category, which will impact the value of the TAB and tax depreciation. Alternative assumptions regarding asset lives may impact revenue but Western Power expects this to be considerably less than the variation between the approach adopted by Western Power and that used as a proxy by the Authority.

Western Power has tested the reasonableness of the removal of capital contributions from the tax asset base against information on asset lives provided to the Authority as part of the AA1 approval process.

In November 2005, Western Power provided the Authority information on asset lives in response to a Section 51 request. This information provided a forecast of the value of capital contributions and the effective remaining useful life as at 30 June 2006.

Western Power has compared the 2005 information with the recent analysis conducted by Ernst & Young and has found the estimated remaining useful lives to be similar. This consistent outcome supports the view that Ernst & Young's analysis of the opening value of capital contributions and the estimated remaining useful is reasonable (see Table 10).

Table 10: Accumulated capital contributions as at 30 June 2006

	AA1 section 51 response RAB		Ernst & Young TAB analysis	
	Opening value 1 July 2006	Estimated remaining useful life	Opening value 1 July 2006	Estimated remaining useful life
Distribution	831.9	39.0	786.8	38.8
Transmission	124.1	47.1	141.7	42.8

In summary, the tax asset register based TAB:

- excludes capital contributions on a consistent basis with the RAB
- correctly applies the Commissioner of Taxation's lives to determine taxation depreciation

Western Power considers the tax asset register based TAB provides a more accurate calculation of actual tax liabilities than the RAB-based TAB and adequately addresses the Authority's concerns. Therefore Western Power's proposed TAB and forecast tax liability should be used to determine the forward looking and efficient cost associated with tax liabilities over the AA3 period.

4.4.3 Revised tax asset base

Western Power's revised tax asset base for the AA3 period is summarised in the following table.

Table 11: Revised opening tax asset base and depreciation over AA3

	Opening tax asset base $ millions as at 30 June 2012	Total depreciation over AA3 $ millions nominal
Transmission	$2,043.3	$-498.5
Distribution	$3,127.7	$-827.9
Total	**$5,171.0**	**$1,326.4**

4.5 Required amendment 29 – Revenue cap

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended as follows:

> *5.6.1 The transmission system revenue cap for revenue cap services determines is used to determine the maximum transmission revenue cap service revenue (MTRt) for Western Power's transmission system for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement~~, Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ transmission revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.*
>
> *5.7.1 The distribution system revenue cap for revenue cap services determines is used to determine the maximum distribution revenue cap service revenue (MDRt) for Western Power's distribution system for each financial year t. ~~Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement~~, Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.*

Required amendment 29 aims to simplify the wording of clauses 5.6.1 and 5.7.1 to make clear that the revenue cap is made up of a number of variables.[20] As required by the Authority, Western Power has introduced the words; '*is used to determine*' to each clause and deleted '*Subject to the annual side constraints on reference tariff movements set out in section 3.11 of this Access Arrangement'.*

Required amendment 29 also aims to ensure Western Power makes reasonable endeavours to ensure the forecast revenue does not exceed the revenue cap.[21] Western Power considers clause 6.5.3, which was included in the 29 May 2012 revised proposed access arrangement achieves the same outcome:

> *6.5.3 Western Power, as a reasonable and prudent person, will set the reference tariffs in the price list so that the forecast transmission system revenue for revenue cap services for year t is equal to MTR_t and the forecast distribution system revenue for revenue cap services for year t is equal to MDR_t.*

Western Power proposes that clause 6.5.3 is retained in its current form and that the Authority's words:

> *'Western Power will use its reasonable endeavours to ensure that the forecast ~~actual~~ distribution revenue cap service revenue in financial year t does not exceed the maximum transmission reference service revenue in financial year t.'*

need not be added to each clause.

Western Power considers clause 6.5.3 has the same effect of ensuring Western Power takes reasonable endeavours to set the revenue caps appropriately. The wording of section 6.5.3 also better reflects the intent to set prices to more accurately recover the revenue cap rather

[20] Paragraphs 2022 and 2023 of the *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.
[21] Paragraphs 2024 and 2025 of the *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.

than continue to under-recover, which can lead to accumulating under-recovery larger price increases in subsequent years. Western Power therefore considers section 6.5.3 adequately addresses the issues that promoted the Authority to make the amendment and is no need to make the required changes to clauses 5.6.1 and 5.7.1.

Further, the positioning of clause 6.5.3 in the ‘Pricing methods, price list and price list information’ section of the access arrangement is more logical for the reader (than placing wording in the ‘Price control’ section) as the clauses that surround it discuss the setting the prices to recover the target revenue. Therefore, Western Power considers it is more straightforward to retain clause 6.5.3 than re-draft the relevant parts of sections 5 and 6 of the access arrangement and considers this approach adequately addresses the Authority’s concerns.

4.6 Required amendment 33 – gain sharing mechanism

Western Power must amend the gain sharing mechanism methodology and values to use the scaling factors, including economy of scale factors, and operating costs approved by the Authority in this Final Decision. The actual values used for scaling factors must be independently audited. The audit must be carried out by an independent auditor approved by the Authority, with Western Power managing and funding the audit. The scope of the audit will be determined by the Authority.

Western Power has implemented this required amendment through changes to section 7.4.8 and by adding a new section 7.4.9 of the *Amended Proposed Revisions to the Access Arrangement*.

Table 12 shows the revised forecast efficiency and innovation benchmarks for each financial year.

Table 12: Efficiency and innovation benchmarks

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Total forecast operating expenditure	452.4	455.0	451.4	449.0	460.5
Less forecast costs for defined benefit superannuation schemes	2.9	3.0	3.0	3.1	3.1
Less forecast non-revenue cap services cost[22]	0	0	0	0	0
Less forecast licence fees	0.05	0.05	0.05	0.05	0.05
Less forecast energy safety levy	4.1	4.1	4.1	4.1	4.1
Less network control service	0	0	0	0	0
Less amounts payable under the Economic Regulation Authority (Electricity Network Access Funding Regulations) 2012	0.9	1.4	1.2	1.2	1.2
Efficiency and innovation benchmark (forecast)	**444.4**	**446.6**	**443.0**	**440.6**	**452.0**

[22] The forecast non-revenue cap services have already been excluded from the total forecast operating expenditure so no adjustment is required.

4.7 Required amendment 51 – Sufficient detail on how the AQP will operate

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- *how competing applications in a "competing applications group" will be processed;*
- *how timing of network augmentations will be coordinated with the applications;*
- *how the competing applications group concept will operate; and*
- *what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants*

Western Power has implemented required amendment 51. To give effect to the ERA's amendment, Western Power has added and amended clauses in the Applications & Queuing Policy (AQP). Western Power has also included the competing applications group process as a new Appendix A to the AQP and comparative timelines for applicant-specific solutions as a new Appendix B. The following sections summarise how each of the bullet points in the Authority's required amendment 51 have been addressed:

How competing applications will be processed <u>and</u> how the competing applications group concept will operate

Clause 24.1 of the AQP has been amended to provide more certainty on how competing applications groups will be formed (additional text is highlighted in red):

> 24.1 Formation of competing applications groups
>
> (a) Where Western Power assesses that an *application* is competing with other *applications* then Western Power will, subject to clause 16.5, manage *competing applications* by forming them into one or more *competing applications groups* and assessing a single set of *works* for *shared assets* required to meet some or all of the requirements of each *competing applications group*. To avoid doubt, where there are more than two *competing applications* Western Power may form all the *competing applications* into one *competing applications group* or it may form them into two or more *competing applications groups* as Western Power considers appropriate given the nature of the *applications*, including how the *competing applications* impede each other in respect of *network* constraints, the size of the *capacity* sought in each of the *competing applications*, and the current level of *spare capacity*.

Clause 24.1(b1) has been added to provide that Western Power will advise applicants within 30 business days if their application has been included in a competing applications group or competing applications groups.

> 24.1(b1) Western Power will notify an *applicant* within 30 business days of the *application* if it has sorted the *application* into one or more *competing applications groups*

How the timing of network augmentations will be coordinated with the applications

Clause 3.15 has been added to clarify the interaction of the AQP and competing application group processes with network augmentation processes.

> 3.15 Network Planning
>
> (a) In processing *applications* (whether as *applicant-specific solutions* or *competing applications groups*) Western Power must have regard to the general network planning otherwise being undertaken by Western Power and seek to develop solutions and process *applications* in a manner which most effectively enables *applicants* to benefit from any efficiencies and costs savings provided by that network planning.

(b) Due to the range of potential network constraints and related solutions, timeframes for the development of solutions will be variable. Western Power will keep *applicants* informed on a regular basis on the network constraints that affect them and expected timeframes for the development of solutions.

(c) The information Western Power will provide to *applicants*, and the further studies it may be requested to undertake, extend to information and studies as to how *applications* co-ordinate with network planning being undertaken by Western Power.

(d) In undertaking network planning Western Power will have regard to the nature and number of *enquiries* and *applications* Western Power has received under this applications and queuing policy it being acknowledged that in doing so Western Power will need to make a good faith assessment as to the likelihood specific projects will proceed.

A step-by-step guide has been attached at Appendix A to the AQP to provide further clarity on the information provided to applicants and how competing applications groups are managed. The two tables within Appendix A describe:

1. information provided to applicants by Western Power at key stages of the process including enquiry, application and solution development, and;
2. how the competing applications groups process will be managed from the formation of competing applications groups to post-competing applications group processes. This includes the interaction with application-specific solutions, developing solutions for the competing applications groups, processes for preliminary access offers and processes for access offers

The timing of the development of solutions for the competing applications groups is variable and the factors that influence this are included in Appendix B to the AQP, which provides the comparative timelines for application-specific solutions and competing applications groups.

What happens when an offer to all members of a competing application group is conditional on acceptance by all applicants

As indicated by the strikethroughs and red text, clause 24.6 has been redrafted to clarify the process for subsequent access offers. Access offers are made to members of a competing applications group when there are sufficient numbers of applicants willing to accept the preliminary access offer.

If all applicants in a competing applications group do not accept the access offer and there are insufficient numbers of applicants willing to accept it, Western Power will modify its preliminary offer.

If there are a greater number of applicants than the access offer can accommodate, Western Power may make access offers in the order of the priority date of the applications.

24.6 Subsequent access offers

After reviewing the responses by all *applicants* to *preliminary access offers* under clause 24.5, Western Power will endeavour within 30 business days of receipt of responses by all *applicants* to *preliminary access offers* to:

(a) ~~make access offers to applicants within the competing applications group,~~ if Western Power considers it can make access offers to *applicants* within the *competing applications group* collectively for the costs nominated in the *access offers*, ~~it may~~ it will make *access offers* ~~make the access offers~~ to *applicants* within the *competing applications group* conditional on sufficient acceptance of the *access offers* by *applicants* to ensure that access can be provided to the *applicants* collectively for the costs nominated in the *access offers*; or

(b) if Western Power does not consider it can make *access offers* to *applicants* within the *competing applications group* collectively for the costs nominated in the *access offers*, revise its *preliminary access offer* and submit those revised *preliminary access offers* to *applicants*; or

(c) where the sum of the *preliminary acceptance* by *applicants* within a *competing applications group* exceeds the *capacity* of the proposed *works*, Western Power may make *access offers* to *applicants* in the order of the *priority date* of *applications* until there is no more *spare capacity*. If Western Power fails to make an *access offer* to an *applicant* within a *competing applications group*, then notwithstanding any other provision in this applications and queuing policy, the *application* will remain valid and retain its *priority date* and Western Power will refund any preliminary offer processing fee or preliminary acceptance fee paid by the *applicant*.

Additional clauses 24.6A to 24.6C step through the competing applications group process in greater detail, explaining where offers are not met or exceeded.

24.6A Minimum and Maximum levels of acceptance

An *access offer* to *applicants* within a *competing applications group* will specify:

(a) if applicable, the minimum number of *applicants* that must accept the *access offers* made to that *competing applications group* (whether expressed by reference to the number of accepting *applicants*, the amount of *capacity* they accept or both) for Western Power to proceed to undertake the *works* specified in the *access offers* at the cost and on the other terms set out in those *access offers*;

(b) if applicable, the maximum number of *applicants* that may accept the *access offers* made to that *competing applications group* (whether expressed by reference to the number of accepting *applicants*, the amount of *capacity* they accept or both) for Western Power to proceed to undertake the *works* specified in the *access offers* at the cost and on the other terms set out in those *access offers*.

24.6B Failure to achieve Minimum Levels

Where the minimum levels of acceptance set out in clause 24.6A are not met then any acceptance of an *access offer* will be of no effect but Western Power will seek to revise the *access offers* so as to meet the requirements of those *applicants* who did accept *access offers* and issue new *access offers*, provided that there is no obligation on Western Power to revise *access offers* where no *applicants* accepted *access offers* (without prejudice to the entitlement of such *applicants* to opt for an *applicant-specific solution* or make new *applications*).

24.6C Exceeding Minimum Levels

(a) Where the maximum levels of acceptance set out in clause 24.6A are exceeded then priority will, subject to clause 24A.5, be given to *applicants* with an earlier *priority date* in determining which *access offers* will be of effect and which of no effect. Subject to paragraph (b) below, where an *applicant's* acceptance is not effective that *applicant ("**reallocated applicant**")* will be allocated to a new *competing applications group*.

(b) In respect of the *reallocated applicant* with the highest queue priority of the *reallocated applicants*, Western Power will, where it is possible to meet the requirements of that *applicant* in part (for example supply part of the *capacity* requested by them), make a further *access offer* to them to supply those partial requirements which that *reallocated applicant* may accept or reject. Where the *reallocated applicant* rejects the *access offer* then they will be allocated to a new *competing applications group*. If the *reallocated applicant* rejects the *access offer* then Western Power will, if practicable to do having regard to the timeframes for undertaking of *works* set out in those *access offers* which have been effectively accepted, make a further *access offer* to the next *reallocated applicant* with the highest queue priority and the process in this paragraph (b) will continue until Western Power determines it is not practicable to make any further *access offers*.

It is also noted that clause 4.5(b) clarifies that once Western Power enters a contract with applicants, the contract is subject to the condition that the other applicants in a competing applications group that were made an offer have accepted those access offers and fulfil conditions. Existing clauses 4.6 and 4.8 clarify how the conditions are dealt with in order to proceed to an unconditional contract.

4.8 Required amendment 54 – Level of information provided

Sections 17A.3 and 17A.4 of the AQP must be amended as set out in paragraph 2591 above.

Western Power has updated AQP clause 17A.3 with the Authority's wording and has updated clause 17A.4 to address the Authority's amendment.

In relation to clause 17A.4, the Authority has requested Western Power uses reasonable endeavours to obtain one applicant's consent to disclosure of its confidential information to a second applicant. Western Power has drafted clause 17.4 (below) to provide that Western Power will request consent for disclosure of confidential information. However, if a confidentiality undertaking is required, while Western Power will facilitate discussion if required, it is more appropriate for applicants to negotiate confidentiality undertakings directly.

Western Power will present information in an aggregated form if consent cannot be obtained.

The Authority's wording for 17A.4 used the term "disclosing party". Western Power notes that the defined term is "disclosing person" and that the definition for "confidential information" refers to "disclosing person". Therefore, Western Power has used the term "disclosing person" in the drafting of clause 17A.4 to retain the Authority's intent.

> 17A.4 Provision of Confidential Information
>
> (a)Where commercial or technical information referred to in clause 17A.3 is *confidential information*:
>
> (i) which is confidential to Western Power and in Western Power's possession, custody or control, Western Power will use reasonable endeavours to enter into an adequate confidentiality undertaking with respect to the disclosure of the *confidential information* to the party deciding whether to make an *application*;
>
> (ii) disclosed to Western Power by a *disclosing person* or an *applicant*, including a disclosure by a third party under clause 17A.4(a) above, Western Power will request the consent of the relevant *disclosing person* or *applicant* to the disclosure of the *confidential information* to the *applicant* and, in the event that the relevant *disclosing person* or *applicant* does not consent to such disclosure, Western Power will use reasonable endeavours to provide the relevant *confidential information* to the party who has requested the information in an aggregated or other form in which its confidential aspects cannot be identified.
>
> (b) Where the relevant *disclosing person* or *applicant (first person)*, under paragraph (a)(ii), notifies Western Power it will consent to the disclosure of the *confidential information* to the other *applicant* (*second person*) if the second person executes a confidentiality undertaking in favour of the first person then Western Power will seek to facilitate the process of conclusion of such undertaking but the first and second person must directly negotiate the terms of that undertaking between themselves.

4.9 Economic Regulation Authority (Electricity Network Access Funding) Regulations 2012

The Economic Regulation Authority (Electricity Network Access Funding) Regulations 2012 were gazetted on 9 October 2011 and came into operation on the following day. The Authority has provided a forecast of its costs for the AA3 period, which will be charged to Western Power. Western Power has converted this forecast (which was in nominal terms) to real 30 June 2012 dollars and included an amount in the business support operating expenditure regulatory category to be included in the target revenue. A pro rata adjustment (264/365) was made to the expected charge for 2012/13 to reflect the mid-period implementation date.

Table 13: Forecast ERA costs for the AA3 period

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17
Economic Regulation Authority (Electricity Network Access Funding) Regulations 2012	0.9	1.4	1.2	1.2	1.2

Western Power has also amended section 7.4.2 of the *Amended Proposed Revisions to the Access Arrangement* to exclude any amount of non-capital costs *in relation to amounts payable under the Economic Regulation Authority (Electricity Network Access Funding Regulations) 2012* for the purposes of determining the efficiency and innovation benchmarks and performance under the gain sharing mechanism, as these costs are not substantially within Western Power's control. This treatment is similar to that of the Energy Safety Levy.

