Final Determination on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section)

Submitted by Western Power

27 January 2012

Economic Regulation Authority
WESTERN AUSTRALIA

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GLOSSARY

AA3	Third access arrangement period
AA4	Fourth access arrangement period
AA5	Fifth access arrangement period
APR	Western Power's Annual Planning Report
AATT	Average Annual Transmission Tariff
Authority	Economic Regulation Authority
CEF	Clean Energy Futures
CMD	Contracted Maximum Demand
CPRS	Carbon Pollution Reduction Scheme
Code	*Electricity Networks Access Code 2004*
DWAT	Discounted Weighted Average Tariff
FID	Final Investment Decision
FERC	Federal Energy Regulatory Commission
GBA	Geoff Brown and Associates
IMO	Independent Market Operator
KML	Karara Mining Limited
LGCs	Large-scale Generation Certificates
MWEP	Mid-West Energy Project (Southern Section)
MJA	Marsden Jacob Associates
NFIT	New Facilities Investment Test
NPC	Net Present Costs
RECs	Renewable Energy Certificates

SWIS	South West Interconnected System
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market
WPN	Western Power Network

FINAL DETERMINATION

1. This final determination gives the Authority's pre-approval to include $377.8 million (real dollars at 30 June 2010) of capital expenditure in Western Power's capital base – to occur at the point in time when the Mid West Energy Project (Southern Section) (**MWEP**) is commissioned at 330kV and component network assets are purchased from Karara Mining Limited **(KML)**.

2. On 3 August 2011, the Economic Regulation Autho**rity (Authority**) received a new facilities investment test **(NFIT)** application *from Western Power submitted under section* 6.71(b) of the *Electricity Networks Access Code 2004* (**Code**). A version suitable for publication was received on 16 August 2011.[1] The application sought for the Authority to determine that forecast new facilities investment proposed by Western Power, for the MWEP, meets the NFIT.

3. The purpose of the NFIT is to determine the extent to which the cost of the proposed augmentation may be rolled into the regulated capital base and therefore financed through network tariffs applying to all network users, or alternatively must be financed by some other means (such as capital contributions from specific network users). A service provider is not required to submit a NFIT application to the Authority prior to committing to any expenditure, but may do so if it wishes.

4. For the NFIT to be satisfied, the proposed investment must not exceed the amount that would be invested by a service provider efficiently minimising costs (the 'efficiency' test) and must satisfy at least one or more of the following benefit conditions:

   - the investment generates enough revenue to cover the investment costs (the 'incremental revenue' test); or
   - the investment provides a net benefit to justify higher network tariffs (the 'net benefits' test); or
   - the investment is necessary to maintain the safety or reliability of the network or its ability to provide network services (the 'safety and reliability' test).

5. Through these conditions, the NFIT seeks to ensure that participants in the electricity market – whether they are generators, network operators, or customers – realise a benefit that is at least sufficient to offset the cost of the new facility. In a competitive market, economic theory suggests that any net benefits would ultimately be passed through to consumers. However, to the extent that the market is less than competitive, some of the benefits may be captured by generators or the network operator.

6. Western Power's pre-approval application for the MWEP was for a total forecast new facilities investment amount for the proposed works of $383.4 million (real dollars at 30 June 2010). This covers the proposed cost of the construction of a double circuit 330 kV transmission line between Neerabup and Three Springs and a

[1] Western Power 2011*, New Facilities Investment Test pre-approval application Mid West Energy Project (Southern Section) - Neerabup to Three Springs Terminal via Eneabba*, www.erawa.com.au, August. (hereafter referred to as '**new facilities investment test application**').

new terminal station interconnecting the 132 kV and 330 kV transmission systems at Three Springs.

7. Western Power submitted that the entire proposed investment of $383.4 million meets the test of section 6.51A of the Code, by virtue of satisfying the NFIT of section 6.52 of the Code. The Authority has determined that 377.8 million of this amount satisfies the NFIT.

8. The Authority released a draft determination on 14 November 2011[2]. In the draft determination, the Authority set out that:

- it considered the proposed expenditure of $383.4 million to be consistent with the efficiency test, with the exception of $16.7 million (4.4 per cent of the total proposed expenditure), which the Authority considered to be potentially inefficient;
- it could not give pre-approval for the total proposed expenditure of $383.4 million to be rolled into the regulated capital base, as based on the information provided at that point by Western Power, there was a possibility that existing customers may be exposed to an unacceptable risk of increased transmission charges with no offsetting benefits; and
- Western Power needed to provide more information to support the case for the pre-approval, and in particular should reconsider the approach to support its estimates for the incremental revenue test.

9. In making a determination on a NFIT application, the Authority is required to consult with the public in accordance with the consultation requirements of Appendix 7 of the Code. The Authority issued an invitation for submissions in response to the draft determination, with a closing date for submissions of 12 December 2011. Submissions were received from:

- Western Power, responding to the Authority's request for further information; and
- 18 other stakeholders.

10. In light of these submissions, the Authority has further considered its position in relation to the conditions of the NFIT.

11. First, with regard to the efficiency test, the Authority accepts a number of Western Power's explanations providing support for proposed expenditures which had previously been questioned. However, the Authority does not accept all of Western Power's responses.

12. On this basis, the Authority has determined that the efficient costs for the MWEP are $377.8 million (real dollars at 30 June 2010).

13. Second, with regard to the incremental revenue test, the Authority had cause to question the large difference between the net present value of incremental revenue that would be allowable under a simple 'existing prices' approach, estimated by the Authority to be around $85 million (real dollars at 30 June 2010), and an estimate

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2 Economic Regulation Authority, 14 November 2011, New Facilities Investment Test Application for the Mid West Energy Project (Southern Section) - Draft Determination.

derived through an 'average tariff' approach, estimated by the Authority to be $181 million (real dollars at 30 June 2010).

14. Analysis by the Authority suggests that this discrepancy is the result of the large difference between the load factor of the new KML block load (around 70 per cent) and the implicit average nodal load factor underpinning the existing price for large transmission users at the Three Springs node (around 35 per cent). If this load factor difference is taken into account in the existing prices calculation, then the incremental revenue would be very similar to that developed through the average tariff approach.

15. However, the Authority considers that the average tariff approach provides an equivalent, and potentially simpler, means to estimate allowable capital under the incremental revenue test.

16. On this basis, the Authority considers that an amount of $181 million (real dollars at 30 June 2010) is approved for the purposes for the incremental revenue test.

17. Third, with regard to the net benefits test, the Authority has reviewed its position in relation to the concerns set out in the draft determination, which encompassed:

- whether the assumptions underpinning the ACIL Tasman analysis were robust, given the significant recent changes in the economic and policy environment;
- the choice of counterfactual scenarios – relating to the assumptions around the ability or otherwise to connect new wind generation;
- the potential for an overestimate in the benefits of increased wind generation capacity; and
- a request for clarification by Western Power of the claimed network deferral benefits.

18. The Authority's resulting determination is that a total of $233 million (real dollars at 30 June 2010) is approved for the purposes of the net benefits test, comprising (all net present values):

- generation net benefits of $188 million;
- a network deferral benefit of $36 million; and
- a reduction in transmission losses of $9 million.

19. The majority of these benefits are expected to flow to consumers.

20. The Authority therefore is satisfied that the overall net present value of the benefits of the MWEP will be at least $414 million (real dollars at 30 June 2010), comprising the sum of $181 million of incremental revenue and $233 million of net benefits. The Authority notes that, to the extent that additional major mining or other block loads connect to the MWEP beyond KML Stage 1, or there is additional wind generation in the region beyond the estimated 275 MW assumed for this determination, then the benefits could be significantly higher.

21. The estimated net present value of the benefits of $414 million exceeds the efficient cost for the MWEP of $377.8 million (real dollars at 30 June 2010). On this basis, the efficient costs for the MWEP are thus pre-approved by the Authority for

inclusion in Western Power's capital base – once the MWEP is commissioned at 330kV and component network assets are purchased from KML.

INTRODUCTION AND OVERVIEW

22. The reasons for this final determination address the following matters:

- the test of section 6.51A of the Code for adding new facilities investment to the capital base;
- the structure and elements of the NFIT under section 6.52 of the Code;
- details of Western Power's proposed works; and
- the assessment of the proposed transmission works against the requirements of the test of section 6.51A of the Code, including the NFIT under section 6.52 of the Code.

Test for adding New Facilities Investment to the Capital Base

23. Section 6.51A of the Code establishes a test that must be satisfied for an amount of new facilities investment to be added to the capital base.

> 6.51A New facilities investment may be added to the capital base if:
>
> (a) it satisfies the new facilities investment test; or
>
> (b) the Authority otherwise approves it being adding *[sic]* to the capital base if:
>
> (i) it has been, or is expected to be, the subject of a contribution; and
>
> (ii) it meets the requirements of section 6.52(a); and
>
> (iii) the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

24. Sections 6.71 and 6.72 of the Code allow a service provider to seek a determination that either an actual amount, or forecast amount, of new facilities investment meets the test of section 6.51A.

> 6.71 A service provider may at any time apply to the Authority for the Authority to determine whether:
>
> (a) actual new facilities investment made by the service provider meets the test in section 6.51A; or
>
> (b) forecast new facilities investment proposed by the service provider is forecast to meet the test in section 6.51A.

6.72 If an application is made to the Authority under section 6.71, then subject to section 6.75 the Authority must make and publish a determination (subject to conditions as the Authority may consider appropriate) within a reasonable time.[3]

The New Facilities Investment Test

25. Section 6.52 of the Code sets out the NFIT.

6.52 New facilities investment satisfies the new facilities investment test if:

(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold - the modified test is satisfied;

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

26. The 'anticipated incremental revenue' for a new facility referred to in Section 6.52 b) i) A above is defined in the Code to mean as follows:

(a) the present value (calculated at the *rate of return* over a reasonable period) of the increased income from *charges* (excluding any *contributions*) reasonably anticipated to arise from the increased sale of *covered services* on the *network* to one or more

3 Section 6.75 of the Code indicates that the Authority must make a determination if the actual or forecast amount of new facilities investment is equal to or greater than $15 million (CPI adjusted); otherwise the Authority may make a determination. The 2011 CPI adjusted threshold is $18.4 million as stated in the Economic Regulation Authority's Notice on 2011 Consumer Price Index Adjustments, 1 July 2011.

users (where 'increased sale of *covered services*' means sale of *covered services* which would not have occurred had the *new facility* not been commissioned), minus

(b) the present value (calculated at the *rate of return* over the same period) of the best reasonable forecast of the increase in *non-capital costs* directly attributable to the increased sale of the *covered services* (being the *covered services* referred to in the expression 'increased sale of *covered services*' in paragraph (a) of this definition),

27. For convenience, the elements of the NFIT are referred to below as the 'efficiency test' (section 6.52(a) of the Access Code), 'incremental revenue test' (section 6.52(b)(i)A of the Access Code), 'net benefits test' (section 6.52(b)(ii) of the Access Code) and 'safety and reliability test' (section 6.52(b)(iii) of the Access Code).

28. For the NFIT to be satisfied, the new facilities investment must satisfy the efficiency test and 'one or more' of the incremental revenue test, net benefits test, or safety and reliability test. The practical interpretation of 'one or more' is taken to be that the sum of the benefit values from the incremental revenue test, the net benefits test or the safety and reliability test needs to exceed the efficient cost of the new assets.[4]

Western Power's NFIT pre-approval application

29. On 3 August 2011, the Authority received a NFIT pre-approval application from Western Power submitted under section 6.71(b) of the Code. A version suitable for publication was received on 16 August 2011.[5]

30. The application sought for the Authority to determine that forecast new facilities investment proposed by Western Power, for the MWEP, meets the NFIT.[6] The project is estimated to cost $383.4 million and involves the construction of a double circuit 330 kV transmission line between Neerabup and Three Springs and a new terminal station interconnecting the 132 kV and 330 kV transmission systems at Three Springs.

