Decision on the Maximum Reserve Capacity Price Proposal for 2009/10

Submitted by the Independent Market Operator

30 January 2007

Economic Regulation Authority
WESTERN AUSTRALIA

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Economic Regulation Authority web site at www.era.wa.gov.au.

For further information, contact:

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

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DECISION

1. The Authority has approved the revised value for the Maximum Reserve Capacity Price (**MRCP**) of $142,200/MW.

2. The approved revised MRCP is for the time period 1 October 2009 to 1 October 2010 (**Review Period**).

3. This approval is granted pursuant to clause 2.26.1(b) of the *Wholesale Electricity Market Rules* (**Market Rules**).

4. The approval is granted on the basis that:

   a) the proposed value for the MRCP reflects the application of the method and guiding principles described in the clause 4.16 of Market Rules; and

   b) the IMO has carried out an adequate public consultation process.

INTRODUCTION AND OVERVIEW

Background

5. The Market Rules require the Authority to annually approve the MRCP proposed by the IMO.

6. The MRCP is used as a basis for payment of Reserve Capacity Credits in year three of the Reserve Capacity Cycle. That is, the MRCP proposed in year 2006 will be used as a basis for payment of Reserve Capacity Credits for the Review Period 1 October 2009 to 1 October 2010.

7. The MRCP proposal and approval process is outlined in Figure 1. The process to be followed is specified in clause 4.16 of the Market Rules (Attachment 1)

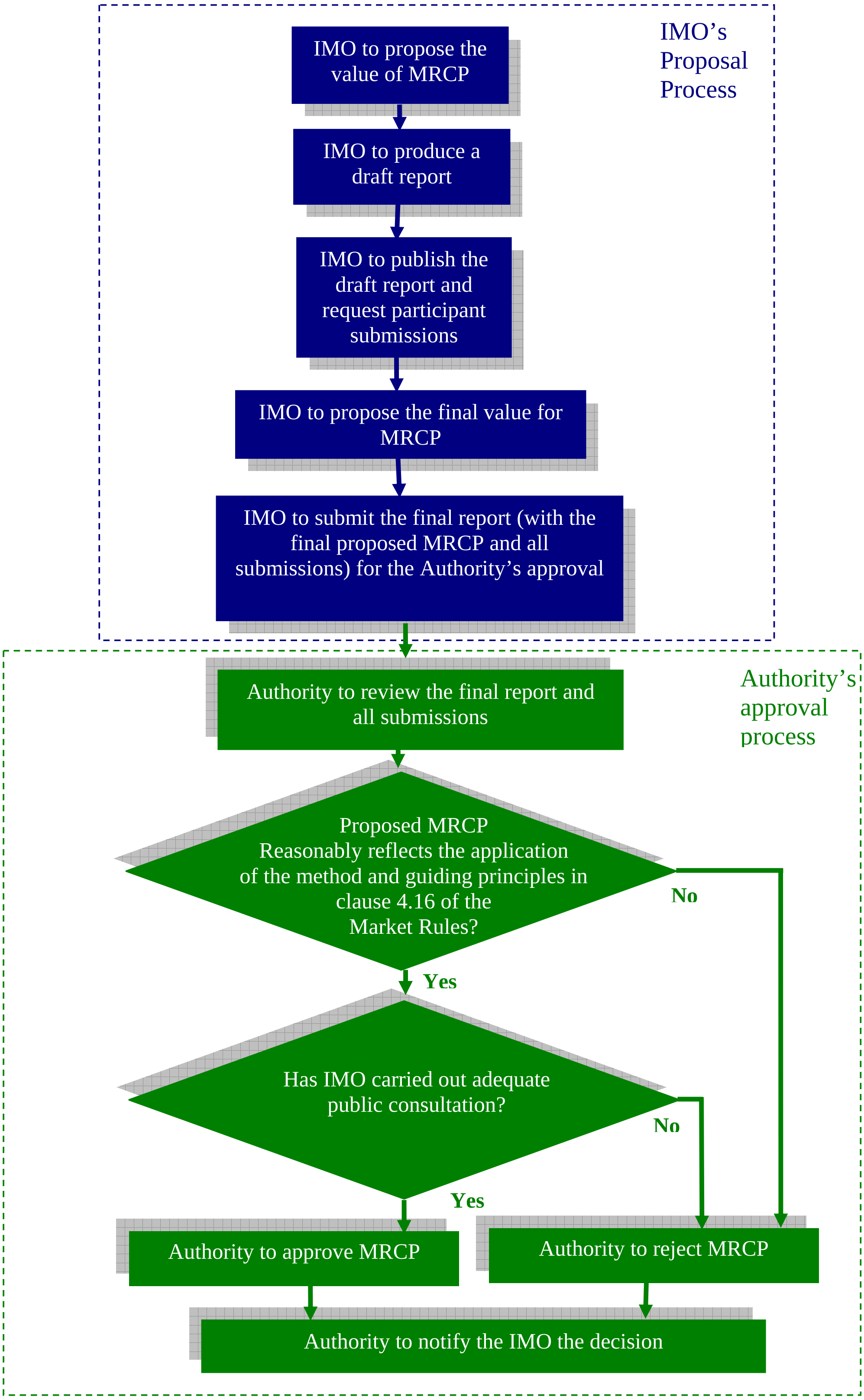
8. As seen in Figure 1, the process required by the Market Rules is as follows:

   a) **Draft Proposal**: the IMO must propose the initial value of MRCP in a draft report. This value must be based on the methodology specified in Appendix 4 of the Market Rules (**MRCP Methodology**) (Attachment 2). Clause 4.16.4 of the Market Rules requires the IMO to assess and evaluate specific input variables of the MRCP Methodology. The draft report must describe how the IMO has arrived at the proposed value.

   b) **Consultation Process**: The IMO must publish the draft report on its web site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australian energy industry, including end-users.

   c) **Final Proposal**: After considering the submissions on the draft report, the IMO must propose a final revised value for the MRCP and submit that value and its final report, including submissions received on the draft report, to the Authority for approval.

Figure 1: MRCP proposal and approval processes



9. To meet the requirements of the Market Rules in relation to the proposal process, the IMO has:

   a) produced the Draft Proposal:

      i) IMO employed engineering consultant Sinclair Knight Merz (**SKM**) to assist it in producing the draft proposal report.

   b) sought public consultation:

      i) IMO published the draft proposal report on the IMO's web site and advertised it in the West Australian newspaper on 21 October 2006. The IMO also published the SKM report on its web site (Attachment 3).

      ii) Three parties provided submissions in response to the draft proposal report. They include Alinta Sales (Attachment 4), Eneabba Gas (Attachment 5) and Beacon Consulting International (Attachment 6).

   c) produced the **Final Proposal**:

      i) After taking into consideration the submissions in the consultation process, the IMO produced the final proposal report (Attachment 7) for the Authority's approval.

10. As seen in Figure 1, the approval process required by the Market Rules is as follows:

    a) **Review of the proposal and submissions**: The Authority must review the report provided by the IMO, including all submissions received by the IMO in the preparation of the report.

    b) **Make Decision**: The Authority must make a decision as to whether or not to approve the final proposed value of the MRCP. To approve the MRCP, the Market Rules require the Authority to consider:

       i) whether the proposed value for the MRCP reasonably reflects the application of the method and guiding principles described in clause 4.16 of the Market Rules (Attachment 1); and

       ii) whether the IMO has carried out an adequate public consultation process.

    c) **Notify**: The Authority must notify the IMO of its decision.

11. In meeting the requirements of the Market Rules in relation to the approval process, the Authority has:

    a) reviewed the Final Proposal and all public submissions. The Authority has employed engineering consultant PB Associates (**PB**) to assist in this approval process;

    b) approved the Final Proposal for an MRCP of $142,200/MW; and

    c) notified the IMO of such approval.

The MRCP Methodology and Assessment of MRCP for Approval

12. The MRCP Methodology is outlined in Appendix 4 of the Market Rules and is also illustrated in Figure 2. As seen in Figure 2, the MRCP Methodology consists of a formula with various inputs variables. The dark green and black shaded areas in the figure indicate the input variables. The red area represents the MRCP Methodology itself. The purple shaded area represents the resulting MRCP.

13. Figure 2 also illustrates the approach to assessing whether the proposed MRCP reflects the method and guiding principles in the Market Rules. The assessment is carried out in two stages:

    a) Stage 1: Assessment of the value proposed for each input variable of the MRCP Methodology. Assessments of some of these variables are explicitly required by clause 4.16.4 of the Market Rules. These variables are represented by the black areas in Figure 2.

    b) Stage 2: Once all variables are assessed, the Authority determines whether they are put together correctly as required by Appendix 4 of the Market Rules (red area of Figure 2).

14. PB has assisted the Authority by evaluating the appropriateness of the following input variables of the MRCP Methodology proposed by SKM:

    a) Fixed Fuel Cost (FFC of Figure 2 and clause 4.16.4(d) of the Market Rules);

    b) transmission connection capital cost (TC of Figure 2 and clause 4.16.4(c) of the Market Rules);

    c) transmission operation and maintenance cost (part of FIXED_O&M of Figure 2 and clause 4.16.4(f) of the Market Rules); and

    d) operation and maintenance cost of Open Cycle Gas Turbine's (OCGT) (part of FIXED_O&M of Figure 2 and clause 4.16.4(f) of the Market Rules).

15. In addition, PB has assisted the Authority in:

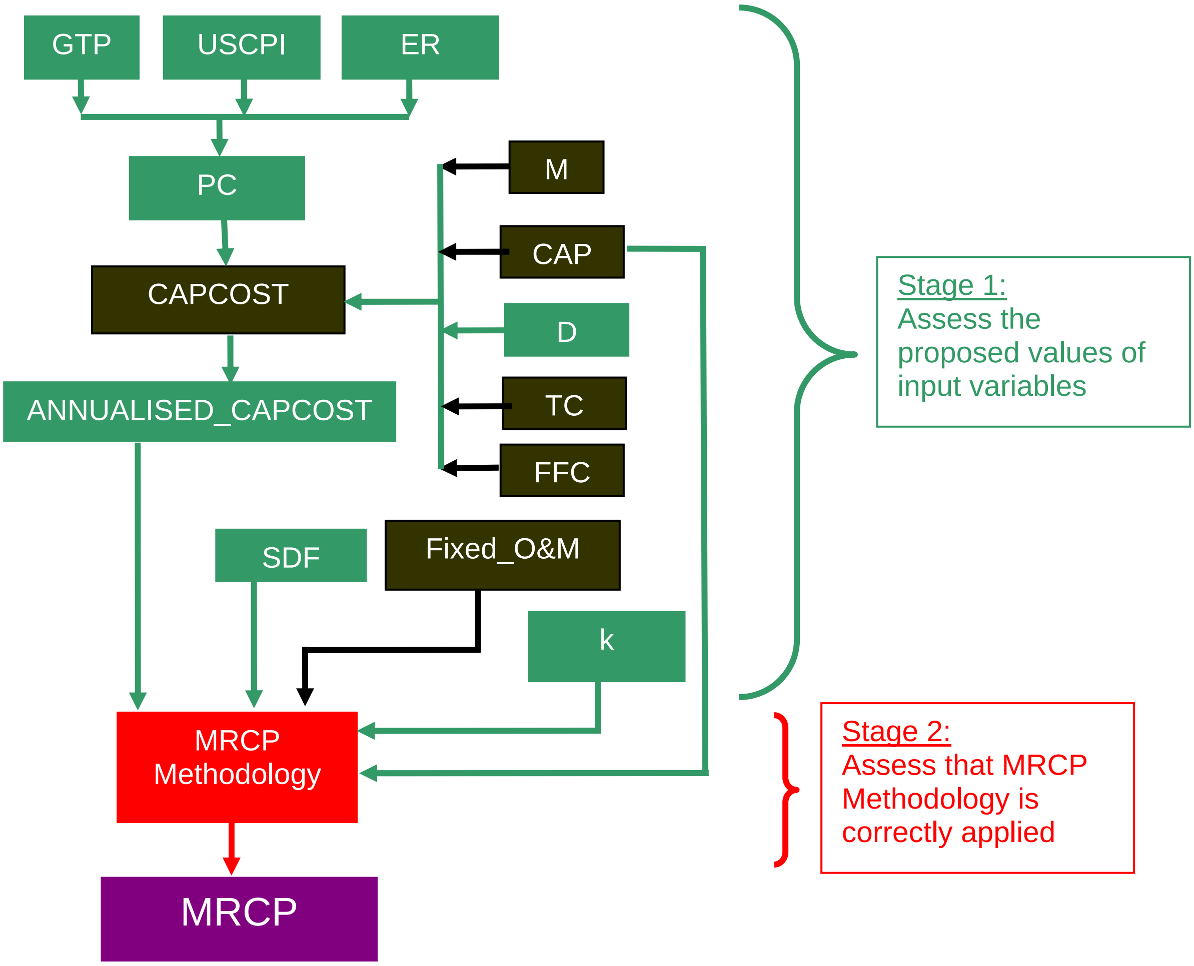
    a) evaluating the Industry Escalation Index (escalation factors to account for price increases) proposed by SKM;

    b) assessing the appropriateness of the IMO's MRCP proposal against clause 4.16.4(a) to clause 4.16.4(f) of the Market Rules (Attachment 1); and

    c) assessing the submissions from industry participants under the public consultation process.

16. PB has documented its findings in the report entitled "Review of the Maximum Reserve Capacity Price" (Attachment 8).

Figure 2: The MRCP Methodology and Approach



Input Variables	Definition (refer to Attachment 2 for further details)
GTP ($M)	Double the lowest quoted equipment price of OCGT
USCPI	CPI of the United States of America
ER (AUD/USD)	Forecast of exchange rate of Australia Dollar to US Dollars
PC ($M)	Capital cost of OCGT station
CAPCOST ($M)	Total capital cost for an OCGT power station
M (%)	Margin to cover legal, approval and financing costs and contingency
CAP (MW)	Capacity of OCGT
D (%)	Interest rate on debt plus the margin of 1.5%
TC ($M)	Capital cost required to connect an OCGT to SWIS
FFC ($M)	Fixed cost associated with an onsite liquid fuel tank
Fixed_O&M ($/MW/year)	O&M costs for OCGT power station and the transmission facility
SDF	Summer derating factor. The value is 1.18
k (%)	Adjustment factor to account for forecast CPI
ANNUALISED_CAPCOST ($)	Annualised CAPCOST over 15 years

REASONS

17. The Authority is satisfied that the IMO has met the requirements of the Market Rules in proposing the MRCP for the 2009/2010 capacity year because:

    a) the proposed value for the MRCP reasonably reflects the application of the method and guiding principles described in clause 4.16 of the Market Rules:

        i) the Authority is satisfied that proposed values of all input variables of the MRCP Methodology reasonably reflect the application of the method and guiding principles described in clause 4.16 of the Market Rules. Although PB has identified several apparent discrepancies in the SKM report, the Authority does not consider that the discrepancies demonstrate that the proposed value for the MRCP is not consistent with the application of the method and guiding principles in clause 4.16 of the Market Rules as their impacts on the final proposed MRCP are minimal (Stage 1 of Figure 2);

        ii) the Authority is satisfied that the MRCP Methodology has been correctly applied (Stage 2 of Figure 2); and

        iii) PB has independently recalculated the MRCP and the Authority is satisfied that the MRCP value proposed by the IMO reasonably reflects the application of the method and guiding principles described in the Market Rules; and

    b) the IMO has carried out an adequate public consultation process and addressed the submissions on the final MRCP proposal.

Assessment of Input Variables of the MRCP Methodology

18. The Authority has assessed input variables into the MRCP Methodology and determined that they meet the requirements of the Market Rules. These input variables include:

    a) Optimum size of an OCGT

        i) Definition: This variable refers to the optimum size of an OCGT for the SWIS to meet the reserve capacity requirement, where the optimum size is a size that is expected by the IMO to minimise the cost of energy over the long term. This is referred to as CAP in Figure 2. Assessment of the value of this variable by the IMO is required by clause 4.16.4(a) of the Market Rules.

        ii) Authority's assessment: The IMO has proposed the value of 160 MW for this variable. This value was also used in the last approval process and no submissions were received in relation to this matter.

    b) Capital cost of OCGT Power Station

        i) Definition: This variable refers to the capital cost of an OCGT power station. This is referred to as PC in Figure 2. Assessment of the value of this variable by the IMO is required by clause 4.16.4(b) of the Market Rules.

        ii) Authority's assessment: The calculation method for this variable is clearly defined in Appendix 4 of the Market Rules (except the deviation noted in section 20 of this document) . The Authority is satisfied that the required process has been followed by the IMO to calculate this value.

c) Electricity Transmission Connection Cost

i) Definition: This variable refers to the level of electricity transmission connection costs. This variable is referred to as TC in Figure 2. This cost includes:

1. The cost of electricity transmission assets required to connect an OCGT power station to the SWIS (**TC Asset Cost**). Assessment of the value of this variable by the IMO is required by clause 4.16.4(c)(i) of the Market Rules.

2. An estimate of the cost of augmenting the shared network to facilitate the connection of the OCGT power station (**TC Deep Connection Cost**). Assessment of the value of this variable by the IMO is required by clause 4.16.4(c)(ii) of the Market Rules.

ii) Authority's Assessment of TC Asset Cost:

1. The Authority has decided to accept the value proposed by the IMO as appropriate although PB's assessment has produced a different value for this variable.

2. PB has adopted a different set of assumptions in its assessment of the value of TC Asset Cost, where PB's assessed value was $7.46M compared to $5.78M proposed by SKM and the IMO. This represents a discrepancy of 30%.

3. Notwithstanding the sizable discrepancy, its effect on the final MRCP is small. The impact of this discrepancy is less than $2,000/MW which represents approximately 1% of the proposed MRCP.

iii) Authority's Assessment of TC Deep Connection Cost:

1. The Authority has accepted the IMO's proposed TC Deep Connection Cost of $10.81M as appropriate.

2. The deep connection costs are very site specific and can only be determined by undertaking detailed power system studies.