Appendix A. Pro forma forecast statements

Pro Forma Forecast Statements

Western Power
Proforma Forecast Statements

1. Historic capital expenditure by asset class
2. Historic capital expenditure by reason
3. Forecast capital expenditure by asset class
4. Forecast capital expenditure by reason
5. Historic non-capital costs by activity category
6. Forecast non-capital costs by activity category

Year ending 30 June	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
June CPI	**157.5**	**164.6**	**167.0**	**172.1**	**178.3**	**180.4**	**185.9**	**190.6**	**195.4**	**200.2**	**205.2**
Annual Inflation	2.07%	4.51%	1.46%	3.05%	3.60%	1.18%	3.00%	2.50%	2.50%	2.50%	2.50%
End of year Inflation factor	0.873	0.912	0.926	0.954	0.988	1.000	1.030	1.056	1.082	1.109	1.137
Mid year inflation factor											

Pro Forma Forecast Statements

1. Historic capital expenditure by asset class

Description	Expenditure $million nominal [Period 2009/10 to 2011/12] Year 1	Year 2	Year 3	Total	$million real at 30 June 2012 Year 1	Year 2	Year 3	Total
Covered transmission services								
Transmission cables	4.5	2.4	1.9	8.8	4.7	2.5	1.9	9.1
Transmission steel towers	80.3	57.5	63.4	201.1	84.1	58.2	63.4	205.7
Transmission wood poles	12.7	9.4	9.7	31.8	13.3	9.5	9.7	32.5
Transmission Metering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission transformers	34.7	22.8	20.8	78.3	36.3	23.1	20.8	80.2
Transmission reactors	1.1	0.8	0.3	2.2	1.1	0.8	0.3	2.3
Transmission capacitors	8.8	4.7	1.6	15.0	9.2	4.7	1.6	15.4
Transmission circuit breakers	34.1	45.9	38.8	118.9	35.8	46.4	38.8	121.1
SCADA and Communications	10.2	6.1	13.2	29.5	10.6	6.1	13.2	30.0
IT&T	10.2	14.9	17.5	42.5	10.7	15.1	17.5	43.2
Other Non-Network Assets	7.3	12.4	14.1	33.8	7.6	12.5	14.1	34.3
Land & Easements	22.2	12.4	9.9	44.5	23.2	12.6	9.9	45.7
Total	225.9	189.3	191.2	606.3	236.7	191.5	191.2	619.4
Excluded transmission services								
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services								
Wooden Pole Lines	152.8	149.7	232.3	534.8	160.2	151.5	232.3	543.9
Underground Cables	213.1	195.5	193.8	602.4	223.4	197.8	193.8	615.0
Transformers	76.1	73.3	74.2	223.6	79.8	74.1	74.2	228.1
Switchgear	66.5	65.6	80.8	212.9	69.7	66.4	80.8	216.9
Street lighting	23.8	23.5	23.8	71.2	25.0	23.8	23.8	72.6
Meters and Services	11.1	16.0	16.7	43.8	11.7	16.2	16.7	44.6
IT&T	16.1	25.1	32.3	73.5	16.9	25.4	32.3	74.6
SCADA & Communications	3.4	3.3	5.0	11.7	3.6	3.3	5.0	11.9
Other Distribution Non-Network	11.5	20.9	22.7	55.2	12.1	21.1	22.7	56.0
Distribution Land & Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	574.5	572.9	681.6	1829.0	602.2	579.6	681.6	1863.5
Excluded distribution services								
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other business and services								
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

2. Historic capital expenditure by reason

Description	Expenditure $million nominal [Period 2009/10 to 2011/12] Year 1	Year 2	Year 3	Total	$million real at 30 June 2012 Year 1	Year 2	Year 3	Total
Covered transmission services								
Growth								
Capacity Expansion	103.1	56.0	42.5	201.6	108.0	56.7	42.5	207.2
Customer Driven	49.9	43.3	58.1	151.3	52.3	43.8	58.1	154.2
Generation Driven	26.6	13.1	0.0	39.7	27.9	13.2	0.0	41.1
Gifted Assets	1.5	0.0	0.0	1.5	1.6	0.0	0.0	1.6
Asset replacement and renewal								
Asset Replacement	5.3	31.6	27.3	64.2	5.6	31.9	27.3	64.8
Improvement in service								
Reliability Driven	1.7	1.3	0.2	3.2	1.7	1.3	0.2	3.3
SCADA & Communications	9.4	5.7	13.0	28.0	9.8	5.7	13.0	28.5
Compliance								
Regulatory Compliance	11.0	11.1	18.4	40.5	11.5	11.3	18.4	41.1
Corporate								
IT	10.2	14.9	17.5	42.5	10.7	15.1	17.5	43.2
Business Support	7.3	12.4	14.1	33.8	7.6	12.5	14.1	34.3
Total	225.9	189.3	191.2	606.3	236.7	191.5	191.2	619.4
Excluded transmission services								
Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asset replacement and renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services								
Growth								
Capacity Expansion	62.8	34.4	48.1	145.3	65.8	34.8	48.1	148.7
Customer Driven	203.1	233.5	174.9	611.5	212.9	236.3	174.9	624.0
Gifted Assets	84.3	54.0	66.7	204.9	88.3	54.6	66.7	209.6
Asset replacement and renewal								
Asset Replacement	80.1	98.0	178.0	356.1	84.0	99.2	178.0	361.1
State Undergrounding Power Program (SUPI	21.1	18.7	33.4	73.2	22.1	19.0	33.4	74.4
Metering	11.1	16.0	14.1	41.2	11.7	16.2	14.1	41.9
Smartgrid	0.0	0.0	4.0	4.0	0.0	0.0	4.0	4.0
Wood Pole Management								
Improvement in service								
Reliability Driven	9.3	8.1	9.1	26.6	9.8	8.2	9.1	27.1
Rural Power Improvement Program (RPIP)	8.2	-0.2	0.0	8.0	8.6	-0.2	0.0	8.4
SCADA & Communications	3.3	3.2	3.5	9.9	3.4	3.2	3.5	10.1
Compliance								
Regulatory Compliance	63.7	61.1	94.9	219.7	66.7	61.8	94.9	223.5
Corporate								
IT	16.1	25.1	32.3	73.5	16.9	25.4	32.3	74.6
Business Support	11.5	20.9	22.7	55.2	12.1	21.1	22.7	56.0
Total	574.5	572.9	681.6	1829.0	602.2	579.6	681.6	1863.5
Excluded distribution services								
Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asset replacement and renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

3. Forecast capital expenditure by asset class

	Expenditure											
	$million nominal						$million real at 30 June 2012					
	[Period beginning 2012/13]											
Description	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Covered transmission services												
Transmission cables	28.4	41.9	23.4	25.4	38.0	157.1	27.6	39.7	21.6	22.9	33.4	145.2
Transmission steel towers	19.5	29.2	17.5	18.9	27.0	112.0	18.9	27.6	16.2	17.0	23.7	103.5
Transmission wood poles	27.2	33.3	32.9	40.3	46.0	179.8	26.4	31.6	30.4	36.4	40.5	165.2
Transmission Metering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission transformers	92.5	131.4	87.9	93.8	126.4	531.9	89.8	124.4	81.2	84.6	111.2	491.2
Transmission reactors	10.7	14.7	8.6	9.3	13.6	57.0	10.4	13.9	8.0	8.4	12.0	52.7
Transmission capacitors	7.2	10.7	6.2	6.7	9.8	40.5	7.0	10.1	5.7	6.1	8.6	37.4
Transmission circuit breakers	36.4	51.4	38.3	40.5	51.3	218.0	35.3	48.7	35.4	36.5	45.2	201.2
SCADA and Communications	14.5	12.6	14.1	20.7	21.2	83.2	14.1	11.9	13.1	18.7	18.7	76.4
IT&T	16.0	15.8	9.5	10.1	10.5	61.8	15.5	14.9	8.7	9.1	9.3	57.6
Other Non-Network Assets	12.7	12.7	9.0	9.4	7.9	51.7	12.3	12.1	8.4	8.4	7.0	48.1
Land & Easements	61.1	90.8	52.7	57.1	83.3	344.9	59.3	86.0	48.7	51.4	73.2	318.7
Total	326.1	444.4	300.1	332.3	435.1	1838.1	316.6	421.0	277.4	299.6	382.7	1697.3
Excluded transmission services												
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services												
Wooden Pole Lines	280.7	314.7	338.2	345.9	376.9	1656.4	272.5	298.1	312.6	311.8	331.5	1526.5
Underground Cables	126.8	117.8	112.0	114.9	123.3	594.8	123.2	111.6	103.5	103.5	108.5	550.3
Transformers	200.2	198.4	201.0	199.0	210.3	1008.9	194.4	187.9	185.7	179.4	185.0	932.4
Switchgear	88.3	87.7	88.9	83.5	89.4	437.8	85.7	83.1	82.2	75.3	78.6	404.9
Street lighting	6.3	5.7	5.3	5.1	5.4	27.7	6.1	5.4	4.9	4.6	4.7	25.7
Meters and Services	15.5	63.5	66.5	59.1	29.9	234.5	15.1	60.1	61.4	53.3	26.3	216.2
IT&T	26.5	26.1	15.7	16.8	17.5	102.5	25.7	24.7	14.5	15.1	15.4	95.4
SCADA & Communications	6.2	15.6	17.6	12.2	14.1	65.7	6.0	14.7	16.3	11.0	12.4	60.5
Other Distribution Non-Network	21.1	21.1	15.0	15.5	13.1	85.8	20.4	20.0	13.9	14.0	11.5	79.8
Distribution Land & Easements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	771.6	850.6	860.3	851.8	879.8	4214.2	749.1	805.7	795.0	768.0	773.9	3891.7
Excluded distribution services												
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other business and services												
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4. Forecast capital expenditure by reason

	Expenditure											
	$million nominal						$million real at 30 June 2012					
	[Period beginning 2012/13]											
Description	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Covered transmission services												
Growth												
Capacity Expansion	198.5	286.3	141.0	155.3	251.7	1032.8	192.7	271.2	130.3	140.0	221.4	955.6
Customer Driven	34.8	61.3	63.5	65.6	68.3	293.5	33.7	58.1	58.6	59.2	60.0	269.7
Generation Driven	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gifted Assets												
Asset replacement and renewal												
Asset Replacement	31.3	35.1	36.4	37.6	40.7	181.1	30.4	33.2	33.6	33.9	35.8	166.9
Improvement in service												
Reliability Driven	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCADA & Communications	14.5	12.6	14.1	20.7	21.2	83.2	14.1	11.9	13.1	18.7	18.7	76.4
Compliance												
Regulatory Compliance	18.4	20.7	26.6	33.4	34.9	134.1	17.9	19.6	24.6	30.2	30.7	122.9
Corporate												
IT	16.0	15.8	9.5	10.1	10.5	61.8	15.5	14.9	8.7	9.1	9.3	57.6
Business Support	12.7	12.7	9.0	9.4	7.9	51.7	12.3	12.1	8.4	8.4	7.0	48.1
Total	326.1	444.4	300.1	332.3	435.1	1838.1	316.6	421.0	277.4	299.6	382.7	1697.3
Excluded transmission services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asset replacement and renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services												
Growth												
Capacity Expansion	58.6	64.7	73.7	75.9	86.8	359.7	56.9	61.3	68.1	68.5	76.3	331.1
Customer Driven	209.0	215.0	226.6	233.9	247.2	1131.6	202.9	203.6	209.4	210.8	217.4	1044.1
Gifted Assets	65.4	67.0	68.7	70.4	72.2	343.7	63.5	63.5	63.5	63.5	63.5	317.4
Asset replacement and renewal												
Asset Replacement	43.4	39.4	38.0	40.6	41.7	203.1	42.1	37.3	35.1	36.6	36.7	187.8
State Undergrounding Power Program (SUPP)	39.6	19.6	0.0	0.0	0.0	59.3	38.5	18.6	0.0	0.0	0.0	57.1
Metering	13.9	47.0	47.8	44.6	18.3	171.6	13.5	44.5	44.1	40.2	16.1	158.4
Smartgrid	2.6	25.4	28.8	22.4	17.7	96.8	2.5	24.0	26.6	20.2	15.6	88.9
Wood Pole Management	169.5	198.9	215.5	232.7	252.7	1069.3	164.5	188.4	199.1	209.8	222.3	984.1
Improvement in service												
Reliability Driven	0.6	0.6	0.7	0.7	0.7	3.3	0.6	0.6	0.6	0.6	0.6	3.0
Rural Power Improvement Program (RPIP)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCADA & Communications	5.3	6.7	7.6	4.3	7.9	31.8	5.2	6.3	7.0	3.9	7.0	29.4
Compliance												
Regulatory Compliance	116.3	119.1	122.4	94.0	103.9	555.8	112.9	112.8	113.2	84.8	91.4	515.1
Corporate												
IT	26.5	26.1	15.7	16.8	17.5	102.5	25.7	24.7	14.5	15.1	15.4	95.4
Business Support	21.1	21.1	15.0	15.5	13.1	85.8	20.4	20.0	13.9	14.0	11.5	79.8
Total	771.6	850.6	860.3	851.8	879.8	4214.2	749.1	805.7	795.0	768.0	773.9	3891.7
Excluded distribution services												
Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asset replacement and renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other business and services												
Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Asset replacement and renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improvement in service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5. Historic non-capital costs by business category and activity

	Cost							
	$million nominal				$million real at 30 June 2012			
	[Period 2009/10 to 2011/12]							
Description	**Year 1**	**Year 2**	**Year 3**	**Total**	**Year 1**	**Year 2**	**Year 3**	**Total**
Covered transmission services								
Operations								
SCADA & Communications	8.3	9.4	11.2	29.0	8.8	9.6	11.2	29.5
Non-revenue cap services	2.7	3.9	4.7	11.4	2.9	4.0	4.7	11.6
Network Operations	9.0	8.6	8.4	25.9	9.4	8.7	8.4	26.5
Maintenance								
Maintenance Strategy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preventive Condition	6.5	9.8	12.0	28.3	6.8	10.0	12.0	28.7
Preventive Routine	12.9	17.6	21.4	51.9	13.5	17.8	21.4	52.7
Corrective Deferred	6.0	10.0	10.7	26.6	6.2	10.1	10.7	27.0
Corrective Emergency	1.6	2.3	2.7	6.6	1.6	2.3	2.7	6.7
Customer service and billing								
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate								
Business Support	39.5	36.0	34.5	110.0	41.4	36.4	34.5	112.3
Other								
Non-recurring opex	0.4	2.5	18.6	21.5	0.4	2.6	18.6	21.6
Total	86.8	100.1	124.2	311.2	91.0	101.3	124.2	316.6
Excluded transmission services								
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer service and billing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services								
Operations								
Reliability	2.2	1.8	3.0	6.9	2.3	1.8	3.0	7.1
SCADA & Communications	3.7	4.8	3.8	12.3	3.9	4.8	3.8	12.6
Non-revenue cap services	17.2	16.0	17.3	50.5	18.0	16.2	17.3	51.5
Network Operations	13.5	14.1	16.8	44.4	14.1	14.3	16.8	45.2
Smartgrid	0.0	0.0	3.0	3.0	0.0	0.0	3.0	3.0
Maintenance								
Maintenance Strategy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preventive Condition	40.1	46.9	47.9	134.9	42.0	47.5	47.9	137.4
Preventive Routine	28.6	38.6	49.5	116.7	30.0	39.0	49.5	118.5
Corrective Deferred	17.4	27.1	26.9	71.5	18.2	27.5	26.9	72.6
Corrective Emergency	74.4	69.3	84.2	228.0	78.0	70.1	84.2	232.4
Customer service and billing								
Call Centre	5.0	6.7	8.0	19.8	5.3	6.8	8.0	20.1
Metering	18.0	18.2	23.8	60.0	18.8	18.4	23.8	61.1
Guaranteed service level payments	0.0	0.0	7.2	7.2	0.0	0.0	7.2	7.2
Distribution Quotations	0.0	0.0	8.8	8.8	0.0	0.0	8.8	8.8
Corporate								
Business Support	56.8	74.0	62.6	193.5	59.5	74.9	62.6	197.1
Other								
Non-recurring opex	4.6	7.6	13.3	25.6	4.9	7.7	13.3	25.9
Total	281.5	325.2	376.3	983.1	295.1	329.0	376.3	1000.5
Excluded distribution services								
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer service and billing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

6. Forecast non-capital costs by business category and activity

	Cost											
	$million nominal						$million real at 30 June 2012					
	[Period beginning 2012/13]											
Description	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Covered transmission services												
Operations												
SCADA & Communications	12.6	13.0	13.5	13.9	14.7	67.6	12.2	12.3	12.4	12.5	12.9	62.4
Non-revenue cap services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Operations	10.1	10.4	10.7	11.0	11.2	53.5	9.8	9.9	9.9	9.9	9.9	49.4
Maintenance												
Maintenance Strategy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preventive Condition	10.3	10.6	11.0	11.4	12.0	55.3	10.0	10.1	10.2	10.2	10.5	51.0
Preventive Routine	18.1	18.7	19.3	20.0	21.1	97.1	17.6	17.7	17.9	18.0	18.5	89.7
Corrective Deferred	10.5	10.9	11.2	11.6	12.2	56.4	10.2	10.3	10.4	10.5	10.7	52.1
Corrective Emergency	1.2	1.2	1.2	1.3	1.4	6.3	1.2	1.2	1.1	1.2	1.2	5.8
Customer service and billing												
N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate												
Business Support	41.2	42.3	43.4	46.1	47.8	220.9	40.0	40.1	40.1	41.6	42.0	203.8
Other												
Non-recurring opex	3.1	1.9	1.7	2.0	2.7	11.4	3.0	1.8	1.6	1.8	2.4	10.5
Total	107.1	109.0	112.1	117.2	123.0	568.5	104.0	103.3	103.6	105.7	108.2	524.7
Excluded transmission services												
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer service and billing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered distribution services												
Operations												
Reliability Operations	1.9	2.0	2.1	2.1	2.2	10.3	1.9	1.9	1.9	1.9	2.0	9.5
SCADA & Communications	5.2	5.4	5.6	5.8	6.1	28.2	5.1	5.1	5.2	5.2	5.4	26.0
Non-revenue cap services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Operations	15.3	15.7	16.2	16.6	17.0	80.6	14.8	14.9	14.9	14.9	14.9	74.5
Smartgrid	5.2	4.2	5.2	7.0	8.7	30.3	5.0	4.0	4.8	6.3	7.7	27.8
Maintenance												
Maintenance Strategy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preventive Condition	61.4	63.3	65.4	55.7	59.5	305.4	59.7	60.0	60.4	50.2	52.3	282.7
Preventive Routine	46.2	49.3	51.1	52.8	55.5	254.9	44.8	46.7	47.2	47.6	48.8	235.2
Corrective Deferred	32.3	33.5	34.7	35.9	37.7	174.1	31.4	31.7	32.0	32.3	33.2	160.6
Corrective Emergency	76.3	78.8	81.5	84.2	88.8	409.6	74.1	74.6	75.3	75.9	78.1	378.1
Customer service and billing												
Call Centre	7.5	7.9	8.3	8.6	9.0	41.2	7.3	7.5	7.6	7.8	7.9	38.0
Metering	20.9	21.9	22.9	23.8	24.8	114.4	20.3	20.7	21.1	21.5	21.9	105.5
Guaranteed service level payments	1.8	1.8	1.8	1.9	1.9	9.2	1.7	1.7	1.7	1.7	1.7	8.5
Distribution quotations	4.3	4.4	4.7	4.8	4.9	23.1	4.2	4.2	4.3	4.3	4.3	21.3
Corporate												
Business Support	69.5	71.1	72.1	76.4	78.9	367.9	67.5	67.3	66.6	68.9	69.4	339.7
Other												
Non-recurring opex	10.9	12.1	5.0	5.2	5.5	38.6	10.6	11.4	4.6	4.7	4.8	36.1
Total	358.8	371.4	376.4	380.8	400.5	1887.9	348.3	351.8	347.8	343.3	352.3	1743.5
Excluded distribution services												
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer service and billing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other business and services												
Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer service and billing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Corporate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Appendix B. Revenue model summary

Output Summary

westernpower

23 November 2012
Final Decision response with amended tax calculations to use diminishing value and 1 Feb 2013 start date

Key metrics

WACC 3.60% Post-tax

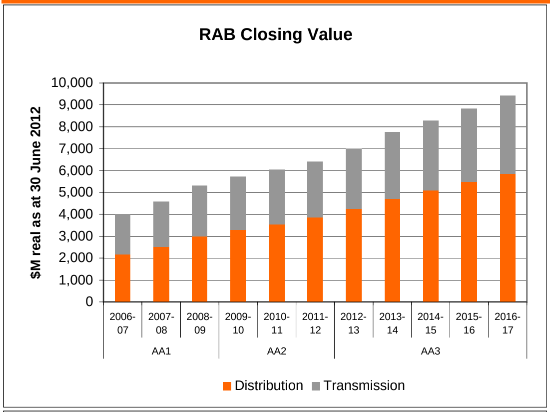
Expenditures	**$M Real$_{30/06/2012}$**	**$M Nominal**
Equity raising costs	22.1	23.4
Ex-post writedown ris	-	-
Total Capex	5,588.9	6,052.3
Total Opex	2,268.2	2,456.3
Total Expenditure	**7,857.2**	**8,508.7**
Total Contributions	**931.7**	**1,008.6**
TEC	**736.0**	**782.0**
Deferred revenue	**451.0**	**488.3**
2012/13 K-factor	**75.6**	**77.9**
Total Revenue	**6,896.8**	**7,475.4**

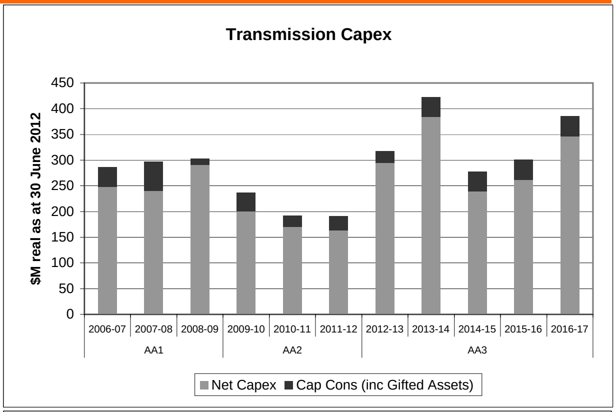
AA2 Deferred Revenue Recovery Period (years)