31. Western Power submitted that the entire proposed investment of $383.4 million meets the test of section 6.51A of the Code, by virtue of satisfying the NFIT of section 6.52 of the Code. In applying the NFIT to the project, Western Power gave separate consideration to three elements of the NFIT:

- the 'efficiency test' under section 6.52(a) of the Code;
- the 'incremental revenue test' under section 6.52(b)(i)A of the Code; and

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4 For a detailed explanation of the Authority's interpretation of the NFIT, see Economic Regulation Authority 2011, *Issues Paper: New Facilities Investment Test Application for Western Power's Mid-West Energy Project (Southern Section)*, Appendix A.

5 Western Power 2011, *New Facilities Investment Test pre-approval application Mid West Energy Project (Southern Section)- Neerabup to Three Springs Terminal via Eneabba*, www.erawa.com.au, August. (hereafter referred to as '**NFIT application**').

6 The Authority already had published its decision on 3 February 2011 that the proposed MWEP project satisfied the **regulatory test** under Chapter 9 of the Access Code. Western Power could not commit to the proposed project until it satisfied the regulatory test by demonstrating that the proposed project was the best means of developing the electricity system compared to alternative options such as alternative network investments, investment in generation or management of electricity demand.

- the 'net benefits test' under section 6.52(b)(ii) of the Code.

Process to date

32. In making a determination on an NFIT application, the Authority is required to consult with the public in accordance with the consultation requirements of Appendix 7 of the Code. The Authority issued an invitation for submissions on 26 August 2011, with a closing date for submissions of 12 September 2011. As part of this consultation, the Authority prepared an issues paper to assist interested parties in understanding the NFIT and Western Power's NFIT application.[7] Submissions were received from the following parties:[8]

    - APA Group
    - Crosslands Resources Ltd
    - ERM Power Ltd
    - Extension Hill Pty Ltd
    - Karara Mining Ltd (confidential)
    - RPV Developments
    - Shire of Perenjori
    - Synergy
    - Vestas Australian Wind Technology Pty Ltd
    - Wind Prospect Pty Ltd.

33. To assist with its assessment of Western Power's NFIT pre-approval application, the Authority also commissioned independent advice from Geoff Brown and Associates (**GBA**) and economic advice from Marsden Jacob Associates (**MJA**).[9]

34. The Authority published its draft determination on 14 November 2011. The Authority's draft determination was that it could not give pre-approval at that point for the total proposed expenditure of $383.4 million to be rolled into the regulated capital base. To address its concerns, the Authority sought further information from Western Power, including:

    - updated estimates for the value of the proposed new network investments – including removal of the amounts identified by the Authority as not consistent with the requirements of the efficiency test;
    - a revised valuation of incremental revenue – utilising existing transmission tariffs, incorporating only those incremental block loads that can be

[7] Economic Regulation Authority, 13 December 2010, Issues Paper: New Facilities Investment Test Application for Western Power's Mid West Energy Project (Southern Section) Submitted by Western Power.

[8] These submissions are available on the ERA's website: http://www.erawa.com.au/3/1178/48/mid_west_energy_project_southern_section_augmentat.pm

[9] Geoff Brown and Associates 2011, *Technical Review of,* prepared for Economic Regulation Authority of Western Australia.

Marsden Jacob Associates 2011, New Facilities Investment Test for Western Power's Mid-West Energy Project (Southern Section), prepared for Economic Regulation Authority of Western Australia.

demonstrated to be reasonably assured, with consideration given to the discounted weighted average tariff approach; and

- a re-working of the net benefits estimates – to provide additional support for the counterfactual scenario chosen for the 'with' and 'without' cases, and to further examine the sensitivity of the outcomes to assumptions which support the entry of new wind generation.

35. Western Power responded to the Authority through a submission on the draft determination.[10]

36. In addition to Western Power's submission, 18 other submissions were received on the draft determination, from:

- ACIL Tasman
- Alinta Energy
- APA Group
- City of Greater Geraldton
- Crosslands Resources Ltd
- Department of Commerce (confidential)
- ERM Power Ltd
- Extension Hill Pty Ltd
- Geraldton Iron Ore Alliance
- Geraldton Port Authority
- Karara Mining Ltd (confidential)
- LandCorp
- Landfill Gas and Power Pty Ltd
- Mid West Development Commission
- Regional Development Australia – Mid West Gascoyne
- Shire of Perenjori
- The Chamber of Minerals and Energy of Western Australia;
- Western Australian Farmers Federation.

37. Submissions were almost overwhelmingly supportive of the MWEP. Key common points made in the submissions included:

- The existing 132 kV power transmission system that services the Mid West has a number of significant capacity constraints that arise due to the long distances involved, the predominance of wind power generation in the region and the technical limitations of the system. As a result, the Mid West transmission system is rapidly approaching its capacity limits. Stakeholders

[10] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, November.

cited numerous instances where the lack of availability of new firm capacity in the Three Springs and Geraldton regions was constraining future growth opportunities.

- The system is currently operating with a margin of safety of less than 1.5 per cent. It is not clear why safety, reliability and limitations in access to supply are not addressed in the Western Power submission.
- Attributing too high a level of risk and uncertainty to developing iron ore mines in the Mid West ignores the high levels of investment already undertaken, and the continuing commitment to projects. The risk seemingly not considered is the potential for major Mid West mining projects not to progress because of deferment of access to 330 kV power supplies. A 330 kV power supply also is essential for development of value adding initiatives at the proposed Oakajee Industrial Estate.
- There is potential for new renewable energy generation in the region, but realisation of this potential is contingent on the MWEP. The Mid West is possibly the most productive region in Australia for renewable energy.
- Data and forecasts published by the Independent Market Operator clearly indicate the need for additional generation in the South West Interconnected System **(SWIS)**. One of the principal reasons for building the 330 kV line to the north is to allow additional generation to locate in this relatively sparsely populated area which has – unlike the outer metropolitan area – many suitable sites for electricity generation. Location in this region would also increase fuel security for the system as a whole. As a result the MWEP has benefits for all consumers, not just for the Mid West iron projects.
- The acceptable NFIT pre-approval amount for the MWEP needs to be quantified in the Authority's determination – as this would allow all parties considering investment in the region to make commitments as required. This would remove current uncertainty about whether the MWEP will go ahead.
- The direct and flow-on benefits coming from mining projects to existing and future Mid West business need to be accounted for. This would help to offset any disadvantage from increased transmission costs to the region.
- The approach to protect existing customers is supported. A number of customers that draw in excess of 50 MW could potentially be affected by increased transmission tariffs in the range of one to five per cent. The price increases for these customers should be weighed against the potential for increased hours of curtailability as transmission outages become more prevalent in the Geraldton region.

38. This final determination takes into account the material received in the above submissions, including from Western Power.

REASONS

39. In what follows, the Authority sets out the reasons for its determination in relation to three elements of the NFIT:

- the efficiency test;
- the incremental revenue test; and
- the net benefits test.

Efficiency Test

40. Western Power's proposed new facilities investment for the MWEP involves construction of new transmission lines and electrical substations. Part of the new facilities is being constructed by KML and subsequently sold to Western Power (Table 1). The facilities currently being constructed by KML will be commissioned in early 2012 in order to provide the mine with a temporary supply of limited capacity so that mining can commence prior to commissioning of the Pinjar to Eneabba line.

Table 1 Proposed MWEP works

Component of Works	Delivery
189 km 330 kV transmission line between Pinjar and Eneabba substation including upgrading the existing Neerabup to Pinjar line from operating at 132 kV to 330 kV and building a new 330 kV circuit bay at Neerabup	To be delivered by Western Power
12 km 330 kV transmission line from Eneabba Substation to Eneabba Terminal	Currently being constructed by KML and subject to commercial negotiations between Western Power and KML.
58 km 330 kV transmission line from Eneabba Terminal to Three Springs	Currently being constructed by KML and subject to commercial negotiations between Western Power and KML.
330/132 kV Three Springs Terminal	Three Springs terminal electrical works will be contracted to KML, with the remainder of the work to be delivered by Western Power. The building of the terminal is initially being funded by KML.
Total cost of project	**$383.4 million**

Western Power's proposal

41. In its original pre-approval application, Western Power proposed a capital cost for the project of $383.4 million.

42. The Authority's draft determination considered that the proposed expenditure of $383.4 million was largely efficient.

43. The exception was some $16.7 million (4.4 per cent) of the total proposed expenditure which the Authority considered to be potentially inefficient. This $16.7 million comprised:

Assets constructed by Western Power

- Western Power has designed the Pinjar to Eneabba line for a maximum conductor thermal rating of 85°C. This has required the use of taller towers to increase ground clearance at an additional cost of $0.5 million. While this additional cost is relatively modest, the Authority's technical adviser GBA did not consider that the additional capacity provided is needed, even under a high load growth scenario. On this basis, the Authority considered that the NFIT cost should be reduced by $0.5 million.

- Western Power provided for the undergrounding of a section of the double circuit 132 kV Pinjar-Cataby line where it passes under the new 330 kV circuit, at an estimated cost of $3 million in order to avoid a double circuit outage in the event of a conductor failure at that particular location. The Authority required that Western Power re-consider this component.

- GBA's assessment was that a 250 MVA transformer would be all that is required at this stage for the Three Springs Terminal, rather than the 490 MVA unit proposed by Western Power. Installation of a smaller transformer would reduce the estimated cost by $1.07 million. On this basis, the Authority required Western Power to show cause why it could not adopt the small transformer option.

Assets constructed by KML

- In the case of the Eneabba Terminal to Three Springs Terminal line being constructed by KML, the NFIT cost is based on a previous design that is not optimal. Had construction been delayed to coincide with the construction of the Pinjar-Eneabba line, the cost would have been reduced by an estimated $5 million because the line would have been built to an optimised design on 600 metre spans.

- In addition, the design of the line is for 85°C, which is estimated to add $175,000 to the cost. The Authority considered that these two additional costs are not efficient, and that the NFIT amount should be reduced accordingly.

Depreciation of assets prior to purchase by Western Power

- A significant element of the total proposed augmentation is initially being constructed by KML and will subsequently be sold to Western Power. Consideration of the amount to be added to Western Power's asset base would include adjustment for any depreciation of assets that have been in use for a period of time (for the benefit of KML).

44. In addition, the Authority noted that:

Minimising project costs

- From the information provided by Western Power, it is not clear whether the proposed expenditure of $21.3 million – for project development costs incurred to date – includes the costs relating to the planning for the original proposed Northern Line and the costs of preparing the 2007 regulatory and NFIT applications. Only those costs which relate to planning for the current proposal should be included. Western Power was requested by the Authority to provide further evidence that this is the case before the Authority can approve the total amount.

Timing of addition of investment to the regulatory capital base

- Costs relating to the assets constructed by KML should only be included in Western Power's capital base on completion of the MWEP, which is scheduled for March 2014, and only after payments have been made by Western Power to KML. Prior to this point, KML is the only party to benefit from the use of the interim assets. For example, commissioning of the Three

Springs Terminal has been accelerated ahead of the Pinjar to Eneabba line only because the facilities at the KML mine require a 330 kV incoming supply. In addition, revenue from KML prior to this point should not be included in the NFIT tests.