3. Whilst the magnitude of the deep connection costs can vary significantly depending on the site, the IMO proposed a value of $10.81M for this cost. This proposed value is based on the pre-approved amount of $10M in year 2004 by the Market Rules Development Group under the advice of the Available Capacity Working Group. The pre-approved amount of $10M was expressed in 2004 dollars and escalated to 2007 dollars of $10.81M.

4. PB has confirmed that an amount of $10.81M as deep connection cost is appropriately included and its value can be representative of deep connection costs.

d) Fixed Fuel Cost

i) Definition: This variable represents the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times. This variable is referred to as FFC in Figure 2. Assessment of the value of this variable by the IMO is required by clause 4.16.4(d) of the Market Rules.

ii) Authority's assessment: The Authority is satisfied that the proposed value of $3.24M is reasonable which is supported by PB's report.

e) Capital Cost of a Pipeline Lateral

i) Definition: This variable refers to the capital cost of a pipeline lateral of reasonable length to connect to a main gas pipeline to allow for duel fuel capability. In the absence of this pipeline lateral, the OCGT is a single-fuel generator running only on liquid fuel. The Market Rules include this as part of the variable referred to as FFC in Figure 2. Assessment of the value of this variable by the IMO is required by clause 4.16.4(e) of the Market Rules.

ii) Authority's assessment:

1. The IMO has not factored in this cost component. Notwithstanding that clause 4.16.4(e) of the Market Rules requires the IMO to assess this variable, the Authority accepts the IMO's decision is still consistent with a reasonable application of the method and guiding principles in clause 4.16 of the Market Rules for the reasons below.

2. The IMO has not factored this variable in the MRCP Methodology because it does not see this as a necessary component for the least-cost OCGT power station in the SWIS. The IMO expects the least-cost OCGT power station to run very infrequently for a limited number of hours (for example, under extreme system load conditions the facility may only run for a few hours once in every ten years). Given the expected low utilisation rate of this OCGT power station, the IMO proposed that it is not justifiable to fund the capital cost of a pipeline lateral to connect to the gas network. In the rare event that this power station needs to be run, the expected saving (of running gas instead of liquid fuel) may not justify the capital cost required to provide the connection to the gas network.

3. In addition, the decision not to fund a gas pipeline lateral was an outcome of the Market Rules Development Group consultation process prior to the determination of the first Maximum Reserve Capacity Price in 2005. The IMO considers it appropriate to continue the funding approach on the same basis that was used previously with the provision that the electricity market participants will be given the opportunity to re-visit this issue. The Authority understands that the IMO is proposing to revisit this issue prior to the next MRCP review in conjunction with the newly formed Maximum Reserve Capacity Price Advisory Group.

4. Given the timing requirement and the complexity involved in studying the economics of the pipeline lateral, the Authority accepts the approach proposed by the IMO, in the interim understanding that the IMO proposes to review the pipeline requirement as soon as practicable, is a reasonable reflection of the application and guiding principles in clause 4.16 of the Market Rules.

f) O&M Cost of OCGT and Transmission Connection

i) Definition: This variable refers to the fixed operating and maintenance costs for a typical OCGT power station (**OCGT O&M**) and any associated electricity transmission facilities (**Transmission O&M**). The IMO has also included an insurance component (**O&M Insurance**) for this input variable. This variable is referred to as FIXED_O&M in Figure 2. Assessment of the value of this variable by the IMO is required by clause 4.16.4(f) of the Market Rules.

ii) Authority's assessment:

1. The proposed OCGT O&M cost is $9,355/MW. PB has independently verified the proposed value and found it to be reasonable.

2. The proposed Transmission O&M cost is $937/MW. PB has independently verified the proposed value and found it to be reasonable.

3. O&M insurance cost has been proposed by the IMO to be 0.5% of the total value of the generation and transmission asset. This equates to the value of $1,421/MW. In considering the issues raised concerning O&M insurance costs, the Authority accepts the reasons set out in the IMO's report.

g) Margin for Legal, Approval and Financing Costs and Contingencies

i) Definition: This variable refers to the margin to cover legal, approval, and financing costs and contingencies. This variable is referred to as M in Figure 2. Assessment of the value of this variable by the IMO is required by clauses 4.16.4(g) and 4.16.4(h) of the Market Rules.

ii) Authority's assessment: The IMO proposed a value of 15% for this variable. This margin was used in the previous assessment. The Authority notes comments in the submissions from Eneabba Gas that it "… found this area particularly poorly covered. Financing costs have a significant impact on the pricing of the Reserve Capacity Price, yet only two short paragraphs were dedicated to this important issue." While a more detailed treatment by the IMO of the margin for legal, approval and financing costs and contingencies would have been desirable, the Authority accepts that the IMO has performed its functions under clause 4.16 of the Market Rules by proposing the value of 15%, for the reason that it was also used for the purpose of the last MRCP approval.

h) Interest Rate on Debt

i) Definition: This variable refers to the real interest rate on debt and equals the Commonwealth 10 Year Bond Rate (real) plus a Margin for Debt of 1.5%. This variable is referred to as D in Figure 2.

ii) Authority's assessment: It is noted that PB in its report indicated a slightly different value of 0.0364. However, the Authority accepts the IMO's proposed value of 0.0391 as a reasonable application of the method and guiding principles of clause 4.16 of the Market Rules.

i) The k-value

i) Definition: This variable refers to a factor set so that the net present value of 10 years worth of payments escalated on a CPI-1% basis is equivalent to the payment stream from 10 years worth of unescalated payments.

ii) Authority's assessment: The IMO has derived the formula to calculate the k value based on the Market Rules in Appendix C of its report. The Authority has assessed the derivation of this value as reasonable.

Application of the MRCP Methodology

19. Using the values of the variables proposed above, the Authority is satisfied that the IMO has reasonably reflected the application of the methods and guiding principles described in clause 4.16 of the Market Rules to produce the MRCP.

20. It is noted that the IMO has deviated slightly from the methodology in the Market Rules in the calculation of the PC value (refer to Figure 2). The IMO has included an extra 5% in the calculation to account for the cost of a NOx burner to meet environmental standards. This inclusion was made following industry consultation conducted prior to the first reserve capacity cycle. The Authority considers that the inclusion of an extra 5% allowance to meet environmental standards is reasonable and consistent with the application of the method and guiding principles of clause 4.16 of the Market Rules.

21. PB has independently calculated the MRCP for 2009/10 to be $139,814/MW. It is noted that PB's calculated MRCP is reasonably close to the value of $142,200/MW proposed by the IMO.

Public Consultation Process

22. The Authority is satisfied that the IMO has carried out an adequate public consultation process and is satisfied that the IMO has appropriately addressed the comments from participants.

23. The IMO's responses to the comments can be found in Appendices D, E and F of the final proposal report (Attachment 7).

24. To address the public comments, the IMO has either:

a) corrected the proposed values of some of the variables of the MRCP Methodology;

b) justified the reason for adhering to the values proposed; or

c) proposed to raise the issues for future review in the Maximum Reserve Capacity Price Advisory Group meeting.

Conclusion

25. Based on the above assessment, the Authority is satisfied that the IMO has met the requirements of the Market Rules and approves the revised value of the MRCP of $142,200/MW for the review period 1 October 2009 to 1 October 2010.

Attachment 1: Extract of Clause 4.16 of the Market Rules

4.16. The Maximum Reserve Capacity Price

4.16.1. For all Reserve Capacity Cycles, the IMO must publish a Maximum Reserve Capacity Price as determined in accordance with this clause 4.16 prior to the time specified in clause 4.1.4.

4.16.2. The Maximum Reserve Capacity Price to apply for the first Reserve Capacity Cycle is $150,000 per MW per year.

4.16.3. The IMO must annually review the value of the Maximum Reserve Capacity Price in accordance with this clause 4.16 and in accordance with the timing requirements specified in clause 4.1.19.

4.16.4. In conducting the review required by clause 4.16.3, the IMO must assess the appropriateness of the following values specified in Appendix 4 for calculating the Maximum Reserve Capacity Price:

(a) the optimum size of an open cycle gas turbine for the SWIS, where the optimum size is a size that is expected by the IMO to minimise the cost of energy to Market Customers over the long term;

(b) the capital cost of open cycle gas turbine power stations based on current data and the methodology specified in Appendix 4;

(c) the level of electricity transmission connection costs, including:

i. the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS; and

ii. an estimate of the cost of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station,

where the IMO may seek a reasonable estimate of this value from the Electricity Network Corporation;

(d) the cost of acquiring and installing fuel tanks sufficient to accommodate 24 hours of liquid fuel storage including the cost of keeping this tank half full at all times;

(e) the capital cost of a pipeline lateral of reasonable length to connect to a main gas pipeline (so as to allow for duel fuel capability);

(f) the estimate of the fixed operating and maintenance costs for a typical open cycle gas turbine power station and the transmission facilities described in (c);

(g) a margin allowed for legal, approval and financing costs; and

(h) a margin allowed for contingences.

4.16.5. The IMO must propose a revised value for the Maximum Reserve Capacity Price using the methodology described in Appendix 4.

4.16.6. The IMO must prepare a draft report describing how it has arrived at a proposed revised value for the Maximum Reserve Capacity Price under clause 4.16.5. The IMO must publish the report on the Market Web-Site and advertise the report in newspapers widely distributed in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users.

4.16.7. After considering of the submissions on the draft report described in clause 4.16.6 the IMO must propose a final revised value for the Maximum Reserve Capacity Price and submit that value and its final report, including submissions received on the draft report, to the Economic Regulation Authority for approval.

4.16.8. A proposed revised value for the Maximum Reserve Capacity Price becomes the Maximum Reserve Capacity Price after:

(a) the Economic Regulation Authority has approved that value in accordance with clause 2.26; and

(b) the IMO has posted a notice on the Market Web Site of the new value of the Maximum Reserve Capacity Price,

with effect from the time specified in the IMO's notice.

Attachment 2: Extract of Appendix 4 of the Market Rules

Appendix 4: Maximum Reserve Capacity Price Methodology

This Appendix presents the method for setting the Maximum Reserve Capacity Price allowed under Clause 4.16. Unless otherwise stated, all dollar amounts are in real dollar terms.

The Maximum Reserve Capacity Price to apply for a Reserve Capacity Auction held in calendar year t is PRICECAP[t] where this is to be calculated as:

PRICECAP[t] = k×(FIXED_O&M[t] + ANNUALISED_CAPCOST[t] / (CAP / SDF))

Where:

PRICECAP[t] is the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction held in calendar year t;

ANNUALISED_CAPCOST[t] is the CAPCOST[t], expressed in Australian dollars in year t, annualised over a 15 year period, using a real pre-tax return to equity equal to the Commonwealth 10 Year Bond Rate (Real) plus a Margin for Equity of 15.1%, a real return to debt equal to the Commonwealth 10 Year Bond Rate (Nominal) plus a Margin for Debt of 1.5%, and a debt to equity ratio of 60:40;

CAP is the capacity of an open cycle gas turbine, expressed in MW;

SDF is the summer derating factor of a new open cycle gas turbine, and equals 1.18;

CAPCOST[t] is the total capital cost, expressed in million Australian dollars in year t, assumed for an open cycle gas turbine power station of capacity CAP; and

FIXED_O&M[t] is the fixed operating and maintenance costs for a typical open cycle gas turbine power station and any associated electricity transmission facilities, expressed in Australian dollars in year t, per MW per year.

k is a factor set so that the net present value of 10 years worth of payments escalated on a CPI-1% basis is equivalent to the payment stream from 10 years worth of an unescalated payments.

The value of CAPCOST[t] is to be calculated as:

CAPCOST[t] = (PC[t] x (1 + M) x CAP x (1 + 1.5D + 0.5xD2))+TC[t]+FFC[t]

Where:

PC[t] is the capital cost of an open cycle gas turbine power station in year t, expressed in Australian dollars in year t per MW;

M is a margin to cover legal, approval, and financing costs and contingencies;

TC[t] is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS, plus an estimate of the costs of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station, expressed in Australian million dollars in year t;

FFC[t] is the fixed fuel costs and must represent the fixed costs associated with an on-site liquid storage tank with sufficient capacity for 24 hours of Liquid Fuel including the cost of keeping this tank half full at all times expressed in Australian million dollars in year t; and

D is the real interest rate on debt and equals the Commonwealth 10 Year Bond Rate (real) plus a Margin for Debt of 1.5%. This rate is used to determine the total interest cost by assuming a construction period of two years with 50% of the capital costs incurred in each year.The value of PC[t] is to be calculated using the following formula:

$$PC[t] = GTP[t-x] \times (USCPI[t] / USCPI[t-x]) \times ER[t,t-x]$$

Where:GTP[t-x] is double the lowest quoted equipment price of the three open cycle gas turbines with capacities nearest to CAP, quoted in United States dollars per MW, contained in the most recent issue of Gas Turbine World Handbook, or a similar reputable international trade price, current as at year t-x.

USCPI[t] is a forecast, made in year t-x, of the Consumer Price Index - All Urban Consumers (CPI-U) for the United States of America midway through year t as compiled by the United States Bureau of Labor Statistics.

USCPI[t-x] is the actual value of the Consumer Price Index - All Urban Consumers (CPI-U) for the United States of America midway through year t-x as compiled by the United States Bureau of Labor Statistics.

ER[t,t-x] is the forecast Australian dollar to United States of America dollar exchange rate, made in year t-x, for midway through year t, based on the Australian Federal Government's budget forecasts.

x is the number of years prior to year t for which the latest available open cycle gas turbine data is available at the time of calculating the value of PRICECAP[t].

For the first Reserve Capacity Cycle, where t=2005, the following values are to be used in evaluating PRICECAP[2005]:

the real pre-tax return to equity = 18%

the real return to debt = 5%

CAP = 160 MW

FIXED_O&M[2005] = $34,000/MW (comprising $15,000/MW for power station O&M costs and $19,000/MW for electricity transmission O &M costs)

M = 15% (comprising a 5% margin associated with legal, approval and financing costs and a 10% margin for contingences).

TC[2005] = $17 million.

FFC[2005] = $3 million.

D = 5%

x = 1

Attachment 3: SKM Report

SINCLAIR KNIGHT MERZ

SKM

Independent Market Operator

IMO

Wholesale Electricity Market

2006 Review of 160 MW OCGT Transmission Link Pricing and GT Fixed O&M

FINAL REPORT

- Transmission Line Capex, O&M and OCGT fixed O&M
- 3.0
- 16 October 2006

2006 Review of 160 MW OCGT Transmission Link Pricing and GT fixed O&M

FINAL REPORT

- 3.0
- 16 October 2006

Sinclair Knight Merz
ABN 37 001 024 095
369 Ann Street, Brisbane 4000
PO Box 246
Spring Hill QLD 4004 Australia
Tel: +61 7 3244 7100
Fax: +61 7 3244 7301
Web: www.skmconsulting.com

Contents

1. Introduction

As part of the Government of Western Australia's commitment to establishing a wholesale electricity market within the South West Interconnected System (SWIS), an Independent Market Operator has been established to administer and operate the Wholesale Market.

The Wholesale Electricity Market rules require the Independent Market Operator to conduct a review of the Maximum Reserve Capacity Price each year. The Independent Market Operator has asked Sinclair Knight Merz to develop costs, in June 2006 money terms, associated with:

- the capital connection cost for connecting a 160 MW generator to a 330 kV transmission line;
- operation and maintenance (O&M) costs of the transmission line connection; and
- fixed operation and maintenance costs of a 160 MW open cycle gas turbine (OCGT) power station based on a single, 160 MW net output gas turbine.

The Independent Market Operator has further requested that the OCGT fixed O&M costs be evaluated for the following operating regimes:

- 1% and 2% capacity factor;
- 4 hours running per start;
  - 22 starts per annum for a 1 % capacity factor;
  - 44 starts per annum for a 2 % capacity factor;

- no fast starts[1];
- one full time load trip to be assumed per annum.

Given no requirement for fast starts in the specified running regime, industrial gas turbines have been evaluated as being more appropriate than aero-derivative alternatives, given the applicability of industrial gas turbines to the running regime, their lower capital cost and lower O&M costs than aero-derivatives.

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1 Given that there is no balancing market in the SWIS Wholesale Electricity Market and hence the plant will be dispatched with sufficient forward notice to avoid the need for fast starts.

The Independent Market Operator has also asked that transmission line connection tie-line costs be produced for a 2km overhead line running over the following terrain types:

- base case: flat, rural, no road crossings; and
- 50% flat/50% undulating, 50% rural/50% urban, one road crossing per km.

To determine transmission line connection capital and O&M costs and OCGT plant fixed O&M costs, Sinclair Knight Merz has developed a set of indices to reflect and incorporate:

- the flow through of raw material/commodity costs (such as steel, aluminium) on equipment prices in proportion to the material element of equipment prices;
- increased labour rate costs in proportion to the labour element of equipment and installation costs, reflecting the tightening labour market in Western Australia, drawn from a range of sources:
  - Australian Bureau of Statistics (ABS) Labour Price Index (LPI);
  - Industrial Relations Commission – Electrical Contractor Award;
  - Electrical Trade Union of Australia – Employer Agree Rates;

- the increase in equipment manufacturer costs (drawn from price surveys undertaken periodically by Sinclair Knight Merz and most recently undertaken in the first quarter of 2006);
- Rawlinsons Australian Construction Handbook;
- CRU Steel Price Index – Longs Steel; and
- the ABS Consumer Price Index (CPI).

In this report, all costs presented are mean costs, cast in June 2006 money terms and have an approximate ± 10 % variation potential.