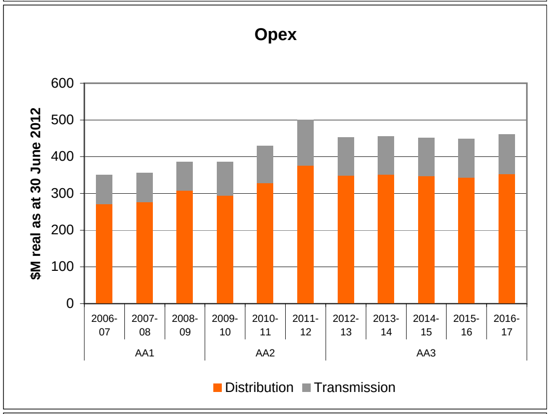
Distribution	10
Transmission	10

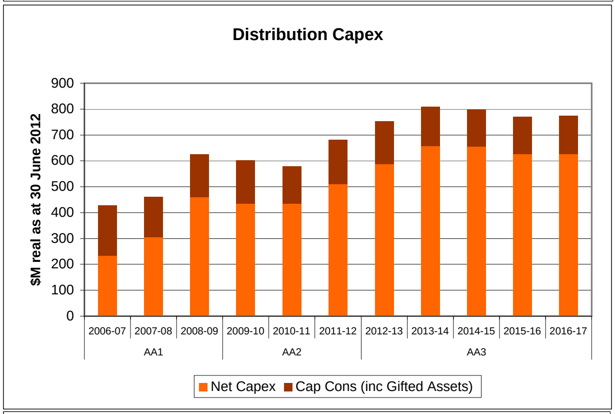
	2012-13	**2013-14**	**2014-15**	**2015-16**	**2016-17**
Price Path (annual change in average price)					
Distribution	15.5%	3.9%	2.6%	2.0%	1.6%
Transmission	0.0%	-13.1%	-13.1%	-13.1%	-13.1%
Bundled (avg tariff $/M'	11.2%	-0.3%	-0.8%	-0.9%	-0.9%
Revenue Cap ($M real as at 30 June 2012) - includes 2012/13 K-factor					
Distribution	885.7	1,014.3	1,056.6	1,112.5	1,166.9
Transmission	413.8	367.1	326.7	292.5	260.7
Total Revenue	1,299.4	1,381.5	1,383.3	1,405.0	1,427.6
Energy (GWh)					
Distribution Sales	14,402	14,627	14,847	15,331	15,831
Transmission Network	18,638	19,030	19,488	20,077	20,589

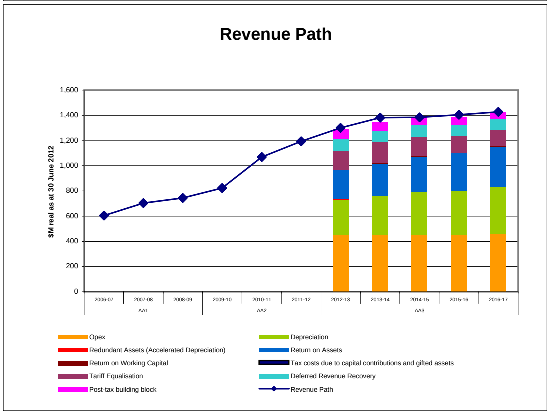
Charts

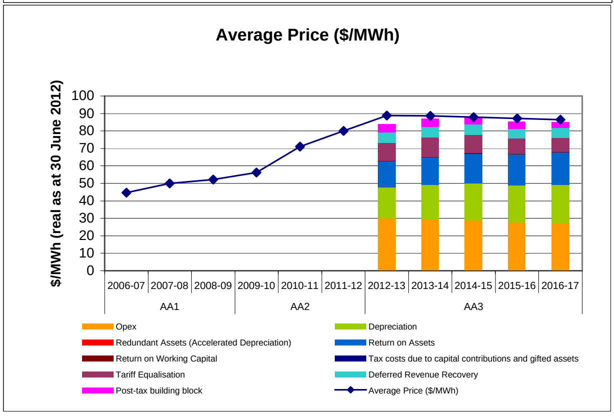












Appendix C. 11/12 Regulatory Financial Statements

C.1 11/12 Regulatory Financial Statements approved by Board and OAG

C.2 11/12 CRAM

Electricity Networks Corporation
Trading as Western Power
Regulatory Financial Statements (reviewed)

for the year ended 30 June 2012

Contents

1. Profit and loss account (disaggregated) for the year ended 30 June 2012

Account Code	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
1100	Network services (reference)	1,198,974	387,876	804,783	6,315	-
1100	Network services (non-reference)	29,624	5,221	24,403	-	-
1100	Network services (unregulated)	80,593	-	-	-	80,593
1200	Contributions (excl. gifted assets)	102,995	18,600	80,625	1,206	2,564
1200	Gifted assets	66,651	-	66,651	-	-
1300	Proceeds from disposal of assets	8,066	38	2,242	-	5,786
1400	Other revenue	3,569	538	1,112	-	1,919
	Total revenue	1,490,472	412,273	979,816	7,521	90,862
2100	Operating expenditure costs	(778,379)	(146,358)	(552,699)	(6,583)	(72,739)
	Operations	(125,443)	(23,784)	(43,824)	-	(57,835)
	Maintenance	(253,213)	(45,369)	(207,844)	-	-
	Customer service and billing	(50,053)	-	(47,838)	-	(2,215)
	Corporate	(91,131)	(30,627)	(55,474)	-	(5,030)
	Other operating expenditure	(258,539)	(46,578)	(197,719)	(6,583)	(7,659)
2200	Depreciation and amortisation	(204,893)	(80,877)	(123,676)	(340)	-
2300	Bad debts	1,917	578	1,220	-	119
2400	Borrowing costs	(278,750)	(96,452)	(178,631)	-	(3,667)
2500	Book value on disposal of assets	(5,001)	(71)	(871)	-	(4,059)
	Total expenses	(1,265,106)	(323,180)	(854,657)	(6,923)	(80,346)
	Earnings before taxation	225,366	89,093	125,159	598	10,516
2600	**Taxation**	(68,235)	(26,975)	(37,895)	(181)	(3,184)
	Profit after taxation	157,131	62,118	87,264	417	7,332

There are no amounts in respect of excluded transmission and excluded distribution activities.

Total revenue and expenses in the regulatory financial statements each differs by $ 5.001 million from total revenue and expenses reported in the statutory financial statements. This is due to the separate disclosure of proceeds and written down value on the disposal of assets in the regulatory financial statements. In contrast, the statutory financial statements discloses proceeds and written down value on the disposal of assets net of one another, ie a gain of $ 3.065 million.

2. Profit and loss account (regulatory financial statement) for the year ended 30 June 2012

Covered transmission

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
1100	Network services (reference)	387,876	-	387,876	
1100	Network services (non-reference)	5,221	-	5,221	
1200	Contributions (excl. gifted assets)	18,600	9,305	27,905	11,12.1
1300	Proceeds from disposal of assets	38	-	38	
1400	Other revenue	538	-	538	
	Total revenue	412,273	9,305	421,578	
2100	Operating expenditure costs	(146,358)	22,115	(124,243)	9,10,12.3, 12.4,12.5
	Operations	(23,784)	(504)	(24,288)	
	Maintenance	(45,369)	(1,484)	(46,853)	
	Corporate	(30,627)	(3,882)	(34,509)	
	Other operating expenditure	(46,578)	27,985	(18,593)	
2200	Depreciation and amortisation	(80,877)	3,882	(76,995)	12.3
2300	Bad debts	578	-	578	
2400	Borrowing costs	(96,452)	(6,396)	(102,848)	12.2
2500	Book value on disposal of assets	(71)	-	(71)	
	Total expenses	(323,180)	19,601	(303,579)	
	Earnings before taxation	89,093	28,906	117,999	
2600	**Taxation**	(26,975)	(8,672)	(35,647)	12.6
	Profit after taxation	62,118	20,234	82,352	

Covered distribution

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
1100	Network services (reference)	804,783	-	804,783	
1100	Network services (non-reference)	24,403	-	24,403	
1200	Contributions (excl. gifted assets)	80,625	23,829	104,454	11,12.1
1200	Gifted assets	66,651	-	66,651	11,12.1
1300	Proceeds from disposal of assets	2,242	-	2,242	
1400	Other revenue	1,112	-	1,112	
	Total revenue	979,816	23,829	1,003,645	
2100	Operating expenditure costs	(552,699)	(4,809)	(557,508)	9,10,12.3, 12.4,12.5
	Operations	(43,824)	(91)	(43,915)	
	Maintenance	(207,844)	(693)	(208,537)	
	Customer service and billing	(47,838)	(34)	(47,872)	
	Corporate	(55,474)	(7,175)	(62,649)	
	Other operating expenditure	(197,719)	3,184	(194,535)	
2200	Depreciation and amortisation	(123,676)	7,175	(116,501)	12.3
2300	Bad debts	1,220	-	1,220	
2400	Borrowing costs	(178,631)	-	(178,631)	12.2
2500	Book value on disposal of assets	(871)	-	(871)	
	Total expenses	(854,657)	2,366	(852,291)	
	Earnings before taxation	125,159	26,195	151,354	
2600	**Taxation**	(37,895)	(7,858)	(45,753)	12.6
	Profit after taxation	87,264	18,337	105,601	

3. Cash flow statement (disaggregated) for the year ended 30 June 2012

Account Code	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
	Operating activities					
1100	*Receipts*	1,551,390	461,538	998,642	7,028	84,182
2100	*Payments*	(850,232)	(160,426)	(604,243)	(4,774)	(80,789)
	Net operating cash flow	701,158	301,112	394,399	2,254	3,393
	Investing activities					
2700	*Receipts*	8,066	38	2,242	-	5,786
2800	*Payments*	(802,611)	(174,780)	(600,665)	(7,332)	(19,834)
	Net investing cash flow	(794,545)	(174,742)	(598,423)	(7,332)	(14,048)
	Financing activities					
2700	*Receipts*	4,166,095	1,432,765	2,663,542	-	69,788
2800	*Payments*	(4,075,954)	(1,412,808)	(2,597,362)	-	(65,784)
	Net financing cash flow	90,141	19,957	66,180	-	4,004
	Net (decrease)/increase in cash	(3,246)	146,327	(137,844)	(5,078)	(6,651)
	Cash at beginning of reporting year	26,174				
	Net decrease in cash	(3,246)				
	Cash at end of reporting year*	22,928	8,050	14,878		

*Cash transactions are recorded collectively in one bank/general ledger account and redistributed so as to equitably fund the core covered transmission and distribution businesses.

4. Cash flow statement (regulatory financial statement) for the year ended 30 June 2012

Covered transmission

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
	Operating activities				
1100	*Receipts*	461,538	-	461,538	
2100	*Payments*	(160,426)	-	(160,426)	
	Net operating cash flow	301,112	-	301,112	
	Investing activities				
2700	*Receipts*	38	-	38	
2800	*Payments*	(174,780)	-	(174,780)	
	Net investing cash flow	(174,742)	-	(174,742)	
	Financing activities				
2700	*Receipts*	1,432,765	-	1,432,765	
2800	*Payments*	(1,412,808)	-	(1,412,808)	
	Net financing cash flow	19,957	-	19,957	
	Net increase in cash	146,327	-	146,327	

Covered distribution

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
	Operating activities				
1100	*Receipts*	998,642	-	998,642	
2100	*Payments*	(604,243)	-	(604,243)	
	Net operating cash flow	394,399	-	394,399	
	Investing activities				
2700	*Receipts*	2,242	-	2,242	
2800	*Payments*	(600,665)	-	(600,665)	
	Net investing cash flow	(598,423)	-	(598,423)	
	Financing activities				
2700	*Receipts*	2,663,542	-	2,663,542	
2800	*Payments*	(2,597,362)	-	(2,597,362)	
	Net financing cash flow	66,180	-	66,180	
	Net decrease in cash	(137,844)	-	(137,844)	

5. Balance sheet (disaggregated) as at 30 June 2012

Account Code	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
	Current assets					
8100	*Cash and cash equivalents*	22,928	8,050	14,878	-	-
8200	*Trade and other receivables*	40,904	12,670	23,755	1,639	2,840
8200	*Prepayments*	7,525	2,642	4,883	-	-
8200	*Accrued revenue*	153,492	50,652	102,840	-	-
8300	*Inventories*	115,400	30,566	63,488	-	21,346
	Total current assets	340,249	104,580	209,844	1,639	24,186
	Non-current assets					
8400	*Property, plant&equip, intangibles*	6,991,283	2,415,826	4,474,182	9,433	91,842
8200	*Trade and other receivables*	252	88	164	-	-
	Total non-current assets	6,991,535	2,415,914	4,474,346	9,433	91,842
	Total assets	7,331,784	2,520,494	4,684,190	11,072	116,028
	Current liabilities					
8600	*Trade creditors and accruals*	(257,304)	(80,542)	(170,423)	(2,388)	(3,951)
8900	*Deferred income*	(110,165)	(26,674)	(83,491)	-	-
8700	*Provisions*	(37,205)	(11,983)	(24,678)	(316)	(228)
	Total current liabilities	(404,674)	(119,199)	(278,592)	(2,704)	(4,179)
	Non-current liabilities					
8500	*Borrowings*	(5,474,774)	(1,883,128)	(3,499,893)	-	(91,753)
8800	*Retirement benefit obligations*	(667)	(145)	(522)	-	-
8600	*Trade creditors and accruals*	(221,393)	(89,579)	(131,814)	-	-
8900	*Deferred income*	(12,010)	(11,983)	(27)	-	-
8700	*Provisions*	(16,967)	(6,086)	(10,640)	(140)	(101)
	Total non-current liabilities	(5,725,811)	(1,990,921)	(3,642,896)	(140)	(91,854)
	Total liabilities	(6,130,485)	(2,110,120)	(3,921,488)	(2,844)	(96,033)
	Net assets	1,201,299	410,374	762,702	8,228	19,995
	Equity					
	Share capital	821,239				
	*Accumulated profits/reserves**	380,060				
	Total equity	1,201,299				
	*Accumulated profits/reserves					
	At start of reporting year	307,341				
	Profit after taxation	157,131				
	Other comprehensive income	(154)				
	Distributions paid/provided in year	(84,258)				
	At end of reporting year	380,060				

There are no amounts in respect of excluded transmission and excluded distribution activities.

6. Balance sheet (regulatory financial statement) as at 30 June 2012

Covered transmission

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
	Current assets				
8100	*Cash and cash equivalents*	8,050	-	8,050	
8200	*Trade and other receivables*	12,670	-	12,670	
8200	*Prepayments*	2,642	-	2,642	
8200	*Accrued revenue*	50,652	-	50,652	
8300	*Inventories*	30,566	-	30,566	
	Total current assets	104,580	-	104,580	
	Non-current assets				
8400	*Property, plant&equip, intangibles*	2,415,826	(19,739)	2,396,087	**12.2,12.4,12.5**
8200	*Trade and other receivables*	88	-	88	
	Total non-current assets	2,415,914	(19,739)	2,396,175	
	Total assets	2,520,494	(19,739)	2,500,755	
	Current liabilities				
8600	*Trade creditors and accruals*	(80,542)	(8,672)	(89,214)	**12.6**
8900	*Deferred income*	(26,674)	25,215	(1,459)	**12.1**
8700	*Provisions*	(11,983)	-	(11,983)	
	Total current liabilities	(119,199)	16,543	(102,656)	
	Non-current liabilities				
8500	*Borrowings*	(1,883,128)	-	(1,883,128)	
8800	*Retirement benefit obligations*	(145)	-	(145)	
8600	*Trade creditors and accruals*	(89,579)	-	(89,579)	
8900	*Deferred income*	(11,983)	11,983	-	**12.1**
8700	*Provisions*	(6,086)	-	(6,086)	
	Total non-current liabilities	(1,990,921)	11,983	(1,978,938)	
	Total liabilities	(2,110,120)	28,526	(2,081,594)	
	Net assets	410,374	8,787	419,161	

6. Balance sheet (regulatory financial statement) as at 30 June 2012

Covered distribution

Account Code	Description	Base Account $'000	Adjustment $'000	Regulatory Account $'000	Support Reference
	Current assets				
8100	*Cash and cash equivalents*	14,878	-	14,878	
8200	*Trade and other receivables*	23,755	-	23,755	
8200	*Prepayments*	4,883	-	4,883	
8200	*Accrued revenue*	102,840	-	102,840	
8300	*Inventories*	63,488	-	63,488	
	Total current assets	209,844	-	209,844	
	Non-current assets				
8400	*Property, plant&equip, intangibles*	4,474,182	2,704	4,476,886	**12.2,12.4,12.5**
8200	*Trade and other receivables*	164	-	164	
	Total non-current assets	4,474,346	2,704	4,477,050	
	Total assets	4,684,190	2,704	4,686,894	
	Current liabilities				
8600	*Trade creditors and accruals*	(170,423)	(7,858)	(178,281)	**12.6**
8900	*Deferred income*	(83,491)	83,491	-	**12.1**
8700	*Provisions*	(24,678)	-	(24,678)	
	Total current liabilities	(278,592)	75,633	(202,959)	
	Non-current liabilities				
8500	*Borrowings*	(3,499,893)	-	(3,499,893)	
8800	*Retirement benefit obligations*	(522)	-	(522)	
8600	*Trade creditors and accruals*	(131,814)	-	(131,814)	
8900	*Deferred income*	(27)	27	-	**12.1**
8700	*Provisions*	(10,640)	-	(10,640)	
	Total non-current liabilities	(3,642,896)	27	(3,642,869)	
	Total liabilities	(3,921,488)	75,660	(3,845,828)	
	Net assets	762,702	78,364	841,066	

7. Capital expenditure (disaggregated) for the year ended 30 June 2012

Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
Capital additions					
Asset replacement	203,774	26,439	177,335	-	-
Capacity expansion	68,333	20,600	47,733	-	-
Customer driven	230,635	56,284	174,351	-	-
Metering	14,032	-	14,032	-	-
Regulatory compliance	112,280	17,668	94,612	-	-
Reliability driven	9,060	222	8,838	-	-
SCADA/communications	15,793	12,347	3,446	-	-
Smartgrid	4,002	-	4,002	-	-
State Underground Power Project (SUPP)	33,261	-	33,261	-	-
Gifted assets	66,651	-	66,651	-	-
Capitalised interest	6,396	6,396	-	-	-
Mobile plant and vehicles	33,472	-	-	-	33,472
Information technology and market reform	57,074	17,465	32,277	7,332	-
Administration and support	37,800	14,143	22,724	-	933
Total capital additions	892,563	171,564	679,262	7,332	34,405

There are no amounts in respect of excluded transmission and excluded distribution activities.

8. Capital expenditure (regulatory financial statement) for the year ended 30 June 2012

Covered transmission

Description	Base Account $'000	Adjustment (Ref 12.2) $'000	Adjustment (Ref 12.4) $'000	Adjustment (Ref 12.5) $'000	Regulatory Account $'000	Support Reference
Growth						
Customer driven	56,284	-	19	1,842	58,145	
Capacity expansion	20,600	-	21,245	674	42,519	
	76,884	-	21,264	2,516	100,664	
Asset replacement and renewal						
Asset replacement	26,439	-	23	865	27,327	
Improvement in service						
SCADA/communications	12,347	-	226	404	12,977	
Reliability driven	222	-	5	7	234	
	12,569	-	231	411	13,211	
Compliance						
Regulatory (safety, environmental, statutory)	17,668	-	109	578	18,355	
Corporate						
Information technology and market reform	17,465	-	-	-	17,465	
Administration and support	14,143	-	-	-	14,143	
	31,608	-	-	-	31,608	
Other						
Capitalised interest	6,396	(6,396)	-	-	-	
Total capital additions	171,564	(6,396)	21,627	4,370	191,165	**12.2,12.4,12.5**

Covered distribution

Description	Base Account $'000	Adjustment (Ref 12.2) $'000	Adjustment (Ref 12.4) $'000	Adjustment (Ref 12.5) $'000	Regulatory Account $'000	Support Reference
Growth						
Customer driven	174,351	-	-	582	174,933	
Gifted assets	66,651	-	-	-	66,651	
Capacity expansion	47,733	-	216	159	48,108	
	288,735	-	216	741	289,692	
Asset replacement and renewal						
Asset replacement	177,335	-	46	592	177,973	
State Underground Power Project (SUPP)	33,261	-	-	111	33,372	
Metering	14,032	-	-	47	14,079	
Smartgrid	4,002	-	-	13	4,015	
	228,630	-	46	763	229,439	
Improvement in service						
Reliability driven	8,838	-	240	30	9,108	
SCADA/communications	3,446	-	-	12	3,458	
	12,284	-	240	42	12,566	
Compliance						
Regulatory (safety, environmental, statutory)	94,612	-	2	316	94,930	
Corporate						
Information technology and market reform	32,277	-	-	-	32,277	
Administration and support	22,724	-	-	-	22,724	
	55,001	-	-	-	55,001	
Total capital additions	679,262	-	504	1,862	681,628	**12.2,12.4,12.5**

Ringfenced independent market operator

Description	Base Account $'000	Adjustment (Ref 12.2) $'000	Adjustment (Ref 12.4) $'000	Adjustment (Ref 12.5) $'000	Regulatory Account $'000	Support Reference
Corporate						
Information technology and market reform	7,332	-	-	-	7,332	
Total capital additions	7,332	-	-	-	7,332	**12.2,12.4,12.5**

9. Operating expenditure (disaggregated) for the year ended 30 June 2012

Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
Directly attributed costs					
Operations	(100,276)	(15,421)	(27,020)	-	(57,835)
Maintenance	(253,213)	(45,369)	(207,844)	-	-
Customer service and billing	(50,053)	-	(47,838)	-	(2,215)
Corporate	(5,001)	-	(499)	-	(4,502)
Other operating expenditure	(77,339)	(46,578)	(16,519)	(6,583)	(7,659)
Total directly attributed costs	(485,882)	(107,368)	(299,720)	(6,583)	(72,211)
Causally allocated costs					
Operations	(25,167)	(8,363)	(16,804)	-	-
Maintenance	-	-	-	-	-
Customer service and billing	-	-	-	-	-
Corporate	(86,130)	(30,627)	(54,975)	-	(528)
Other operating expenditure	(181,200)	-	(181,200)	-	-
Total causally allocated costs	(292,497)	(38,990)	(252,979)	-	(528)
Total operating expenditure costs	(778,379)	(146,358)	(552,699)	(6,583)	(72,739)

There are no amounts in respect of excluded transmission and excluded distribution activities.