Interest during construction

- Interest during construction (**IDC**) in relation to the assets constructed by KML should not be included for the period of interim use of the assets by KML, subsequent to completion, but prior to the commissioning by Western Power of the MWEP. Accordingly, Western Power should revisit the estimates of IDC.

45. The Authority sought updated estimates from Western Power for the value of the proposed new network investments – to address the amounts identified as not consistent with the requirements of the efficiency test.

46. In response to the Authority's draft determination, Western Power addressed each of the above points. The Authority has considered Western Power's response, as well as other submissions, in what follows.

Considerations of the Authority

Assets constructed by Western Power

Higher conductor thermal rating on the Pinjar to Eneabba line

47. Western Power considers the higher 85°C thermal rating for the Pinjar to Eneabba line is appropriate because:

    - it provides significant extra capacity for a very small incremental cost;
    - retrofitting the line at a later stage to increase capacity is not possible;
    - most of Western Power's existing 330 kV lines already have a conductor thermal rating of 85°C, and there are advantages of a standard approach in relation to simplifying operations, maintenance and risk management.

48. The Authority sought the response of its technical consultant GBA.[11] GBA accepts that the additional cost of $0.5 million for the higher conductor thermal rating is not material to the total project cost, but will increase the ultimate thermal capacity of the line significantly.

49. The Authority, noting the comments of GBA, accepts the arguments put forward by Western Power that the higher conductor thermal rating delivers increased capacity for minimal cost, which ultimately may save further augmentation costs over the 50 years plus life of the MWEP.

[11] Geoff Brown and Associates 2011, *Comments on Chapter 3 of Western Power's Response to the MWEP NFIT Draft Decision*, www.erawa.com.au.

Undergrounding of the Pinjar to Cataby 132kV line

50. In response to the Authority's request in the draft determination that it re-consider the undergrounding of the Pinjar to Cataby line, Western Power submitted that:

- It had investigated three options during the scoping and planning phases of the project. These options together with their direct construction cost are:
  - Option 1: Overhead crossing 330 kV under existing 132 kV ($3.0 million);
  - Option 2: Overhead crossing by lowering 132 kV under 330 kV ($2.9 million);
  - Option 3: Underground crossing 132 kV under 330 kV ($3.1 million).
- The cost difference between the options is very small but benefits of Option 3 such as 'constructability' and minimum operation risk across the whole life-cycle outweigh this cost difference. Therefore, Option 3, the undergrounding option is the most efficient option.
- Option 3 minimizes outages of existing 132 kV circuits during construction. The outages for Option 1 and 2 are much longer. In addition, there is a greater risk of double outage of both existing 132 kV circuits being required to enable construction to be undertaken. A double outage has a high potential to lead to an event which would interrupt supplies to customers. Using a cost based on value of customer reliability (**VCR**) of $55.52 per kWh shows that an outage of 10 minutes would cover the cost difference of implementing Option 3.
- Moreover, Option 3 is the only option that will not cause any double circuit outage in the event of a conductor failure at the crossing. The risk of conductor failure cannot be fully mitigated. A double circuit outage of the 132 kV line due to a broken conductor of the 330 kV line would black out all the 132 kV substations North of Pinjar to Eneabba. This includes the Cataby, Regans, Emu Downs and Eneabba substations.
- The 2010 peak load for these substations was 21 MW. A four hour disruption during this peak period will incur a cost to customers of $4.7 million, given the VCR. The cost of a single broken conductor event is higher than the cost differential of implementing the underground option. The cost of this risk will be higher in the future as the load supplied by these substations increases. As a consequence, Western Power believes that the whole of the $3.1 million cost of this crossing passes NFIT.

51. In response, GBA noted:

- The Pinjar to Cataby 132 kV line is elevated at this particular point to cross the 'cricket wicket' line that will be removed as part of the MWEP.
- As a result, the crossing is complex due to the fact that the tower on the east side of the crossing is a 45 degree angle tower. The location of this tower significantly increases the complexity and cost of an overhead solution. On this basis, GBA accepts Western Power's position for undergrounding as a lower cost option.

52. Noting the explanation provided by Western Power and the comments by GBA, the Authority, therefore, now accepts that the undergrounding of the Pinjar to Cateby line is the most efficient option.

Size of transformer at Three Springs Terminal

53. In relation to the size of the transformer at Three Springs Terminal, Western Power submitted:

- The transformer has been sized based on the high forecast demand growth scenario. The high forecast scenario represents a more likely estimate of future demand growth than either the central or the low forecast, which was a view endorsed by the Authority in its Regulatory Test determination for the MWEP.
- The 490 MVA transformer is the most efficient, lowest cost option to meet the high forecast load. A 490 MVA transformer provides superior flexibility for further growth.

54. In response, GBA noted:[12]

> Western Power's analysis is contingent on the high load forecast. It is misleading to suggest that the Authority considered in the Regulatory Test decision that the high load forecast would be most likely. It would be more accurate to state that Western Power's medium forecast provided only for the Karara mine Stage 1 load and that the Authority considered it possible that more mining load (Karara Stage 2 or Extension Hill Stage 1) would want to connect within 20 years. It would be prudent to ensure the MWEP had sufficient capacity to provide for this. It is important to note that this load is likely to connect at 330 kV at Three Springs and not at 132 kV at Geraldton, so will not utilise the Three Springs transformer.

55. The Authority agrees with GBA that it is misleading to suggest that the Authority considered the high load forecast to be more likely. Rather, the Authority noted the large uncertainty surrounding future demand, accepting that a range of outcomes could be possible for the future:[13]

> In its major augmentation proposal, Western Power has considered 'central', 'low' and 'high' load growth scenarios...
>
> Noting the advice to the Authority, the Authority accepts that forecasts of electricity demand are inherently subjective and contingent on assumptions about the probability of new loads eventuating. The degree of subjectivity is particularly great for the Mid West region where new loads arise predominantly from proposed mining projects that are subject to changes in timing and scope. Taking these matters into account, along with information submitted by Western Power and submissions to the Authority, the Authority considers that the demand forecasting procedures used by Western Power are consistent with good industry practice and form an appropriate basis for the consideration of alternative options for increasing capacity of the electricity system in the Mid West region.

56. The Authority agrees with GBA's comments in relation to block load developments in the Geraldton region and the implications for the most likely future development options and timing for transmission augmentation to the Geraldton region. The 330/132 kV transformer in question is for the supply of this region, which is expected to continue to be supplied at 132 kV for the foreseeable future. Other

[12] GBA 2012, *Comments on Chapter 3 of Western Power's Response to the MWEP NFIT Draft Decision*, www.erawa.com.au.

[13] Economic Regulation Authority 2011, *Final determination on the Regulatory Test for the Mid West Energy Project (Southern Section)*, www.erawa.com.au, p22.

mining loads to the north and east of Three Springs would likely connect at 330 kV, so are not related to this transformer.

57. The Authority considers that on this basis Western Power has not demonstrated a sufficient need for the larger transformer option. Accordingly, the amount allowable for this transformer should be reduced by $1.07 million.

Assets constructed by Karara Mining Limited

Design of the Eneabba Terminal to Three Springs line

58. Western Power submitted that the cost of the Eneabba Terminal to Three Springs Terminal line being constructed by KML was consistent with the appropriate design standards available at the time committed decisions were made. This standard was the prevailing Western Power design intended for the 330 kV Northern Line transmission project at the time.

59. The Authority recognises that the design was based on the standard available at the time. Accordingly, the Authority has re-considered its position. The Authority now accepts that the design of the line was considered efficient at the time the decision to proceed was taken, and thus that the capital expenditure amount proposed by Western Power should be accepted.

Depreciation of KML assets prior to purchase by Western Power

60. Western Power in its submission on the draft determination agreed with the Authority that the amount to be added to Western Power's asset base should account for any depreciation of assets that have been in use for a period of time by KML.

61. However, Western Power submitted that the depreciation suggested by GBA of $6.93 million is too high:

- Western Power's access arrangement is based on expected economic lives of 60 years for transmission lines and 50 years for transmission substations;
- the expected date of purchase is the first quarter of 2014; and
- the amount of $4.5 million is the calculation of the amount that should be considered as the depreciation in the NFIT.

62. The Authority accepts that the life of transmission lines is longer than 40 years assumed by GBA, and hence that a re-calculation of the depreciation amounts is reasonable. However, the Authority did not accept that the life of transmission lines is 60 years. The actual life of transmission network components will vary between 6 and 60 years.

63. The Authority made a further request to Western Power to revise its estimate of depreciation in line with the lives set out in Table 2. Western Power subsequently provided a revised estimate of $4.5 million, identical to the initial estimate, but with revised components. The Authority accepts this revised figure.

Table 2 Proposed expected asset lives relating to the MWEP works

Transmission component	Pre AA3 (years)	AA3 (years)
Transmission cables	55	55
Transmission steel towers	60	60
Transmission wood poles	45	45
Transmission metering	40	40
Transmission transformers	50	50
Transmission reactors	50	50
Transmission capacitors	40	40
Transmission circuit breakers	50	50
SCADA and communications	34	11
IT	17	6
Other non-network assets	17	17

Source: Western Power's AA3 financial model

Minimising project costs

64. In its draft determination the Authority noted that it was not clear, from the information provided by Western Power, whether the proposed expenditure of $21.3 million for project development costs incurred to date includes the costs relating to the planning for the original proposed Northern Line and the costs of preparing the 2007 regulatory and NFIT applications. The Authority considered that only those costs which relate to planning for the current proposal should be included.

65. In response Western Power submitted that:

- The development cost to date of $21.3 million is the actual cost incurred to date on the MWEP Southern Section project – for project planning and approvals, project estimates, project management, design and strategic purchase of plant and equipment.
- The $21.3 million of cost to date is made up of two parts. One is the cost incurred to date by Western Power on the MWEP Southern Section work. The second part is the cost incurred for purchase of primary plant for the

construction of Three Springs Terminal. In relation to the first part, Western Power states:[14]

> The cost to date does not include any costs for work related to the Northern Section (Eneabba to Moonyoonooka), with Western Power having separated the relevant cost elements of the Northern and Southern sections of the previous combined project, prior to proceeding with the current MWEP Southern Section submissions. Western Power reconfirms that a further $9.1 million is allocated to a MWEP (Northern Section) potential future project and is excluded from this MWEP Southern Section project, as previously communicated to Authority in its letter dated 13 September 2011.

Table 3 MWEP Southern Section development cost to date (nominal values)

Cost items	$million	$million
Western Power MWEP Southern Section Work		
Project planning and approvals, project estimates and project management	5.34*	
Project design (inc testing of lines)	2.47	
Purchase of foundation materials	1.73	
Early works in substations	1.09	
Sub-total		**10.7**
KML Payments		
Three Springs Terminal (to be refunded subject to NFIT)	10.6	
Sub-total		**10.6**
Total development cost to date		**21.3**

Notes: * This cost of $5.34M is not related to the estimated project planning cost of $5.72M presented in Table 4.1 of Western Power's Planning Phase Cost Estimate Report. This cost of $5.34M includes a component of planning cost incurred to date but is not solely attributed to planning. It also includes the Project Management cost incurred to date.

Source: Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, November, p17.

[14] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, November, p16.

66. GBA commented:

- The Three Springs Terminal component of the $21.3 million should not be added to the regulated asset base until the MWEP is fully complete. That is, until an incoming 330 kV supply is available, Three Springs Terminal will remain a KML connection asset.