2. Transmission Connection Capital Costing

2.1 General Issues and Assumptions

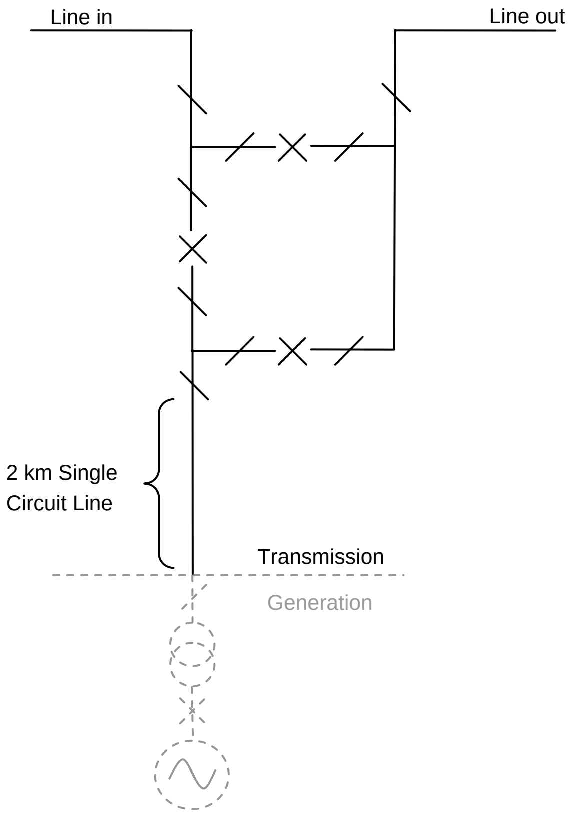
Connection costs have been based on a single 160 MW peaking OCGT generator connected to a 330 kV transmission network via a single overhead 2 km transmission tie-line utilising a turn in / turn out connection configuration. Two terrain types have been evaluated for the tie-line costs as detailed in section 1, repeated here for convenience:

- base case: flat, rural, no road crossings; and
- 50% flat/50% undulating, 50% rural/50% urban, one road crossing per km.

The assumed transmission tie-line MVA rating is 200 MVA (at 0.8 pf). All transmission connection costs have been calculated from the isolator on the high voltage side of the generator transformer and therefore do not include costs associated with the generator transformer and switchgear. Costs have been determined for an 80°C line operating temperature.

For a turn in / turn out connection, Sinclair Knight Merz has assumed a Mesh configuration. This involves locating the primary plant at the transmission connection point and running a single circuit line (transmission tie-line) to the generator substation. A simplified single line diagram of the proposed arrangement is shown in Figure 1 below.

Figure 1 Connection configuration



This arrangement will require protection modifications at the remote (generator) end substation to allow for breaker failure protection at the transmission connection point.

2.2 Cost Indexation Calculation

In order to determine the transmission line connection capex and opex in June 2006 money terms a series of indexation formulae to apply to the different cost make up elements has been developed.

2.2.1 Transmission Line Tie-line and Tee-in Capital Cost Escalation

For the transmission line connection tie-line and tee-in capital cost indexation, the follow data types[2] have been drawn on:

2 This includes Sinclair Knight Merz cost data drawn from market surveys.

SKM

- **Table 1 Transmission Line Connection Cost Indexation Data Sources**

Escalation Sources - Transmission Line Connection - Tie-Line & Tie-in	
Source	Used for
Australian Bureau of Statistics - Consumer Price Index	Earthwire, Fittings & Insulators
Australian Bureau of Statistics - Labour Price Index (WA)	All Labour Categories
Industrial Relations Commision - Electrical Contractor Awards	All Labour Categories
Electrical Trade Union of Australia - Employer Agree Rates	All Labour Categories
SKM - Power Industry market price survey: 1st Quarter 2006	Conductor Rates
Rawlinsons Australian Construction Handbook	Foundations
CRU Steel Price Index - Longs Steel	Towers

For the construction of the tie-line, these indices have been applied to both material and construction cost and compounded in proportion to the relative mix of these costs for the different cost make up elements (Table 2):

- **Table 2 Transmission Tie-line Construction Cost Elements**

Transmission Tie-Line
Cost Item
Clearing & access
Conductor
Earthwire
Fittings
Foundations
Insulators
Survey
Towers
EPC

A number of these cost make up elements can be directly linked to published indices, such as the foundations costs. The conductor prices are escalated from Sinclair Knight Merz' most recent market surveys (undertaken first quarter 2006)[3]. These are based on market contract values and take into consideration movement in labour and commodity prices.

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3 Sinclair Knight Merz periodically undertakes power industry pricing surveys and collates capex and opex data from a range of parties. This data is used to populate a power transmission and distribution cost database. The most recent update to the cost database took place in the first quarter of 2006. Material and labour cost rates have been escalated in accordance with the escalation method outlined in this section.

SKM

The purchase cost for transmission towers has been escalated by a combination of steel, labour and consumer price indices proportionate to the ratio of these costs elements in the fabrication costs of the towers. It is important to note that these indices have been calculated for cost element escalation to June 2006 and that they do not take into consideration movement of the input indices after this date (for example resulting from recent reductions in commodity prices).

The engineering procurement and construction management (EPCM) cost element arising from costs associated with management of contractors has been taken as the mean EPCM cost for similar work drawn from Sinclair Knight Merz' most recent pricing survey. This is applied in the form of a 15% cost uplift on all other costs and hence is also represented in June 2006 money terms.

2.2.2 Transmission Line Connection Switchyard costs Escalation

The following data types have been drawn on for the transmission line connection switch yard cost escalation determination:

- **Table 3 Transmission Line Connection Switchyard Capital Costs Escalation Sources**

Escallation Sources - Transmission Line Connection - Switchyard	
Source	Used for
Australian Bureau of Statistics - Consumer Price Index	Equipment after 2005, P&C Equipment, Misc Materials
Australian Bereau of Statistics - Labour Price Index (WA)	Installation, Commissioning, Erection
Industrial Relations Commision - Electrical Contractor Award	Installation, Commissioning, Erection
Electrical Trade Union of Australia - Employer Agree Rates	Installation, Commissioning, Erection
SKM - Power Industry Price Surveys	Electrical Equipment
Rawlinsons Australian Construction Handbook	Foundations
CRU Steel Price Index - Longs Steel	Structure

Again these indices have been compounded for each element in proportion to the ratio of the make up costs to which the indices are applicable. The composite 2005-2006 capital cost escalator determined for the transmission connection capital costs is 5.48 %.

SKM

2.2.3 Transmission Line Tie-line, Tee-in and Switchyard O&M Cost Escalation

The transmission tie-line O&M costs and Switchyard O&M costs are taken as a percentage multiplier[4] of the transmission line total construction costs and switchyard construction costs respectively. Hence the indexation applied for the transmission line and switchyard O&M cost is identical to that applied to the transmission tie-line and switchyard connection costs. As such the transmission line connection (tie-line, Tee-in and switchyard) O&M costs are medium values with a potential range of ± 10 %.

2.3 Transmission Line Costs

Based on a capacity of 200 MVA, the transmission line thermal rating needs to be approximately 350 Amps per phase. To accommodate this requirement Sinclair Knight Merz has evaluated costs for a 330 kV line with steel tower construction and 2 x Mango ACSR conductor with an 80 °C thermal operating rating.

Capital costs for a 2 km overhead transmission tie-line for:

- a base case: (flat terrain, rural, no road crossings); and
- an alternate case: (50% flat, 50% undulating terrain, 50% urban, 50% rural and one road crossing per km)

are provided in Table 4 below. These costs include an EPCM cost of 15 % of the aggregate of all other cost elements.

- **Table 4 330 kV Transmission Connection Tie-line Costs**

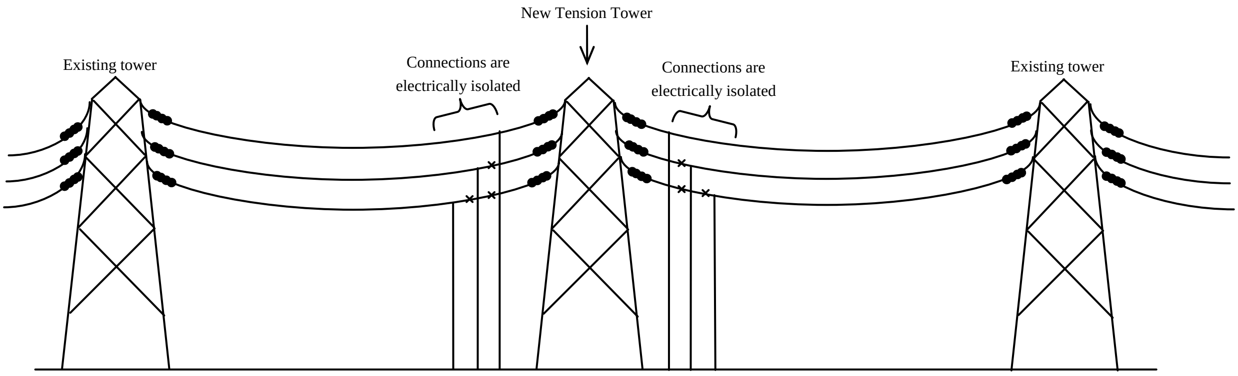
Summary of base and alternate case transmission tie-line costs June 2006		
Line Length	Base Case June 2006 Terms $(000's)	Alternate Case June 2006 Terms $(000's)
2 km	$711	$764

[4] This multiplier has been determined from operation and maintenance data gathered over a number of years by Sinclair Knight Merz and is periodically validated against known operation and maintenance costs. The multiplier varies in an increasing and approximate exponential manner with equipment age. As with the EPCM uplift determination, this multiplier takes into account recent labour and material cost data obtained from Sinclair Knight Merz' 2006 survey and hence O&M costs are cast in June 2006 money terms.

2.4 Substation and Transmission Line Connection Costs

A single tension tower configuration has been adopted, with the new tension tower being positioned between two existing towers. This option is considered to be the most economic. A simplified diagram is shown below in Figure 2.

- **Figure 2 Transmission Line Tee-in Arrangement**



The Mesh switchyard configuration cost has been evaluated for a three circuit breaker bay model. The total cost for breaking into the existing transmission line and for the Mesh switchyard arrangement is estimated at $ 5,017,510 including site establishment, line tee-in and EPCM costs. A summary of total capital costs for the transmission line connection consisting of the tie-line, tee-in, switchyard and EPCM costs for the base and alternate case terrain scenarios for an overhead 2 km tie-line length are provided in Table 5. A more comprehensive breakdown of each connection cost element for the base and alternate case scenarios is provided in Appendix A.

SKM

- **Table 5 Total Transmission Line Connection Capex: base and alternate case**

Transmission Tie-Line, Tie In and Switchyard Costs June-2006 2km base, and alternate case		
Item	2km Base Case June 2006 Values $	2km Alternate Case June 2006 Values $
Tie-line costs (2km)	$ 618,375	$ 664,753
Line Tee-in	$ 242,247	$ 242,247
Site Establishment	$ 1,128,545	$ 1,128,545
Switchyard	$ 2,992,259	$ 2,992,259
Subtotal	$ 4,981,427	$ 5,027,805
EPCM @ 15%	$ 747,214	$ 754,171
Total	**$ 5,728,641**	**$ 5,781,976**

3. Transmission Connection Operation and Maintenance Costs

The O&M costs for the transmission connection have been developed on an asset class basis. This has been achieved by using the unit cost developed in the capital costing exercise and applying a variable percentage value for O&M over the life of the assets[4]. It has been assumed that the average life of the 330 kV overhead transmission line is 60 years and the average life of the switchyard assets are 50 years.

Table 7 and Table 8 below show the transmission line and switchyard O&M costs over the life of the assets for the:

- base case (flat terrain, rural, no road crossings); and
- alternate case (50%flat/50% undulating terrain, 50% urban/50% rural, 1 road crossing per km)

terrain scenarios for an overhead 2km transmission tie-line length. Figures are presented for aggregated five yearly intervals.

An annual breakdown of transmission tie-line lifetime O&M costs for the base and alternate case terrain scenarios for a 2km overhead transmission tie-line length are presented in Appendix B together with an annual breakdown of the switchyard O&M costs. It should be noted that annual insurance costs have been omitted from the O&M costs figure as this will be very dependent on the ownership arrangement for the transmission tie-line.

The average annual O&M cost over the asset lifetime of 60 years for the 2 km, base case transmission line is $ 5,989 (June 2006 money terms) and $ 6,438 (June 2006 money terms) for the 2 km alternate terrain case. The average annual O&M costs for the Meshed switchyard over its 50 year life is $ 60,278 (June 2006 values). Since the lifetime of the OCGT plant is given as 30 years it is reasonable to present the lifetime O&M costs of the related assets in the same time frame. This is provided in Table 6.

- **Table 6 2 km, base case tx and switchyard O&M 2006 base case and alternate case cost comparison**

30 Year Lifetime Operation and Maintenance Costs for the Transmission Connection: 2 km Base Case and 2 km Alternate Case		
Years	Base Case 1 to 30 yrs June 2006 Values	Alternate Case 1 to 30 yrs June 2006 Values
Turn in Turn Out Connection		
Tie-line O&M Costs over the life of the GT plant (Assumed 30 years)	$ 99,202	$ 106,643
Meshed Switchyard O&M Costs over the life of the GT plant (Assumed 30 years)	$ 1,320,491	$ 1,320,491
Total Line and Switchyard O&M Costs over the life of the GT plant (Assumed 30 years)	$ 1,419,693	$ 1,427,134
Average Annual O&M cost over the life of the GT plant (Assumed 30 years)	$ 47,323	$ 47,571

SKM

Table 7 Lifetime O&M costs, 2km Base Case Tx Tie-line and Meshed Switchyard

Life Time O&M costs for 2 km Base Case Transmission Line and Meshed Switchyard			
5 yearly costs for periods:	Transmission Line $(June 2006)	Meshed Switch Yard $(June 2006)	Total $(June 2006)
1 to 5 years	$10,659	$151,725	$162,384
6 to 10 years	$12,516	$174,136	$186,652
11 to 15 years	$14,698	$199,856	$214,555
16 to 20 years	$17,260	$229,376	$246,636
21 to 25 years	$20,268	$263,257	$283,525
26 to 30 years	$23,801	$302,141	$325,942
31 to 35 years	$27,949	$346,769	$374,718
36 to 40 years	$32,821	$397,989	$430,810
41 to 45 years	$38,541	$456,774	$495,315
46 to 50 years	$45,259	$524,242	$569,501
51 to 55 years	$53,148	N/A	
56 to 60 years	$62,411	N/A	

SKM

- **Table 8 Lifetime O&M costs, 2 km Alternate Case Tx Tie-line and Meshed Switchyard**

Life Time O&M costs for 2 km Alternate Case Transmission Line and Meshed Switchyard			
Cost over 5 year period	Transmission Line $(June2006)	Meshed Switch Yard $(June 2006)	Total $(June2006)
1 to 5 years	$11,458	$151,725	$163,183
6 to 10 years	$13,455	$174,136	$187,591
11 to 15 years	$15,800	$199,856	$215,657
16 to 20 years	$18,554	$229,376	$247,931
21 to 25 years	$21,788	$263,257	$285,045
26 to 30 years	$25,586	$302,141	$327,727
31 to 35 years	$30,046	$346,769	$376,815
36 to 40 years	$35,282	$397,989	$433,271
41 to 45 years	$41,432	$456,774	$498,206
46 to 50 years	$48,653	$524,242	$572,896
51 to 55 years	$57,134	N/A	
56 to 60 years	$67,092	N/A	

4. Generation Operation and Maintenance Costs

4.1 Assumptions and Estimated Maintenance Costs

At the request of the Independent Market Operator, an OCGT plant, based on a single gas turbine capable of delivering a net 160 MW output fuelled predominantly with natural gas has been evaluated for a 30 year operating life. An allowance for 5 % running on distillate (light fuel oil) has been provided to allow for gas pipeline outages. Given the low capacity factor, a non-firm (i.e. interruptible) gas supply has been assumed. Sinclair Knight Merz has developed a gas turbine operation and maintenance model based on these parameters using the net output and net heat rate produced by Thermoflow GT PRO® software. Sinclair Knight Merz has assumed an ambient temperature of 35 °C, with a relative humidity of 40 % and an altitude of 15 m for the plant specification. The three turbines considered in this analysis are the:

- Alstöm 13E2;
- Siemens V94.2 (SGT5-200E); and
- General Electric GE9171E.

The running regime advised by the Independent Market Operator is as described in section 1, repeated here for convenience:

- 1 % and 2 % capacity factor;
- 4 hours running per start;
  - 22 starts per annum for a 1 % capacity factor;
  - 44 starts per annum for a 2 % capacity factor;

- no fast starts[5]; and
- one full time load trip to be assumed per annum.

---

5 Given that there is no balancing market in the SWIS Wholesale Electricity Market, the Independent Market Operator has advised that there will be no requirement for fast starts in the operating regime and hence it is assumed that the plant will be dispatched with sufficient forward notice to avoid the need for fast starts.

SKM

4.1.1 Generator O&M Cost Escalation

As with the transmission line connection capital and O&M cost escalation, a range of data sources have been drawn on (Table 9) to develop appropriate costs and price escalators for the OCGT plant fixed O&M costs data. These escalators have been applied to the cost data available to Sinclair Knight Merz that is not already couched in 2006 money terms.

- **Table 9 Gas Turbine Plant Fixed O&M Cost Data Indexation Sources**

Escallation Sources - Gas Turbine Fixed O&M	
Source	**Used for**
Australian Bureau of Statistics - Consumer Price Index	Market fee, gas connection fee, blance of plant, consent, legal, corporate overhead, engineering support, electrical, fire protection, rates
Australian Bereau of Statistics - Labour Price Index (WA)	Non operator blue collar labour elements 2005-2006
Industrial Relations Commision - Electrical Contractor Award	Contractor costs 2005-2006
SKM - OCGT Project Data (amalgam - 2006)	Insurance, Plant Opertor labour, OCGT substation

These indices have been compounded for each cost element in proportion to the ratio of the make up costs for which the indices are applicable. The compound 2005-2006 escalator for the gas turbine plant fixed O&M is determined at: 4.25%.

All costs are presented as mean values ± 10 %.

4.1.2 Expected fixed Maintenance Costs

The fixed O&M cost elements shown below in Table 10 have been developed from cost data derived from a range of sources including an amalgam of data from current and recent similar OCGT projects. These costs have been escalated, where appropriate, to June 2006 money terms. As with the transmission line connection, O&M plant insurance has been omitted from the figures. However, Sinclair Knight Merz would estimate this at 0.5% of replacement capex (June 2006).