10. Operating expenditure (regulatory financial statement) for the year ended 30 June 2012

Covered transmission

Description	Base Account $'000	Adjustment (Ref 12.3) $'000	Adjustment (Ref 12.4) $'000	Adjustment (Ref 12.5) $'000	Regulatory Account $'000	Support Reference
Operations						
SCADA/communications	(10,861)	-	-	(355)	(11,216)	
Network operations	(8,363)	-	-	-	(8,363)	
Non revenue cap services	(4,560)	-	-	(149)	(4,709)	
	(23,784)	-	-	(504)	(24,288)	
Maintenance						
Preventative routine	(20,762)	-	-	(679)	(21,441)	
Preventative condition	(11,621)	-	-	(380)	(12,001)	
Corrective deferred	(10,328)	-	-	(338)	(10,666)	
Corrective emergency	(2,658)	-	-	(87)	(2,745)	
	(45,369)	-	-	(1,484)	(46,853)	
Corporate						
Business support	(30,627)	(3,882)	-	-	(34,509)	
Other operating expenditure						
Non-recurring expenditure	(46,578)	-	21,627	6,358	(18,593)	
Total operating expenditure costs	(146,358)	(3,882)	21,627	4,370	(124,243)	**12.3,12.4,12.5**

Covered distribution

Description	Base Account $'000	Adjustment (Ref 12.3) $'000	Adjustment (Ref 12.4) $'000	Adjustment (Ref 12.5) $'000	Regulatory Account $'000	Support Reference
Operations						
Non revenue cap services	(17,257)	-	-	(58)	(17,315)	
Networks operations	(16,804)	-	-	-	(16,804)	
SCADA/communications	(3,808)	-	-	(13)	(3,821)	
Smartgrid	(2,999)	-	-	(10)	(3,009)	
Reliability operations	(2,956)	-	-	(10)	(2,966)	
	(43,824)	-	-	(91)	(43,915)	
Maintenance						
Corrective emergency	(83,927)	-	-	(280)	(84,207)	
Preventative routine	(49,356)	-	-	(165)	(49,521)	
Preventative condition	(47,759)	-	-	(159)	(47,918)	
Corrective deferred	(26,802)	-	-	(89)	(26,891)	
	(207,844)	-	-	(693)	(208,537)	
Customer service and billing						
Metering	(23,815)	-	-	(5)	(23,820)	
Distribution quotation	(8,798)	-	-	(29)	(8,827)	
Call centre	(7,976)	-	-	-	(7,976)	
Guaranteed service level payments	(7,249)	-	-	-	(7,249)	
	(47,838)	-	-	(34)	(47,872)	
Corporate						
Business support	(55,474)	(7,175)	-	-	(62,649)	
Other operating expenditure						
Tariff equalisation contribution	(181,200)	-	-	-	(181,200)	
Non-recurring expenditure	(16,519)	-	504	2,680	(13,335)	
	(197,719)	-	504	2,680	(194,535)	
Total operating expenditure costs	(552,699)	(7,175)	504	1,862	(557,508)	**12.3,12.4,12.5**

11. Contributions for the year ended 30 June 2012

Covered transmission

Reason for contributions	Base Account $'000	Adjustment (Ref 12.1) $'000	Regulatory Account $'000	Support Reference
Customer driven	18,425	9,305	27,730	
Asset replacement	84	-	84	
Capacity expansion	68	-	68	
Regulatory compliance	23	-	23	
Total contributions	18,600	9,305	27,905	**12.1**

Covered distribution

Reason for contributions (incl. gifted assets)	Base Account $'000	Adjustment (Ref 12.1) $'000	Regulatory Account $'000	Support Reference
Gifted assets	66,651	-	66,651	
Customer driven	65,464	13,277	78,741	
State Underground Power Project (SUPP)	15,057	10,552	25,609	
Asset replacement	101	-	101	
Metering	3	-	3	
Total contributions (incl. gifted assets)	147,276	23,829	171,105	**12.1**

12. Regulatory adjustments for the year ended 30 June 2012

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
Accounting policy adjustments						
12.1	**Contributions (incl. gifted assets)**	**169,646**	**18,600**	**147,276**	**1,206**	**2,564**
	less opening deferred contributions	(87,582)	(27,893)	(59,689)	-	-
	add closing deferred contributions	120,716	37,198	83,518	-	-
	Net movement in reporting year	33,134	9,305	23,829	-	-
	Total contributions received	**202,780**	**27,905**	**171,105**	**1,206**	**2,564**

To align Western Power's statutory accounting policy with regulatory accounting policy, i.e. customer and developer capital contributions are recognised in the profit and loss account (regulatory financial statement) when received and not when the associated asset is energised.

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
12.2	**Capitalised borrowing costs b/fwd**	53,545	53,545	-	-	-
	Net movement in reporting year	6,396	6,396	-	-	-
	Capitalised borrowing costs c/fwd	**59,941**	**59,941**	**-**	**-**	**-**

To align Western Power's statutory accounting policy with regulatory accounting policy, i.e. borrowing costs are not capitalised from the profit and loss account (regulatory financial statement) to the balance sheet (regulatory financial statement).

Accounting disclosure adjustments

12.3 To reclassify depreciation as operating expenditure to offset the credit (from business unit charge recovery) in Corporate operating expenditure costs.

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
Regulated asset base adjustments						
12.4	**Cancelled/deferred projects b/fwd**	14,543	14,205	338	-	-
	Net movement in reporting year	22,131	21,627	504	-	-
	Cancelled/deferred projects c/fwd	**36,674**	**35,832**	**842**	**-**	**-**

To transfer the statutory write down for cancelled/deferred capital projects from operating expenditure (regulatory financial statement) to capital expenditure (regulatory financial statement), i.e. this expenditure qualifies for recognition in the regulatory asset base (RAB).

	Description	Base Account $'000	Covered Transmission $'000	Covered Distribution $'000	Independent Market Operator $'000	Unregulated $'000
12.5	**Early strategic planning costs b/fwd**	-	-	-	-	-
	Net movement in reporting year	6,232	4,370	1,862	-	-
	Early strategic planning costs c/fwd	**6,232**	**4,370**	**1,862**	**-**	**-**

To allocate the early strategic planning costs expensed in the statutory financial statements to specific operating and capital projects, with the latter transferred from operating expenditure (regulatory financial statement) to capital expenditure (regulatory financial statement), i.e. the expenditure qualifies for recognition in the RAB.

12.6 Tax is calculated on regulatory adjustments at a rate of 30%.

Summary of significant accounting policies

This is a special purpose financial report prepared for the sole purpose of the Guidelines for Access Arrangement Information 2010. The accounting policies adopted in the preparation of these financial statements are set out below. These policies have been consistently applied, unless otherwise stated.

a) Basis of preparation

These financial statements have been prepared in accordance with Australian accounting standards and other authoritative pronouncements of the Australian Accounting Standards Board (AASB) (including Australian interpretations), as modified by the Guidelines for Access Arrangement Information 2010, with the exception of the disclosure requirements in the following pronouncements:

AASB 101	*Presentation of financial statements*
AASB 107	*Statement of cash flows*
AASB 123	*Borrowing costs*
AASB 7	*Financial instruments: disclosures*
AASB Interpretation 18	*Transfers of assets from customers*

Western Power has been classified to be a not-for-profit entity and accordingly applies the not-for-profit elections available in the Australian accounting standards where applicable.

The modifications to the Australian accounting standards as required by the Guidelines for Access Arrangement Information 2010 include:

Any interest (or like allowance) incurred during construction is expensed;
Asset revaluations or adjustments for impairment are only recognised in accordance with the provisions for redundant capital under sections 6.61 to 6.63 of the Access Code;
Goodwill and any related impairments are not recognised; and
Disaggregated financial information has been provided in accordance with the business segments outlined in the Guidelines for Access Arrangement Information 2010.

b) Accrual accounting and historical cost convention

These financial statements are prepared on the accrual accounting basis and in accordance with the historical cost convention, except for derivative financial instruments that are measured at fair value, and certain non-current financial assets and financial liabilities that are measured at amortised cost.

c) Critical accounting and historical cost convention

The preparation of financial statements in conformity with Australian accounting standards requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of revenue, expenses, assets and liabilities. Actual results may differ from these estimates.

Estimates, judgements and underlying assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that may have a financial impact on Western Power and that are believed to be reasonable under the circumstances. Revisions to accounting estimates are recognised in the year in which the estimate is revised and any future years affected.

The area(s) where estimates and assumptions are significant to the financial statements, or a higher degree of judgement or complexity is involved are referenced in the following notes:

Revenue (unbilled network tariff revenue): note g)
Trade and other receivables (impairment provision): note k)
Property, plant and equipment and intangibles (useful lives): notes n) and o)
Provisions (employee benefits and retirement benefit obligations): notes s) and t)

Summary of significant accounting policies (continued)

d) Rounding

All financial information presented in Australian dollars has been rounded to the nearest thousand unless otherwise stated.

e) Cost allocations

Costs that cannot be directly attributable to a business segment are allocated in accordance with the Western Power cost and revenue allocation method.

f) Foreign currency translation

Functional and presentation currency

This financial report is presented in Australian dollars, which is the functional and presentation currency of Western Power.

Transactions and balances

Transactions in currency other than the functional currency of Western Power are translated into the functional currency at the rates of exchange prevailing on the dates of the transactions. At each reporting date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at closing exchange rates. All foreign currency translation differences are recognised in profit or loss, except where deferred in equity for translation differences of qualifying cash flow hedges.

g) Revenue recognition

Revenues are recognised to the extent it is probable that future economic benefits will flow to Western Power and the revenue can be measured reliably. It is measured at the fair value of the consideration received or receivable, net of the amount of goods and services tax. The following specific criteria must also be met before revenues are recognised:

Network charges

Western Power receives network services revenue from the transmission and distribution of electricity, and provision of related services. Network services revenue is recognised when the service is provided. As at each reporting date, network services revenue and trade receivables include amounts attributable to ‘unbilled tariff revenue’ (30 June 2012: $153.492 million; 30 June 2011: $132.290 million). Unbilled tariff revenue is an estimate of electricity transported to customers that has not been billed at the reporting date. It is calculated using projected revenue assumptions for unread meters based on the billing profile of Western Power customers.

Western Power is subject to a regulatory agreement, which determines the revenues receivable for its network tariff services. No liabilities are recognised when revenues received or receivable exceed the maximum amount permitted by regulatory agreement and adjustments will be made to future prices to reflect this over-recovery. Similarly, no assets are recognised when a regulatory agreement permits adjustments to be made to future prices in respect of an under-recovery of permitted revenues.

Contributions

Western Power receives developer and customer contributions toward the extension of electricity infrastructure to facilitate network connection. Contributions are recognised when received. Contributions can be in the form of either cash contributions or gifted network assets. Gifted network assets are measured at their fair value.

Network assets resulting from contributions received or gifted are recognised as property, plant and equipment and depreciated over their expected useful life.

Other income

Western Power receives other income from the provision of activities incidental to the core activities of the business. Other income is recognised when the activity is provided.

Summary of significant accounting policies (continued)

h) Income taxes

Western Power is exempt from the Commonwealth of Australia's Income Tax Assessment Acts but makes income tax equivalent payments to the Western Australian State Government. The calculation of the liability in respect of these taxes is governed by the Income Tax Administration Acts and the National Taxation Equivalent Regime guidelines.

The income tax expense for the reporting year comprises current and deferred tax. Income tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity.

Current tax is the expected tax receivable/payable on the taxable income for the reporting year, using tax rates enacted or substantially enacted at the reporting date, and any adjustment to tax in respect of previous years.

Deferred tax is provided using the liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantially enacted at the reporting date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the asset can be utilised. Deferred tax assets are reviewed at the end of each reporting year and are reduced to the extent it is no longer probable that the related tax benefit will be realised.

Current and deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the tax balances relate to the same taxation authority.

i) Leases

Leases where the lessee retains substantially all the risks and benefits of ownership of the asset are classified as finance leases. As at 30 June 2012 Western Power does not have any finance leases.

Leases where the lessor retains substantially all the risks and benefits of ownership of the asset are classified as operating leases. Payments made under operating leases are charged to profit and loss on a straight-line basis over the term of the lease.

j) Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and other short-term deposits that have an original maturity of three months or less, net of outstanding bank overdrafts.

k) Trade and other receivables

Trade and other receivables are non-interest bearing, unsecured and are initially recognised at fair value and subsequently measured at amortised cost less provision for impairment. They are usually settled on 14 or 30 day payment terms, unless contractually agreed otherwise.

Trade and other receivables are determined to be impaired when objective evidence exists that Western Power will not be able to collect all amounts due. Objective evidence includes known financial difficulties of the debtor, and default or delinquency in payments (more than 30 days overdue). The amount impaired is the difference between the carrying value of the receivable and the net present value of the estimated future cash flows discounted at the original effective interest rate. Amounts impaired are recognised in profit and loss. When a trade receivable for which an impairment provision has been recognised becomes uncollectible in a subsequent reporting year it is written off against the provision account. Subsequent recoveries of amounts written off are credited to profit and loss.

Summary of significant accounting policies (continued)

l) Inventories

Inventories are stated at the lower of weighted average cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated selling costs.

A provision to allow for the expected diminution in the value of inventory due to obsolescence is determined by periodic review.

m) Derivative and hedging activities

Derivative financial instruments

Derivative financial instruments are used to hedge exposures to movements in interest rates, exchange rates and commodity prices. Western Power uses derivative financial instruments in accordance with Board approved policy. Speculative trading of derivatives is strictly prohibited.

Derivative financial instruments are initially recognised at fair value on the date a derivative contract is entered into and are subsequently remeasured to their fair value at each reporting date. Changes in the fair value of derivative financial instruments are included in profit and loss to the extent that hedge accounting is not applied. Fair value is based on quoted market prices at the reporting date.

Financial instruments are derecognised when Western Power no longer controls the contractual rights that comprise the financial instrument.

Hedge accounting

For all derivative transactions designated as a cash flow hedge, the portion of gain or loss on the hedging instrument that is determined to be an effective hedge is recognised in other comprehensive income and accumulated in the hedging reserve. The ineffective portion is recognised in profit and loss immediately. When the cash flows occur, the amount that has been deferred to equity is transferred to either the carrying value of the asset, in the case of non-financial assets, or reclassified to profit or loss as appropriate.

Hedge accounting is discontinued when the hedging instrument expires or is sold, terminated or exercised, or no longer qualifies for hedge accounting. Any cumulative gain or loss recognised in equity is immediately reclassified to profit or loss.

Summary of significant accounting policies (continued)

n) Property, plant and equipment

Cost

Property, plant and equipment represent the capital works and plant required for the operation of the business, and is recognised at historical cost less accumulated depreciation. Historical cost includes all expenditure directly attributable to the acquisition or construction of the asset. Cost may also include transfer from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

The cost of self-constructed assets includes the cost of materials and labour, and any other costs, directly attributable to bringing the asset to a working condition for its intended use. Gifted network assets are recognised at fair value when received.

Subsequent costs are included in property, plant and equipment only when it is probable the item associated with the cost will generate future economic benefits and the cost can be measured reliably. The carrying amounts of items replaced are derecognised. All other repairs and maintenance plus minor capital assets less than $5,000 are expensed to profit and loss during the reporting year in which they are incurred.

Depreciation

Depreciation is calculated using the straight-line method over the estimated useful economic lives presented below.

Depreciation periods for categories of property, plant & equip.	***Years***
Substations, transformers, poles & cables	45-50
Buildings	40
Meters, streetlights	20-25
Pole reinforcements, smart-meters	15
Furniture & fittings, refurbishments	10
Other plant and equipment	10
Communications	6.5-10
Fleet	5-10
Computer hardware	4
Low value pool	3
Leasehold improvements	Life of lease

Property, plant and equipment received on disaggregation of Western Power Corporation is depreciated over their residual useful economic lives. No depreciation is provided on freehold land, easements and assets in the course of construction.

The residual value and useful lives of property, plant and equipment are reviewed, and adjusted as appropriate, at the end of each reporting year.

Rehabilitation costs

Upon recognition of an item of property, plant and equipment, the cost of the item includes the anticipated costs of rehabilitating the site on which it is located.

Disposals

An item of property, plant and equipment is derecognised upon disposal. The proceeds and carrying amount on disposal are recognised in profit or loss.

Summary of significant accounting policies (continued)

o) Intangibles

Cost

Intangibles represent identifiable capitalised software costs and intellectual property, and are recognised at historic cost less accumulated amortisation.

Internally generated intangibles are recognised only if an asset is created that can be identified; it is probable that the asset created will generate future economic benefits; and that the development cost of the asset can be measured reliably. Where no internally generated asset can be recognised the development expenditure is expensed to profit or loss.

Amortisation

Amortisation is calculated using the straight-line method over the estimated useful economic lives listed below:

Amortisation periods for categories of intangibles	***Years***
Intellectual property	25
Software (major developments/enhancements)	10
Software (minor purchases/enhancements)	2.5

The residual value and useful lives of intangibles are reviewed, and adjusted as appropriate, at the end of each reporting year.

Disposals

An intangible asset is derecognised upon disposal. The proceeds and carrying amount on disposal are recognised in profit and loss.

p) Trade and other payables

Trade and other payables are typically non-interest bearing, unsecured and are initially recognised at fair value and subsequently measured at amortised cost. They are usually settled within 30 days of recognition.

q) Borrowings

Borrowings are initially recognised at fair value net of transaction costs incurred and subsequently measured at amortised cost using the effective interest method.

Borrowings are classified as current liabilities unless Western Power has an agreement with the lender that allows refinancing of the liability for at least 12 months after the reporting date. This includes where a forward borrowing commitment exists that replaces the existing borrowing on the date of maturity, and where this extends the maturity of the original borrowing to greater than 12 months after the reporting date.

r) Borrowing costs

Borrowing costs are expensed when incurred.

s) Provisions

Provisions are recognised when Western Power has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the amount of the obligation. Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. The discount rate used to determine the present value reflects the market assessments of the time value of money and the risks specific to the liability.

Rehabilitation costs

A provision for site rehabilitation costs is recognised when there is either a legal or constructive obligation to rehabilitate a site; the land is contaminated; it is probable a rehabilitation expense will be incurred; and the costs can be reliably estimated.

The amount of the provision for future rehabilitation costs is capitalised into the cost of the related plant, property and equipment, and depreciated over the expected useful life.