67. The Authority accepts that the amounts specified by Western Power in Table 3 are part of the overall project cost, except for the amounts of $5.34 million and $2.47 million. Based on Western Power's statement quoted at paragraph 65 above, it is clear that the latter amounts are part of the old previous combined project planning costs. However, subsequent additional information from Western Power has satisfied the Authority that these project planning and design costs are directly related to the elements of the new Southern Section project. This is because the alignment for the old project south of Eneabba, and associated relevant design work, has been carried through to the new project.

68. On this basis, the Authority accepts the amount of $21.3 million for development costs to date.

69. The timing of addition of KML assets to the regulatory capital base is dealt with in the next section.

Timing of addition of investment to the regulatory capital base

70. The Authority considers that costs relating to the assets used by KML should only be included in Western Power's capital base on completion of the MWEP, at the point at which it is electrified at 330 kV, which currently is scheduled for March 2014. Prior to this point, KML is the only party to benefit from the use of the interim assets. For example, the Three Springs transformer will be required by KML until the Pinjar to Eneabba line is commissioned and an incoming 330 kV supply is available. In addition, revenue from KML prior to this point should not be included in the NFIT tests.

71. Western Power subsequently confirmed in its submission that assets acquired from and constructed by KML only will be included in its capital base on completion of MWEP.

72. GBA noted Western Power's confirmation but commented:

- The assets to be included in the capital base on completion of the MWEP should apply to the full Three Springs Terminal Station, not just the transformer as indicated in paragraph 78 of the draft determination.
- The $10.6 million of development costs that Western Power has incurred to date (which GBA understood previously had been argued by Western Power to be included immediately in the capital base consistent with its 'capitalise when spent' policy) was for the construction of Three Springs Terminal assets that will be used by KML, prior to the completion of the MWEP, and hence should not be capitalised until the completion of the full project.

73. The Authority notes Western Power's confirmation that assets acquired from and constructed by KML will only be included in its asset base on completion of MWEP. In this context, the Authority notes that the Three Springs Terminal is being used by KML and hence is a KML connection asset until its transfer to Western Power and the MWEP is commissioned at 330 kV – expected in March 2014. This includes the

330/132 kV transformer which is being used by KML to provide power to the KML mine at 330 kV until the MWEP is commissioned.

74. On this basis, the Authority agrees with GBA that the whole of the cost of the Three Springs Terminal, including the $10.6 million for primary plant, should only be included in its asset base following commissioning of the MWEP at 330 kV and the purchase of the assets from KML.

75. The Authority also notes that the amounts included in the asset base necessarily will need to reflect the actual amounts paid by Western Power to KML, and the point in time at which the payments are made. There is a need to ensure that there are no windfall gains to Western Power arising from any differences in the price indexes applied to the payments, as opposed to those applied to the asset base valuations.

Interest during construction

76. The Authority considers that IDC should not be included for the period of interim use of the assets by KML, subsequent to completion, but prior to the commissioning by Western Power of the MWEP.

77. Western Power submitted

- The IDC costs in Table 14, 15 and 16 of Western Power's pre-NFIT application submission were calculated for the construction period of the projects only in relation to the assets constructed by KML.
- The construction period considered is the proposed period of construction for the individual projects should those projects be developed by Western Power based on its requirement and on an efficient delivery prospective.
- The estimate of the cost is therefore consistent with the approach suggested by GBA to account for the IDC.

78. On this basis, the Authority is satisfied that the estimate of IDC by Western Power is acceptable.

Conclusions on efficient costs

79. The Authority considers that an amount of $377.8 million (real dollars at 30 June 2010) constitutes efficient costs for the MWEP, in line with the foregoing analysis.

Incremental Revenue Test

80. The incremental revenue test refers to the test under section 6.52(b)(i)A of the Code as to whether the 'anticipated incremental revenue for the new facility is expected to at least recover the new facilities invesment' (see paragraph 25 for the definition of 'anticipated incremental revenue').

81. In previous issues papers and decisions relating to new facilities investment applications the Authority has taken the view that the incremental revenue test component may be developed through:

- discounted cash-flow analysis – with the amount of allowable new facilities investment under the incremental revenue test being the present value of revenues at *existing* tariffs, that would be paid by the new 'incremental' loads made possible by the new facility; or
- average tariff analysis – which may be based on a discounted weighted average tariff (**DWAT**) approach – with the amount of allowable new facilities investment under the incremental revenue test being that amount which would not increase the average tariff for the covered network on inclusion of the new facility investment in the capital base, accounting for the new 'incremental' loads made possible by the new facility.

82. For either of these forms of analysis, the incremental revenue test should be applied such that:

    - the analysis should be undertaken over a period of no longer than the expected economic life of the principal assets of the new facility; and
    - the discount rate applied in the analysis may be the rate of return applied in the determination of reference tariffs in either the current access arrangement or proposed revisions to the access arrangement, or may be a rate of return otherwise determined by the Authority to be in accordance with the Code objective and in a manner consistent with Chapter 6 of the Access Code.

83. The intent of the incremental revenue test is that existing customers will not face higher prices as a result of augmentations to accommodate new customers (Box 1).

Box 1 The incremental revenue test

The incremental revenue test in Code is drawn from the same test in the original National Gas Code, now the National Gas Rules (**NGR**).

The spirit of the test is that the incremental revenue should be based on existing prices – to ensure that existing customers do not subsidise new customers. Any additional new load revenue beyond this amount could be considered a contribution by the new load to the cost of the new asset.

The incremental revenue test has its roots in a decision by the Federal Energy Regulatory Commission (**FERC**) in the mid 1990s.[15] The FERC had been debating whether capital expenditure relating to expansion should be treated on an 'incremental' or 'rolled-in' basis.[16]

- 'incremental' – new users pay the incremental costs required to provide the expansion in capacity.
- 'rolled-in'– all new capital expenditure for capacity expansion is added to the existing capital base and both new and existing users pay the same adjusted tariff.

In the 1995 decision, the FERC opted for a hybrid of 'incremental pricing' and 'rolled in' pricing for including new assets in the regulated asset base. The policy provided for a case-by-case determination of whether a policy of roll-in or incremental pricing should apply. Each assessment was required to be based on an evaluation of the 'system-wide benefits' of the project and the impact on tariffs paid by existing pipeline users.

The NGR and Code NFIT tests are also a hybrid of incremental and rolled in pricing – in both, additional capital may be 'rolled in' beyond incremental revenue (and hence by corollary, prices to existing users are allowed to rise) to the extent that net benefits for existing customers can be demonstrated, over and above the incremental revenue amount. The net benefits part of the NFIT estimates this additional amount.

[15] Federal Energy Regulatory Commission 1995, *Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipeline: Statement of Policy*, 71 FERC 61, 241 Docket No. PL 94-4-000, May.

[16] For a useful summary of the FERC's consideration of this issue, see Shepler D. 2006, *Memorandum to Senator Therriault re rolled-in pricing versus incremental pricing for pipeline expansions at FERC*, http://lba.legis.state.ak.us/sga/doc_log/2006-05-20_shepler_memo_on_expansion_ratemaking.pdf. Importantly, Shepler notes that the subsequent policy of the FERC changed from a hybrid approach to a strict incremental pricing approach:

> For a number of years in the Lower-48, the FERC policy was that it would allow pipelines to use rolled-in pricing for system expansions if there were general system benefits to all users and there was a presumption in favour of rolled-in pricing if the impact on existing shippers was a rate increase of 5 per cent or less. The FERC departed from this policy in order to establish a more level playing field among competing pipeline companies. Under FERC's 'lower-48' policy, all expansions must now be priced on an incremental basis so that [new] customers see (and feel) that actual cost of providing the new service.

Western Power's proposal

84. Western Power in its pre-approval application estimated that the net present value of the incremental revenue arising from the proposed MWEP would amount to $206 million over the next 40 years.[17] This estimate comprised incremental transmission revenue of $187 million from new iron ore mining loads (including revenue from an interim supply arrangement with KML) and $19 million from new wind turbine generation.

85. The Authority in its draft determination expressed significant concern in relation to this estimate, as it considered that the majority of the proposed new incremental revenue relates to two new mining operations, one of which has yet to achieve Final Investment Decision (**FID**). Given the inherent uncertainties associated with mining investment, the Authority was concerned that existing customers should not be left exposed to the risk of a project not going ahead, resulting in the forecast incremental revenue not being realised and exposing existing customers to increases in charges. The Authority also considered that there were some flaws in Western Power's calculation of incremental revenue – relating to the use of a future rather than an existing incremental price – which should be revised.

86. In response, Western Power submitted, among other things, that:[18]

- not all connection applicants will formally announce that they have reached the FID milestone;
- developing economically efficient augmentations of the shared network requires consideration of expected future loads, not just those that have reached FID;
- expected future loads for the purpose of the pre-approval application were developed through Western Power's Monte Carlo risk model, which estimates the level of 'latent' (as opposed to actual) demand;
- Western Power manages the risk of latent demand by requiring connection applicants to provide bank security and other forms of legally binding assurance for forecast future revenues;
- two stakeholder forums conducted by Western Power on the draft determination indicated broad stakeholder support for the risk allocation implied by the Western Power Monte Carlo risk model;
- the methodology used to develop the incremental price at Three Springs Terminal takes into account the costs of the line from Neerabup to Three Springs – as it considers excluding the cost of this line would not be a reasonable reflection of the actual cost of transporting electricity at 330 kV to Three Springs; and
- Western Power's final decision to proceed with the MWEP project is conditional on finalising a commercial agreement with KML – and will include

[17] Western Power 2011, *New Facilities Investment Test pre-approval application Mid West Energy Project (Southern Section)- Neerabup to Three Springs Terminal via Eneabba*, www.erawa.com.au, August, p19.

[18] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, November.

a security over a forecast revenue stream that is consistent with the future incremental price utilised for Western Power's incremental revenue estimate.

87. Western Power also set out a DWAT estimate of incremental revenue in its submission on the draft determination, as a means to demonstrate that existing customers would not be worse off. The approach assessed the difference between transmission average tariffs 'without MWEP' (Scenario 1) and 'with MWEP' (Scenario 2).[19]

> In scenario 1, the forecast capital expenditure for the MWEP (Southern Section) and KML's annual energy requirement were excluded. This established a baseline transmission DWAT of $31.753 per MWh.
>
> In Scenario 2, KML's energy requirement was added and the model used to solve for the maximum asset value that could be added without increasing DWAT above $31.753 per MWh. The result was that $248 million dollars (nominal) can be added to the capital base with no increase in the average transmission network tariff. This means that $248 million in capital could be added to the capital base without affecting prices given the additional load expected. For comparability to previous analysis, this amount was discounted to July 2010 dollars [sic], resulting in an estimate of $223 million.
>
> Deducting this amount from the estimated capital cost of $379 million results in a residual capital cost of $156 million. Adding this amount would increase transmission tariffs. However, this project is estimated to deliver net benefits of $271 million. Therefore there is a net benefit to the market of $115 million. This provides a benefit-cost ratio of 1.7 for customers which confirms that the MWEP (Southern Section) is economically efficient.
>
> It is acknowledged that the current AA3 cost-of-service model assumes the forecasts included in Western Power's proposed access arrangement revisions currently being reviewed by the Authority. It is expected that these assumptions will be revised through the process. However, plausible variations in the AA3 parameters are not expected to materially affect the outcome.