SKM

- **Table 10 Generator fixed O&M costs**

Generator Fixed O & M costs breakdown	
O & M Cost Component	**$M pa June (2006)**
Plant operator labour	0.400
OCGT Substation (connection to tie-line)	0.020
Rates	0.052
Market Fee	0.052
Gas Connection (excludes amortised gas pipeline connection costs)	0.052
Balance of Plant	0.104
Consent (EPA annual charges, emissions tests)	0.026
Legal	0.021
Corporate Overhead	0.187
Travel	0.021
Subcontractors	0.261
Engineering Support	0.052
Security	0.104
Electrical (Including Control & Instrumentation)	0.100
Fire	0.052
Total	**1.504**

Five yearly aggregate fixed OCGT O&M costs (mean values ± 10 %) are provided in Table 11 for each five year period of the 30 year operating life.

- **Table 11 Combined Generator O&M costs**

Fixed Operation and Maintenance costs for 160 MW OCGT $(June 2006)							Total
Cumulative five yearly costs: Years:	**1 to 5**	**6 to 10**	**11 to 15**	**16 to 20**	**21 to 25**	**26 to 30**	**1 to 30**
Fixed O&M Costs $(June2006)	$7,178,665	$7,178,665	$7,178,665	$7,178,665	$7,178,665	$7,178,665	$43,071,990

SKM

Appendix A Connection Cost Estimates 2 km, 10 km, 20 km, base & high case

- **Table 12 Connection Cost Breakdown for 2 km, base case transmission line connection**

Connection Cost Estimate for Independent Market Operator			
2km base case: Flat, Rural, no Road Crossings			
Assumptions	*Site establishment costs estimated* *Single-circuit steel tower construction* *Based on standard 1 1/2 breaker 3CB configuration* *Demarcation at Generator is the site fence* *Includes additional tension tower and terminations associated with turn in and out*		
Exclusions	*No switching costs associated with breaking existing transmission line* *No land or easement acquisition included* *No additional costs allowed for remote locations*		
Estimate			
Item	**Details**	**Qty**	**Cost Estimate**
Site Establishment	Earthworks, Gravel, Fencing, Earthgrid, Building, Auxillaries etc	1 lot	1,128,545
Line Tee-in	Tension tower, conductor and connection to landing spans	1 lot	242,247
Switchyard			
Equipment	Supply & Delivery of 3 CB, 3 sets of CT, 1 set of VT, 6 Isolators, 3 Isolators with Earth switch, station posts and PLC set	1 lot	1,815,663
Structure	Bus, gantry and support structures for HV equipment	1 lot	248,866
Foundations	Construction of foundations for HV equipment	1 lot	183,326
Protection & control	Standard protection schemes	1 lot	305,969
Electrical erection	Erection of equipment	1 lot	260,728
Miscellaneous	Minor construction & materials, commissioning	1 lot	177,708
Sub-total			*2,992,259*
Tie-line			
Line Construction	330kV SCST, 2 x Mango, Flat, Rural, No Road Crossings	2 km	475,673
Ajustment Factor	Short line ajustment factor (0.3)	1 lot	142,702
Sub-total			*618,375*
Sub-total			*4,981,427*
EPCM @ 15%			*747,214*
Total (AUD)			**5,728,641**

SKM

- **Table 13 Connection Cost Breakdown for 2 km, alternate case transmission line connection**

Connection Cost Estimate for Independent Market Operator
2km alternate case: 50% Flat/50% Undulating, 50%Urban/50% Rural, one Road Crossing per km

Assumptions	*Site establishment costs estimated* *Single-circuit steel tower construction* *Based on standard 1 1/2 breaker 3CB configuration* *Demarcation at Generator is the site fence* *Includes additional tension tower and terminations associated with turn in and out*
Exclusions	*No switching costs associated with breaking existing transmission line* *No land or easement acquisition included* *No additional costs allowed for remote locations*

Estimate

Item	Details	Qty	Cost Estimate
Site Establishment	Earthworks, Gravel, Fencing, Earthgrid, Building, Auxillaries etc	1 lot	1,128,545
Line Tee-in	Tension tower, conductor and connection to landing spans	1 lot	242,247
Switchyard			
Equipment	Supply & Delivery of 3 CB, 3 sets of CT, 1 set of VT, 6 Isolators, 3 Isolators with Earth switch, station posts and PLC set	1 lot	1,815,663
Structure	Bus, gantry and support structures for HV equipment	1 lot	248,866
Foundations	Construction of foundations for HV equipment	1 lot	183,326
Protection & control	Standard protection schemes	1 lot	305,969
Electrical erection	Erection of equipment	1 lot	260,728
Miscellaneous	Minor construction & materials, commissioning	1 lot	177,708
Sub-total			*2,992,259*
Tie-line			
Line Construction	330kV SCST, 2 x Mango, 50%Flat/50% Undulating, 50% Rural/50% Urban, 1 Road Crossing per km	2 km	511,349
Ajustment Factor	Short line ajustment factor (0.3)	1 lot	153,405
Sub-total			*664,753*
Sub-total			*5,027,805*
EPCM @ 15%			*754,171*
Total (AUD)			**5,781,976**

Note (EPCM) Engineering, Procurement and Contract Management

SKM

Appendix B Lifetime costs for transmission line and Mesh switchyard O&M

- **Table 14 Operation and Maintenance Costs for 2 km Transmission Connection Line and Switchyard (Base Case Terrain Scenario)**

Operation and Maintenance Costs for the Transmission Connection: 2km Base Case (Flat, Rural, no Road Crossings)													
Five yearly period costs for:	Years	1 to 5	6 to 10	11 to 15	16 to 20	21 to 25	26 to 30	31 to 35	36 to 40	41 to 45	46 to 50	51 to 55	56 to 60
Turn in Turn Out Connection													
Line O&M Costs	$(June 2006)	$ 10,659	$ 12,516	$ 14,698	$ 17,260	$ 20,268	$ 23,801	$ 27,949	$ 32,821	$ 38,541	$ 45,259	$ 53,148	$ 62,411
Meshed Switchyard O&M Costs	$(June 2006)	$ 151,725	$ 174,136	$ 199,856	$ 229,376	$ 263,257	$ 302,141	$ 346,769	$ 397,989	$ 456,774	$ 524,242	N/A	N/A
Total Spend in Period	$(June 2006)	$ 162,384	$ 186,652	$ 214,555	$ 246,636	$ 283,525	$ 325,942	$ 374,718	$ 430,810	$ 495,315	$ 569,501		
Average Annual spend in period	$(June 2006)	$ 32,477	$ 37,330	$ 42,911	$ 49,327	$ 56,705	$ 65,188	$ 74,944	$ 86,162	$ 99,063	$ 113,900		
Average Annual O&M cost over the life of the GT plant (Assumed 30 years)	$(June 2006)	$ 47,323											

- **Table 15 Operation and Maintenance Costs for 2 km Transmission Connection Line and Switchyard (Alternate Case Terrain Scenario)**

Operation and Maintenance Costs for the Transmission Connection: 2 km Alternate Case (50% Flat/50% Undulating, 50%Rural/50%Urban, 1 Road Crossing per km)													
Five yearly period costs for:	Years	1 to 5	6 to 10	11 to 15	16 to 20	21 to 25	26 to 30	31 to 35	36 to 40	41 to 45	46 to 50	51 to 55	56 to 60
Turn in Turn Out Connection													
Line O&M Costs	$(June 2006)	$ 11,458	$ 13,455	$ 15,800	$ 18,554	$ 21,788	$ 25,586	$ 30,046	$ 35,282	$ 41,432	$ 48,653	$ 57,134	$ 67,092
Meshed Switchyard O&M Costs	$(June 2006)	$ 151,725	$ 174,136	$ 199,856	$ 229,376	$ 263,257	$ 302,141	$ 346,769	$ 397,989	$ 456,774	$ 524,242	N/A	N/A
Total Spend in Period	$(June 2006)	$ 163,183	$ 187,591	$ 215,657	$ 247,931	$ 285,045	$ 327,727	$ 376,815	$ 433,271	$ 498,206	$ 572,896		
Average Annual spend in period	$(June 2006)	$ 32,637	$ 37,518	$ 43,131	$ 49,586	$ 57,009	$ 65,545	$ 75,363	$ 86,654	$ 99,641	$ 114,579		
Average Annual O&M cost over the life of the GT plant (Assumed 30 years)	$(June 2006)	$ 47,571											

Attachment 4: Submission from Alinta Sales

3 November 2006

Patrick Peake
Manager, System Capacity
Independent Market Operator
PO Box 7096, Cloisters Square
Perth WA 6850

Alinta

Alinta Sales Pty Ltd
ABN 92 089 531 984

The Quadrant
1 William Street
Perth WA 6000
GPO Box W2030
Perth WA 6846

Telephone 08 9486 3000
Facsimile 08 9486 3030

Dear Patrick

Draft Report: Maximum Reserve Capacity Price for the 2009/2010 Capacity Year

This submission from Alinta Sales Pty Ltd (**Alinta**) provides comments on the Draft Report issued by the Independent Market Operator (**IMO**) proposing that the Maximum Reserve Capacity Price applicable to the 2009/10 year should be set at $129,900 per MW.

Alinta has a number of concerns with the IMO's proposed Maximum Reserve Capacity Price.

Specifically, Alinta is concerned that some of the cost estimates used to determine the proposed Maximum Reserve Capacity Price do not accurately reflect actual market costs. Alinta is also concerned with regulatory risk aspects of the IMO's proposal.

Alinta has addressed each of these concerns in the sections below, however, given the limited time frame to respond Alinta has not been able to perform the detailed review that this important issue deserves. Alinta asks that the IMO provide Alinta with an opportunity to discuss its concerns directly with the IMO before the IMO issues a final decision.

Capital Cost - Gas Turbine Price

Alinta suggests that the IMO reviews the requirement to utilise the lowest of the quoted gas turbine prices. Practically, it may not be appropriate to utilise the manufacturer with the lowest quoted price as they may not be able to deliver the project within the required timeframes.

Electricity Transmission Connection Costs – Connecting to the SWIS

Alinta disagrees with the Sinclair Knight Merz (**SKM**) approach to calculating the electricity transmission connection costs.

The Wholesale Electricity Market (**WEM**) rules state that the transmission connection cost '*is the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS…*'. However, the SKM report appears to have calculated the capital connection cost for connecting a 160MW generator to a generic 330kV transmission line and has not taken into account the actual costs required to meet Western Power's requirements that are unique to the SWIS. For example, the underlying configuration proposed in the SKM report is unlikely to be acceptable to Western Power given the outages required on the 330kV system to construct it.

In order to obtain more accurate cost estimates Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4.16.4c of the WEM rules; and

- confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice.

Transmission Connection Costs – Length of Tie Line and Tie Line Cost

Alinta proposes that the length of the tie-line used in the transmission connection cost estimate is typically less than that required by generators connected to the South West Interconnected System (**SWIS**). Alinta estimates that, on average, tie-lines connecting generators to the SWIS 330kV system are longer than 2km assumed by the IMO and that an amount of 10km to 20km would be more appropriate. Alinta suggests that the IMO assess the location of existing, proposed and under construction generators with a 330kV connection to the SWIS in order to determine an average tie-line length on which to base the cost estimate.

Furthermore, the tie line costs incurred by proponents in the current market are significantly greater than those utilised in the SKM report. Over the last 3 years Alinta has experienced significant cost increases in raw materials and labour associated with the construction of transmission lines that do not appear to be considered in the SKM report.

In order to obtain more accurate cost estimates Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4.16.4c of the WEM rules; and
- confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice.

Transmission Connection Costs – Switchyard Costs

Alinta comments that the switchyard costs incurred by proponents to meet Western Power requirements are significantly greater than those assumed in the SKM report. In order to obtain more accurate cost estimates Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4.16.4c of the WEM rules; and
- confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice.

Transmission Connection Costs - Removal of SVCs

The SWIS is becoming increasingly constrained, with Western Power imposing additional capital contribution requirements on users to enable Western Power to fund voltage support initiatives and fault level upgrades.

Alinta has significant concerns with the sudden change of methodology to remove costs associated with SVCs.

The draft report (Page 10) states that this change is '*discussed in detail*'. However, Alinta has been unable to locate any detailed discussion that goes toward the justification of this key change in the methodology and the basis on which it needs to diverge from the previous two Maximum Reserve Capacity Price determinations by the IMO.

The draft report states that '*there are other locations in the network where connections will not require an SVC*'. This assertion ignores the vast array of complex considerations and limitations that a generation proponent faces in the locating and eventual construction of a power station. For example, costs to meet more stringent location specific planning requirements, provision of water supplies, etc. Generally proponents are unable to locate generation in the metropolitan area.

Alinta notes that the conclusion of the draft report refers to a '*transmission costing model*' and '*funding model*' that will be impacted by the removal of the SVCs. There appears to insufficient detail in the report on these two models for Alinta to understand what allowances may have existed in these previously for SVCs and how they will be impacted by removing SVCs from them.

Alinta suggests that the IMO prepare a detailed document on this matter and invite further public comment before releasing a final report.

Transmission Connection Costs – Shared Network/Deep Connection Costs

The WEM rules state that the transmission costs should include '*an estimate of the cost of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station.*'

The draft report (Page 11) states that a value of $10.25M was used in the previous review for deep connection and network reinforcement costs. Given that the total proposed transmission connection cost estimate is $6.098M Alinta can only conclude that deep connection and network reinforcement costs are to be excluded in the current transmission connection cost. If this is the proposal it should be explicitly stated in the report as it is a significant change in methodology.

In a recent submission to the Economic Regulation Authority (**ERA**) concerning Western Power's proposed network Access Arrangement, Alinta submitted that the majority of Western Power's costs to connect a generator or large load to the SWIS should be added to Western Power's capital base, rather than being paid by users in the form of a capital contribution. If the ERA agrees with Alinta's submission then there would be a drop in the electricity transmission connection costs, which could then be reflected in determination of the Maximum Reserve Capacity Price. However, whilst the status quo is maintained, Alinta contends that electricity transmission connection costs have increased, not decreased. Alinta submits that the IMO should be increasing electricity transmission costs and that deep connection and network reinforcement costs should be included.

Fixed Transmission O&M Costs

Transmission fixed O&M costs were estimated as $19,000/MW for the 2005 cycle, determined to be $7,823/MW for the 2006 cycle and proposed to be only $249/MW for the 2007 cycle. This is a very significant reduction proposed by the IMO in the Draft Report and, because it is an annual cost rather than one that will be capitalised over a number of years, it will have a large impact on the Maximum Reserve Capacity Price. Alinta submits that the IMO has not provided sufficient detail on the derivation of the proposed operating and maintenance cost (including why there has been such a significant change from previous estimates) to enable meaningful comment on the figures. Given the impact of the proposed change, Alinta suggests that the IMO prepare a detailed document on this matter and invite further public comment before releasing a final report.

Fixed Fuel Costs - Lateral Pipeline Installation Cost

Alinta comments that the level of detail on fixed fuel costs on Page 10 is insufficient for Alinta to provide meaningful comment. Alinta notes that bullet (e) in the Introduction states that the IMO is required to assess the appropriateness of '*the capital cost of a gas lateral to allow for dual fuel capability*'. Alinta notes that there is no mention of a gas lateral in the remainder of the report.

Alinta submits that the IMO should be including the cost of a lateral pipeline installation when determining the Maximum Reserve Capacity Price. Clauses 4.16.4(d) and (e) of the Wholesale Electricity Market Rules require that the maximum reserve capacity price will be based on a dual fuel gas turbine in which the cost of fuel tanks and a gas lateral pipeline are included. It appears that the IMO has included the cost of fuel tanks but not the cost of a lateral pipeline.

Insurance

The draft report provides insufficient detail as to how the 0.5% of the capital replacement cost was derived to determine the level of insurance. Alinta suggests that the actual amounts are greater and significantly greater during the construction phases of a project.

Given that the capital replacement cost used to derive the level of insurance is also low the resulting provision for insurance appears too low.

IMO Disclaimer

Alinta submits that the IMO should review and amend the disclaimer attached to the report. The disclaimer states that the document is published '*as an information service*'...'*contains only general information*' and '*makes no representations or warranty as to the accuracy, reliability, completeness or suitability for particular purposes of the information in this document*'. These statements appear inconsistent with the importance and intent of the report and question the point of publishing the report at all.

Regulatory Risk Concerns

Alinta notes that the cost estimates utilised to derive the maximum reserve capacity price seem to be at the very low end and at times unrealistically low.

Alinta also notes its ongoing concern that there is significant variability in methodology and outcomes between each capacity year. Changes of such magnitude, and the risk that further similar significant changes may take place in future, will cause instability and uncertainty amongst project proponents and investors. Alinta has significant concerns with the regulatory risks inherent in the IMO's proposals and considers that making such significant changes will be detrimental to the long-term development of the electricity market. The regulatory process needs to provide some long-term certainty to users and prospective users, particularly as there is likely to be an absence of price signals in an energy market where there are very low price caps and probable low volatility such as the proposed Wholesale Energy Market in WA.

Report Structure and Readability

Alinta suggests the report be reworked to improve its readability by:

- including an appendix containing all the inputs and calculation for both the maximum reserve capacity price, including underlying components such as the WACC and k-factor.
- include a chart showing where the increases and decreases are from the previous cycle(s)
- Adjust Table 1 as it currently could misrepresent the proposed transmission connection cost estimates increasing from the 2006 review cycle to the 2007 cycle.

Alinta brings to the IMOs attention the following typographical errors it has found in draft report:

1. The bold GTP[2006] appears to have the wrong units. It shows MW whereas it should be kW (Page 9)
2. The exchange rate contained in the draft report appears to be incorrect. 0.7627 is the number of $US to an $A rather than being the number of $A to a $US as is required in the formulae (Page 9)

3. Cap cost formulae missing the CAP component (Page 12)
4. Price cap formulae missing brackets around CAP/SDF (Page 15)

Alinta would like to thank the IMO for the opportunity to provide comments on the draft report and would welcome future involvement prior to the release of a final report. Alinta also intends to distribute this submission to the Economic Regulation Authority.