Summary of significant accounting policies (continued)

t) Employee benefits

Wages and salaries, annual leave

Liabilities arising in respect of employee benefits that are expected to be settled within 12 months of the reporting date are measured at their nominal amount based on remuneration rates that are expected to be paid when the liabilities are settled. The liability for wages, salaries and annual leave is recognised in other payables. The liability for all other short-term employee benefits is recognised in the provision for employee benefits.

Long service leave

The liability for unconditional long service leave is recognised in the provision for employee benefits, and measured as the present value of expected future payments to be made in respect of services provided by employees up to the reporting date using the projected unit credit method. Consideration is given to factors including the expected future wages and salaries levels and settlement dates. Expected future payments are discounted using the Commonwealth Bond rates whose terms most closely match the terms of the related liabilities. Actuarial valuations are carried out at each reporting date.

Retirement benefit obligations

Defined contribution plans

A defined contribution plan is a post-employment benefit plan under which an entity pays fixed contributions into a separate entity and will have no legal or constructive obligation to pay further amounts. Contributions to defined contribution plans are recognised as an expense as they become payable.

Defined benefit plans

A defined benefit plan is a post-employment benefit other than a defined contribution plan. A liability or asset in respect of defined benefit superannuation plans is recognised in the balance sheet and is measured as the present value of the defined benefit obligation in respect of services provided by employees up to the reporting date, adjusted for unrecognised actuarial gains/losses, the fair value of any fund assets at that date and any unrecognised past service cost.

The present value of the defined benefit superannuation plans is based upon expected future payments and is calculated using discounted cash flows consistent with the projected unit credit method. Consideration is given to factors including the expected future wages and salaries level, experience of employee departures and periods of service. Expected future payments are discounted using the Commonwealth Bond rates whose terms most closely match the terms of the related liabilities. Actuarial valuations are carried out at each reporting date.

Current service cost is recognised in full in profit or loss in the reporting year in which the obligation increases as a result of employee services. Actuarial gains and losses arising from experience adjustments and changes in actuarial adjustments are recognised directly in other comprehensive income.

u) Dividends

Dividends are provided for in the reporting year in which the dividends recommended by the Board are accepted by the Minister for Energy, with the concurrence of the Treasurer.

v) Goods & services taxation (GST)

Revenue, expenses and assets are recognised net of the amount of associated GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included in other receivables or payables in the balance sheet.

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financial activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

Directors' Declaration

This is a special purpose financial report prepared for the purposes of the Guidelines for Access Arrangement Information 2010.

In the directors' opinion the financial statements and summary of significant accounting policies set out on pages 14 to 20 have been prepared in accordance with the Guidelines for Access Arrangement Information 2010, and comply with Australian accounting standards and other authoritative pronouncements.

This declaration is made in accordance with a resolution of the directors dated 28 September 2012.

A Mulgrew
Board Chair

28 September 2012

J Cahill
Board Deputy Chair

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LEGAL &
GOVERNANCE

Office of the Auditor General
Serving the Public Interest

Our Ref: 5563-03

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Chairman of Directors
Electricity Networks Corporation
363 Wellington Street
PERTH WA 6000

Dear Sir

AGREED UPON PROCEDURES ENGAGEMENT ON WESTERN POWER'S REGULATORY FINANCIAL STATEMENTS FOR THE YEAR ENDED 30 JUNE 2012

Attached is the Report on agreed upon procedures for the regulatory financial statements for the year ending 30 June 2012, prepared for submission to the Economic Regulator Authority.

I would like to take this opportunity to thank you, the management and the staff of your Corporation for their cooperation with the audit team.

Feel free to contact me on 6557 7526 if you would like to discuss these matters further.

Yours faithfully

DON CUNNINGHAME
ASSISTANT AUDITOR GENERAL ASSURANCE SERVICES
Delegate of the Auditor General for Western Australia
Perth, Western Australia
2 October 2012

Attach

Office of the Auditor General
Serving the Public Interest

Report on agreed upon procedures in connection with the Regulatory Financial Statements (RFS) for the year ended 30 June 2012

We have performed the procedures requested by you as detailed in the written instructions dated 2 April 2012. The procedures performed relate to the 30 June 2012 RFS and are described below.

The engagement was undertaken in accordance with Australian Auditing Standards applicable to agreed-upon procedures engagements. The responsibility for determining the adequacy or otherwise of the procedures agreed to be performed is that of the directors.

The procedures were performed solely to assist Western Power with their access arrangement information which is submitted to the Economic Regulation Authority (ERA). The procedures performed are as follows:

1. Obtain the 30 June 2012 RFS and agree the base account numbers to Western Power's audited 30 June 2012 financial statements for:

    a. Total Revenue, Total Expenses, Profit/(Loss) after taxation

    b. Net operating cash flow, Net investing cash flow, Net financing cash flow, Net increase/(decrease) in cash held

    c. Total Assets, Total Liabilities, Net Assets.

2. Randomly select one revenue item from each of the revenue accounts (i.e. Network services (reference), Network services (non-reference), Network services (unregulated), Contributions (excl. gifted assets), Gifted Assets, Proceeds from disposal of assets and Other revenue) as disclosed in the 30 June 2012 RFS Profit and Loss account and agree the business segment allocation to Western Power's Cost and Revenue Allocation Method (CRAM).

3. Randomly select one transaction from each of the operating expenditure accounts (i.e. Operations, Maintenance, Customer service and billing, Corporate and Other operating expenditure) as disclosed in the 30 June 2012 RFS Profit and Loss account and agree the business segment allocations with the CRAM.

4. Randomly select five transactions disclosed in the 30 June 2012 RFS capital expenditure account, and agree the business segment allocations to the CRAM.

5. Agree the allocation of Depreciation and amortisation, Book value on sale of assets, Bad debts and Borrowing costs as disclosed in the 30 June 2012 RFS Profit and Loss account to the CRAM.

6. Agree the allocation of cash flows for operating activities, investing activities and financing activities as disclosed in the 30 June 2012 RFS Cash flow statement to the CRAM.

7. Agree the allocation of assets and liabilities as disclosed in the 30 June 2012 RFS Balance Sheet to the CRAM.

8. Randomly select two regulatory adjustments as disclosed in the 30 June 2012 RFS and agree supporting documentation and/or underlying methodology and calculations.

9. Check the mathematical accuracy and perform an internal cross reference check of the balances disclosed within the 30 June 2012 RFS.

Because the procedures do not constitute either an audit in accordance with Australian Auditing Standards or a review in accordance with Australian Auditing Standards applicable to review engagements, we do not express any assurance or opinion on the Regulatory Financial Statements for the year ended 30 June 2012.

Had we performed additional procedures or had we performed an audit in accordance with Australian Auditing Standards or a review in accordance with Australian Auditing Standards applicable to review engagements, other matters might have come to our attention that would have been reported to you.

Findings:

The findings are recorded in Appendix A.

Our report is solely for your information and that of the ERA and is not to be used for any other purpose or distributed to any other party; however, we understand that our report may be used to discuss findings therein with Western Power Network management.

This report relates only to the attached Regulatory Financial Statements for the year ended 30 June 2012 (Appendix One) and does not extend to any other financial report of Western Power, taken as a whole. We do not accept any responsibility for losses occasioned to Western Power or to any other party as a result of the circulation, reproduction or use of our final or draft report contrary to the provisions of this paragraph.

Regulatory Financial Statements (RFS)

30 June 2012

Scope of agreed upon procedures and findings:

1	***Procedure:*** *Obtain the 30 June 2012 RFS and agree the base account numbers to Western Power's audited 30 June 2012 financial statements for:* a. *Total Revenue, Total Expenses, Profit/(Loss) after taxation* b. *Net operating cash flow, Net investing cash flow, Net financing cash flow, Net increase/(decrease) in cash held* c. *Total Assets, Total Liabilities, Net Assets.*
	Findings: We have agreed the base numbers within the RFS for 30 June 2012 to Western Power's audited 30 June 2012 financial report as follows:

Category	Agreed without exception	Notes
Total Revenue	No	1
Total Expenses	No	1
Profit/(Loss) after taxation	Yes	
Net operating cash flow inflow (outflow)	Yes	
Net investing cash flow inflow (outflow)	Yes	
Net financing cash flow inflow (outflow)	Yes	
Net increase/(decrease) in cash held	Yes	
Total Assets	Yes	
Total Liabilities	Yes	
Net Assets	Yes	

Notes:

1. Total Revenue and Total Expenses does not agree to the 30 June 2012 audited Financial Report. Explanation of this variance is noted in the 30 June 2012 RFS on page 1. A difference of $5,001,000 arises for each category. This is due to gross amounts being disclosed for gains/losses on the disposal of assets within the RFS, whilst this balance is disclosed on a net basis within the 30 June 2012 audited Financial Report.

2	***Procedure:*** *Randomly select one transaction from each of the revenue accounts (i.e. Network services (reference), Network services (non-reference), Network services (unregulated), Contributions (excl. gifted assets), Gifted Assets, Proceeds from disposal of assets and Other revenue) as disclosed in the 30 June 2012 RFS Profit and Loss account and agree the business segment allocation to Western Power's Cost and Revenue Allocation Method (CRAM).*
	Findings: Western Power's revenue is categorised into one of two categories: 1. Direct revenue and; 2. Indirect revenue. The CRAM provides for the following allocation with respect to revenue: *'Our account code structure (e.g. via a project and/or work order) is used to identify and attribute direct revenue within the financial system. We allocate indirect revenue to the transmission, distribution, IMO-related system management and unregulated business segments using a method that most appropriately reflects the causal correlation of the underlying transaction."* *'Asset segment: comprises the third group of four characters of the cost centre code. The characters are numeric and are used to identify the business segment for which the transaction relates, i.e. 1@@@ denotes corporate, 2@@@ denotes transmission, 3@@@ denotes distribution and 4@@@ denotes system management.'* The RFS revenue categories (e.g. Network services, contributions, other revenue) each comprise a number of general ledger accounts, which are further comprised of a number of sub-ledgers. We have selected our revenue transactions from the sub-ledger level. For those transactions allocated on the 'direct' basis we have assessed whether their account coding is consistent with the CRAM. For those transactions allocated on the 'indirect' basis we have discussed with management (Senior Business Analyst - BP&A Branch) or reviewed documentation to ascertain the nature of the revenue item and consequently the rationale for the transaction's business segment allocation. The sample selected and reviewed is documented on the following page.

The sample selected and reviewed is shown below:

Revenue category and $ (as disclosed in the RFS)	Chart of accounts description and account code	$ and RFS business segment	Period of transaction	Type of allocation	Account coding agreed to CRAM
Network services (reference) $1,198,974,000	Open Access Ref Service Revenue (220012733000101)	$124,533,589 (distribution)	February 2012	Direct	Yes
Network service (non-reference) $29,624,000	Other Rev Electricity Non Energy (533012772000160)	$650,222 (transmission)	December 2011	Direct	Yes
Network services (unregulated) $80,593,000	Other Rev Electricity Non Energy (633310001000151)	$871,548 (unregulated)	September 2011	Direct	Yes
Contributions (excl. gifted assets) $102,995,000	Other Rev Electricity Non Energy (815031254000160)	$98,0000 (IMO)	May 2012	Direct	Yes
Gifted assets $66,651,000	MS014101 (3000)	$10,027 (distribution)	August 2011	Direct	Yes
Proceeds from disposal of assets $8,066,000	Colorado Space Cab T/Top WPC1864	$18,182 (unregulated)	March 2012	Indirect	Yes, 1
Other revenue $3,569,000	Fin Rev Interest Recd Domestic	$100,184 ($65,009 transmission and $35,175 distribution)	July 2011	Indirect	Yes, 2

Notes:

1. We have not reviewed the account coding for this transaction as the item has been allocated on an indirect basis (i.e. coding is not applied). The CRAM, section 7.1, stipulates that unregulated revenue includes external sales of fleet services and we have confirmed with management (Senior Business Analyst – BP&A Branch) that the transaction selected relates to a fleet vehicle sale.
2. We have not reviewed the account coding for this transaction as the item has been allocated on an indirect basis (i.e. coding is not applied). We have reviewed management's work papers supporting interest allocation. The allocation to the transmission and distribution segments has been based on the value of Property, plant and equipment (PPE). This is in line with section 7.2 of the CRAM.

3	***Procedure:*** *Randomly select one transaction from each of the operating expenditure accounts (i.e. Operations, Maintenance, Customer service and billing, Corporate and Other operating expenditure) as disclosed in the 30 June 2012 RFS Profit and Loss account and agree the business segment allocations with the CRAM.*
	Findings: The CRAM, Appendix A details the methodology for the allocation of operating expenses. The methods applied include allocation based on full-time employees, property plant and equipment and direct allocation (i.e. cost code). We note that the CRAM provides the following information regarding the allocation under the 'Direct' method where account codes are assigned to projects: *'Asset segment: comprises the third group of four characters of the cost centre code. The characters are numeric and are used to identify the business segment for which the transaction relates, i.e. 1@@@ denotes corporate, 2@@@ denotes transmission, 3@@@ denotes distribution and 4@@@ denotes system management.'* The RFS operating expenditure categories each comprise of a number of general ledger accounts, which are further comprised of a number of sub-ledgers. We have selected our operating expenditure transactions from the sub-ledger level. For those transactions allocated on the 'direct' basis we have assessed whether their account coding is consistent with the CRAM. For those transactions allocated on the 'indirect' basis we have discussed with management (Senior Business Analyst, BP&A Branch) or reviewed documentation to ascertain the nature of the expenditure item and consequently the rationale for the transaction's business segment allocation. The sample selected and reviewed is documented on the following page.

The sample selected and reviewed is shown below:

Expenditure category and $ (as disclosed in the RFS)	**Chart of accounts description and account code**	**$ and RFS business segment**	**Period of transactio n**	**Type of allocatio n**	**Account coding agreed to CRAM**
Operations $125,443,000	Mats-Elect Wire, Light & Pwr Distn Equip (633310001000359)	$84,628 (unregulated)	July 2011	Direct	Yes
Maintenance $253,213,000	Contractors – Operational (602520613000415)	$866,370 (distribution)	September 2011	Direct	Yes
Customer service and billing $50,053,000	Int Charge Exp Indirect - Total Cost (946343203000956)	$10,395 (distribution)	November 2011	Direct	Yes
Corporate $91,131,000	BIT Software Support (145065481000)	$3,790 (transmission $1,182, distribution $2,583, and unregulated $24)	February 2012	Indirect	Yes , 1
Other operating expenditure $258,539,000	Contractors – Computing (815071524000413)	$25,531 (IMO)	April 2012	Direct	Yes

Notes:

1. This transaction relates to corporate services and has been allocated to the transmission, distribution and unregulated business segments within the RFS on the FTE basis. This is consistent with the CRAM.

4	***Procedure:*** *Randomly select five transactions disclosed in the 30 June 2012 RFS capital expenditure account, and agree the business segment allocations to the CRAM.*
	Findings: The CRAM, Appendix C Capital Expenditure Reporting Structure, details the methodology for the allocation of capital expenditure. The methods applied include allocation based on property plant and equipment and direct allocation (i.e. account code). We note that the CRAM provides the following information regarding the allocation under the 'Direct' method where account codes are assigned to projects: *'Asset segment: comprises the third group of four characters of the cost centre code. The characters are numeric and are used to identify the business segment for which the transaction relates, i.e. 1@@@ denotes corporate, 2@@@ denotes transmission, 3@@@ denotes distribution and 4@@@ denotes system management.'* The RFS capital expenditure categories each comprise of a number of accounts, which are further comprised of a number of sub-accounts. We have selected our capital expenditure transactions from the sub-account level. For those transactions allocated on the 'direct' basis we have assessed whether their account coding is consistent with the CRAM. For those transactions allocated on the 'indirect' basis we have discussed with management (Business Analyst - BP&A Branch) or reviewed documentation to ascertain the nature of the expenditure item and consequently the rationale for the transaction's business segment allocation. The sample selected and reviewed is documented on the following page.

The sample selected and reviewed is shown below:

Capital expenditure category and $ (as disclosed in the RFS)	Chart of accounts description and asset segment code	$ and RFS business segment	Period of transaction	Type of allocation	Account coding agreed to CRAM
Asset replacement $203,774,000	Construction asset replacement (2000)	$3,648 (transmission)	June 2012	Direct	Yes
Customer driven $230,635,000	Construction customer access (2000)	$703 (transmission)	February 2012	Direct	Yes
Metering $14,032,000	Asset purchases meters low value pool (3000)	$440 (distribution)	May 2012	Direct	Yes
State Underground Power Project (SUPP) $33,261,000	Construction cables - underground (3000)	$193,207 (distribution)	June 2012	Direct	Yes
Mobile plant and vehicles $33,472,000	Asset purchases plant (1000)	$42,480 (unregulated)	May 2012	Direct	Yes

5

Procedure:

Agree the allocation of Depreciation and amortisation, Bad debts, Borrowing costs and Book value on sale of assets as disclosed in the 30 June 2012 RFS Profit and Loss account to the CRAM.

Findings:

The allocation as per the CRAM is as follows (as extracted from Appendix A, Table 6 of the CRAM):

Other Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Depreciation and Amortisation	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Bad Debts	Network Services Revenue	Network Services Revenue	n/a	Network Services Revenue
Borrowing Costs	PPE	PPE	n/a	PPE
Book Value on Disposal of Fixed Assets	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct

We have reviewed the allocation methodology applied for each of the Other Expenditure categories. The allocation methodology applied is consistent with the CRAM. The procedures applied included:

- Review of management allocation work papers.
- Re-performed and checked the allocation calculation for those categories that were based on a ratio calculation.

Other Expenditure	CRAM allocation method applied
Depreciation and Amortisation	Yes
Bad Debts	Yes
Borrowing Costs	Yes
Book Value on Disposal of Fixed Assets	Yes

6	***Procedure:*** *Agree the allocation of cash flows for operating activities, investing activities and financing activities as disclosed in the 30 June 2012 RFS Cash flow statement to the CRAM.*
	Findings: Each cash flow item above comprises many activities. We have reviewed the allocation methodology applied to each account. The allocation methodologies applied reflect the causal relationship in line with the nature of the balance and hence are in accordance with the CRAM. We have re-performed and checked the allocations for all activities that have been based on ratio calculation and note no exceptions.

7	***Procedure:*** *Agree the allocation of assets and liabilities as disclosed in the 30 June 2012 RFS Balance Sheet to the CRAM.*

Findings:

Appendix B of the CRAM stipulates the following methodology for asset and liability allocation:

Current Assets	Transmission	Distribution	IMO-related System Management	Unregulated
Cash and Cash Equivalents	PPE	PPE	n/a	n/a
Trade and Other Receivables (excl. Open Access/NetCIS Trade & Other receivables, & Provision for Doubtful Debts)	Direct & then PPE for remaining	Direct & then PPE for remaining	n/a	n/a
Trade and Other Receivables: Open Access/NetCIS Trade Receivables	Accrued Revenue	Accrued Revenue	n/a	n/a
Trade and Other Receivables: Other Receivables & Provision for Doubtful Debts	Direct & then Network Services Revenue for remaining	Direct & then Network Services Revenue for remaining	Direct	Direct & then Network Services Revenue for remaining
Prepayments	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Accrued Revenue	Direct & then Accrued Revenue for remaining	Direct & then Accrued Revenue for remaining	n/a	n/a
Inventories	Direct (per internal issues)	Direct (per internal issues)	n/a	Direct (per external sales)

Non-Current Assets	Transmission	Distribution	IMO-related System Management	Unregulated
Property, Plant and Equipment, Intangibles	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Trade and Other Receivables	PPE	PPE	Direct	Direct

	Transmission	Distribution	IMO-related	Unregulated

Current Liabilities			System Management	
Trade Creditors and Accruals (excluding Employee Related)	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Trade Creditors and Accruals: Employee Related	FTE	FTE	FTE	FTE
Deferred Income	Direct	Direct	n/a	n/a
Provisions (excl. Dividends)	Direct & then FTE/PPE for remaining	Direct & then FTE/PPE for remaining	Direct & then FTE for remaining	Direct & then FTE for remaining
Provisions: Dividends	Profit after taxation	Profit after taxation	n/a	n/a

Non Current Liabilities	Transmission	Distribution	IMO-related System Management	Unregulated
Borrowings	Net assets (before borrowings)	Net assets (before borrowings)	n/a	Net assets (before borrowings)
Retirement Benefit Obligations	Direct & then FTE	Direct & then FTE	n/a	n/a
Trade Creditors and Accruals	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Deferred Income	Direct	Direct	n/a	n/a
Provisions	Direct & then FTE/PPE for remaining	Direct & then FTE/PPE for remaining	Direct & then FTE for remaining	Direct & then FTE for remaining

We have reviewed each of the asset and liability allocations and compared the allocation to the CRAM. The allocation methodology applied is consistent with the CRAM.