Considerations of the Authority

88. The purpose of the incremental revenue test is to ensure that existing customers would not face higher prices as a result of an augmentation that is undertaken principally to accommodate new customers – except to the extent that the augmentation provides an additional, separate net benefit for the broader electricity market (which may include maintaining the safety and reliability of the existing network).

Existing prices analysis of incremental revenue

Incremental load

89. The forecast of the amount of new load likely to connect to the new assets is important - if the forecast incremental revenue measured at existing prices fails to

[19] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, November, p37.

materialise due to a shortfall in load, network users could potentially incur the costs of the augmentation over and above any actual net benefits. Consequently, it is the Authority's view that the forecast of incremental revenue be sufficiently robust for reliance to be placed upon it for the purposes of assessing the NFIT.

90. However, Western Power's proposed incremental revenue included a prospective load associated with Asia Iron's Extension Hill Stage 1 development that has yet to formally announce it has reached FID. The Authority's view was that this prospective load is not reasonably assured, and thus should be excluded from the incremental revenue test.

91. Western Power submitted that not all connection applicants will formally announce that they have reached the FID milestone. However, the Authority notes that:

- the prospective Extension Hill load contributes some 40 per cent of the effective load, and is thus a major contributor to the Western Power estimate;
- Extension Hill has stated that FID would be achieved in the first quarter of 2012;[20]
- Extension Hill has yet to announce FID has been reached;
- Western Power has not indicated that it has any commercial arrangements with Extension Hill which would indicate that the future transmission revenue is secure.

92. A number of the other submissions on the draft determination suggested that Authority should also account for a risk weighted 'expected' load, that takes account of loads that have not yet reached FID.[21]

93. The Authority considers that 'latent' or 'expected' demand does not provide a basis for determining incremental load, as it is not consistent with the spirit of the test. If the forecast incremental load fails to materialise, existing network users potentially could incur the costs of the augmentation over and above any actual net benefits. The Authority's view in this context is that there is nothing to prevent either Western Power, or new loads for that matter, taking on the risk of investment in additional new assets that are beyond the NFIT value, paid for either by:

- the new load customers, as a contribution; or
- by Western Power, and placed in a speculative investment fund.

As additional new loads eventuated beyond those included in the NFIT, Western Power or customer contributions would be recompensed.

94. Overall, the Authority remains of the view that the Extension Hill load is not reasonably assured at this point in time. The Authority considers that the reasonably assured new loads that will support new incremental revenue for the MWEP include:[22]

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[20] Extension Hill Pty Ltd 2011, Submission on the ERA Issues Paper on the Regulatory Test Application for the Mid West Energy Project (Southern Section), www.erawa.com.au, 11 January, p1.

[21] For example, see Mid West Development Commission 2011, *Submission on the Draft Determination*, www.erawa.com.au, December.

[22] Note that the natural load growth in the Geraldton region is excluded, as this is assumed to be similar both 'without MWEP' and 'with MWEP', and hence will not deliver incremental revenue.

- KML's Stage 1 block load of 120 MW;[23]
- new wind generation between Pinjar and Eneabba of 275 MW.[24]

Existing transmission prices

95. The test evaluates the amount of incremental revenue that would be derived from the new connections made possible by the augmentation, *measured at existing transmission prices*. The use of existing prices in the calculation is important, as it ensures that existing customers are not paying higher prices to support the expansion of the network, simply to service the new load. In other words, existing customers should not be required to subsidise the connection of new loads, where those existing customers do not receive a net overall benefit.

96. However, Western Power used an estimate of the value of the new transmission assets in order to derive a 'new' transmission nodal price at Three Springs of around $125.46 per kW per annum, and applied this price to the new loads. The Authority's view in its draft determination was that this sets up a circularity, whereby the cost of the new assets is used to develop transmission prices, which in turn are used to justify the cost of the new asset. Accordingly, the Authority's view was that Western Power's approach was flawed, and that Western Power should have used the existing transmission price at Three Springs, of $73.50 per kW per annum (around $8.39 per MWh at a 100 per cent load factor).

A revised 'existing prices' incremental revenue

97. At the time of the draft determination, the Authority estimated that the net present value of incremental revenue for the purposes of the MWEP (over 40 years) would be:

- almost halved if the Extension Hill load was disallowed but Western Power's incremental price was used (reduced from $206 million to roughly $120 million); and
- further reduced if the existing Three Springs price is used (to roughly $85 million).

Average tariff analysis of incremental revenue

Western Power's average tariff analysis

98. In response to the draft determination, Western Power undertook further average tariff analysis based on the DWAT approach in order to demonstrate that existing customers would not be worse off. The formula for a DWAT calculation divides the net present value of expected future revenues by the net present value of the quantity of energy sold, all taken over the life of the asset.

99. Western Power's DWAT modelling is based on the third Access Arrangement (**AA3**) financial model, but extended out a further ten years through the fourth (AA4) and fifth (AA5) access arrangement periods.[25] The model utilises a range of

[23] Western Power's standard load factor assumption for new block loads is 70 per cent.

[24] The Authority's assumption for 275 MW of new wind generation is set out at paragraph 136 below.

[25] A copy of the extended AA3 financial model was provided by Western Power to the Authority.

assumptions about future capital expenditure and demand growth. Western Power's model estimates that:

- absent the MWEP, the DWAT for AA3 through AA5 would be around $32 per MWh (real dollars as at 30 June 2010);
- as the DWAT of the full $379 million capital cost of the MWEP with the Karara load and additional wind generation is more than $30 per MWh, it is not possible to roll the full value into Western Power's capital base without lifting the DWAT; and
- however, $223 million (real dollars at 30 June 2010) of MWEP capital could be rolled into the capital base without increasing the transmission network average DWAT above $32 per MWh.

100. The Authority appreciates the effort made by Western Power to develop an additional point of reference for the incremental revenue. The Authority considers that the underlying Western Power DWAT approach is sound. Nevertheless, the Authority questions the levels of untested new growth capital expenditure that is included in the model. This has the effect of lifting the DWAT from around $19 per MWh when data from AA2 is used, to around $32 per MWh when data from the period of AA3 to AA5 is used. In the Authority's view, this undermines the utility of Western Power's modelling for the purpose at hand.

The Authority's average tariff analysis

101. Given this view, the Authority has developed an estimate of the existing 'average tariff' for 2011-12, of $16.09 per MWh (real dollars at 30 June 2010) (Appendix 1 provides greater detail on the calculations underpinning this estimate). This average tariff is a static single year figure, whereas the DWAT is an average tariff over a longer period. This average tariff estimate also takes out the cost pool relating to transmission connections, which are a significant component of the system wide average transmission tariff, but are not relevant for the cost of the MWEP.

102. The Authority considers that $16.09 per MWh is the closest estimate of the relevant average transmission tariff for transmission services applicable at the commencement of the MWEP, given approved capital expenditures to date. It thus provides a robust basis for the average tariff approach to estimating the incremental revenue.

103. The Authority's corresponding estimate for the amount of MWEP capital that may be included in the capital base without disturbing the average transmission tariff for the system (excluding transmission connections revenue) is $181 million (real dollars at 30 June 2010) (see Appendix 1 for greater detail). This estimate is based on new incremental use 'with MWEP' of both the KML Stage 1 block load, and 275 MW of new wind generation connecting to the MWEP.

Existing prices versus average tariff analysis of incremental revenue

104. In assessing these results, the Authority had cause to question the large difference between the incremental revenue that would be allowable under the existing pricing approach ($85 million), compared to the amount that would be allowable under the average tariff approach ($181 million).

105. Analysis by the Authority suggests that this discrepancy is the result of the large difference between the load factor of the new KML block load (70 per cent) and the implicit existing average nodal load factor underpinning the existing price for large transmission users at the Three Springs node (around 35 per cent). If this load factor difference was taken into account in the existing prices calculation, then the incremental revenue would be very similar to that developed through the average tariff approach.

106. The implication is that the incremental revenue estimated through the methodology of multiplying incremental loads by existing transmission prices, is only likely to be accurate where the existing nodal average transmission load factor is close to that of the new incremental loads. This might be the case for an augmentation in an existing major mining region, but is unlikely to be the case for a large transmission augmentation such as the MWEP delivering a step change in the amount of possible load. This issue may be overcome by applying a load factor adjustment.

107. However, the Authority considers that the average tariff approach provides an equivalent, and potentially simpler, means to estimate allowable capital under the incremental revenue test.

Incidence of the allocation of increased costs

108. With such a large augmentation and the implied change in electrical flows on the system, Western Power would likely need to re-balance the pattern of allocation of transmission charges between nodes to ensure cost reflective transmission prices. The likely outcome would be that some transmission customers would face higher charges, and some lower charges – even as the overall revenue requirement remained the same.

109. The Authority has assessed that the incidence of any increase in transmission tariffs is likely to be fairly uniform across different (large and small) customer types.[26] To show this, the Authority has broken down the overall average transmission tariff into its 'small customer' and 'large customer' components. The Authority has then added in the allowable incremental annual revenue and load for the MWEP to the 'large customer' pool, to evaluate the impact on the average tariff for each type of transmission customer.

110. First, estimates by the Authority indicate that the existing 2011-12 average transmission tariffs for 'large customers' – excluding connection charges – are somewhat higher than for 'small customers' (Table 4).[27]

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[26] Western Power has stated that with the *total cost* of the MWEP of $383 million, customers would likely face higher network charges of around 2 per cent on average *if there were no offsetting benefits for the system*. Given network charges are around half of final electricity prices, this equates to an average retail electricity price increase of less than 1 per cent. Western Power has also stated that transmission charge increases are likely to be higher, the closer they are to the MWEP augmentation. The Authority notes that the net benefits (see the next section) will work to offset the majority of any increase in transmission charges incident on some customers.

[27] It is worth noting that if connection charges are included, then both customer types pay almost identical average tariffs.

Table 4 2011-12 Western Power transmission average tariff by customer type (excluding connection charges) – without MWEP

	All customers average	Small customers	Large customers
Existing revenue ($m June 2010)	303	191	112
Energy transported (GWh)	18,816	14,094	4,722
Average transmission tariff ($/MWh)	**16.1**	**13.6**	**23.6**

Source: Economic Regulation Authority, based on data contained in Table 6 and Table 10 of Western Power 2011, *2011/12 Price List Information*, www.erawa.com.au.

111. Second, the incremental revenue for the MWEP from the average tariff analysis (of $13 million – see Table 8 in Appendix 1) and the incremental load (of 856 GWh) may be added to the relevant values in Table 4, assuming that these costs will accrue to 'large customers'. This does not change the overall 'all customers' average transmission tariff or that for 'small customers' (the results are shown in Table 5, with the percentage changes in the last row). However, the average transmission tariff for 'large customers' falls.[28]

[28] The additional 'with MWEP' incremental annual revenue and load has an average tariff equivalence that is the same as the 'all customers' average (by definition – as this 'with MWEP' addition must not perturb the 'all customers' average tariff). As this average tariff equivalence is lower than the existing average tariff for large customers in Table 4, the addition of the MWEP amounts to the large customer pool in Table 5 reduces the large customers' average tariff.