Please contact either myself on (08) 6213 7304 or Mark McKinnon (08) 6213 7316 to discuss the issues raised in this submission.

Yours faithfully

Kristian Myhre

Kristian Myhre
Manager, Market Analytics

Attachment 5: Submission from Eneabba Gas

ENEABBA GAS LIMITED
ABN 69 107 385 884
Office: Level 1, 30 Ord Street, West Perth WA 6005 All Mail: P O Box 772 West Perth WA 6872
Tel+61 8 9321 0099 Fax+61 8 9321 0299 E-mail: admin@eneabbagas.com.au Website: www.eneabbagas.com.au

1 November 2006

Mr Patrick Peake
Manager, System Capacity
Independent Market Operator
PO Box 7096
CLOISTERS SQUARE WA 6850

Dear Patrick

RESPONSE TO DRAFT REPORT: MAXIMUM RESERVE CAPACITY PRICE REVIEW FOR THE 2009/10 RESERVE CAPACITY YEAR

Eneabba Gas Limited has read the abovementioned draft Report and our response is **enclosed**

Yours sincerely

Mark H Babidge

Mark H Babidge
Managing Director
ENEABBA GAS LIMITED

Enc

D/Admin/305/D 11/1 2006

ENEABBA GAS LIMITED
ABN 69 107 385 884
Office: Level 1, 30 Ord Street, West Perth WA 6005 All Mail: P.O. Box 772 West Perth WA 6872
Tel+61 8 9321 0099 Fax+61 8 9321 0299 E-mail: admin@eneabbagas.com.au Website: www.eneabbagas.com.au

2 November 2006

Mr Patrick Peake
Manager, System Capacity
Independent Market Operator
PO Box 7906 Cloisters Square
PERTH WA 6850

Dear Sir

SUBMISSION BY ENEABBA GAS LIMITED ON THE DRAFT REPORT: "MAXIMUM RESERVE CAPACITY REVIEW FOR THE 2009/10 RESERVE CAPACITY YEAR" RELEASED BY THE INDEPENDENT MARKET OPERATOR DATED OCTOBER 2006

1. INTRODUCTION

Eneabba Gas Limited ("Eneabba") welcomes the opportunity to comment on the Draft report released by the Western Australian Independent Market Operator "Maximum Reserve Capacity Price Review for the 2009/10 Reserve Capacity Year ("the Report").

Eneabba is a new entrant in the Western Australian energy scene. Eneabba has to date :

- purchased a power station site 8 kilometres east of Dongara (known as Centauri 1) for the purposes of constructing a power station;
- entered into a conditional contract with GE to purchase and install gas turbines at Centauri 1;
- obtained all EPA and local shire approvals to allow construction of the power station to proceed;
- acquired sufficient gas and gas transport arrangements for commissioning of the power station;
- made significant progress towards resolving interconnection issues with Western Power

These activities demonstrate Eneabba's commitment to installing new capacity as part of the Western Australian electricity market. Eneabba maintains a keen interest in the outcome of the review process for establishing the Capacity Reserve Price for new Reserve Capacity. This process is important in providing critical data as part of the matrix of information necessary to make important investment decisions.

2. RESERVE CAPACITY PRICING

Eneabba notes that the 2007 Maximum Reserve Capacity Price is proposed to be set at $129,900 per MW per year for the 2009 year. This price compares to previous calculations and "Ministerial" directions released. With the following pricing:

2007/08	$150,000/MW
2008/09	$122,500/MW
2008/09 (rev)	$129,900/MW

Under the rules this is meant that the annual payment available has fluctuated from $127,500/MW to as low as $94,375/MW

Eneabba uses the pricing information released by the IMO and previously by "Ministerial direction" inter alia, as a basis of investment decision making. Investing in a power station plant carries many risks namely construction risk, technology risk, market risk and regulatory risk to name a few. Clearly, power station proponents seek to minimize all of these risks where possible and where they can influence them. Eneabba is looking to invest between $130 million - $160 million on the power plant and associated land in Western Australia. It is disturbing to note that a potentially important revenue stream in the form of Reserve Capacity Payments can have such a wide variation as outlined above. Investment decision making becomes extremely difficult in such an uncertain and volatile environment.

3. DRAFT REPORT

The overriding concern of Eneabba with respect to the Report is the lack of detail provided in the report to support the conclusions reached. This ordinarily may not be of a concern but when coupled with the significant variation as outlined above the reader of the Report is unable to undertake their own analysis to confirm any of the conclusions reached in the Report.

As a minimum a format that covers the following headings, with sufficient information to convey confidence to the reader that the analysis is both complete in capturing all costs as well as providing detail on costs, is considered necessary.

Suggested areas that need to be provided in the Report are outlined below:

Power Station Site:
- Where is the site located regional or metropolitan?
- Are site acquisition and preparation costs included?
- Are EPA and local shire approval costs included?

Power station Costs:
- Are the total costs of an open cycle plant included?
- Do the "total costs" include all ancillary plant, such as water treatment, oil recovery, etc?
- Are the construction costs based on today's high priced construction?
- Market?
- is the cost of acquiring and installing fuel tanks as outlined in page 5 of the Report included in the Reserve Capacity Price of $129,900.

O & M

These issues have sufficient detail for analysis purposes.

Financing Costs

Eneabba found this area particularly poorly covered. Financing costs have a significant impact on the pricing of the Reserve Capacity Price, yet only two short paragraphs were dedicated to this important issue. A review of regulation determinations in the Eastern States reveal that considerable attention is given to this area. As a minimum the IMO should provide a table with the key parameters as outlined below to allow for analysis:

Table 1 Cost of Capital Parameters

1	Nominal risk-free interest rate	7.	Imputation credit value
2	Expected inflation rate	8	Asset beta
3	Debt margin	9.	Debt beta
4	Cost of debt = 1+3	10	Nominal post-tax return on equity
5	Maximum risk premium	11	Post tax nominal WACC
6	Ratio of Debt to equity	12	Pre-tax real WACC.

The information contained in the table reflects the cost of capital given the nature of a company operating in the electricity industry with its attendant financial risks. A review of the information, if contained in the Report, can then be made to see whether the data is considered reasonable

4. CONCLUSION

Eneabba maintains that information provided in the Report should be of sufficient detail to allow for a detailed analysis by recipients of the Report. As subsequent Reports are released comparison on variations on key areas can then be made to determine what has caused any variation in the Capacity Price

Eneabba is concerned at the wide fluctuations in the Reserve Capacity Price over such a relatively short time period and the inability to analyse why this has occurred. The process of review should be transparent for all participants and the current report is lacking is this regard. These fluctuations coupled with changes to the market rules is creating regulatory uncertainty and risk to potential investors in the market

Finally, as a result of many of the issues outlined above not being contained in the report, it is not possible for Eneabba to provide a more detailed response to the Report

Yours faithfully

Peter Oates
Director
ENEABBA GAS LIMITED

Attachment 6: Submission from Beacons Consulting International

BEACONS Consulting International Pty Ltd

WA SUSTAINABLE PROJECTS

November 2, 2006

Mr. Patrick Peake
Manager System Capacity
Independent Market Operator
Level 22, The Forrest Centre
221 St Georges Terrace
Perth WA 6000

Dear Patrick

Review of the Maximum Reserve Capacity Price for the 2009/2010 year.

Beacons Consulting International Pty Ltd welcomes the opportunity to comment on the Review of the Maximum Reserve Capacity Price for the 2009/2010 year.

Having studied in detail the IMO draft report and the SKM 2006 review as listed below we have concerns in regards to the costs used for the 330 kV transmission link.

- The Draft Report: Maximum Reserve Capacity Price Review for the 2009/2010 Reserve Capacity Year.
- 2006 Review of 160MW OCGT Transmission Link Pricing and GT Fixed O & M

Based on prices for similar 132 kV transmission links we have for various projects currently under consideration, it is our belief the price for the 330 kV transmission link in the 2006 review is less than actual current market pricing for this type of works.

Western Power Networks costing for the 330 kV transmission link needs to be obtained for comparison to the costs used in the 2006 Review.

If you have any questions in relation to Beacons position on the pricing issue for the 330 kV & 132 kV transmission links, pleases do not hesitate to contact me.

Yours sincerely

MW Thorpe.

Mike Thorpe
Senior Associate
Mobile: **0405 174 741**
Telephone: **9302 1192**
Fax: **9302 1725**
mwt@beaconsconsulting.com.au

Attachment 7: IMO’s Final MRCP Proposal Report

Independent Market Operator

Final Report: Maximum Reserve Capacity Price Review for the 2009/10 Reserve Capacity Year

January 2007

REPORT DETAILS

IMO Report No.:	19
Report Title:	Final Report: Maximum Reserve Capacity Price Review for the 2009/10 Reserve Capacity Year
Version No.:	1.2.2
Author:	Troy Forward
Release Status:	Approved for Public Release
Confidentiality Status:	Public

EXECUTIVE SUMMARY

Each year, the IMO is required to conduct a review of the Maximum Reserve Capacity Price. This Final Report details the outcome of the review conducted in 2006 to determine the Maximum Reserve Capacity Price for the 2007 Reserve Capacity Cycle. The value used for the 2007 Reserve Capacity Cycle will be effective from 1 October 2009 through to 1 October 2010.

In October 2006, the IMO published a Draft Report and proposed a Maximum Reserve Capacity Price of $129,900 per MW per year.

The review process included updating the costs of purchasing a 160MW Open Cycle Gas Turbine (OCGT), and a technical costing review of the prices associated with connection of the power station to the 330 kV transmission system. The technical review also considered the operations and maintenance costs associated with the transmission connection and the OCGT power station.

After publishing the Draft Report in accordance with clause 4.16.6 of the *Wholesale Electricity Market Amending Rules (September 2006)* (Market Rules), the IMO requested public submissions on the review. Three submissions were received by the IMO in respect of the Draft Report. Following consideration of the submissions received, the IMO has amended the transmission connection costs by approximately $11M per year. The IMO has also provided an increase to the operations and maintenance costs. These changes increase the Maximum Reserve Capacity Price to $142,200 per MW per Year.

The Maximum Reserve Capacity Price determined for the 2007 Reserve Capacity Cycle is approximately 16.1% higher than the similar value determined for the 2006 Reserve Capacity Cycle. The main cost increases have resulted from:

- An increase in the cost of purchasing the 160 MW OCGT (from prices published in the Gas Turbine World Handbook);
- Increases in the transmission connection and O&M costs.

These cost increases have been offset by the reduction in funding allocated to static var compensators.

This Final Report is produced in accordance with clause 4.16.7 of the *Market Rules* and is submitted to the Economic Regulation Authority for review in accordance with clause 2.26of the Market Rules.

TABLE OF CONTENTS

INTRODUCTION

Each year the IMO is required to conduct a review of the appropriateness of a number of the components that are used to determine the Maximum Reserve Capacity Price. This Final Report is produced in accordance with clause 4.16.7 of the *Wholesale Electricity Market Amending Rules (September 2006)* (Market Rules). Under clause 4.16.4 of the Market Rules, the IMO is required to assess the appropriateness of the following values, which are used to calculate the Maximum Reserve Capacity Price:

a) The optimum size of an open cycle gas turbine (OCGT) for the SWIS;

b) The capital cost of OCGT power stations;

c) The level of electricity transmission connection costs;

d) The cost of acquiring and installing fuel tanks sufficient to accommodate 24 hours of liquid fuel storage;

e) The capital cost of a gas pipeline lateral to allow for dual fuel capability;

f) The estimate of the fixed operating and maintenance costs for the power station and the transmission facilities listed above;

g) A margin for legal, approval, financing costs and contingencies.

This Final Report has been developed following the preparation of a Draft Report published in accordance with clause 4.16.6 of the Market Rules and consideration following a public consultation process. In accordance with the Market Rules, the IMO has reviewed the appropriateness of each of these values for the 2007 Reserve Capacity Cycle by considering the input parameters that are used in calculating the Maximum Reserve Capacity Price. The Maximum Reserve Capacity Price is calculated in accordance with Appendix 4 of the Market Rules.

This Final Report and the submissions made through the public consultation process have been published on the IMO website (www.imowa.com.au). A copy of the Draft Report and the accompanying technical report can also be found on the IMO website.

Reserve Capacity Cycle Timing

This Final Report is presented for the 2007 Reserve Capacity Cycle. The Maximum Reserve Capacity Price determined for the 2007 Reserve Capacity Cycle will be effective from 1 October 2009 through to 1 October 2010.

General Costing Methodology and Structure of this Final Report

There are three main components to this review. The first is the determination of the capital cost of an OCGT power station. The second component is the determination of the cost associated with connection of that OCGT to the transmission system, and the third component is the estimation of O&M costs associated with the transmission connection and the OCGT plant.

The first component, that of determining the cost of developing an OCGT, is well specified in Appendix 4 of the Market Rules. The IMO makes comment about the appropriateness of this method as part of this Final Report.

Transmission connection costs associated with connecting an OCGT to the transmission system have been estimated by Sinclair Knight Merz (SKM), who were retained by the IMO for this purpose. The IMO has published the SKM report in the Reserve Capacity section of the IMO website (www.imowa.com.au)

Operations and Maintenance costs associated with the OCGT and the Transmission assets were also analysed by SKM. This is a similar methodology that was adopted in a similar review conducted in 2005/2006.

Maximum Reserve Capacity Price Outcome for the 2007 Reserve Capacity Cycle

Following the review of the Maximum Reserve Capacity Price for the 2007 Reserve Capacity Cycle and the subsequent public consultation process the IMO proposes a final revised value of the Maximum Reserve Capacity Price to be **$142,200** per MW per year. This value is proposed in accordance with clause 4.16.4 of the Market Rules.

The main upward cost drivers have been increases associated with the OCGT and transmission costs. Smaller downward pressures have resulted from an adjustment to the insurance costs that are funded as an ongoing Operations and Maintenance cost.

This Final Report is presented in a similar format as the Draft Report. This report first discusses the public consultation process and then presents the issue of cost escalation. The issue of cost escalation was raised previously in the public consultation process conducted in support of the determination of the Maximum Reserve Capacity Price for the 2008/09 Reserve Capacity Year. The following section lists the input parameters that are used in the Maximum Reserve Capacity Price calculation of Appendix 4 of the Market Rules. This section will allow the reader to verify the correct computation of the Maximum Reserve Capacity Price, in accordance with the Market Rules. The report then concludes with a discussion of the outcome of the Maximum Reserve Capacity Price review process.

PUBLIC COSULTATION PROCESS

After publishing Draft Report in accordance with Market Rule 4.16.6, the IMO initiated a public consultation process which included a formal call for submissions on the Draft Report and emailing the Draft Report to approximately 150 stakeholders and interested parties. The formal call for submissions was published in the West Australian on Saturday 21 October 2006. Three submissions were received by the IMO. These submissions were from:

- Alinta Sales Pty Ltd;
- Eneabba Gas Limited; and
- Beacons Consulting;

Copies of the submissions can be found on the IMO website. Appendices D through F present the IMO's response to the main issues raised in the submissions.

In response to the submissions received, the IMO has amended the transmission connection costing methodology to reflect the process used previously by the IMO. The transmission connection costs have been increased from A$6.0899M to A$ 16.908800 M. This results in a substantial increase to the Maximum Reserve Capacity Price for the 2009/10 Reserve Capacity Year. However, returning the funding model to the same basis that was used previously will help reduce regulatory risk associated with introducing changes.

In addition to the change to the transmission connection costs, the IMO has also included more detail in a number of the areas of concern raised by those making submissions to the IMO.

ESCALATION OF COSTS

One of the outcomes from the review conducted last year was the apparent increase in construction related costs that have been experienced over the past few years. Following the review and public consultation process conducted at the end of 2005, the IMO increased the costs allocated to transmission construction components within the Maximum Reserve Capacity Price calculation. Presented below are official CPI rates as provided by the Australian Bureau of Statistics.

CPI

The following CPI values are quoted by the Australian Bureau of Statistics for the period June 2005 and June 2006.

CPI June 2005	148.4
CPI June 2006	154.3

Where the CPI is the weighted average of eight capital cities.

These values result in an inflation rate of 3.98% over the period of June 2005 through June 2006 and are provided here as a reference for the Industry Escalation discussion below.

Industry Escalation

This year, the IMO requested that SKM provide an assessment of the cost escalation for the transmission capital and O&M costs between 2005 and 2006. SKM conducted an analysis of a number of publicly available indices, and compared the impact of these to increases in actual component and construction costs. SKM determined that the transmission costing outcomes between 2005 and 2006 should be indexed at 5.48%. SKM has also referenced this escalation parameter against their internal costing database for transmission capital and O&M costs.

A similar analysis was conducted for the generator O&M costs that were provided in the SKM report titled "2006 Review of 160MW OCGT Transmission Link Pricing and GT fixed O&M". This analysis showed an increase of 4.25% in costs between 2005 and 2006. A copy of the SKM report can be found on the IMO website (www.imowa.com.au).

The IMO proposes to use a cost escalation of 5.48% for transmission related components and 4.25% for generation related components when translating 2006 costs into costs to June 2007 for the purposes of the Maximum Reserve Capacity Price. Therefore, it is the IMO's view that the most appropriate methodology for estimating future cost escalation (between 2006 and 2007) is to use those values determined for the 2005 to 2006 period by SKM for the appropriate components.

INPUT PARAMETERS TO THE MAXIMUM RESERVE CAPACITY PRICE CALCULATION

US CPI

In accordance with Appendix 4 of the Market Rules, CPI values have been sourced for the United States of America. CPI information was sourced from the following US Bureau of Labor Statistics website:

ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt

This information shows the following CPI information:

June 2004: 189.7

June 2005: 194.5

June 2006: 202.9

Appendix 4 of the Market Rules indicates that the US CPI must be forecast to June of the year in which the Reserve Capacity Auction would take place, in this case June 2007. The IMO is not in a position to provide detailed speculation on the future level of this value. The IMO therefore proposes to use a simple linear extrapolation of the CPI from June 2006 to June 2007 using the period June 2005 to June 2006. This results in the following equation:

$$\frac{USCPI[2006]^2}{USCPI[2005]}$$

The extrapolated CPI for June 2007 becomes:

June 2007: 211.663

Therefore, the terms used in the Maximum Reserve Capacity Price calculation are:

USCPI[2006]: 202.9

USCPI[2007]: 211.7

Exchange Rate

The Market Rules indicate that the Australian/US exchange rate to be used "is the forecast Australian dollar to United States of America dollar, made in year t-x, for midway through year t, based on the Australian Federal Government's budget forecasts." The IMO believes that given the speculative nature of an exchange rate forecast, it is appropriate in this case to simply adopt the most recent exchange rate available.