8	***Procedure:*** *Randomly select two regulatory adjustments as disclosed in the 30 June 2012 RFS and agree supporting documentation and/or underlying methodology and calculations.*
	Findings: We have randomly selected the adjustment in respect to developer/customer contributions and the adjustment in respect of the treatment of capitalised borrowing costs. We note these adjustments are required in accordance with the guidelines for the access arrangement. The basis for these adjustments are outlined below: (i) Developer contributions: The base accounts include developer contributions as revenue when assets are energised; however the guidelines for the access arrangement require revenue to be recognised with respect to developer contributions when received. (ii) Borrowing costs: The base accounts include capitalised borrowing costs; however the guidelines for the access arrangement require all borrowing costs to be expensed. As part of our procedures we have reviewed the adjustments included within the RFS for each of these areas and note they are consistent with the access arrangement guidelines. It is noted additional adjustments have been made. As these have not been selected for testing we have understood the rationale for these adjustments and reviewed management support only. The adjustments can be seen in the RFS 12.3 – 12.6.

9	***Procedure:*** *Check the mathematical accuracy and perform an internal cross reference check of the balances disclosed within the 30 June 212 RFS.*
	Findings: We have checked the mathematical accuracy by recalculation and have reviewed the internal consistency of the 30 June 2012 Regulatory Financial Statements.

Cost & Revenue Allocation Method 2011/12

westernpower

July 2012

Document control

Author / custodianship

Author:	Noel Ryan, Amanda Brennan and Kym Lilleyman
Process owner / custodian:	1. Daniel Kennedy, Manager, Business Planning & Analysis 2. Sally McMahon, Manager, Access Arrangement Development

Stakeholders

In the process of document update, the following people must be consulted:

Name	Position / title
Business Planning & Reporting Manager	Business Planning & Analysis Branch
Group Accountant	Corporate Accounting & Taxation Branch
Revenue & Pricing Manager	Access Arrangement Development Branch

Distribution list

When this document is updated, the following people must receive a copy of the updated version:

Name	Position / title
Branch Manager	Business Planning & Analysis Branch
Branch Manager	Work Program Finance Branch
Branch Manager	Corporate Accounting & Taxation Branch
Branch Manager	Access Arrangement Development Branch

Document version history

Version	Date	Details
1	Sept 2011	Original version
9	July 2012	Final Version

Related / referenced documents

Document title	Document ID (DM #)
Guidelines for Access Arrangement Information (6 December 2010)	http://www.erawa.com.au
Chart of Accounts	DM#: 8230049
Indirect Cost Allocation Guidelines	DM#: 4495224
Contributions Policy	DM#: 5012829

Review and authorisation

Internal review of the CRAM is undertaken on an annual basis in preparation for the production of the June year-end regulatory financial statements. Internal review includes members of the Business Planning & Analysis Branch (Finance), Work Program Finance Branch (Finance), Corporate Accounting & Taxation Branch (Finance) and Access Arrangement Development Branch (Regulatory).

Approval and sign-off by Branch Managers of the Business Planning & Analysis Branch (BPA) and Access Arrangement Development Branch (AAD) is required to finalise the CRAM.

Name	Role	Document	Date authorised	Next review date
Daniel Kennedy	Branch Manager, Business Planning & Analysis	V9	24/7/12	August 2013
Noel Ryan for Sally McMahon	Project Director, Access	V9	24/07/12	August 2013

Table of contents

1 Background

Western Power is a regulated transmission and distribution network business supplying electricity to Western Australian homes and businesses. We are the owner and operator of the Western Power Network (WPN) situated in the south west of Western Australia.

We manage the poles, wires, substations and other infrastructure to deliver electricity from generators to the homes and businesses in the WPN. We are independent of the competing generation and retail segments of the electricity supply chain. Access is provided to all market participants on the network in an equitable and transparent fashion.

Our key business responsibilities are to:

- Manage the development, operation and system management of the transmission and distribution networks in the WPN
- Operate on a sound commercial basis
- Provide even-handed network access for all applicants
- Meet and deliver the levels of network performance prescribed by external regulatory bodies
- Carry out the above responsibilities safely in accordance with safety and environmental legislation.

We also undertake unregulated services such as external sales (supply chain materials), external information technology and fleet services, private vegetation management, external power training services, external underground pillar to customer meter work and employee rental property services.

To meet our responsibilities, we must balance the requirements to operate commercially and meet regulatory, government and community expectations for reliability of supply. We report regularly to the market regulators and operators. Our operations are guided by legislation, regulations and codes. These cover almost every aspect of our operation, from performance targets and revenue control to the disposal of waste and the safety of employees and the public.

We are regulated by:

- Economic Regulation Authority (ERA) - an independent body reporting directly to the Western Australian parliament. The ERA regulates us to ensure the delivery of an efficient service at a fair price. This includes approving our Access Arrangement (AA). The 'Electricity Network Access Code 2004' (the Access Code) defines and describes our AA in respect of:
    - Network revenue projections and access tariffs, service standards and the supporting capital and operating investment required to meet these standards
    - The terms and conditions in which users (typically generators and retailers) can obtain access to our network.
- Public Utilities Office - a government office within Western Australia's Department of Finance which guides energy policy in Western Australia.
- Energy*Safety* - part of Western Australia's Department of Consumer Protection. Energy*Safety* licenses electrical contractors and sets technical guidelines for our network in relation to safety.
- Independent Market Operator (IMO) - an independent organisation funded by industry. The IMO controls the supply and trading of energy and electricity capacity in Western Australia's wholesale electricity market (WEM). A system management function exists as a ring-fenced business segment within our business. The objective of this segment is to ensure sufficient

generation capacity, system integrity and configuration to meet the predicted load, and to provide centralised control and access to the network.

2 Purpose and scope of this document

We are regulated by the ERA in accordance with the Access Code. Under the Access Code, we must develop and adhere to an AA that defines the terms and conditions under which users may access our network. The ERA ensures that the AA complies with Access Code requirements and approves revenue and the resulting network tariffs for the regulatory period. The Access Code is supplemented by the 'Guidelines for access arrangement information 2010' (the Guidelines)[1].

Clause 3.5 of the Guidelines details the information requirements regarding the cost allocation applied in preparing the annual regulatory financial statements. We apply the cost allocation methods within this Cost and Revenue Allocation Method (CRAM) to prepare our regulatory financial statements for the ERA in accordance with the Access Code.

2.1 Purpose

The purpose of this document is to present and explain the methods we adopt to allocate costs and revenues to our regulated and unregulated business segments as reported in our regulatory financial statements.

This CRAM sets out:

- The method of cost and revenue allocation applied in preparing our regulatory financial statements (submitted annually to the ERA)
- How we record costs and revenues in Ellipse 6.3.

2.2 Scope

This CRAM provides details on the allocation of:

- costs (refer section 6)
- revenue (refer section 7)
- other regulatory financial statement allocations and adjustments (refer section 8)

between the following business segments and services:

- transmission
- distribution
- IMO-related system management
- unregulated.

[1] Refer to http://www.erawa.com.au/.

3 Responsibilities for implementation and compliance

3.1 Role responsibility

We apply the principles of this CRAM in preparing our annual regulatory financial statements. The statutory financial statements (base accounts) are used as the foundation for this. The CRAM is the instrument applied to derive the regulatory financial statements from the statutory financial statements.

We engage external auditors to audit and review our statutory and regulatory financial statements respectively, including internal controls. The ERA may require a further audit of the regulatory financial statements in accordance with clause 2.7 of the Guidelines.

The information below sets out the relevant responsibilities within our business to ensure the internal monitoring, reporting and application of the CRAM is conducted on an ongoing basis.

3.1.1 Western Power management

- Approve the CRAM.
- Certify that the regulatory financial statements have been prepared in accordance with the CRAM.

3.1.2 Corporate Accounting & Taxation Branch, Work Program Finance Branch and Business Planning & Analysis Branch (finance branches)

- Ensure compliance with the CRAM.
- Prepare regulatory financial statements and develop supporting working papers in accordance with the CRAM.
- Update the CRAM to ensure that our allocation methods appropriately reflect those used in the production of our regulatory financial statements.
- Report on the consistency of the works program with the CRAM

3.1.3 Access Arrangement Development Branch (regulatory branch)

- Advise key stakeholders of changes to the Guidelines and AA which impact the CRAM.
- Support the finance branches in the decisions and implementation of any changes required to account structures, to ensure (or advise on) compliance with the regulatory framework.

3.1.4 All staff

Attribute direct costs and revenue to the transmission, distribution, IMO-related system management and unregulated business segments in accordance with the CRAM using the correct coding on timesheets (labour), account codes, projects and/or work orders.

3.2 Compliance

We monitor the application of the CRAM for accuracy and completeness to ensure that the annual regulatory financial statements reflect the CRAM. An internal review of the CRAM takes place annually in preparation for the production of the June year-end regulatory financial statements.

The internal review is undertaken by members of the Business Planning & Analysis Branch (Finance), Work Program Finance Branch (Finance), Corporate Accounting & Taxation Branch (Finance) and Access Arrangement Development Branch (Regulatory). Members of the four branches meet to discuss the outcomes and any issues involved in the production of the regulatory financial statements. The performance and operation of the CRAM is reviewed through this process.

Approval and sign-off by Branch Managers of the Business Planning & Analysis Branch and Access Arrangement Development Branch is required to finalise the CRAM.

4 Organisation structure and services

We are a Government Trading Enterprise (GTE) operating under the *Electricity Corporations Act 2005*. This means that we:

- Are ultimately accountable to the state government (via the Minister for Energy) as our owner and sole shareholder
- Operate as a corporatised enterprise with the autonomy to make decisions regarding the management and operation of the WPN.

4.1 Corporate structure

Western Power's divisional structure is presented below. There have been no significant changes from 2011.

- Managing Director / (Acting) CEO
- Networks
- System Management (non-IMO related)
    - IMO-related system management (ring fenced)
- Regulation & Sustainability
- Finance (in 2012 the Strategy Branch moved to the Enterprise Solutions Partner Division)
- Operations (including separate groups for Transmission, Distribution and Customer Service)
- Corporate Services
- Enterprise Solutions Partner
- Legal & Governance

- Categories of service

  Our services fall into one of five categories from a regulatory perspective. These are network access, miscellaneous services, capital works, ring-fenced services (IMO-related system management) and unregulated services. Our categories of service are illustrated in Figure 4.1.

Figure 4.1 Western Power's categories of service

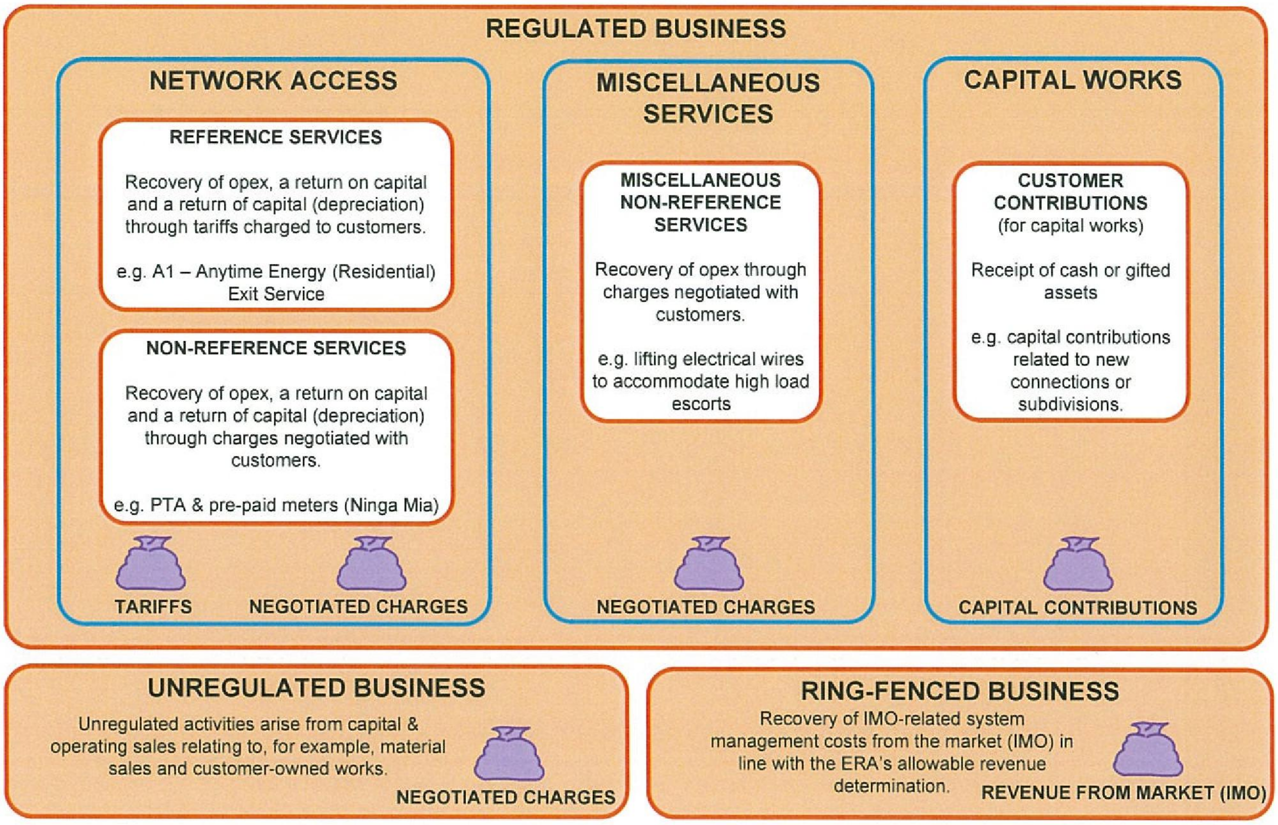

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Table 4.1 identifies the customer types that utilise our services.

Table 4.1 Services provided to customers

Regulated/ Unregulated	Category of service	Type of customers to utilise service
Regulated	Network access: 1. Reference services 2. Non-reference services	Residential and business transmission and distribution customers
	Miscellaneous non-reference services	
	Capital works	
Unregulated	Unregulated services	
Regulated and ring-fenced	IMO-related system management (ring-fenced services)	IMO (service provided to facilitate control, access and sufficiency of generation and the network)

5 Business segments

The Guidelines require that we disaggregate financial information into the following business segments[2]:

- Covered (regulated) transmission services
- Covered (regulated) distribution services
- IMO-related system management (regulated and ring-fenced)
- Unregulated (ring-fenced) services.

This section provides an overview of the categories of services provided by these business segments.

5.1 Reference services

Reference services are provided to generators and retailers in accordance with the terms and conditions of the electricity transfer access contract and are subject to revenue regulation by the ERA.

We currently offer the following reference services:

- Two entry services (transmission entry service and distribution entry service)
- 11 exit services
- One bi-directional service.

5.2 Non-reference services

Non-reference services are categorised into:

- Non-reference services that relate to network access
- 'Miscellaneous' non-reference services that relate to the transportation of electricity by means of a covered (regulated) network.

Non-reference service charges sit outside the ERA's regulated revenue cap. The commercial terms and conditions for non-reference service charges are negotiated between the parties. The Access Code objectives require that these charges be reasonable and negotiated in good faith.

We currently provide:

- Non-reference network access services to the Public Transport Authority and Ninga Mia[3] (via pre-paid meters)
- A suite of 'miscellaneous' non-reference services charged to the initiating customer, including customer requested services. These services are restricted to operating expenditure services (e.g. extended metering services and the lifting of electrical wires to transport high loads down freeways and highways) and exclude work that is capitalised.

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[2] There are currently no excluded transmission or distribution services in our AA.

[3] Ninga Mia is an aboriginal community near Kalgoorlie with a direct retail arrangement with each premise through the installation of pre-payment meters that allow households to manage their electricity consumption individually.

5.3 IMO-related system management (ring-fenced)

IMO-related system management was established under the WEM rules and is a ring-fenced business segment within our business. Under the WEM rules, IMO-related system management is responsible for ensuring that the power system is operated in a safe, secure and reliable manner through the operation and control of generator facilities, transmission and distribution networks, and large customer retailer supply management including demand side management.

IMO-related system management has a central role in the scheduling of generator and transmission outages, and manages the real-time operation of the network. In order to fulfill this obligation, IMO-related system management controls key technical characteristics of the network such as frequency and voltage through ancillary services.

The ERA determines IMO-related system management expenditure through an allowable revenue determination. Indirect (shared) business support costs are identified, allocated and ring-fenced to IMO-related system management in accordance with this CRAM. These costs are identified and allocated only once. This allocation is consistent with the methodology applied by the ERA in its allowable revenue determination. These costs are fully recovered through IMO-related system management revenue.

5.4 Unregulated services (ring-fenced)

We are not obliged to provide unregulated services because they are capable of being provided on a contestable basis by a range of suppliers. The prices we charge are not regulated by means of our AA as a result. The commercial terms and conditions for unregulated services are negotiated between the parties.

Examples of the unregulated services we provide include the:

- External sale/salvage of supply chain (including undergrounding) materials
- Provision of external information technology and fleet services
- Provision of private vegetation management
- Provision of external power training services
- Provision of external undergrounding 'pillar to customer meter' work.

We identify, allocate and ring-fence the costs associated with unregulated services in accordance with this CRAM.

6 Cost allocation

Costs are allocated to the transmission, distribution, IMO-related system management and unregulated business segments in accordance with the Guidelines.

We broadly categorise the allocation of costs into one of three categories:

- Direct (attributable) costs (refer section 6.5)
- Indirect (allocatable) costs that relate to our approved works program (AWP) (refer section 6.6)
- Corporate (allocatable) costs that relate to business support and other services (refer section 6.7).

This section provides an overview of our cost allocation method.

6.1 Principles and compliance with Guidelines

Clause 3.5 of the Guidelines requires that costs are allocated based on the following principles.

- Items that are directly attributable to a business component are attributed accordingly.
- Items that are not directly attributable to a business component are to be allocated, where practicable, on a causation basis.
- Items that are not directly attributable and cannot be practicably allocated on a causation basis shall be allocated by a method determined by the service provider. In such cases, we must include a supporting note for each item allocated indicating:
    - The basis for allocation
    - The reason for choosing that basis
    - An explanation for why no causal relationship could be established.

6.2 Application of principles

In support of the above, we commit to the following principles:

- A cost will not be attributed and/or allocated more than once.
- A direct cost will only be attributed to one category of service.
- An indirect cost will only be allocated once between business segments.
- The same cost will not be treated as both a direct and an indirect cost.
- The same cost will only be recovered once through tariffs and charges.
- Unregulated costs will be allocated to the unregulated business segment and will be ring-fenced from the recovery of costs through regulated services.
- The allocation of costs will be determined by the substance of the transaction or event rather than the legal form.
- An avoided cost allocation method (or any other method of allocation not specifically referred to within this CRAM) is not currently applied to allocate costs or revenues.

6.3 Cost categories

For cost allocation purposes, we use three categories:

- Direct costs, where the underlying transaction can be directly identified and attributed to a business service. (Refer section 6.5).
- Indirect costs that do not a have direct means of attribution but relate to our AWP. These costs are allocated using the indirect cost allocation method. The use of this method applies to the allocation of costs which have a network or operational service. The allocation of costs across the AWP attributes costs to both regulated and unregulated services. (Refer section 6.6).
- Corporate costs that do not have a direct means of attribution and relate to a business support service or other cost category. These costs are allocated using a method that most appropriately reflects the corporate cost's causal correlation with the underlying transaction. Full time staff equivalents (FTE), property, plant and equipment and intangibles (PPE) and land and buildings (L&B) are the common allocation methods we apply. The allocation of costs using these methods attributes costs to both regulated and unregulated services. (Refer section 6.7).