Table 5 2011-12 Western Power transmission average tariff by customer type (excluding connection charges) – with MWEP incremental revenue and energy transported added in

	All customers average	Small customers	Large customers
Existing revenue ($m June 2010)	303	191	112
MWEP annual incremental revenue that does not peturb 'all customers' average tariff ($m June 2010)	14	0	14
Total transmission revenue with MWEP ($m)	**316**	**191**	**125**
Existing energy transported (GWh)	18,816	14,094	4,722
MWEP incremental load (GWh)	856	0	856
Total energy transported with MWEP (GWh)	**19,673**	**14,094**	**5,578**
Average tariff with MWEP ($/MWh)	**16.1**	**13.6**	**22.5**
Increase in average tariff from adding in MWEP (per cent)	0%	0%	-5%

Source: Economic Regulation Authority

Conclusions on incremental revenue

112. The Authority considers that the average tariff approach provides an acceptable means to inform the amount of capital allowable under the incremental revenue condition of the NFIT for a large transmission augmentation.

113. On this basis, the Authority considers that an amount of $181 million (real dollars at 30 June 2010) could be pre-approved for the purposes of this NFIT under the incremental revenue test.

Net Benefits Test

114. The net benefits test refers to the test under section 6.52(b)(ii) of the Access Code to determine whether the 'new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs'. Under the Code, 'net benefit' is limited to net benefits accruing to those who generate, transport and consume electricity in, as the case may be, the covered network and/or any interconnected system.

Western Power's proposal

115. Western Power proposes that net benefits are likely to arise from four sources:

- reductions in the total cost of energy to consumers;
- changes in the costs and revenue of generation on the WPN;
- deferral of planned network reinforcements that would need to be implemented to maintain a safe and reliable supply to customers in the Geraldton region if the proposed augmentation was not built; and
- reductions in network losses.

116. Western Power estimated in its original submission that the present value of the total net benefits arising from the MWEP augmentation amount to $271 million, comprising (Table 6):

- $236 million in net 'generation' benefits to consumers and generators – being the sum of net increases in revenues and net reductions in costs; comprising:
  - $149 million in reductions in the total cost of energy to consumers;
  - $87 million in net benefits for generators;
- $26 million from the deferral of network reinforcements that would otherwise be required; and
- $9 million from reduced transmission network losses.[29]

117. These net benefits were based on Western Power's High Load Case for load growth in the north region (Table 6).

118. The majority of the $236 million in net benefits for generators and consumers derives from the ability to connect an additional 230 MW of new wind capacity with the MWEP, which would not be possible otherwise. These benefits were estimated for Western Power by ACIL Tasman during 2010, utilising their bottom up model of the Wholesale Electricity Market.

[29] Western Power, New Facilities Investment Test Application, p20.

Table 6 Western Power's estimates of net benefits ($ million)

Benefit		Net Present Value
Reductions in total cost of energy to consumers	$149	
Net benefits to consumers		$149
Reduction in revenue to generators	($149)	
Fixed Costs for new entrant plant	($227)	
Change in variable costs for all plant	$271	
REC revenue	$192	
Steam revenue	$1	
Net benefit to generators		$87
Deferral of planned network reinforcements that would need to be implemented to maintain a safe and reliable supply to customers if the proposed augmentation was not built		$26
Reduction in network losses		$9
Total Benefits		**$271**

119. In its draft determination, the Authority had a number of concerns in relation to the ACIL Tasman analysis, specifically:

- whether the assumptions underpinning the ACIL Tasman analysis were robust, given the significant recent changes in the economic and policy environment;
- the choice of counterfactual scenarios – relating to the assumptions around the ability or otherwise to connect new wind generation;
- the potential for an overestimate in the benefits of increased wind generation capacity.

120. In the draft determination, the Authority also sought clarification from Western Power on the claimed network deferral benefits.

121. In the draft determination, the Authority accepted Western Power's estimates of the reductions in network losses.

Considerations of the Authority

122. The Authority has considered each of the issues identified in paragraphs 119 to 121, taking into account further material provided by Western Power in its submission on the draft determination, as well as the submissions of other stakeholders on the draft determination.

123. The Authority's consideration of these matters is set out in what follows.

Robustness of the ACIL Tasman assumptions

124. The ACIL Tasman analysis was conducted during the early part of 2010, and completed in June 2010. Key changes since that time that might have a material impact on the estimates include:

- revisions to the Commonwealth Government's carbon pricing scheme;
- revisions to the Commonwealth Government's renewable energy schemes;
- revisions to the Wholesale Electricity Market (**WEM**) rules relating to capacity credits for wind generation; and
- estimated generation costs.

125. The Authority in its draft determination considered that there was significant uncertainty surrounding these elements and the resulting case for increased wind generation. The Authority sought additional analysis to determine whether the net benefits were highly dependent on outcomes for these elements.

126. ACIL Tasman provided further support in Appendix 3 of the Western Power submission for its estimates of the 'generation' benefits.[30] As part of this work, ACIL Tasman re-ran the *RECMark* model of the market for renewable energy generation certificates to update the assumptions supporting the case for new wind generation in the 'with MWEP' and 'without MWEP' counterfactuals.

127. ACIL Tasman notes that in the revised *RECMark* modelling, the higher capacity payments and higher black energy prices in Western Australia mean that wind farms located in Western Australia are among the most profitable in Australia. However, in relation to the updated assumptions, ACIL Tasman observe:[31]

> ... there are a number of recent actual and potential changes which have reduced this advantage [for wind generation in Western Australia] including:
>
> i) potential increase in ancillary service costs in WA (i.e. the $10 to $15/MWh load following charge)
>
> ii) generally much higher transmission connection charges in WA which were not fully accounted for in ACIL Tasman's earlier study
>
> iii) increased black energy prices in eastern Australia due to higher expected future gas prices associated with LNG developments in Queensland
>
> iv) potential reduction in black energy price for WA wind farms through reduction in proportion of capacity attracting capacity payments

[30] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3.

[31] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3, p5.

v) lower carbon price trajectory

vi) updated renewable project database including more proposed wind farms in WA and an allowance for the higher transmission connection costs in WA.

However, because of their higher capacity factor of generally around 40%, the wind farms in the north which would rely on the MWEP, would still be among the first to be developed in Australia assuming transmission and system constraints are alleviated; even assuming a transmission connection cost of over $200/kW. However wind farms with capacity factors in the low 30% range, such as those proposed in the south of the WPN, will be marginalised by these developments particularly with the high transmission connection cost.

128. On the basis that wind generation in the central and north regions of the WPN has generally higher capacity factors than that in the south, ACIL Tasman argues that – if anything – the case for the location of wind in the central region of Western Australia is strengthened. ACIL Tasman's views are discussed further in what follows.

Revisions to the Commonwealth's carbon pricing arrangements

129. In relation to carbon prices, the Authority expressed concern in its draft determination that the Treasury's forecast carbon price trajectory with the (now legislated) Clean Energy Future (**CEF**) policy is significantly lower than that for the (now defunct) Carbon Pollution Reduction Scheme (**CPRS**) policy. ACIL Tasman adopted the CPRS carbon price trajectory for all its net benefits modelling scenarios.

130. In response to this concern, ACIL Tasman noted that variations to the carbon price are essentially second order in effect in terms of its estimates of the generation net benefits.[32] This is because:

- the same carbon price trajectory is assumed in the 'with MWEP' and 'without MWEP' counterfactuals – so while a change in the carbon price trajectory could have an effect on the underlying load growth trajectory, this would affect the 'with MWEP' and 'without MWEP' cases equally, and thus would not affect significantly the estimated benefits of introducing the MWEP;[33]
- the Large scale Renewable Energy Scheme is effectively a quantity target for 41,000 GWh of renewable energy generation by 2020, hence the supporting Large-scale Generation Certificate **(LGC)** prices provide a 'swing' factor to compensate for variations in the carbon price and in black energy prices;
- lower carbon prices and black energy prices will imply higher LGC prices, all other things equal, and vice versa – the carbon price plus the LGC price together provide the subsidy for new renewable generation;
- the corollary is that the future plant program in the WEM, particularly for new wind generation, is unlikely to be affected by any variations in the future carbon price trajectory.

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[32] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to draft determination for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3.

[33] It is worth observing that that a lower carbon price trajectory under the CEF would, if anything, support faster load growth compared to the CPRS policy, and thus increase the benefits of the MWEP.

131. On this basis, the Authority accepts that changes in the Commonwealth's carbon pricing arrangements will not have a material impact on generation net benefits estimated in the original ACIL Tasman modelling.

Revisions to the Commonwealth's renewable energy schemes

132. As noted above, in response to the Authority's comments in its draft determination, ACIL Tasman re-ran their *RECMark* model to update for recent changes to the Commonwealth's renewable energy schemes since the original run in 2010, as well as for other changes in the economic and policy environment.

133. This leads to revised prices for the new LGCs, which replace the previous Renewable Energy Certificates (**RECs**). The factors affecting the overall LGC prices in the latest *RECMark* modelling include:[34]

- increased black energy prices in eastern Australia due to higher expected future gas prices associated with LNG developments in Queensland – this would tend to reduce LGC prices, all other things equal;
- a potential increase in ancillary service costs in Western Australia (that is, the $10 to $15/MWh load following charge) – this would tend to increase LGC prices, all other things equal;
- generally much higher transmission connection charges in Western Australia which were not fully accounted for in ACIL Tasman's earlier study – this would tend to increase LGC prices, all other things equal;
- a potential reduction in black energy price for Western Australian wind farms through the rule change reduction in the reserve capacity credit payments – this would tend to increase LGC prices, all other things equal;
- the lower carbon price trajectory with the CEF – this would tend to increase LGC prices, all other things equal;
- an updated renewable project database including more proposed wind farms in Western Australia – it is not clear what impact this has on LGC prices (although greater availability of low cost wind generation from Western Australia may tend to reduce LGC prices).

134. Overall, the higher black energy prices in the east dominate other factors in the latest *RECMark* modelling. ACIL Tasman observe:[35]

> One output of the *RECMark* modelling is the LGC price which is noticeably lower in the current modelling results than the estimates made in mid 2010 and used in the original study. This has occurred because of the noticeably higher black energy prices now projected in eastern Australia resulting from higher gas prices due to the additional demands from LNG developments in Queensland.

135. ACIL Tasman report that with the new *RECMark* modelling, LGC prices are around 15 per cent lower than in the original modelling results.[36] This is a significant issue,

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[34] Ibid, p5.

[35] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to draft determination for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3, p8.

as LGC revenue provides for some $193 million of the total estimated benefit of $207 million in the preferred ACIL Tasman Scenario 4 (the remaining $14 million arising from savings in generation costs). Options to deal with this include:

- reducing the LGC revenue in scenario 4 by around 15 per cent, giving LGC revenue of $164 million, which when added to $14 million of savings in generation costs gives a total scenario 4 generation net benefit of $178 million; or
- recognising that at least 15 per cent more wind generation is likely to connect 'with MWEP' compared to the 230 MW assumed in the original ACIL Tasman modelling (see next section, which concludes that up to 275 MW is possible even with Western Power's Central Load forecast) – which would be sufficient to offset the decline in LGC prices.

136. The Authority's view is that the revised modelling suggests that up to 275 MW is likely 'with MWEP', hence it is prepared to accept the estimated 'generation' benefits from Scenario 4, all other things equal.

Revisions to the allocation of capacity credits to wind in the WEM

137. The issue of what amount of reserve capacity credits to assume for new wind generation is relevant to assessing the net benefits of the MWEP. In assessing the 'generation' benefits, the ACIL Tasman modelling assumed a capacity credit rate for wind of:

- 40 per cent of name plate capacity in its Base Case scenario and in Scenarios 2 and 5; and
- 20 per cent of name plate capacity, as a sensitivity, in scenarios 3, 4 and 6.

138. However, the Independent Market Operator (**IMO**) has adopted a rule change for calculating the capacity credits for intermittent generation. The rule change took effect on 1 January 2012. The rule change has the effect of reducing the capacity credits available to wind generation, on average.