The Australian/US exchange rate as quoted by the Reserve Bank of Australia (13 October 2006) for the month ending August 2006 was 1.3111. This information can be found at http://www.rba.gov.au/Statistics/Bulletin/F11hist.xls. The IMO has based the exchange rate at June 2007 on the latest available monthly information, as at the end of August 2006. Therefore, for the purposes of the Maximum Reserve Capacity Price calculation,

ER[2007]: 1.3111

Capacity Parameter CAP

The optimum size of an OCGT is one that is expected to be the last procured machine required to fulfilling the Reserve Capacity Reliability Criterion. In this case, the IMO considers the appropriate capacity for an OCGT is approximately 160 MW and there is no basis for changing the size, denoted as CAP. A capacity of 160 MW does represent a reasonably cost-efficient size of power station, when the OCGT prices listed in the Gas Turbine World Handbook are assessed. Reducing CAP below 100 MW appears to result in substantial increases to the OCGT cost.

The IMO has initiated a high-level review of the Maximum Reserve Capacity Price methodology, but it is not viable to conduct this review in the timeframe required for the 2007 Reserve Capacity Cycle.

CAP: 160 MW

GAS Turbine Price

As at the time of this review, the most current version of Gas-Turbine World is the 2006 edition. The lowest quoted price of the three open cycle gas turbines with capacities closest to 160MW is US$180,000/MW for a Siemens SGT5-2000E machine.

GTP[2006]: US$360000/MW.

Capital Cost of an OCGT

In accordance with Appendix 4 of the Market Rules, the capital cost of an open cycle gas turbine in Australian dollars is expressed as PC[t] and is calculated by the following formula.

$$PC[2007] = GTP[2006] \times (USCPI[2007]/USCPI[2006]) \times ER[2007]$$

In conducting the review in accordance with clause 4.16.4 of the Market Rules, the IMO considers it still appropriate to include an allowance for low NOx burners which are commonly specified to meet environmental standards. A margin of 5% is included in the Margin M for this purpose. Using the term *NOx* to represent the low nitrous-oxide emissions component, PC[t] is now represented by the following equation:

$$PC[2007] = GTP[2006] \times (USCPI[2007]/USCPI[2006]) \times ER[2007] \times (1 + NOx)$$

PC[2007] therefore becomes:

PC[2007]: A $517,103 per MW

The IMO proposes to use the value above in the determination of the Maximum Reserve Capacity Price for the 2007 Reserve Capacity Cycle.

The inclusion of a separate component for low NOx burners has always been included in the Maximum Reserve Capacity Price determination. The Environmental Protection Authority (EPA) States[1] "In relation to large gas turbines burning natural gas, the EPA notes that most new industries are now, as a matter of course, adopting dry lox NOx burner technology as best practice. The IMO supports this position and the inclusion of low NOX burners on this basis. The rate of 5% was decided through the industry consultation process conducted prior to the First Reserve Capacity Cycle. However, the IMO proposes to consider the separate funding of low NOx burners as part of a wider review currently being conducted by an industry-based Advisory Group. This Advisory Group will assess the general determination methodology of the Maximum Reserve Capacity Price and will propose changes to the Market Rules if necessary.

D – Real Interest Rate

The real interest rate has been calculated in accordance with Appendix 4 of the Market Rules by estimating the Commonwealth 10 Year Bond Rate (real) plus a Margin for Debt of 1.5%. The Real Commonwealth 10 Year Bond Rate for 30 June 2017 was found by interpolation between the Indicative Mid Rates of Commonwealth Government Securities with maturity dates of 20 August 2015 and 20 August 2020 respectively. This information was current as at 9 October 2006. The data used in this calculation are included at Appendix A for reference.

The Real Commonwealth 10 Year Bond Rate is calculated as 2.41%. The parameter D is:

D 0.0391

Fixed Fuel Costs

The Fixed Fuel Costs (ie. the costs associated with the installation of fuel capacity) calculated in 2005/06 will be escalated for the 2006/07 determination of Maximum Reserve Capacity Price. An escalation rate of 5.48% will be used to reflect the escalation of costs within the electricity and construction industries. The FFC[2006] was A$3.075M. FFC[2007] therefore becomes:

FFC[2007] A$3.243500 M

The FFC was determined prior to the first Reserve Capacity Cycle based on similar costs of installing tanks on Torrens Island. The values have been escalated each year. A gas pipeline lateral connection is not factored into the Fixed Fuel Costs as this is not seen as a necessary component for the least-cost OCGT power station on the system that would be expected to be run for a limited number of hours very

[1] Environmental Protection Authority (2000) Guidance Statement for Emissions of Oxides of Nitrogen from Gas Turbines, Guidance Statement 15, p5.

infrequently (for example, under extreme system load conditions the facility may only run for a few hours once in every ten years).

Transmission Connection Costs

SKM were retained to provide estimates of connecting a 160MW OCGT to the 330KV transmission system. In 2006, the total transmission connection cost was estimated at A$14.410M and later revised to A$17.516M following the public consultation and review process. It is noted that this price included a significant component for the funding of Static Var Compensators (SVCs). This methodology has been changed for the 2007 Maximum Reserve Capacity Price Review.

For this price review, a range of different options were costed as part of the SKM work package. The SKM report can be found in the Reserve Capacity section of the IMO website (www.imowa.com.au). The IMO has elected to use a more complex case than last year, which is now characterised by:

Line Length:	2km
Terrain:	50% Flat/50% Undulating
Urban/Rural:	50% Urban/50% Rural
No Road Crossings per km:	1

The scenario last year was based on a 2km connection, 100% flat terrain, 100% rural and no road crossings. This scenario was chosen to reflect the likely environment in which a 2km transmission connection would be developed. The selection of the new scenario does not result in a material change to the total transmission costs. The total transmission cost increases by approximately $55,000. Transmission connection costs for the Turn-in and Turn-out configuration are shown in Table 1.

Table 1 Transmission Connection Costs (Current an projected for the 2007 Reserve Capacity Cycle)

ITEM	*Cost Estimate (2006)*	*Cost Estimate (2007)*
Site Establishment	$ 1,128,545	$ 1,190,389
Line Tee-in	$ 242,247	$ 255,522
Switchyard	$ 2,992,259	$ 3,156,235
Tie Line	$ 664,753	$ 701,181
Subtotal	$ 5,027,804	$ 5,303,327
EPCM@15%	$ 754,171	$ 795,499
Deep Connection	$ 10,250,000	$ 10,810,000
Total	$ 16,031,975	$ 16,908,826

The 2006 costs provided by SKM are further escalated by 5.48% to represent costs in 2007 figures. The 2005/06 review also included a component for deep connection costs and network reinforcement costs associated with new generation development. A value of A$10.25M was used in the 2005/06 Maximum Reserve Capacity Price review. The IMO is now of the understanding that deep connection costs are likely to be borne managed through either:

- capital contributions by the generation proponents; or
- as a shared asset augmentations connection cost, distributed through the asset base of and recovered by the Network Operator from all network users via tariffs; or
- a combination of these methods.

The 2005/06 Maximum Reserve Capacity Price estimation also included the cost of an SVC. However, the IMO does not consider this to be an essential requirement as part of the Maximum Reserve Capacity Price. The reason for this is that an SVC is typically needed in conjunction with a generator remote from the load centre and is therefore a major component of the location-specific connection costs to be considered by the developer. There are other locations in the network where connections will not require an SVC. Prior to publishing the Draft Report, the IMO removed the deep connection cost ($10.25M previously). SVC costs were inseparable from other deep connection costs within the total value allocated. While the IMO considers that the Maximum Reserve Capacity Price should not include location specific SVC costs, following consideration of the submissions received through the public consultation process, the IMO has reinstated the total allocation for deep connection costs. The IMO has escalated the historical values using the industry escalation parameters determined by SKM. The previous value of A$10.25M becomes A$10.81M in 2007 terms following escalation by 5.48%.

The IMO undertakes to raise this issue within the Advisory Group that has been developed to review the Maximum Reserve Capacity Price methodology.

After revision, the parameter TC becomes:

TC[2007] = A$ 16,908,826

TC[2007] = A$ 16.908800 M (rounded)

The review conducted by SKM appears to have appropriately captured the costs associated with connection of a 160MW OCGT to the 330 kV transmission system. SKM have used their comprehensive cost database to analyse transmission connection costs and have evaluated price escalation factors in a robust manner.

Margin M

The margin M is included to cover legal, approval and financing costs and contingencies. This term was set in 2005 and 2006 at 15%. The IMO believes this is appropriate in 2007. Margin M therefore is:

M = 0.15

Capital Cost

The term CAPCOST[t] refers to the total capital cost, expressed in million Australian Dollars in year t, assumed for a 160 MW OCGT. This is calculated using the following formula:

$$CAPCOST[t] = PC[t] \times (1 + M) \times CAP \times (1 + 1.5 \times D + 0.5 \times D^2) + TC[t] + FFC[t]$$

CAPCOST[2007] = A $120,952,307

Fixed Operation and Maintenance Costs

Fixed Transmission O&M Costs

These costs have been estimated by SKM. Details of the costing methodology used by SKM can be found in the SKM report. Transmission O&M costs make up part of the total fixed O&M costs referenced by the term FIXED_O&M[t] in Maximum Reserve Capacity Price calculation of Appendix 4 of the Market Rules.

Transmission O&M Costs: A $937 per MW per year.

This is determined by taking the average of the first 15 years of Transmission costs determined by SKM and presented in Table 8 of the report “2006 Review of 160MW OCGT Transmission Link Pricing and GT fixed O&M”. The 2006 costs provided in the SKM report have been escalated to 2007 figures using an escalation of 5.48%.

Following the public consultation process and review, the transmission O&M costs have been revised from $249 per MW per year to $937 per MW per year. This represents a revision of the costing model and the changes result from the Western Power use of system charges that should be funded.

Fixed OCGT O&M Costs

Fixed O&M costs for a 160 MW OCGT have been estimated by SKM. The first 15 years of costs are included to represent the funding basis considered in Appendix 4 of the Market Rules. The SKM report details the total fixed O&M costs of the OCGT to year 15 as A $21,535,995 in 2006 terms. This is then escalated at 4.25% to 2007 values equates to A $9,355 per MW per year.

Generation O&M Costs: A $9,355 per MW per year.

Insurance Costs as an O&M Cost

The IMO believes it appropriate to fund insurance to a level required to cover replacement costs of the capital equipment. The IMO believes it is not appropriate to fund insurance at a level which provides any cover for lost income or the contractual and risk position of the proponent. Therefore, an allowance of 0.5% of the capital replacement cost has been included in the Fixed O&M costs. Table 2 shows the insurance costs included as fixed O&M costs within the Maximum Reserve Capacity Price. Following the public consultation process and further review, the IMO has increased the insurance cost funding to include the Line-Tee-In as a capital replacement item. This adds $255,522 to the total amount insured and raises the insurance premium from $1,413 per MW per year to $1,421 per MW per year.

Table 2 Insurance Costs

ITEM	*Value*
Transmission Capital Costs [2007]	
Tie Line	$ 701,181
Switchyard	$ 3,156,235
Line Tee In	$ 255,522
Generation Capital Costs [2007]	
Generator	$41,368,222
Total [2007]	
Insurance Premium	0.005
Total Insurance Costs	$1,421 per MW per year

Total Fixed O&M Costs

The total Fixed O&M Costs are presented in Table 3 below.

Table 3 Fixed Operation and Maintenance Costs

ITEM	*Cost Estimate (per MW per year)*
Transmission Fixed O&M [2007]	$ $937
OCGT Fixed O&M [2007]	$9,355
Insurance as Fixed O&M [2007]	$1,421
Total	$11,713 per MW per year

FIXED_O&M: $11,713 per MW per year

Annualised Capital Cost

The Weighted Average Cost of Capital (WACC) is calculated using the real Commonwealth 10 year bond rate of 2.41%, a margin for debt of 0.015 and a margin for equity of 0.151.

The resulting WACC is 0.0935. The WACC calculation has been included in Appendix B.

The annualised capital cost, using a capital cost of $120,952,307 , a WACC of 0.0935 and a term of 15 years becomes:

ANNUALISED_CAPCOST[2007]: A$15,316,608 per year

Summer De-rating Factor

A summer de-rating factor of 1.18 is outlined in the Market Rules.

SDF: 1.18

Factor K

Factor K is set so that the net present value of 10 years worth of payments escalated on a CPI-1% basis is equivalent to the payment stream from 10 years worth of unescalated payments. The forecast GDP increases from the 2006 Statement of Opportunities Report have been used as a proxy to CPI. A WACC of 9.35% represents the rate of return.

Table 4 Inflation Rates used to Determine Factor K

Year	*09/10*	*10/11*	*11/12*	*12/13*	*13/14*	*14/15*	*15/16*	*16/17*	*17/18*	*18/19*
Inflation Rate (CPI)	2.8	4.0	4.5	3.7	3.7	4.2	4.0	4.0*	4.0*	4.0*

Note: Some inflation values estimates are beyond the forecast horizon of the SOO. These are denoted by *

To increase fidelity of the computation, this year NPV calculations have been conducted on a monthly basis. This also replicates the monthly Reserve Capacity payment regime. The factor K has been computed as:

K: 1.1409

A formulation of the Factor K is included in Appendix C.

Maximum Reserve Capacity Price

The Maximum Reserve Capacity Price is calculated using the following equation from Appendix 4 of the Market Rules.

$$PRICECAP[2007] = K \times \begin{pmatrix} FIXED\_O\&M[2007] + \\ ANNUALISED\_CAPCOST[2007]/(CAP/SDF) \end{pmatrix}$$

Using the values determined by the IMO and presented in the above sections, PRICECAP for the 2007 Reserve Capacity Cycle is determined to be $142,239.40, which is rounded to:

PRICECAP[2007]: $142,200 per MW per year

A Maximum Reserve Capacity Price of **$142,200** per MW per year is proposed by the IMO. This represents an increase of 16.1% of the price determined for the 2006 Reserve Capacity Cycle.

CONCLUSION

The IMO has conducted a review of the main factors used to determine the Maximum Reserve Capacity Price. For the 2007 Reserve Capacity Cycle, the IMO proposes that the Maximum Reserve Capacity Price be set at **$142,200** per MW per year.

The Maximum Reserve Capacity Price of **$142,200** per MW per year represents an increase of 16.1% above the price for the 2008/09 Reserve Capacity Year. The main cost increases have been in the purchase price of a 160 MW OCGT, as listed in the Gas Turbine World Handbook, and increases in the prices associated with transmission components, which are estimated to be in the order of approximately 5.5%. Counteracting these cost increases has been the removal of static var compensators from the transmission costing model. This is a discretionary item resulting from choice of location when selecting a power station site and is therefore not a necessary component within the costing model.

The review conducted to support the analysis of the factors contributing to the Maximum Reserve Capacity Price included the selection of a more detailed transmission connection option and a detailed review of escalation parameters that have influenced transmission prices between 2005 and 2006.

The IMO has conducted a public consultation process and received three submissions in response to the Draft Report that was published. As a result of the public consultation process, the IMO has revised a number of the values and included more detail on financial components that contribute to the determination of the Maximum Reserve Capacity Price. These outcome of the revisions is an increase to the Maximum Reserve Capacity Price from the first proposed value of $129,900 per MW per year to $142,200 per MW per year.

APPENDIX A - COMMONWEALTH BOND RATES

Item	Issue Date	TI405 Maturity Date 20-Aug-15	TI406 Maturity Date 20-Aug-20
1	12-Sep-2006	2.505	2.335
2	13-Sep-2006	2.500	2.320
3	14-Sep-2006	2.505	2.325
4	15-Sep-2006	2.555	2.370
5	18-Sep-2006	2.575	2.390
6	19-Sep-2006	2.570	2.385
7	20-Sep-2006	2.485	2.300
8	21-Sep-2006	2.495	2.305
9	22-Sep-2006	2.435	2.245
10	25-Sep-2006	2.400	2.205
11	26-Sep-2006	2.405	2.205
12	27-Sep-2006	2.450	2.240
13	28-Sep-2006	2.450	2.240
14	29-Sep-2006	2.450	2.245
15	2-Oct-2006	2.470	2.255
16	3-Oct-2006	2.435	2.230
17	4-Oct-2006	2.460	2.255
18	5-Oct-2006	2.495	2.280
19	6-Oct-2006	2.500	2.290
20	9-Oct-2006	2.580	2.365

20-day Moving Average	2.48600	2.28925
Rate Delta	-0.197	
Date Delta (DAYS)	1,827.000	
Start Date	20-Aug-15	
Target Date	**30-Jun-17**	
End date	20-Aug-20	
Interpolated Rate	**2.41277**	

Source Data
http://www.rba.gov.au/Statistics/HistoricalIndicativeMidRates/2005_to_2006.xls

APPENDIX B - WEIGHTED AVERAGE COST OF CAPITAL

The following WACC formula is used for the determination of the Maximum Reserve Capacity Price.

ITEM	Value
Margin for Debt (M_D)	1.5%
Margin for Equity (M_E)	15.1%
Real Commonwealth 10 Year Bond Rate (B)	2.41%
Return to Debt (Rd)	(B+Md) = 3.91%
Return to Equity (Re)	(B+Me) = 17.51%
Debt to Equity Ratio	60:40
D/V	0.6
E/V	0.4

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

The values of M_D, M_E, E/V and D/V are all detailed in the Market Rules and the IMO does not consider there any basis to change these parameters.