The remainder of this section explains these cost categories and their methods of allocation in more detail. Readers should refer to Appendix A for a line item description of each cost and the allocation method applied.

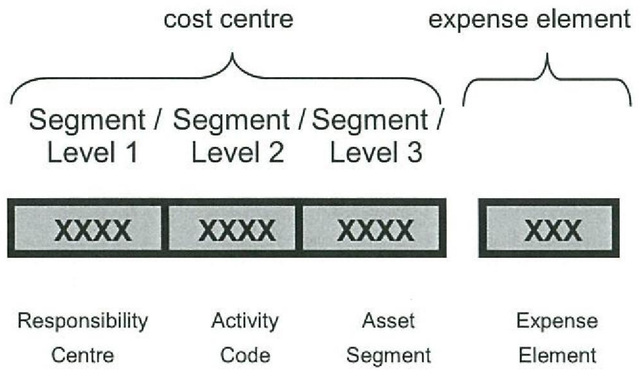
6.4 Western Power's account code structure

All costs are recorded using our financial system via the account code structure[4]. The account code structure enables the production of management, statutory and regulatory reports.

The account code structure comprises 15 characters made up of a 12 character cost centre (refer section 6.5.1) and a three character expense element (refer section 6.5.2). Costs and revenues are differentiated through the use of expense elements for account code reporting.

Figure 6.4 outlines the composition of the account code structure.

Figure 6.4 Western Power's account code structure



[4] DM#: 8230049 provides our account codes with a listing of cost centre segments and expense elements.

6.5 Direct costs (attribution through account code structure)

Our account code structure is used to attribute direct costs (and revenues) within the financial system. Direct costs are primarily comprised of materials, services and labour costs. These costs are booked to an account code (typically using a project and/or work order) to identify and directly attribute their value to a specific service within one of the transmission, distribution, IMO-related system management or unregulated business segments.

6.5.1 Cost centre

A cost centre is assigned to every project and work order. The three segments of the cost centre are explained as follows:

- Responsibility centre: comprises the first group of four characters of the account code. The characters are numeric and are used to identify the various areas within, and/or services offered.
- Activity code: comprises the second group of four characters of the cost centre code. The characters are numeric and are used to identify the service being carried out, e.g. 1@@@ denotes external work, 2@@@ denotes operating work and 3@@@ denotes capital work.
- Asset segment: comprises the third group of four characters of the cost centre code. The characters are numeric and are used to identify the business segment for which the transaction relates, i.e. 1@@@ denotes corporate, 2@@@ denotes transmission, 3@@@ denotes distribution and 4@@@ denotes system management.

6.5.2 Expense element

An expense element is assigned to a cost centre (via a project and/or work order) to form a complete account code when a transaction is recorded within our financial system. The expense element comprises the last three characters of the account code. The characters are numeric and are used to identify the nature of the cost or revenue incurred.

Costs relating to regulated and unregulated services are identified and allocated using the activity code, asset segment and/or expense element of the underlying transaction's account code (via a project and/or work order for example). Unregulated costs are ring-fenced from our other business segments.

6.6 Indirect approved works program costs (allocation through the indirect cost allocation method)

The indirect costs incurred in our network and operational areas (such as training and travel costs and non-timesheet labour) cannot be directly attributed to specific services within the AWP. Instead, these costs are identified in an 'indirect cost pool' and allocated across the AWP, using our indirect cost allocation method.

The AWP is a complete schedule of the operational and capital works that we undertake during a financial year on the construction, operation and maintenance of our network. It includes the construction of new assets, maintenance of existing assets, connecting new customers and enhancing power supply. The AWP includes both regulated and unregulated services.

The indirect cost allocation method allocates the costs within the 'indirect cost pool' to the AWP through two steps. The first step involves allocating the labour related indirect costs using a 'labour time' recovery rate for every internal labour hour charged to a specific service.

The second step allocates the remaining non-labour related indirect costs proportionally across the AWP based on the direct costs incurred by each specific service. The proportional rate at which this occurs (the indirect cost recovery rate) is calculated annually during the budget process and is monitored on a monthly basis to review actual recovery against the works program. Quarterly adjustments are made if the actual recovery of costs through the indirect cost allocation method varies from the actual indirect overheads incurred.

The rationale for this allocation is that the amount of indirect costs incurred by a specific service in the networks and operational areas is likely to be related to the amount of direct costs incurred by the service. This indirect cost allocation method does not differentiate in the method of allocation across capital and operating expenditures. It capitalises the indirect costs that are allocated to capital projects, while the indirect costs allocated to the maintenance program are charged to the profit and loss account (and so treated as operational expenditure).

This allocation method allows us to allocate the indirect costs from our network and operational services to specific works in the AWP. The allocation across the whole AWP ensures a transparent method of allocating indirect costs. This ensures that projects and programs in the AWP receive both the allocation of their direct costs and a fair portion of related indirect costs. The application of the method achieves:

- Standardised cost allocation rules and a consistent allocation of non-attributable indirect costs
- Accountability for the allocation of costs and sensible and relevant cost allocation.

Further information on how indirect network and operational costs are allocated can be found in the document titled *Internal Cost Allocation Guidelines*[5].

6.7 Corporate and other costs (allocation methods)

Our *corporate* (business support) costs include common or shared services that support all parts of the business including the transmission, distribution, IMO-related system management and unregulated business segments, but are not directly or indirectly attributed/allocated to the AWP.

Our *other* costs include depreciation and amortisation, bad debts, borrowing costs, the book value on the disposal of fixed assets, taxation as reported in the profit and loss account and capital expenditure that is not yet issued to a service, e.g. strategic spares.

We allocate corporate and other costs to the transmission, distribution, IMO-related system management and unregulated business segments using a method that most appropriately reflects the causal correlation of the underlying transaction. FTE, PPE and L&B are the common allocation methods applied to allocate these costs, where a direct means of attribution is not available. These allocation methods are explained as follows:

- FTE is determined by the ratio of FTE within a business segment (i.e. transmission, distribution, IMO-related system management or unregulated) to total business FTE. Allocation on a FTE basis is applied when the underlying transaction has a causal correlation to the consumption of staff/labour.
- PPE is determined by the ratio of PPE in the transmission and distribution asset segments to the total transmission and distribution PPE. Allocation on a PPE basis is applied when the underlying transaction has a causal correlation to our principal responsibilities of:

[5] Refer to: DM#: 4495224 for Western Power's *Internal Cost Allocation Guidelines.*

- Managing the network of poles, wires, substations and other infrastructure
- Delivering electricity from power generation plants to homes and businesses.

- L&B is determined by the ratio of L&B in the transmission and distribution asset segments to the total transmission and distribution L&B. Allocation on a L&B basis is applied when the underlying transaction has a causal correlation to our ownership of land and buildings.

7 Revenue allocation

We allocate revenue to the transmission, distribution, IMO-related system management and unregulated business segments using a similar method to the allocation of costs (refer section 6.3).

Our revenue is categorised into one of two categories:

- Direct revenue (refer section 7.1)
- Indirect revenue (refer section 7.2).

This section provides an overview of our revenue allocation method.

7.1 Direct revenue

Our account code structure (via a project and/or work order) is used to identify and attribute direct revenue within the financial system. This is in the same manner as direct costs are identified and attributed (refer section 6.5).

The following revenue is directly attributed:

- **Reference services:** Reference services generate covered transmission and distribution network access revenue. This revenue is directly attributed via the activity code (nature of service), asset segment (business segment) and expense element (revenue) of the underlying transaction's account code.
- **Non-reference services:** Non-reference services generate revenue from external works, extended metering services and high load escorts. This revenue is directly attributed via the activity code (nature of service), asset segment (business segment) and/or expense element (revenue) of the underlying transaction's account code and/or project.

  We allocate indirect non-reference services to the transmission, distribution, IMO-related system management and unregulated business segments using a method that most appropriately reflects the causal correlation of the underlying transaction. FTE and PPE are the common allocation methods applied for this purpose where a direct attribution is not available (refer section 6.7).

- **Capital contributions:** Capital works may result in our receipt of capital contributions. A capital contribution is a payment or provision in kind (gifted assets) made, or to be made, by a user in respect of any new facilities investment (or forecast new facilities investment) in required work.

  Capital contributions are calculated in accordance with our contributions policy and are approved by the ERA through our AA. Capital contributions are to be reasonable and negotiated in good faith in line with the Access Code objectives[6].

  Capital contributions received from developers and customers are recognised as revenue by the standards set by the Australian Accounting Standards Board (AASB) (refer section 8.3.1). These contributions are identified via the capital activity code (nature of service), asset segment (business segment) and/or expense element (revenue) of the underlying transaction's account code. The regulatory category is either:

  1. Directly attributed via the parent capital project underlying the contribution
  2. Indirectly allocated using the method that most appropriately reflects the causal correlation of the contribution, i.e. capital expenditure category for distribution.

[6] Refer to DM#: 5012829 for Western Power's *Contributions Policy*.

Where capital contributions have been received for cancelled projects the contributions are subsequently recognised as non-reference service revenue. This is to match the expenditure which is recognised in the profit and loss account.

- **Unregulated revenue:** Unregulated revenue is primarily generated from external sales (supply chain materials), external information technology and fleet services, private vegetation management, external power training services and external underground pillar to customer meter work. This revenue is identified and directly attributed via the activity code (nature of service), asset segment (business segment) and/or expense element (revenue) of the underlying transaction's account code. This revenue is ring-fenced from our regulated revenue.
- **IMO-related system management revenue:** IMO-related system management revenue is identified via the responsibility centre (System Operations - System Management Market), asset segment (business segment) and expense element (revenue) of the underlying transaction's account code. The IMO-related system management portion is ring-fenced from our other business segments.
- **Proceeds from the disposal of fixed assets:** Proceeds generated from the disposal of fixed assets are identified and recorded in the fixed asset register. The asset segment (business segment), expense element (revenue) and asset profile (regulated) of the underlying transaction's account code/asset is used to identify and directly attribute these proceeds. Where the asset segment and/or asset profile relates to a regulated Corporate fixed asset (such as information technology) the proceeds are indirect and allocated accordingly (refer section 7.2).

7.2 Indirect revenue

Our indirect revenue includes the proceeds from the disposal of regulated Corporate fixed assets (such as information technology), and other revenue. Other revenue includes interest and rent received (including unregulated employee rental property services), and is identified via the activity code (nature of service), asset segment (business segment) and/or expense element (revenue) of the underlying transaction's account code.

We allocate indirect revenue to the transmission, distribution, IMO-related system management and unregulated business segments using a method that most appropriately reflects the causal correlation of the underlying transaction. PPE (for interest received) and L&B (for rent received) are the allocation methods used where a direct attribution is not available (refer section 6.7).

8 Other regulatory financial statement allocations and adjustments

This section provides an overview of our balance sheet and cash flow allocation methods.

8.1 Balance sheet

We allocate assets and liabilities to the transmission, distribution, IMO-related system management and unregulated business segments based on the substance (and not the legal form) of the underlying transactions. This is typically identified via the corresponding operating and capital transactions, and subsequently attributed/allocated consistent with the related cost and revenue allocation methods (refer sections 6 and 7 respectively).

Assets and liabilities that cannot be directly attributed to the transmission, distribution, IMO-related system management and unregulated business segments (such as integrated/consolidated taxation, receivables, creditors and borrowings), are allocated using the method that most appropriately reflects the causal correlation with the underlying transaction. FTE and PPE are the common allocation methods applied for this purpose where a direct attribution is not available (refer section 6.7).

Readers should refer to Appendix B for a line item description of each asset and liability and the method of allocation applied.

8.2 Cash flow statement

Our cash transactions are recorded collectively in a single bank/general ledger account. For the production of the regulatory cash flow statement, these transactions are allocated to the transmission, distribution, IMO-related system management and unregulated business segments using the method that most appropriately reflects a causal correlation with the underlying transaction. This is typically identified by the corresponding profit and loss, and balance sheet transactions, and allocated consistent with the related cost, revenue and balance sheet allocation methods (refer sections 6, 7 and 8.1 respectively).

Cash is only allocated to the transmission and distribution business segments when preparing the regulatory balance sheet. PPE is the allocation method applied for this purpose because a direct attribution is not available (refer section 6.7).

8.3 Regulatory adjustments

When preparing the regulatory financial statements, we adjust the statutory financial statements (base accounts) for differences in:

- Accounting policies - differences between the statutory financial statements and the regulatory accounting policies (refer section 8.3.1)
- Accounting disclosures - differences between the statutory financial statements and the current AA submission (refer section 8.3.2)
- Capital expenditure - differences between the statutory financial statements and the regulated asset base (RAB) (refer section 8.3.3).

Any tax impact associated with the above, using the tax rate enacted at the reporting date, is also adjusted for.

8.3.1 Accounting policy adjustments

Clause 3.6 of the Guidelines requires that we make adjustments to the regulatory financial statements where the accounting policies differ to those in the statutory financial statements.

We currently report accounting policy adjustments for the following.

- **Capital contributions**: all capital contributions received in the reporting period are recognised as revenue in our regulatory profit and loss account. This differs from the treatment applied in the statutory financial statements, where we only recognise capital contributions as revenue when the associated developers and/or customers are connected to the network. Prior to this, such contributions are deferred to the statutory balance sheet. This is per *AASB Interpretation 18 Transfers of Assets from Customers*.

  As a result, adjustments are made to our regulatory financial statements to:

  1. Restate contributions in the regulatory profit and loss account for capital contributions received in the reporting period but which were deferred in the statutory balance sheet[7]

  2. Remove deferred income (for capital contributions only) from the regulatory balance sheet.

- **Borrowing costs**: All borrowing costs are expensed to our regulatory profit and loss account and are excluded from recovery through regulated revenue[8]. This differs from the treatment applied in the statutory financial statements, where we capitalise borrowing costs that are directly attributable to the acquisition, construction or production of qualifying assets[9]. Western Power elects to capitalise borrowing costs in line with *AASB 123 Borrowing Costs*.

  Therefore, adjustments are made to our regulatory financial statements to:

  1. Restate borrowing costs in the regulatory profit and loss account for those capitalised in the statutory financial statements

  2. Remove capitalised borrowing costs from regulated capital additions (per clause 3.8.1 of the Guidelines)

  3. Remove capitalised borrowing costs from property, plant and equipment, and intangibles in the regulatory balance sheet

[7] Transmission capital contributions restated in the regulatory profit and loss account are directly attributed to the regulatory categories via the parent capital projects underlying the contributions. Distribution capital contributions are indirectly allocated to the regulatory categories that most appropriately reflect the causal correlation of the contributions, that is, customer driven or underground cables (for our state underground power projects).

[8] This occurs because our regulated revenue cap already includes a *return on* capital component (calculated as the sum of our regulated asset base multiplied by our weighted average cost of capital).

[9] Qualifying assets are defined as assets that take a substantial period of time to prepare for their intended use.

8.3.2 Accounting disclosure adjustments

We currently report accounting disclosure adjustments for the following:

- **Depreciation:** Unregulated fleet depreciation (along with other fleet operating expenses) is charged through internal Business Unit Charges (BUCs) to our regulated business based on vehicle usage. The use of the BUC mechanism ensures that an appropriate amount is charged to regulated operating expenditure.

  This differs from the treatment applied in the statutory financial statements, where the statutory financial statements report depreciation as a depreciation and amortisation expense, with an offsetting credit in Corporate operating expenditure from the BUC recovery.

  Therefore, an adjustment is made to our regulatory financial statements to reclassify depreciation back to operating expenses to offset this credit. This adjustment eliminates a potential double count of both regulated expenditure charged as BUCs and as fleet depreciation. The adjustment (including the adjustment amount) is authorised by the BPA Manager.

8.3.3 Regulated asset base (RAB) adjustments

Where statutory accounting treatment is inconsistent with RAB treatment, adjustments are made in the regulatory financial statements to reflect these differences. Adjustments are currently made for:

a. <u>Cancelled and deferred projects</u>: Our statutory accounting treatment expenses cancelled and deferred projects where the capital expenditure is unlikely to contribute to an energised asset. However, our regulatory accounting treatment does not automatically follow suit. Our regulatory accounting treatment is to capitalise expenditure on cancelled and deferred projects when it can be demonstrated that our expenditure has met the requirements of the New Facilities Investment Test (NFIT) at section 6.52 of the Access Code.

b. <u>Early planning costs not directly attributable to a project:</u> Our statutory accounting treatment expenses early planning costs that are not directly attributable to a project. However, our regulatory accounting treatment considers that this expenditure has been efficiently incurred in the development and selection of appropriate network options. Given that these costs cannot be directly attributed to a project however, and may benefit both capital and operating activities, our regulatory accounting treatment is to apply these costs based on an indirect cost allocation methodology.

These adjustments (including the adjustment amount) are authorised by the Expenditure and Services Manager of the AAD branch and the Manager Network Planning & Development branch. The register of statutory capital write-offs is maintained by the Senior Business Analyst (Networks) of the Work Program Finance Branch.

9 Maintenance of records

We maintain our accounting records and ensure that our statutory and regulatory financial statements are prepared in accordance with approved accounting standards, legislative requirements and the Guidelines.

Our regulatory financial statements reflect the application of the CRAM. As part of the audit of the statutory and regulatory financial statements, supporting work papers are made available for review by auditors. Each work paper is provided with supporting calculations, where appropriate.

Appendix A: Cost allocation method applied

Clause 3.8.2 of the Guidelines requires that Western Power report at a minimum, within each business segment, the following operating expenditure categories:

- Operations, e.g. reliability, performance, system control
- Maintenance, e.g. corrective and preventative
- Customer service and billing, e.g. call centre and metering (excluding unregulated and extended metering services)
- Corporate, e.g. business support costs
- Other, e.g. tariff equalisation contribution, unregulated external services.

Operational expenditure

Operational expenditure includes the costs associated with the operation of the transmission and distribution networks. It includes reliability improvements, network performance planning and monitoring, system control monitoring and switching, and fault investigations.

Unless otherwise stated below, operational expenditure is attributed directly by business segment based on the activity code and asset segment of the underlying transaction's account code.

Table 1: Operational expenditure allocation

Operational Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Reliability Operations	Direct	Direct	n/a	n/a
SCADA Communications	Direct	Direct	n/a	n/a
Access Applications	Direct	Direct	n/a	n/a
Transmission Line Relocation	Direct	Direct	n/a	n/a
Works in Vicinity	Direct	Direct	n/a	n/a
Other Non-Reference Services (e.g. extended metering services & high load escorts)	Direct	Direct	n/a	n/a
SCADA Services	Direct	Direct	n/a	n/a
Smartgrid (including Perth Solar City)	Direct	Direct	n/a	n/a
Network Operations (System Management excl. IMO-related)	FTE	FTE	n/a	n/a
Unregulated Supply Chain External Materials Sale (excluding obsolete stock)	n/a	n/a	n/a	Direct
State Underground Power Project (SUPP) (*pillar to customer meter* component)	n/a	n/a	n/a	Direct

Maintenance expenditure

Maintenance expenditure refers to the costs associated with maintaining the transmission and distribution networks. It consists of emergency and non-emergency maintenance, including corrective, condition-based and routine maintenance, maintenance project and field support services, and failed/damaged equipment repairs.

Maintenance expenditure is directly attributed by business segment based on the activity code and asset segment of the underlying transaction's account code.

Table 2: Maintenance expenditure allocation

Maintenance Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Corrective Deferred	Direct	Direct	n/a	n/a
Corrective Emergency	Direct	Direct	n/a	n/a
Preventative Condition	Direct	Direct	n/a	n/a
Preventative Routine	Direct	Direct	n/a	n/a

Customer service and billing expenditure

Customer service and billing expenditure includes the costs associated with the ongoing operations of the call centre, and provision of metering (excluding unregulated and extended metering services) and connection related services. It is directly attributed by business segment based on the activity code and asset segment of the underlying transaction's account code.

Table 3: Customer service and billing expenditure allocation

Customer Service & Billing Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Call Centre [1]	Direct	Direct	n/a	n/a
Regulated Metering (excl. extended metering services)	Direct	Direct	n/a	n/a
Cancelled Project Design Costs (distribution customer driven)	Direct	Direct	n/a	n/a
Distributions Quotation & Management	Direct	Direct	n/a	n/a
Guaranteed Service Payment	Direct	Direct	n/a	n/a
Unregulated Power Training Services	n/a	n/a	n/a	Direct

[1] Call centre expenditure is directly attributed to the transmission and distribution business segments because the subject matter of calls are categorised and recorded.