139. In its Final Rule Change the IMO adopted the proposed amendments set out in rule change RC_2010_25, albeit modified by a number of amendments outlined in the Draft Rule Change Report (this rule change with amendments is referred to as 'modified methodology 1').[37] A glide path over the Reserve Capacity Cycle periods 2012 - 2014 gradually adjusts the amount of capacity credits awarded to intermittent generation, to align with the new rule.

140. 'Modified methodology 1' may be summarised as allowing capacity credits for intermittent generation based on the:

[36] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3, Figure 1, p9.

[37] Independent Market Operator 2011, *Final Rule Change Report: RC_2011_25 & RC_2010_37*, www.imowa.com, p13.

'Facility Average Performance Level' in MW during the top 12 trading intervals drawn from separate days from the most recent five year period, less a 'Facility Adjustment Factor' in MW, where:[38]

- a highest 'Load for Scheduled Generation' methodology (with amendments) is utilised to determine the Facility Average Performance Level in MW of the top 12 trading intervals;
- the Facility Adjustment Factor = min (G x Facility Variance, Facility Average Performance Level/3 + K x Facility Variance);
- G= K + U/(Facility Average Performance Level) reflects both known variability (reflected in K) and uncertainty of the distribution of output (reflected in U/Facility Average Performance Level);
- K and U are parameter values determined by the IMO; and
- all averages and variances are determined over the same peak Trading Intervals from facility output measured in MW.

141. The parameter values adopted reflect the advice of the technical consultant Sapere.[39] Based on the recommended values, Sapere estimates that the resulting *average* capacity credits for wind generation on the WPN would be around 25 per cent of nameplate capacity, with specific facilities falling in the range of 12 per cent to 39 per cent.[40]

142. In light of this, the Authority considers that ACIL Tasman's Scenario 4 and 6 modelling best informs the net benefits of new wind generation, all other things equal. Scenarios 3, 4 and 6 assume a 20 per cent reserve capacity credit rate for new wind generation (compared to 40 per cent in the other scenarios). These scenarios are thus conservative with respect to the final rule change, and may be reasonably adopted on this count.

Choice of counterfactual scenario

143. The issues raised by the Authority relating to choice of the ACIL Tasman counterfactual scenarios relate to:

- the amount of wind entry in the 'without MWEP' case; and
- the amount of wind entry in the 'with MWEP' case.

Wind entry in the 'without MWEP' case

144. In its draft determination, the Authority sought additional information to support the case for the constraint on wind entry in the 'without MWEP' scenarios.

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[38] Independent Market Operator 2011, *Draft Rule Change Report: RC_2011_25 & RC_2010_37*, www.imowa.com, p23.

[39] Sapere 2011, *Capacity value of intermittent generation: Public report*, www.imowa.com.

[40] Ibid, p vi and p x.

145. In response, Western Power in its submission on the draft determination noted that:[41]

- Technical issues prevent additional wind generation connections in the east region of the SWIS.

- It would be possible to connect an additional 290 MW of new wind generation in the south region of the SWIS from 2015, once technical issues – including limited capacity in the 132 kV network between Muja and Perth – are resolved. ACIL Tasman's modelling reflects this advice – there is 285 MW of new wind generation in the south region from 2015.

- This new wind generation entry in the south is included in both the 'with MWEP' and 'without MWEP' scenarios.

- After 2015, new wind generation in the south is limited, due partly to the assumption that a further step change in transmission capacity does not occur before 2020, and due partly to the assumed termination of the then Renewable Energy Certificate Scheme in 2030.

146. Western Power also notes that if constructed, the Muja-Southdown transmission line may also facilitate connection of new wind generation. However, Western Power argues that as new magnetite developments would not crowd each other out, and as it is more profitable for wind generation to connect in the central and northern regions of the WPN, then it is more likely that the wind generation would enter in the central and northern regions, even if the Grange Resources Southdown magnetite project goes ahead.

147. The Authority notes in this context that the Southdown project has yet to reach Final Investment Decision, and is thus not reasonably assured. On this basis, the Authority accepts that new wind generation on the WPN – over and above the additional wind generation identified by ACIL Tasman from 2015 – has a low probability. The Authority therefore accepts the wind generation scenario adopted by ACIL Tasman for the 'without MWEP' scenarios.

Wind entry in the 'with MWEP' case

148. In its draft determination, the Authority sought additional information to support the case for new wind entry in the 'with MWEP' scenarios. The Authority was concerned that without the Extension Hill block load, there may not be sufficient demand to support the 230 MW of new wind generation in the Central region of the WPN, which underpinned the ACIL Tasman estimates of the 'with MWEP' generation net benefits.

149. In relation to the scenarios for load growth, ACIL Tasman note that their original modelling report provided for sensitivity analysis on load growth.[42] In particular,

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[41] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, p25.

[42] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3, p2.

Scenarios 1 to 4 of their original report corresponded to Western Power's Central Load Case – which only includes Stage 1 of the KML development (a block load of 120 MW of contracted maximum demand).

150. Western Power in its submission on the Draft Decision states that:[43]

- The benefits of wind in the Central Load Case are still significant.
  - First, the MWEP creates scope for an additional 155 MW of wind generation without any new block loads on the WPN – due to the network reinforcement relieving existing power transfer constraints.[44] This is because new wind generation made possible by the MWEP can displace existing generation on the system.
  - Second, a further 120 MW of new wind can be supported by the new KML Stage 1 block load. The sum of these two quantities gives a total of 275 MW of new wind being feasible under the Central Load scenario with MWEP.
- ACIL Tasman updated their *RECMark* modelling at the behest of Western Power so as to respond the Authority's draft determination.[45] The factors accounted for in the updated *RECMark* modelling include:
  - a potential increase in ancillary service costs in Western Australia to a $15/MWh load following charge;
  - generally much higher transmission connection charges in Western Australia which were not fully accounted for in ACIL Tasman's earlier study (up to $217/kW for new wind generation);
  - increased black energy prices in eastern Australia due to higher expected future gas prices associated with LNG developments in Queensland and a potential reduction in black energy price for Western Australian wind farms through the rule change reduction in the reserve capacity credit payments;
  - the lower carbon price trajectory with the CEF;
  - an updated renewable project database including more proposed wind farms in Western Australia;
- The updated *RECMark* modelling suggests that even with $70/kW transmission connection charges in the south, and $217/kW in the north, that (1,065 MW north of Pinjar plus 57 MW south of Pinjar equals) 1,122 MW of new wind generation which would be possible 'with MWEP'. This compares to (0 MW north of Pinjar plus 795 MW south of Pinjar equals) 795 MW 'without MWEP' – a difference of 327 MW compared to the 'with MWEP'

[43] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, p32.

[44] Western Power 2011, *Submission to the Economic Regulation Authority: New Facilities Investment Test pre-approval application: Mid West Energy Project (southern section)*, www.erawa.com.au, Attachment 2 (Planning Considerations), p20.

[45] Western Power 2011, *Submission to the Economic Regulation Authority: Western Power's Response to Draft Decision for NFIT Pre-approval of Mid West Energy Project (southern section)*, www.erawa.com.au, Appendix 3.

counterfactual. A significantly higher difference is possible if higher transmission connection charges in the south are assumed, and if additional wind generation could connect north of Eneabba 'with MWEP'.

- Together, these elements suggest that at least 230 MW of new wind generation can be supported 'with MWEP' compared to 'without MWEP', and possibly much more.

151. The Authority notes that Western Power, in its original submission, adopted ACIL Tasman's Scenario 5 analysis to inform the net benefits. Scenario 5 was predicated on Western Power's High Load Case – which includes KML mining Stage 2+ and the Extension Hill mining Stage 1 block loads. The Authority considers that as these two major block loads have not reached Final Investment Decision, they are not reasonably assured.

152. However, the Authority is satisfied that KML Stage 1 is reasonably assured. Based on the analysis set out above, the Authority therefore accepts the use of ACIL Tasman's modelling Scenarios 1 to 4 for the purposes of estimating the net benefits of the MWEP.

153. As a corollary, the Authority is further satisfied that an addition of a minimum of 230 MW of new wind generation can be supported 'with MWEP', as is assumed in ACIL Tasman's modelling Scenarios 1 to 4.

154. The Authority considers that Scenario 4 is likely to approximate conservative outcomes with respect to:

- reserve capacity credits for intermittent generation; and
- load following costs.

155. On this basis, the Authority accepts that ACIL Tasman's estimated benefits for Scenario 4 – of $207 million – may be used to inform the 'generation' benefits for the NFIT.

Benefits associated with increased wind generation

156. The incremental revenue analysis provided by Western Power in its original submission included estimated incremental revenue of $19 million for the new Central region wind generators' payment of transmission use of system charges. However, as this payment is a cost to new wind generators, it is in effect a transfer from generators to the network, rather than a net benefit. As it had been counted as incremental revenue, the Authority considered that the corresponding costs should be included in the net benefits component of the NFIT, so as to avoid double counting.

157. The revised estimate of incremental revenue used for this final determination – which is based on the DWAT approach and which is set out above and in Appendix 1 – also includes benefits associated with wind generation transmission use of system.

158. On this basis, the Authority remains of the view that there is a double count, and that the ACIL Tasman estimates of the benefits of the MWEP should be discounted by the amount of this estimated cost to wind generators – of $19 million.

Net benefits from deferral in network augmentation

159. Western Power in its original application estimated a network deferral benefit of the MWEP of $26 million.[46]

160. The Authority in its draft determination did not have a problem in principle with Western Power's approach to estimating the network deferral benefit. Further, the Authority considered that the assessment of the 'without MWEP' scenario net present cost (**NPC**) of network reinforcement for the Geraldton region (Option 1) was demonstrated in Western Power's original application.

161. However, the Authority considered that there was a lack of information provided in the application to support Western Power's 'with MWEP' NPC estimate of $164 million of network reinforcement for the Geraldton region (Option 6), and hence the resulting estimate of the net benefit of $26 million (which was based on the difference between Option 1 and Option 6).

162. Western Power subsequently provided the Authority with the following explanation for the 'with MWEP' reinforcement cost estimate and implied overall benefit:[47]

> The benefit stems from network reinforcement for the Mid West region north of Eneabba under two scenarios:
>
> - the 'without MWEP' scenario (Options 1 to 5)
> - the 'with MWEP (Southern Section)' scenario (Option 6)
>
> The least cost network reinforcement option under the 'without' scenario is estimated to be $190M in net present cost terms (NPC) (i.e. Option 1). The least cost network reinforcement option under the 'with' scenario is $189.8M in NPC terms (i.e. Option 6). This cost includes ($26M NPC) for the Three Springs Terminal (transformer and substation related work) that will be part of the Mid West Energy Project (MWEP) (Southern Section). The $26M cost will be sunk once the MWEP (Southern Section) is built. Therefore, the additional cost required to implement this option is really $164M.
>
> Comparing the 'with' scenario to the 'without' scenario indicates a cost saving of $26M (i.e. $190M less $164M).

163. The Authority is satisfied with Western Power's explanation of its derivation of the network deferral benefit. The Authority agrees that to include the $26 million as part of Option 6 would be a double count.