It is noted that with respect to the return to debt component of the WACC, the methodology listed in Appendix 4 of the Market Rules states:

> "…a real return to debt equal to the Commonwealth 10 Year Bond Rate (Nominal) plus a margin for debt of 1.5%..."

The IMO considers this statement to be misleading and partially incorrect. This statement should read:

> "…a real return to debt equal to the Commonwealth 10 Year Bond Rate (Real) plus a margin for debt of 1.5%..."

Similar to the way the sentence has been structured for the return to equity component.

There does not appear to be a basis for mixing real and nominal risk-free rate terms in this portion of WACC computation and the historical calculations have always been performed completely on a real basis. Therefore the IMO has adopted the second interpretation presented and proposes to introduce rule changes to clarify this typographical error.

This results in a real pre-tax WACC for the purposes of determining the Maximum Reserve Capacity Price.

The IMO believes it appropriate to re-visit this issue as part of the wider review being undertaken by the IMO and the Advisory Group.

APPENDIX C - FACTOR K

The Market Rules indicated that the Factor K should be set so that the net present value of 10 years worth of payments escalated on a CPI-1% basis is equivalent to the payment stream from 10 years worth of unescalated payments. The following formulae are used to describe the methodology of deriving the factor K.

Let the net present value of unescalated payments be defined by:

$$NPV_{unescalated} = \sum_{t=1}^{n} \frac{C}{(1+r_w)^t}$$

Where:

C is the payment
r_w is the return equal to WACC
n is equal to 10

Also let the net present value of escalated payment be defined by:

$$NPV_{escalated} = \sum_{t=1}^{n} \frac{C(1+r_e)^t}{(1+r_w)^t}$$

Where:

r_e is the escalation parameter equal to CPI-1%.

Introducing the factor K, the derivation becomes

$$K \times \sum_{t=1}^{n} \frac{C}{(1+r_w)^t} = \sum_{t=1}^{n} \frac{C(1+r_e)^t}{(1+r_w)^t}$$

Normalising C, Factor K becomes:

$$K = \left. \sum_{t=1}^{n} \frac{(1+r_e)^t}{(1+r_w)^t} \middle/ \sum_{t=1}^{n} \frac{1}{(1+r_w)^t} \right.$$

It is noted that the above equations consider an equal and consistent escalation of CPI through the investment period. In practice, the IMO has used a proxy CPI as detailed in Table 4 of this report.

The term $r_e(t)$ id introduced to capture the time-dependent mature of this parameter.

$$K = \left. \sum_{t=1}^{n} \frac{(1+r_e(t))^t}{(1+r_w)^t} \middle/ \sum_{t=1}^{n} \frac{1}{(1+r_w)^t} \right.$$

The IMO conducts this computation on a month-by-month basis across the 10-year term, so it is impractical to include the spreadsheet in this report. It is further noted that CPI as used in the Market Rules is not strictly the correct terminology, but has been used in the above equations to maintain consistency. Estimates of inflation (Table 4) are used.

APPENDIX D IMO DISCUSSION REGARDING SUBMISSION MADE BY ALINTA

The IMO wishes to thank Alinta providing the response to the Draft Report. The IMO has considered the main issues raised by Alinta and has made a number of changes to the price methodology in response to Alinta's submission. Detailed below are specific comments in reference to the main points raised by Alinta. IMO comments are in BLUE text font. In general, the submission made by Alinta raises a number of pertinent questions, but no evidence is provided to support the claims. Supporting evidence was strongly encouraged in the public submission process. Generally, Alinta raises concerns about the level of pricing of some components within the Maximum Reserve Capacity Price determination methodology. These claims are difficult to quantify without supporting evidence.

Regulatory Risk is also raised as an issue in the Alinta submission. However, Alinta then suggests that the IMO conduct confidential discussions with Market Generators, and to change the pricing methodology of the transmission scenario. This is inconsistent with the issue of reducing variability. However, following the arguments presented by Alinta with respect to the inclusion of deep connection costs, the IMO has increased the level of funding in this component. The impact of this is an increase to the Maximum Reserve Capacity.

Capital Cost - Gas Turbine Price

Alinta suggests that the IMO reviews the requirement to utilise the lowest of the quoted gas turbine prices. Practically, it may not be appropriate to utilise the manufacturer with the lowest quoted price as they may not be able to deliver the project within the required timeframes.

The determination of the Gas Turbine Price is clearly defined in the Market Rules. There is no basis for deviating from this methodology under the current framework without detailed review. This methodology was developed under the umbrella of the Market Rules Development Group, an industry-based consultation group established to consider such methodologies. Alinta Sales was represented in this group. That said, a new industry-based Advisory Group has been established to determine if the pricing methodology is appropriate for circumstances within the SWIS.

Electricity Transmission Connection Costs — Connecting to the SWIS

Alinta disagrees with the Sinclair Knight Merz (SKM) approach to calculating the electricity transmission connection costs.

The Wholesale Electricity Market (WEM) rules state that the transmission connection cost *'is the cost of electricity transmission* assets *required to connect an open cycle gas turbine power station to* the *SWIS.*' However, the SKM report appears to have calculated the capital connection cost for connecting a 160MW generator to a generic 330kV transmission line and has not taken into account the actual costs required to meet Western Power's requirements that are unique to the SWIS. For example, the underlying configuration proposed in the SKM report is unlikely to be acceptable to Western Power given the outages required on the 330kV system to construct it.

In order to obtain more accurate cost estimates Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4 16 4c of the WEM rules; and
- Confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice.

The costing approach, including the selection of the scenario is the same as that used last year. Through the public consultation process and informal discussions Western Power have been provided with an opportunity to comment on the appropriateness, among other things, of the transmission connection costs associated with the determination of the Maximum Reserve Capacity Price. Western Power has not challenged the connection option and costs presented by the IMO in the Draft Report through the public submission process.. Therefore the IMO considers them to be appropriate.

The proposal for the IMO to confidentially liaise with Market Generators does not provide sufficient levels of transparency for the entire process. This approach would be of particular concern for Market Customers who would potentially be affected by any pricing changes discussed and agreed confidentially with the IMO and Market Generators.

Transmission Connection Costs — Length of Tie Line and Tie Line Cost

Alinta proposes that the length of the tie-line used in the transmission connection cost estimate is typically less than that required by generators connected to the South West Interconnected System (SWIS). Alinta estimates that, on average, tie-lines connecting generators to the SWIS 330kV system are longer than 2km assumed by the IMO and that an amount of 10km to 20km would be more appropriate Alinta suggests that the IMO assess the location of existing, proposed and under construction generators with a 330kV connection to the SWIS in order to determine an average tie- line length on which to base the cost estimate.

Furthermore, the tie line costs incurred by proponents in the current market are significantly greater than those utilised in the SKM report. Over the last 3 years Alinta has experienced significant cost increases in raw materials and labour associated with the construction of transmission lines that do not appear to be considered in the SKM report.

In order to obtain more accurate cost estimates Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4. 16 4c of the WEM rules; and
- confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice.

The Maximum Reserve Capacity Price model is based on a generic scenario, \the details of which were largely discussed and agreed to within the aforementioned Market Rules Development Group. This assumed a site located close to the transmission system to minimise costs. The IMO has increased the complexity of the scenario from last year without changing the scenario entirely. The change to a different scenario would, as is raised in Alinta's submission would increase regulatory risk, something not supported by Alinta. Alinta does not provide and evidence or supporting information for its claims that and amount of 10km or 20km would be more appropriate.

Transmission Connection Costs — Switchyard Costs

Alinta comments that the switchyard costs incurred by proponents to meet Western Power requirements are significantly greater than those assumed in the SKM report. In order to obtain more accurate cost estimates. Alinta suggests that the IMO should:

- arrange for its consultant to liaise more closely with Western Power for current market advice;
- directly obtain the relevant cost estimates from Western Power as suggested in s4 .16 .4c of the WEM rules; and
- confidentially liaise with Market Generators, who have the most recent/current experience of these costs, for current market advice

Comments have been made in the previous response regarding the proposal to include Western Power and to confidentially liaise with Market Generators.

Transmission Connection Costs - Removal of SVCs

The SWIS is becoming increasingly constrained, with Western Power imposing additional capital contribution requirements on users to enable Western Power to fund voltage support initiatives and fault level upgrades.

Alinta has significant concerns with the sudden change of methodology to remove costs associated with SVCs.

The draft report (Page 10) states that this change is *discussed in detail.* However, Alinta has been unable to locate any detailed discussion that goes toward the justification of this key change in the methodology and the basis on which it needs to diverge from the previous two Maximum Reserve Capacity Price determinations by the IMO.

The draft report states that *'there are other locations in the network where connections will not require an SVC'.* This assertion ignores the vast array of complex considerations and limitations that a generation proponent faces in the locating and eventual construction of a power station. For example, costs to meet more stringent location specific planning requirements, provision of water supplies, etc. Generally proponents are unable to locate generation in the metropolitan area.

Alinta notes that the conclusion of the draft report refers to a *transmission costing model* and *'funding model* that will be impacted by the removal of the SVCs. There appears to insufficient detail in the report on these two models for Alinta to understand what allowances may have existed in these previously for SVCs and how they will be impacted by removing SVCs from them.

Alinta suggests that the IMO prepare a detailed document on this matter and invite further public comment before releasing a final report.

Following the consultation process, the IMO has re-instated the deep connection costs, which include an inseparable component for SVCs. Therefore they are now included in the final revised value. The IMO believes that this is one of the issues that should be discussed as part of the review process currently underway. This review will involve discussions with an industry Advisory Group and a public consultation process..

Transmission Connection Costs — Shared Network/Deep Connection Costs

The WEM rules state that the transmission costs should include *'an estimate of the cost of augmenting the shared network to facilitate the connection of the open cycle gas turbine power station..'.*

The draft report (Page 11) states that a value of $10.25M was used in the previous review for deep connection and network reinforcement costs. Given that the total proposed transmission connection cost estimate is $6 098M Alinta can only conclude that deep connection and network reinforcement costs are to be excluded in the current transmission connection cost. If this is the proposal it should be explicitly stated in the report as it is a significant change in methodology.

In a recent submission to the Economic Regulation Authority (ERA) concerning Western Power's proposed network Access Arrangement, Alinta submitted that the majority of Western Power's costs to connect a generator or large load to the SWIS should be added to Western Powers capital base, rather than being paid by users in the form of a capital contribution. If the ERA agrees with Alinta's submission then there would be a drop in the electricity transmission connection costs, which could then be reflected in determination of the Maximum Reserve Capacity Price. However, whilst the status quo is maintained, Alinta contends that electricity transmission connection costs have increased, not decreased. Alinta submits that the IMO should be increasing electricity transmission costs and that deep connection and network reinforcement costs should be included.

The IMO accepts this argument and has included the previous cost of $10.25M, escalated to 2007 by 5.48% to $10.81M.

Fixed Transmission O&M Costs

Transmission fixed O&M costs were estimated as *$19,000/MW* for the 2005 cycle, determined to be $7,823/MW for the 2006 cycle and proposed to be only $249/MW for the 2007 cycle, This is a very significant reduction proposed by the IMO in the Draft Report and, because it is an annual cost rather than one that will be capitalised over a number of years, it will have a large impact on the Maximum Reserve Capacity Price. Alinta submits that the IMO has not provided sufficient detail on the derivation of the proposed operating and maintenance cost (including why there has been such a significant change from previous estimates) to enable meaningful comment on the figures. Given the impact of the proposed change, Alinta suggests that the IMO prepare a detailed document on this matter and invite further public comment before releasing a final report.

The transmission fixed O&M costs estimates for the 2006 cycle (2008/09 Reserve Capacity Year) and for the 2009/10 Reserve Capacity Year are based on a more rigorous analysis of the costing inputs that were used for the 2005 Reserve Capacity Cycle (Energy Market Commencement through to 1 October 2008). The major difference between the Maximum Reserve Capacity Price for 2008/09 and the Maximum Reserve Capacity Price for 2009/10 was the inclusion of $1,200,000 per year in insurance costs which were added to the Fixed Transmission O&M cost component last year. The addition resulted from the public consultation process and raised this as an issue this year. The $1.2M equates to $7500 per MW per year, accounting for the main difference in values ($7823 per MW per Year as opposed to $249 per MW per year). These costs have been included, but have been provided separately this year. The IMO has also reviewed ongoing connection charges following the consultation process.

Fixed Fuel Costs - Lateral Pipeline Installation Cost

Alinta comments that the level of detail on fixed fuel costs on Page 10 is insufficient for Alinta to provide meaningful comment, Alinta notes that bullet (e) in the Introduction states that the MC is required to assess the appropriateness of *'the capital cost of a gas lateral to allow for dual fuel capability'.* Alinta notes that there is no mention of a gas lateral in the remainder of the report.

Alinta submits that the IMO should be including the cost of a lateral pipeline installation when determining the Maximum Reserve Capacity Price. Clauses 4.164(d) and (e) of the Wholesale Electricity Market Rules require that the maximum reserve capacity price will be based on a dual fuel gas turbine in which the cost of fuel tanks and a gas lateral pipeline are included. It appears that the IMO has included the cost of fuel tanks but not the cost of a lateral pipeline.

The decision to fund fuel tanks and not a gas pipeline lateral was an outcome of the Market Rules Development Group consultation process prior to the determination of the first Maximum Reserve Capacity Price in 2005. Alinta was a party to this consultative process. In accordance with clause 4.16.4 of the Market Rules, the IMO considers it appropriate to continue the funding approach on the same basis that was used previously with the provision that the issue is re-visited by the Maximum Reserve Capacity Price Advisory Group.

Insurance

The draft report provides insufficient detail as to how the 0.5% of the capital replacement cost was derived to determine the level of insurance. Alinta suggests that the actual amounts are greater and significantly greater during the construction phases of a project.

Given that the capital replacement cost used to derive the level of insurance is also low the resulting provision for insurance appears too low.

The insurance rates of 0.5% of the capital replacement costs are derived from the statement made on page 15 of the SKM technical report. The statement made by SKM refers to insurance for the transmission line connection costs. This rate has been applied to both the transmission line connection and the generation plant costs. The insurance cost estimate includes the replacement cost of generator and the replacement cost of the main transmission components. Alinta makes the statement that both the rate of 0.5% and the capital replacement costs are too low, but provides no supporting evidence for such claims. In addition to this, Alinta states that the insurance costs are higher during the construction phases. It would not seem appropriate to include an O&M cost for insurance over the life of the project for short-term developmental costs. No comment is made as to whether the cost estimates referred to by Alinta include any energy or capacity contractual risk cover. As such, the IMO does not believe sufficient argument has been presented to warrant substantial change to this component. However, the IMO has reviewed the input values used and has expanded the insurance to cover line-tee-in costs.

IMO Disclaimer

Alinta submits that the IMO should review and amend the disclaimer attached to the report. The disclaimer states that the document is published *'as an information* service'. *'contains only general in formation'* and *'makes no representations or warranty* as *to the accuracy, reliability, completeness or suitability for particular purposes of the information in this document'.* These statements appear inconsistent with the importance and intent of the report and question the point of publishing the report at all.

The IMO has removed this disclaimer.

Regulatory Risk Concerns

Alinta notes that the cost estimates utilised to derive the Maximum Reserve Capacity Price seem to be at the very low end and at times unrealistically low.

Alinta also notes its ongoing concern that there is significant variability in methodology and outcomes between each capacity year Changes of such magnitude, and the risk that further similar significant changes may take place in future, will cause instability and uncertainty amongst project proponents and investors. Alinta has significant concerns with the regulatory risks inherent in the IMO's proposals and considers that making such significant changes will be detrimental to the long-term development of the electricity market. The regulatory process needs to provide some long-term certainty to users and prospective users, particularly as there is likely to be an absence of price signals in an energy market where there are very low price caps and probable low volatility such as the proposed Wholesale Energy Market in WA.

The IMO acknowledges that regulatory risk is a concern, particularly with regard to visibility and consistency of IMO processes. To streamline and optimise the process the IMO has undertaken to review the existing methodology used to determine the Maximum Reserve Capacity Price in a wider context. However, the IMO does not believe proposals by Alinta to include confidential consultations with selected market generators would be a viable solution to any of the issues raised, particularly in the context of further raising issues regarding Regulatory Risk. Strong investment signals have been observed by the IMO, with the process securing surplus capacity in both years in which the Reserve Capacity Mechanism has been run. While this is a very short timeframe, the signals are encouraging. The IMO does acknowledge that long-term certainty will be a key driver to investment within the SWIS, and this was that reason for making the process more transparent this year than for previous cycles. The level of transparency of the process for determining the Maximum Reserve Capacity Price has been increased substantially this.year.

Report Structure and Readability

Alinta suggests the report be reworked to improve its readability by:

- including an appendix containing all the inputs and calculation for both the maximum reserve capacity price, including underlying components such as the WACC and k-factor
- include a chart showing where the increases and decreases are from the previous cycle(s)
- Adjust Table 1 as it currently could misrepresent the proposed transmission connection cost estimates increasing from the 2006 review cycle to the 2007 cycle.

The IMO has made a number of changes to the report format to improve clarity. Subject to the outcomes of the Maximum Reserve Capacity Price Advisory Group, the IMO undertakes to include changes from previous Reserve Capacity Cycles in future reviews.

APPENDIX E IMO DISCUSSION REGARDING SUBMISSION MADE BY ENEABBA GAS LIMITED

The IMO wishes to thank Eneabba Gas Limited (EGL) for providing their response to the Draft Report. The IMO provides the following responses to a number of the comments raised by EGL. The following issues are discussed in reference to the ELG submission. Again, IMO comments are shown in BLUE font.

Reserve Capacity Pricing

Eneabba notes that the 2007 Maximum Reserve Capacity Price is proposed to be set at $129,900 per MW per year for the 2009 year. This price compares to previous calculations and "Ministerial" directions released. With the following pricing:

2007/08 $150,000/MW

2008/09 $122,500/MW

2008/09 (rev) $129,900/MW

Under the rules this is meant that the annual payment available has fluctuated from $127,500/MW to as low as $94,375/MW.