Business support costs (corporate expenditure)

Corporate expenditure is the business support costs associated with the adequate and effective corporate governance of Western Power.

Unless otherwise stated below, business support costs are attributed directly by business segment based on the activity code and asset segment of the underlying transaction's account code.

Table 4: Business support costs allocation

Business Support Costs	Transmission	Distribution	IMO-related System Management	Unregulated
Supply Extension Scheme (SES)/ Contributory Extension Scheme (CES)	Direct	Direct	n/a	n/a
Redundancies [1]	Direct then FTE for remaining	Direct then FTE for remaining	n/a	Direct then FTE for remaining
Unregulated IT External Services	n/a	n/a	n/a	Direct
Unregulated Metering	n/a	n/a	n/a	Direct
Rental Properties Costs	n/a	n/a	n/a	Direct
Chief Executive Officer	FTE	FTE	n/a	FTE
Corporate Services (excl. rates & taxes, rental property costs)	FTE	FTE	n/a	FTE
Enterprise Solutions Partners (ESP)	FTE	FTE	n/a	FTE
Fringe Benefit Tax	FTE	FTE	n/a	FTE
Finance (excl. IT & Commercial allocated via indirect cost allocation method) [2]	PPE	PPE	n/a	FTE
Legal & Governance	PPE	PPE	n/a	FTE
Insurance [2]	PPE	PPE	n/a	FTE
Regulation & Sustainability (excl. Tariff Equalisation Contribution, Energy*Safety* Levy and Environment Mgt)	PPE	PPE	n/a	n/a
Energy Safety Levy	PPE	PPE	n/a	n/a
Admin Fines & Penalties	PPE	PPE	n/a	n/a
Obsolete stock	Inventory	Inventory	n/a	n/a
Rates and Taxes	L&B	L&B	n/a	n/a

[1] Redundancies are allocated in two steps. First, they are allocated to transmission and distribution business segments. Second, the remaining redundancies are indirectly allocated on a FTE basis to the transmission and distribution business segments.

[2] Finance, Legal & Governance, IT Branch and insurance costs are allocated in two steps. First, they are allocated to the unregulated business segments on an FTE basis. Second, the remaining regulated costs are indirectly allocated on a PPE basis to the transmission and distribution business segments.

Other operating expenditure

Other operating expenditure refers to the operational costs that are not associated with operational, maintenance, customer services and billing, and business support costs. It includes the tariff equalisation contribution, unregulated external services (fleet and private vegetation management), service level agreements and IMO-related system management.

Unless otherwise stated below, other operating expenditure is attributed directly by business segment based on the activity code and asset segment of the underlying transaction's account code.

Table 5: Other operating expenditure allocation

Other Operating Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Non Recurring Operating Expenses[1]	Direct	Direct	n/a	n/a
Cancelled Project Costs (internally driven)	Direct	Direct	n/a	n/a
Network Planning Costs	Direct	Direct	n/a	n/a
Investigations	Direct	Direct	n/a	n/a
Tariff Equalisation Contribution	n/a	Direct	n/a	n/a
IMO-related System Management	n/a	n/a	Direct	n/a
Private Vegetation Management	n/a	n/a	n/a	Direct
Unregulated Fleet External Services	n/a	n/a	n/a	Direct
All Other External Services (incl. Service Level Agreements (SLAs))	n/a	n/a	n/a	Direct

[1] Non recurring operating expenses have occurred in 2011/12. These costs include individual projects specified in the AA2 submission as falling in this category, i.e. field information capture project, alternative funding of training, removal of redundant transmission assets and the research and development expenditure for demand side management and energy solutions projects.

Other expenditure

Other expenditure is presented separately in the profit and loss account and includes depreciation and amortisation, bad debts, borrowing costs, the book value on disposed assets and taxation.

Table 6: Other expenditure allocation

Other Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Depreciation and Amortisation[1]	Direct & then PPE for remaining[2]	Direct & then PPE for remaining[2]	Direct	Direct
Bad Debts[3]	Network Services Revenue	Network Services Revenue	n/a	Network Services Revenue
Borrowing Costs	PPE	PPE	n/a	PPE
Book Value on Disposal of Fixed Assets[4]	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Taxation[5]	Earnings before Taxation	Earnings before Taxation	Earnings before Taxation	Earnings before Taxation

1 Depreciation and amortisation are allocated in two steps. First, direct depreciation and amortisation are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining depreciation and amortisation (e.g. capitalised depreciation, regulated Corporate and unregulated fleet depreciation[2]) are indirectly allocated on a PPE basis to the transmission and distribution business segments.

2 Unregulated fleet depreciation is allocated to the transmission and distribution business segments consistent with their disclosure as AWP operating expenditure in Western Power's AA2.

3 Network services revenue is generated from reference, non-reference and unregulated services.

4 Book value on the disposal of fixed assets is allocated in two steps. First, direct disposals are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining disposals (e.g. regulated information technology) are indirectly allocated on a PPE basis to the transmission and distribution business segments.

5 Earnings before taxation refers to profit before tax.

Appendix B: Balance sheet and cash flow allocation methods

Assets and liabilities that cannot be directly attributed to the transmission, distribution, IMO-related system management and unregulated business segments (e.g. integrated/consolidated taxation, receivables, creditors and borrowings) are allocated using the method that most appropriately reflects the causal correlation with the underlying transaction. FTE and PPE are the common allocation methods applied by Western Power for this purpose (refer section 6.7), i.e. where a direct attribution is not available.

Balance sheet - current assets

Current assets include cash and cash equivalents, trade and other receivables, prepayments, accrued revenue and inventories. They are allocated as follows:

Table 7: Current assets allocation

Current Assets	Transmission	Distribution	IMO-related System Management	Unregulated
Cash and Cash Equivalents[1]	PPE	PPE	n/a	n/a
Trade and Other Receivables (excl. Open Access/netCIS Trade & Other Receivables, & Provision for Doubtful Debts)[2]	Direct & then PPE for remaining	Direct & then PPE for remaining	n/a	n/a
Trade and Other Receivables: Open Access/netCIS Trade Receivables[2]	Accrued Revenue	Accrued Revenue	n/a	n/a
Trade and Other Receivables: Other Receivables & Provision for Doubtful Debts[2,3]	Direct & then Network Services Revenue for remaining	Direct & Network Services Revenue for remaining	Direct	Direct & then Network Services Revenue for remaining
Prepayments[4]	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Accrued Revenue[5]	Direct & then Accrued Revenue for remaining	Direct & then Accrued Revenue for remaining	n/a	n/a
Inventories	Direct (per internal issues)	Direct (per internal issues)	n/a	Direct (per external sales)

1 Cash and cash equivalents are recorded collectively within a single bank/general ledger account, and are indirectly allocated on a PPE basis to the transmission and distribution business segments.

2 Trade and other receivables are allocated in two steps. First, direct trade and other receivables are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining trade and other receivables are indirectly allocated on a PPE, accrued revenue or network services revenue basis to the transmission, distribution and unregulated business segments.

3 Network services revenue is generated from reference, non-reference and unregulated services.

4 Prepayments are allocated in two steps. First, direct prepayments are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining prepayments are indirectly allocated on a PPE basis to the transmission and distribution business segments.

5 Accrued revenue is allocated in two steps. First, direct accrued revenue is attributed to the transmission and distribution business segments. Second, the remaining accrued revenue is indirectly allocated on an direct accrued revenue basis to the transmission and distribution business segments.

Balance sheet - non-current assets

Non-current assets include property, plant and equipment, intangibles and trade and other receivables. They are allocated as follows:

Table 8: Non-current assets allocation

Non-Current Assets	Transmission	Distribution	IMO-related System Management	Unregulated
Property, Plant and Equipment, Intangibles[1]	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Trade and Other Receivables	PPE	PPE	Direct	Direct

[1] Property, plant and equipment and intangibles are allocated in two steps. First, direct property, plant and equipment and intangibles are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining property, plant and equipment and intangibles (e.g. regulated system management and Corporate) are indirectly allocated on a PPE basis to the transmission and distribution business segments. (Regulated work in progress is allocated to the transmission and distribution business segments on the assumption that these projects are typically commissioned within 12 months).

Balance sheet - current liabilities

Current liabilities include trade creditors and accruals, deferred income and provisions. They are allocated as follows:

Table 9: Current liabilities allocation

Current Liabilities	Transmission	Distribution	IMO-related System Management	Unregulated
Trade Creditors and Accruals (excl. Employee Related)[1]	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Trade Creditors and Accruals: Employee Related	FTE	FTE	FTE	FTE
Deferred Income	Direct	Direct	n/a	n/a
Provisions (excl. Dividends)[2]	Direct & then FTE/PPE for remaining	Direct & then FTE/PPE for remaining	Direct & then FTE for remaining	Direct & then FTE for remaining
Provisions: Dividends	Profit after taxation	Profit after taxation	n/a	n/a

[1] Trade creditors and accruals (excluding employee related) are allocated in two steps. First, direct trade creditors and accruals are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining trade creditors and accruals are indirectly allocated on a PPE basis to the transmission and distribution business segments.

[2] Provisions (excluding dividends) are allocated in two steps. First, direct provisions are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining provisions such as employee entitlements, environmental costs and rehabilitation site costs are indirectly allocated on a FTE or PPE basis to the transmission, distribution, IMO-related system management and unregulated business segments.

Balance sheet - non-current liabilities

Non-current liabilities include borrowings, retirement benefit obligations, trade creditors and accruals, deferred income and provisions. They are allocated as follows:

Table 10: Non-current liabilities allocation

Non-Current Liabilities	Transmission	Distribution	IMO-related System Management	Unregulated
Borrowings	Net assets (before borrowings)	Net assets (before borrowings)	n/a	Net assets (before borrowings)
Retirement Benefit Obligations[1]	Direct & then FTE	Direct & then FTE	n/a	n/a
Trade Creditors and Accruals[2]	Direct & then PPE for remaining	Direct & then PPE for remaining	Direct	Direct
Deferred Income	Direct	Direct	n/a	n/a
Provisions[3]	Direct & then FTE/PPE for remaining	Direct & then FTE/PPE for remaining	Direct & then FTE for remaining	Direct & then FTE for remaining

[1] Retirement benefit obligations are allocated in two steps. First, direct retirement benefit obligations are attributed to the transmission and distribution business segments. Second, the remaining retirement benefit obligations are indirectly allocated on a FTE basis to the transmission and distribution business segments.

[2] Trade creditors and accruals (excluding employee related) are allocated in two steps. First, direct trade creditors and accruals are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining trade creditors and accruals are indirectly allocated on a PPE basis to the transmission and distribution business segments.

[3] Provisions are allocated in two steps. First, direct provisions are attributed to the transmission, distribution, IMO-related system management and unregulated business segments. Second, the remaining provisions such as employee entitlements, environmental costs and rehabilitation site costs are indirectly allocated on a FTE or PPE basis to the transmission, distribution, IMO-related system management and unregulated business segments.

Appendix C: Capital expenditure reporting structure

Clause 3.8.1 of the Guidelines requires Western Power to report at a minimum, and within each business segment, the following capital expenditure categories:

- Growth: capital expenditure for the purposes of increasing the capacity of assets or construction of new assets to meet growth in demand
- Asset replacement and renewal: capital expenditure for the purposes of replacing assets and maintaining service levels
- Improvement in service: capital expenditure for the purposes of improving service levels and reliability to meet customer preferences
- Compliance: capital expenditure for the purposes of meeting regulatory obligations
- Corporate: capital expenditure for corporate activities.

Western Power's capital expenditure categories by business segment are presented below:

1. Transmission capital expenditure (regulated)

Covered (regulated) transmission includes:

Growth
- Capacity expansion
- Customer driven

Asset replacement and renewal
- Asset replacement

Improvement in service
- Reliability driven
- SCADA/communications

Compliance
- Regulatory compliance

Corporate
- Information technology & market reform
- Administration & support

2. Distribution capital expenditure (regulated)

Covered (regulated) distribution includes:

Growth
- Customer driven
- Capacity expansion
- Gifted assets

Asset replacement and renewal
- Asset replacement
- Metering
- Smartgrid
- State Underground Power Project (SUPP)

Improvement in service
- Reliability driven
- SCADA/communications

Compliance
- Regulatory compliance

Corporate
- Information technology & market reform
- Administration & support

3 Non-approved works program capital expenditure (regulated and unregulated) and IMO-related system management

IMO-related system management and non-AWP capital expenditure includes:

- Mobile plant and vehicles - unregulated
- Information technology - regulated: strategic program of work (SPOW), business tactical and IT infrastructure) and market reform (IMO-related system management)
- Administration and support - regulated and unregulated (fleet).

Unless stated below, capital expenditure is typically attributed directly to the transmission, distribution, IMO-related system management and unregulated business segments based on the activity codes and asset segments of the parent capital projects[10] underlying the transactions:

- The activity code identifies the category associated with the underlying transaction
- The asset segment identifies the business segment associated with the underlying transaction.

The responsibility centre of account codes is also used to directly attribute some capital expenditure to IMO-related system management and non-AWP categories.

Table 12: Non-AWP capital expenditure allocation (regulated) and IMO-related system management

Non-AWP and IMO-related System Management Capital Expenditure	Transmission	Distribution	IMO-related System Management	Unregulated
Corporate Real Estate	PPE	PPE	n/a	n/a
East Perth Control Centre	PPE	PPE	n/a	n/a
Information Technology (SPOW, business tactical (BAU), infrastructure)	PPE	PPE	n/a	n/a
Intellectual Property	Direct & then PPE for remaining	Direct & then PPE for remaining	n/a	n/a
Low Value Assets	Direct & then PPE for remaining	Direct & then PPE for remaining	n/a	n/a
Metering	n/a	Direct	n/a	n/a
Other Plant and Equipment	Direct & then PPE for remaining	Direct & then PPE for remaining	n/a	n/a
IMO-related System Management	n/a	n/a	Direct	n/a

[10] Where capital expenditure is not posted to a project (strategic spares not yet issued to a service), the asset segment and capital expenditure category (asset replacement) is determined using a method that most appropriately reflects the causal correlation of the underlying transaction.

Glossary

Term	Description
Australian Accounting Standards Board (**AASB**)	The AASB is responsible for developing, issuing and maintaining Australian accounting standards and related pronouncements.
Access Arrangement (**AA**)	The AA is the legal document that provides the details, terms and conditions that Western Power is to provide access to the Western Power Network. The AA complies with the requirements of the Access Code and is approved by the ERA.
Approved works program (**AWP**)	The AWP is a complete schedule of the operational and capital works Western Power carries out during a financial year on the construction, operation and maintenance of the network.
Business segments	The business segments for Western Power are transmission, distribution, IMO-related system management and unregulated.
Cost and Revenue Allocation Method (**CRAM**)	The CRAM is an authorised document presenting the method adopted by Western Power when allocating costs and revenue to the regulated and unregulated business segments and services in the annual regulatory financial statements.
Covered service	A covered service is the transportation of electricity provided by means of a covered network, e.g. a service provided within the SWIN.
Economic Regulation Authority (**ERA**)	The ERA is the independent economic regulator in Western Australia with responsibility for the regulation of monopoly services in the gas, electricity, rail and water industries.
Electricity Networks Access Code 2004 (**the Access Code**)	The Access 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".
Full time equivalents (**FTE**)	FTE is the allocation method applied by Western Power when the underlying transaction has a casual correlation to the consumption of staff/labour. It is generally determined by the ratio of FTE within a business segment to total Western Power FTE.
Government Trading Enterprise (**GTE**)	A GTE is a Government owned body, operating under an Act establishing it with the same functions as a private sector enterprise, e.g. *Electricity Corporations Act 2005.*
Guidelines for Access Arrangement Information Guidelines 2010 (**the Guidelines**)	The Guidelines set out in detail the information required (e.g. annual regulatory financial statements) within the AA for the purposes of informing the ERA, applicants and users. Compliance with the Guidelines is required by the Code.
Independent Market Operator (**IMO**)	The IMO controls the supply and trading of energy and electricity capacity in Western Australia's WEM.
Indirect Cost Allocation Method	The Indirect Cost Allocation Method is the method applied by Western Power when allocating the indirect costs of network or operational service nature to the AWP.
Land and buildings (**L&B**)	L&B is the allocation method applied by Western Power when the underlying transaction has a casual correlation to the ownership of land and buildings. It is determined by the ratio of L&B in the transmission and distribution asset segments to the total transmission and distribution L&B.
Non-reference services	Non-reference services sit outside the ERA's allowable revenue determination, e.g. high load escorts. The commercial terms and conditions for these services are negotiated between the parties.
New Facilities Investment Test (**NFIT**)	The New Facilities Investment Test (NFIT) is described at section 6.52 of the Access Code. The NFIT is the test applied to determine whether investment can be added to the regulated capital base (or RAB).
Property, plant and equipment and intangibles (**PPE**)	PPE is the allocation method applied by Western Power when the underlying transaction has a casual correlation to the principal responsibilities of managing the network and infrastructure, and/or delivering electricity from power generation plants to homes and businesses. It is determined by the ratio of PPE in the transmission and distribution asset segments to the total transmission and distribution PPE.

Term	Description
Reference services	Reference services are subject to ERA revenue regulation via the AA. They include covered services likely to be sought by a significant number of network users and applicants, or a substantial proportion of the market, e.g. network access.
Regulated asset base (**RAB**)	The regulated capital base used to determine the capital costs (the *return on* and *return of* components) to be recovered through regulated network tariff prices.
Western Power Network (**WPN**)	The Western Power Network is the transmission and distribution electricity network situated in the south west of Western Australia that is owned and operated by Western Power.
Wholesale Electricity Market (**WEM**)	The WEM is the wholesale electricity market operating in the SWIN.

List of Tables

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document.

Abbreviation / Acronym	Definition
AA1	Access arrangement for the first period, 2006/07 to 2008/09
AA2	Access arrangement for the second period, 2009/10 to 2011/12
AA3	Access arrangement for the third period, 2012/13 to 2016/17
AAI	Access arrangement Information (AAI) - supporting information submitted to the ERA and published for public review.
Access Code	Electricity Networks Access Code 2004
the Authority	Economic Regulation Authority
AQP	Applications and queuing policy
CAG	Competing applications group
DM	Document management
ETAC	Electricity Transfer Access Code
ERA	Economic Regulation Authority
IAM	Investment adjustment mechanism
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SSAM	Service standard adjustment mechanism
SSB(s)	Service standard benchmark(s)
WACC	Weighted average cost of capital
Western Power Network	The Western Power Network is the portion of the SWIN that is owned by Western Power. The Western Power Network incorporates the integrated transmission and distribution networks. It is commonly referred to as 'the network' throughout this document.

Document index

As per the Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information (6 December 2010), this section provides a document index.

…the service provider must provide the Authority with a "document index" that identifies the following information for each document or group of documents

- *Document title and, if applicable, document reference number/identifier*
- *Date of issue/publication*
- *A summary of the document's purpose and relevance (that is, the specific reason as to why the document has been provided)*
- *Page references to specific information of relevance within the document*

Ref	Title	Issue Date	Purpose and relevance	Page Ref
A	Pro forma forecast statements	18 Sep 2012	These statements provide the forecasts for AA3 expenditure in accordance with section 4.3.3 of the AAI Guidelines and the pro forma statement requirements provided in Appendix B of the AAI Guidelines.	All
B	Revenue model summary	18 Sep 2012	This is a summary of the revenue model outputs showing the total target revenue, price path and annual revenue caps (distribution, transmission and total revenue). The revenue model implements the calculations to determine the target AA3 revenue for the transmission and distribution systems in the Western Power Network.	All
C	2011/12 Regulatory Financial Statements	28 Sep 2012	This document provides the regulatory financial statements for the 2011/12 financial year. This is presented in accordance with section 3 and the pro forma statements requirements provided in Appendix A of the AAI Guidelines.	All
C	2011/12 CRAM	24 July 2012	This report provides the details of the cost and revenue allocation method applied in 2011/12 when preparing the 2011/12 regulatory financial statements, as required by section 3.5 of the AAI Guidelines.	All