164. However, two additional issues also have bearing on the estimate:

- the Authority's view that Western Power's Central Load Case should be used for the purposes of estimating the NFIT net benefits – as discussed in paragraphs 150 to 157 above; and

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[46] Western Power 2011, *New Facilities Investment Test pre-approval application Mid West Energy Project (Southern Section) - Neerabup to Three Springs Terminal via Eneabba*, www.erawa.com.au, Attachment 2, p 24. (Attachment 2 of the New Facilities Investment Test Application is Western Power 2010, *Planning Report: North Country: Transmission System Reinforcement*/)

[47] Western Power 2011, Explanation of MWEP (Southern Section) network reinforcement benefit, letter dated 21 December.

- the value of the Three Springs Terminal transformer and associated works of $26 million.

165. In relation to the first issue, Western Power's application estimate of the network deferral benefits set out above were based on load growth in the Geraldton region associated with its High Load Case. The estimate thus needs to be adjusted to align with that for the Central Load Case, so as to ensure consistency with the approach in the rest of this final determination.

166. Second, the Authority does not accept the case for the 450 MVA transformer at Three Springs (paragraph 57 refers). The Authority in this final determination requires Western Power to reduce the cost of these works by $1.07 million. The resulting 'sunk cost' is thus not $26 million, but $24.9 million. However, this adjustment does not have bearing on the calculation of the network deferral benefit here – as the $26 million was used by Western Power for the purposes of the Option 6 estimate, and is being taken out.

167. On this basis, the least cost network reinforcement option under the 'without MWEP' scenario is estimated by Western Power to be $170 million in net present cost terms (Option 1 with the Central Load Case). The corresponding least cost network reinforcement option under the 'with MWEP' scenario is estimated to be $134 million.[48] The net benefit is the difference between the two scenarios and is $36 million.

168. The Authority thus considers that $36 million of network deferral benefit may be included for the purposes of estimating the net benefits of the MWEP.

Net benefits from a reduction in transmission losses

169. The MWEP will deliver reduced transmission losses. The reduced costs of transmission losses are likely to accrue either to generators or energy consumers. However, for the purposes of the net benefits test, it does not matter where these benefits go, provided that they accrue to those who 'generate, transport and consume electricity'.[49]

170. The Authority accepts Western Power's approach to estimating transmission losses. The Authority notes that the future value of the transmission loss reduction is uncertain, but that any variance is likely to be small in terms of the overall NFIT. On this basis, the Authority accepts that the amount proposed by Western Power – of $9 million – provides a reasonable estimate for this component of net benefits.

[48] The least cost network reinforcement option under the 'with MWEP' scenario is estimated to be $160 million in NPC terms (Option 6 with the Central Load Case). This cost included the estimated $26 million net present cost for the Three Springs Terminal (transformer and substation related work) that will be part of the Mid West Energy Project (MWEP) (Southern Section). These costs are part of the MWEP (Southern Section) project itself, and thus needs to be subtracted from the Option 6 total to allow the true difference between Option 1 and Option 6 to be calculated. Therefore, the *additional* cost required to implement this option 'with MWEP' is $134 million (that is, $160 million less $26 million).

[49] Government of Western Australia, Electricity Networks Access Code 2004, Section 6.52 (b) (ii).

Conclusions on net benefits

171. The Authority's determination on net benefits may be summarised as including the following net benefits associated with (real dollars at 30 June 2010):

- generation net benefits of $207 million, less the double count of $19 million, for a final generation net benefits amount of $188 million;
- a network deferral benefit of $35 million;
- a reduction in transmission losses of $9 million.

172. These elements sum to a total net benefit for the purposes of the NFIT of $233 million (real dollars at 30 June 2010).

APPENDICES

Appendix 1 Average tariff calculations

1. This Appendix sets out the Authority's analysis of the amount of capital to approve under the incremental revenue component of the NFIT, using the average tariff approach.

The discounted weighted average tariff

2. Average tariffs over a number of years may be combined to a single value through the discounted weighted average tariff (**DWAT**) approach. The DWAT is defined as the constant price in real terms (after correcting for inflation), which, applied to each unit sold over the evaluated life of the investment producing the product, gives the required overall rate of return on the investment.

$$DWAT = \frac{Present\ Value\ of\ Revenue\ over\ the\ evaluated\ life\ of\ the\ investment}{Present\ Value\ of\ Product\ Sold\ over\ the\ evaluated\ life\ of\ the\ investment}$$

The *Present Value of Revenue* is the sum, over all years of the evaluated life of the investment, of:

$$\frac{Revenue_t}{\left(1+\frac{r}{100}\right)^t}$$

where:

t	=	the year, counting from zero in the initial year
$Revenue_t$	=	revenue in year t
r	=	discount rate (%)

and where $Revenue_t$, and the discount rate may both be in real terms (corrected for inflation) or both be in nominal terms (not corrected for inflation).

The *Present Value of Product Sold* is the sum, over all the years of the evaluated life of the investment, of:

$$\frac{Quantity_t}{\left(1+\frac{r}{100}\right)^t}$$

where:

t	=	the year, counting from zero in the initial year
$Quantity_t$	=	quantity sold in year t
r	=	real discount rate (%)

3. The discounting of quantity sometimes causes conceptual difficulties. Note that it is not quantity as such which is being discounted, but the value of the quantity sold – it is part of the weighting process.

The average tariff base case

4. The first consideration is what base case to use for the average tariff calculation. This base case evaluates the average tariff for existing customers, prior to the MWEP.

5. Ideally, in line with the formula set out above, the base case average tariff would be developed from a DWAT based on the expected future stream of revenues and quantities of transmission services sold, over the 40 years from 2014, but without the MWEP or incremental loads associated with it.

6. Western Power endeavoured to estimate the expected future stream of revenues and quantities in this way by extending its financial model for the third Access Arrangement (**AA3**) – as set out at paragraph 98 above.

7. As noted, the Authority considers that the underlying Western Power DWAT approach is sound. Nevertheless, the Authority questions the levels of untested new growth capital expenditure that is included in the model. This has the effect of lifting the DWAT from around $19 per MWh when data from AA2 is used, to around $32 per MWh when data from the period of AA3 to AA5 is used. In the Authority's view, this undermines the utility of Western Power's modelling for the purpose at hand.

8. The Authority considers that a conservative, simple estimate of the transmission average tariff for the purposes of the NFIT may be developed by taking the value of the annual average transmission tariff (**AATT**) near to the time the MWEP is to be commissioned – expected to be in 2013-14. As 2013-14 falls in AA3, and as capital expenditure has not yet been approved for AA3, the Authority considers that the AATT for last year of AA2 – that is, for 2011-12 – provides the closest approximation to the AATT that is being paid by existing customers prior to the commissioning of the MWEP.

9. The Authority has utilised the approved financial model used for the AA2 transmission tariff determination for this estimate, which is set out in Table 7, and summarised in what follows.

10. First, for the purposes of the estimate, the Authority has adjusted the 2011-12 AATT from AA2 to incorporate approved capital expenditure in 2011-12 as well as to account for changes in the Weighted Average Cost of Capital (**WACC**). The latter adjustments account for recent changes in the estimates of the Risk Free Rate and of expected inflation – so as to ensure the WACC is forward looking from this point in time, consistent with current economic conditions. This has the effect of reducing the WACC to 6.23 per cent (the AA2 WACC was 7.98 per cent).

11. Second, as a further adjustment, the Authority has removed the component of the Maximum Tariff Revenue that relates to connection assets. The Authority considers that as these charges are paid by individual customers, they are separate

to the charges for transmission line services, as provided by the MWEP. This step deducts about 25 per cent of the total Maximum Tariff Revenue pool.[50]

Table 7 Estimated average transmission tariff for 2011-12 – excluding connection costs

Component	Value	Unit	Comment
Maximum tariff revenue	393.2	$ million	From the AA2 tariff model, but adjusted for a WACC of 6.23%
Connection revenue	101.7	$ million	Sum of entry and exit connection cost pool allocations from Table 10 in Western Power's 2011/12 price list information
Net transmission revenue	291.5	$ million	Difference of above
Energy transported	18,816	GWh	From the AA2 tariff model
Average tariff for 2011-12	16.09	$ per MWh	Division of above two rows

Note: All dollar values are 30 June 2010

Source: Economic Regulation Authority and Western Power 2011, *2011/12 Price List Information*, www.westernpower.com.au.

12. Based on the method outlined above in paragraphs 8 to 11 above, the Authority has determined that the AATT for 2011-12 is $16.09 per MWh (real dollars at 30 June 2010). This is the AA2 AATT for transmission transport services for 2011-12, but with the return on Western Power's capital base adjusted to yield the 6.23 per cent WACC for that year.

Calculating the MWEP's capital allocation consistent with the average tariff

13. The next step is to determine what capital value for the MWEP would produce the same average tariff as the existing 2011-12 system AATT. To do this the Authority assumes:

- a WACC of 6.23 per cent;
- a life of the MWEP asset of 50 years;
- a new incremental block load from the KML mine of 120 MW, which at an average load factor of 70 per cent implies a transmission use of system off take of 736 GWh per year;[51]

[50] The total Maximum Tariff Revenue in 2011-12 was nominal $417 million. The connection asset pool was $108 million (see Western Power 2011, *2011/12 Price List Information*, www.westernpower.com.au, p17. This left a total pool of $309 million in nominal terms, or June 2010 $291 million.

- new incremental wind generation connection in the Central region of 275 MW, at an average load factor of 25 per cent, paying 20 per cent of the full transmission network charges – giving an effective transmission use of system of 120 GWh per year 'sent out';
- there is no need to account for existing loads in the region – as these are assumed to be serviced by the existing system.

14. The total transmission use of system of the KML incremental block load (736 GWh) and the 275 MW of new wind generation (120 GWh) is 856 GWh per year. The Authority uses this GWh figure to back out the result that an annual incremental transmission revenue of $13.8 million would give an average tariff of $16.09 per MWh.

15. Given an assumed life for the MWEP asset of 50 years, and a WACC of 6.23 per cent, this annual revenue stream translates to a net present value of $210 million (real dollars at 30 June 2010).

16. As a final step, the Authority subtracts the net present value of the non-capital costs of the MWEP at a WACC of 6.23 per cent. This is a requirement of the incremental revenue test – only the capital component of the MWEP may be included in the capital base. Non-capital costs are estimated by the Authority, based on the estimates provided by Western Power as part of its pre-approval submission, to be $29.1 million (real dollars at 30 June 2010).

17. The amount of incremental revenue capital that would be allowable under this methodology for the purposes of the NFIT would be $181 million (real dollars at 30 June 2010). The foregoing calculations are summarised in Table 8.

18. If there was a shortfall in the pre-approval amount for the MWEP from this method, compared to the total cost of the MWEP, then the Authority considers that any shortfall could be placed in a 'speculative fund' or a contribution sought. This view was set out in the draft determination.

[51] A load factor of 70 per cent is Western Power's standard assumption for new major block loads.

Table 8 Estimated allowable capital from the average tariff approach

Component	Value	Unit	Comment
Allowable capital	181	million	NPV of incremental revenue, less NPV of non-capital costs
NPV of non capital costs	29	million	Net present value over 40 years, based on Western Power's estimates of annual non-capital costs
NPV of incremental revenue	210	million	Net present value of annual incremental revenue over 50 years life at WACC
WACC	6.23	%	AA2 WACC updated
Life of MWEP	50	years	Life of augmentation assets
Annual incremental revenue	13.8	million/yr	Derived from GWh use of system and weighted average transmission tariff
GWh use of system	856		KML mine Stage 1 plus 275 MW of new wind connection
Average annual transmission tariff 2011-12	16.09	$/MWh	Goal seek target - June 2010 prices

Note: All dollar values are $ June 2010

Source: Economic Regulation Authority