Eneabba uses the pricing information released by the IMO and previously by "Ministerial direction" inter alia, as a basis of investment decision making. investing in a power station plant carries many risks namely construction risk, technology risk, market risk and regulatory risk to name a few. Clearly, power station proponents seek to minimize all of these risks where possible and where they can influence them. Eneabba is looking to invest between $130 million - $160 million on the power plant and associated land in Western Australia. It is disturbing to note that a potentially important revenue stream in the form of Reserve Capacity Payments can have such a wide variation as outlined above. Investment decision making becomes extremely difficult in such an uncertain and volatile environment.

The Maximum Reserve Capacity Price for the first Reserve Capacity Cycle, which extends from Energy Market Commencement (21 September 2006) through to 1 October 2008 of $150,000 per MW per year was set under the Market Rules and was not subject to the same price determination and review process that has been conducted for the 2008/09 Reserve Capacity Year (determination and review conducted in 2005/06) and for the 2009/10 Reserve Capacity Year conducted as part of this review. The administered price in the case where the Reserve Capacity Auction is cancelled is not within the scope of the Draft Report or the public submission process.

Draft Report

The overriding concern of Eneabba with respect to the Report is the lack of detail provided in the report to support the conclusions reached. This ordinarily may not be of a concern but when coupled with the significant variation as outlined above the reader of the Report is unable to undertake their own analysis to confirm any of the conclusions reached in the Report.

As a minimum a format that covers the following headings, with sufficient information to convey confidence to the reader that the analysis is both complete in capturing all costs as well as providing detail on costs is considered necessary.

Suggested areas that need to be provided in the Report are outlined below:

Power Station Site

- Where is the site located regional or metropolitan?
- Are site acquisition and preparation costs included?
- Are EPA and local shire approval costs included?

Power Station Costs

- Are the total costs of an open cycle plant included?
- Do the 'total costs' include all ancillary plant, such as water treatment, oil recovery, etc?
- Are the construction costs based on today's high priced construction?
- Market?
- Is the cost of acquiring and installing fuel tanks as outlined in page 5 of the Report included in the Restive Capacity Pi ice of $129,900

Financing Costs

Eneabba found this area particularly poorly coveted. Financing costs have a significant impact on the pricing of the Reserve Capacity Price. Yet only two short paragraphs were dedicated to this important issue. A review of regulation determinations in the Eastern States reveal that considerable attention is given to this area. As a minimum the IMO should provide a table with the key parameters as outlined below to allow for analysis.

Power Station and Site Costs

The IMO has endeavoured to make the process more transparent this year and the information presented in the Draft Report, combined with the SKM technical report and knowledge of the Market Rules can be used to replicate the pricing. A number of questions are raised regarding location-dependent issues of the determination strategy.

The pricing methodology of the OCGT power station under Appendix 4 of the Market Rules does not take into account and location specific pricing signals. The general concept of the Maximum Reserve Capacity Price is to provide adequate capital cost recovery of an OCGT power station project entered through the Reserve Capacity Auction. Inherent in this mechanism is the assumption that overall project costs are minimised for the purposes of providing peaking capability. This would not provide increased costing resulting from sub-optimal location of the power station.

Site acquisition and preparation costs are not specifically included under Appendix 4 of the Market Rules, however the generator price is doubled to include power station development costs. General approval costs are included in accordance with Appendix 4 of the Market Rules and presented as margin M in the Draft Report. The IMO is conducting a more general review of the current methodology to assess the appropriateness of the entire methodology.

Financing Costs

More detail has been included in the Final Report, including the determination of the WACC and the Factor K. However many of the parameters of interest can already be found in Appendix 4 of the Market Rules.

APPENDIX F IMO DISCUSSION REGARDING SUBMISSION MADE BY BEACONS CONSULTING INTERNATIONAL

Based on the prices for similar 132 kV transmission links we have for various projects currently under consideration, it is our belief the price for the 330 kV transmission link in the 2006 review is less than the actual current pricing for this type of works.

Western Power Networks costing for the 330 kV transmission link needs to be obtained for comparison to the costs used in the 2006 Review.

The IMO wishes to thank Beacons Consulting for providing their submission on the Draft Report. Beacons Consulting contends that the transmission pricing appears to be low in reference to current projects under consideration. Unfortunately no supporting information is provided to substantiate such claims. Western Power has been given the same opportunity to make a formal submission on the adequacy of the transmission connection scenario and pricing. The IMO will consider this position for future reviews.

Attachment 8: PB Associates Report - Review of the Maximum Reserve Capacity Price

REVIEW OF THE MAXIMUM RESERVE CAPACITY PRICE

An independent review

Prepared for

Economic Regulation Authority
WESTERN AUSTRALIA

***PB** Quality System:*

Document Reference:	2159251A-REPT-003.doc
Report Revision :	3_0
Report Status :	Final
Prepared by :	M Walbank
Reviewed by :	P Williams
Approved by :	P Williams
Date Issued :	23 January 2007

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SECTIONS

EXECUTIVE SUMMARY

On 6 December 2006 the Authority engaged PB to undertake a review of the Maximum Reserve Capacity Price (MRCP) proposal by the Independent Market Operator (the IMO) with the assistance of its consultant, Sinclair Knight Merz (SKM).

This work has involved an evaluation of the final reports prepared by the IMO and the provision of expert advice in regard to approval of the MRCP. Specifically, PB has evaluated the engineering inputs and the application of the MRCP as proposed by the IMO and SKM.

PB is able to summarize its findings as follows.

Transmission Connection Capital Costing

In general, the SKM capital costs for transmission connection are found to be lower than PB would expect. The drivers for the variance are described below.

- PB has used a 200% short-line adjustment factor compared to a factor of 130% used by SKM;
- PB has assumed for the 2km line there will probably be at least 6 non-cyclonic towers of which at least two towers will be strain towers. Giving a ratio of 33% strain towers and a 400m span length;
- PB has included capacitor-coupled voltage transformers (CVT) and arresters for every line exit at the substation, compared to the SKM use of only one set of voltage transformers (VT);
- PB has included the cost of a control building;
- PB has included the cost of SCADA and communication facilities; and
- PB has calculated protection and control costs to be higher than those used by SKM.

OCGT costs including fixed fuel cost

Based on the data that is available, PB is satisfied that reasonable adjustments have been made to the 2005 costs to bring them into line with 2006.

Industry escalation Index

PB has verified that the publicly available indices have been correctly applied. PB also used internal benchmarks and are satisfied that, overall, the escalation factor are reasonable.

Determination against the Wholesale Electricity Market rules

PB has reviewed the determination against Clause 4.16.4 of the WEM Rules and has identified several discrepancies in the calculation of the MRCP. PB has assessed the overall affect that each of the discrepancies has on the MRCP. The result is given in Table A.

PB reviewed clause 4.16.4(e) and in our opinion, needs to be revisited to ensure that the capital cost of a gas pipeline has been adequately covered.

Table A – Total change in MRCP by correcting for the discrepancies

	IMO final report	PB calculation	variance
Price cap [2007]	$142,200	$139,814	-1.7%

1. INTRODUCTION

The Economic Regulation Authority ('the Authority") is responsible for approving the proposed Maximum Reserve Capacity Price (MRCP) annually. In accordance with the Wholesale Electricity Market (WEM) Rules this approval process commences three years ahead of the Capacity Year to which the prices apply. The current review is associated with the MRCP for the time period from 01 October 2009 to 01 October 2010.

On 6 December 2006 the Authority engaged PB to undertake a review of the MRCP proposal by the Independent Market Operator (the IMO) with the assistance of its consultant, Sinclair Knight Merz (SKM).

This work has involved an evaluation of the final reports prepared by the IMO and the provision of expert advice in regard to approval of the MRCP. Specifically, in the report, PB has evaluated the engineering inputs and the application of the MRCP as proposed by the IMO and SKM. This includes, but is not limited to, a review of the following items.

- transmission connection capital costs;
- transmission operational and maintenance costs;
- OCGT operation and maintenance costs;
- fixed fuel costs;
- the appropriateness of the industry escalation index; and
- the appropriateness of the IMO's final determination against clause 4.16.4(a) to clause 4.16.4(f) of the WEM Rules.

This report describes the outcome of the PB review of the MRCP, and sets out our views on the appropriateness of the IMO final determination in respect to application of clause 4.16.4(a) through to clause 4.16.4(f).

In Sections 2 and 3 we set out our views on transmission connection costs and OCGT operations and maintenance costs (and fixed fuel costs) respectively. In Section 4 we review the industry escalation index whilst in Section 5 we provide the PB assessment of the appropriateness of the IMO's final determination against the WEM Rules. In Section 6 we provide details of our review of the public submissions.

2. TRANSMISSION CONNECTION COSTS

This section contains PB's findings on the capital cost relating to the transmission connection and the cost of operation and maintenance.

2.1 TRANSMISSION CONNECTION CAPITAL COSTS

The total transmission connection capital costs will be affected by the connection topology as well as the cost of the line and the assets associated with the connection to the substation. The PB review of each of these items is set out below.

2.1.1 Scenarios for connection to the transmission system

PB observes that only one 330kV connection option appears to have been considered by SKM. It is not clear how exhaustive the list of alternative options needed to be for this exercise, however, PB considers that the option selected by SKM (using the meshed three circuit breaker topology) is efficient and we note that it is often preferred by Transmission Network Service Providers (TNSPs). PB is of the view that this topology represents a cost effective way to connect a radial generation source to an existing transmission line.

The connection configuration modelled assumes the switching substation is located at the existing transmission line tee-in, remote from the generation site. If the substation is required to be located at the generation site, an alternative configuration based on a double circuit transmission line to the existing transmission line tee-in might be suitable. This option has not been assessed by SKM.

For connections to existing substations, a viable option commonly used is a 'breaker and a half'[1] arrangement. While this arrangement was considered in the last report, it does not appear to have been assessed this year.

We note also that a 'teed' connection option has not been assessed. However this arrangement is generally not used at 330kV for system security reasons as loss of the line will also result in loss of generation. This arrangement can also introduce protection complications. However, it could attract a lower overall capital cost if this is the overriding objective.

2.1.2 Transmission line costs

The transmission line rating chosen by SKM appears to have been selected to match the power station rating. For technical reasons, the rating of the 330kV line will be substantially higher than 200MVA. PB is of the view that the use of twin 'mango' conductor and the choice of rating is satisfactory for a 330kV connection of a 160MW generator.

Based on the SKM figure[2] of $475,673 for 2km of 330kV twin conductor transmission line for a flat rural terrain, the unit rate used by SKM is $238k per km. We believe that this is within the expected range for a single circuit 330kV twin mango line with 400m spans and 10% strain towers in a rural area.

1 "Breaker and a half" is a commonly used substation configuration that allows the connection of two transmission lines to two independent busbars using three circuit breakers. The number of circuit breakers per line is therefore one and a half, hence the term "breaker and a half". This configuration is more cost effective than the "double switched" configuration which uses two circuit breakers per line.

2 SKM report.: 2006 Review of 160MW OCGT Transmission Link Pricing and GT Fixed O&M; Dated 16 October 2006; Appendix A

An adjustment factor of 130% has been applied by SKM to the unit costs (which are based on 100km) for the 2km transmission line. Applying a factor such as this is an accepted practice for costing short transmission lines for cost accuracy in the order of ±25%.

The use of an adjustment factor for short lines is to cover the fixed cost overheads associated with the construction of an overhead transmission line and the higher proportion of strain towers required. Depending on the accuracy requirements of the costs, to obtain a cost estimate any better then ±25% accuracy (such as the ±10% nominated by SKM) may require a bottom-up approach using the cost of material components for the specific transmission line.

No indication of the assumed number of strain structures or span length has been provided in the SKM report. For a 2km line, there will probably be at least 6 non-cyclonic towers with at least two strains giving 33% strain towers, 400 metre spacing. PB would regard the 130% short line adjustment factor used by SKM as too low for a 2km line. We suggest that an adjustment factor of around 200% would be more appropriate.

The tie-line costs provided by SKM in table 4 of its report[3] do not appear to align with the costs summarised in the first row of Table 5. A discrepancy also appears to exist for the alternate case. These discrepancies are summarised in Table 2-1.

Table 2-1 – Discrepancies identified in the SKM report

Tie-line Costs (2km)	Table 4 of the SKM Report	Table 5 of the SKM Report
Base case	$0.71m	$0.62m
Alternate case	$0.76m	$0.66m

In the opinion of PB, the SKM cost of $711,000 is a low estimate. We believe that a cost of approximately $1,160,000 would be more appropriate (as given in Table 2-2).

The Appendix A of the SKM report title indicates that cost estimates are provided for 2km, 10km and 20km, however the content only provides costs for the 2km short line case. There is no indication of how the short line costing can be extrapolated to longer lines. Any long line costing assessment is recommended to be performed based on a 100km line rather than 20km.

The difference in cost between the base terrain case and alternate terrain case appears, to PB, to be too small in the SKM report. SKM has used a 7% increase, whereas PB estimates an 18% increase. This is shown in Table 2-2.

Table 2-2 – Base case and alternate cost estimates and variances

Tie-line cost case	SKM cost estimate	PB cost estimate	variance
Base case costs	$0.62m	$1.16m	+87%
Alternate case costs	$0.66m	$1.37m	+107%
Cost change	+7%	+18%	

SKM has specified in the appendices that they have not estimated costs or included costs for land and easements, remote end and interfacing works, switching and outage planning costs. These costs may need to be included to determine overall project costs.

3 SKM report: 2006 Review of 160MW OCGT Transmission Link Pricing and GT Fixed O&M; Dated 16 October 2006 Table 4, page 7

2.1.3 Substation and transmission line connection costs

The line tee-in costs calculated by SKM are within PB expected range and we believe that the tee-in connection arrangement using a new tension tower is an efficient solution. Table 2-3 summarises the estimates.

Table 2-3 – Line Tee-in cost estimates

Item	SKM cost estimate	PB cost estimate	variance
Line Tee-in	$0.24m	$0.22m	-8%

The SKM cost for the switchyard primary equipment is in line with that estimated by PB. However, PB has nominated additional capacitor-coupled voltage transformers (CVT) for each line and arrester equipment and included the cost of a control building.

Higher costs have also been calculated for the secondary equipment which includes protection, control, communication and SCADA equipment. We also note that communication and SCADA system costs do not appear to be included in the SKM cost estimate.

The substation costs (excluding establishment cost) nominated by SKM is therefore lower than PB estimate. The site establishment costs, however, are in line with PB expectations. Table 2-4 summarises the costs.

Table 2-4 – Substation site establishment cost estimates

Item	SKM Cost Estimate	PB Cost Estimate	Variance
Site Establishment	$1.13m	$1.16m	+3%
Switchyard	$2.99m	$3.96m	+32%

2.1.4 Combined line and switchyard costs

PB is of the view that the Engineering Procurement and Construction Management (EPCM) overhead rate of 15% is at the high end of the scale, but satisfactory.

SKM's costs include estimates for site establishment, engineering, procurement and contract management. This is standard practice and we believe that the values used by SKM are appropriate. Table 2-5 summarises the costs.

Table 2-5 – Combined line and switchyards cost estimate

Base case item	SKM cost estimate	PB cost estimate	variance
EPCM	$0.75m	$0.75m	0%
Base case	$5.73m	$7.25m	+26%
Alternate case	$5.78m	$7.46m	+29%

2.1.5 Deep connection costs

Deep connection costs are those augmentation costs within the transmission system which are required to be undertaken as a result of the generator connection. Such costs can include the installation of equipment for maintaining system stability, quality of supply or fault level mitigation. The deep connection costs are very site specific and are determined by the findings of detailed power system studies. The magnitude of the deep connection costs in relation to the total connection costs can be substantial, and in some cases, the major component of the total cost.

The IMO has used a value of $10.25M for 2006 and escalated this figure to $10.81M for 2007. The escalation methodology applied between 2006 and 2007 is valid in PB's opinion. In discussion with ERA and the IMO, PB agreed that the magnitude of the deep connection cost can vary significantly depending on the site and that it would be appropriate for the pre-approved 2006 figure of $10.25M to be used as the benchmark for this review. In our view, the basis for including the deep connection cost is valid and the magnitude used can be representative of the deep connection costs.

2.2 TRANSMISSION OPERATION AND MAINTENANCE COSTS

SKM has developed costs based on asset class and asset life. PB concurs that this is a satisfactory way of developing operation and maintenance costs as each class of plant has varying degrees of inspection, servicing and refurbishment requirements and generally these costs increase over time. The costs have been developed by SKM over the engineering life of 60 years for transmission lines and 50 years for the substation. We believe that this is a satisfactory time period for these types of assets. Table 2-6 summaries these costs.

PB notes that the SKM figures are in five-yearly aggregates and exclude insurance costs. We believe that this is appropriate.

Table 2-6 – Operation and maintenance cost estimate

Asset	Base case annual O&M	Alternate case annual O&M
Transmission line 60 years	$5,989	$6,438
Substation 50 years	$60,278	$60,278

Note: costs expressed in June 2006 dollars

The average annual O&M costs of around $66,000 per annum ($417/MW) are at around 1.1% of the total capital costs (based on SKM costs). PB is of the view that this is at the lower end of the expected range. A value in the range of 1% to 2% would be expected.

Table 8 of the SKM report shows that the maintenance costs increase appropriately over the life of the asset.

We conclude that the annualised cost set by IMO of $937/MW (being the annualised cost over the first 15 years escalated to 2007 dollars and including Western Power's use of system charges) is reasonable.

2.3 CONCLUSION

On average, PB has found the SKM cost estimates to be 23% lower than the PB estimates. The variance can be explained by the following.

- PB has used a 200% short-line adjustment factor compared to a factor of 130% used by SKM;
- PB has assumed for the 2km line there will probably be at least 6 non-cyclonic towers of which at least two towers will be strain towers. Giving a ratio of 33% strain towers and a 400m span length.
- PB has included capacitor-coupled voltage transformers (CVT) and arresters for every line exit at the substation, compared to the SKM use of only one set of voltage transformers (VT);
- PB has included the cost of a control building;

- PB has included the cost of SCADA and communication facilities; and

- PB has calculated protection and control costs to be higher than those used by SKM.

3. OCGT OPERATION, MAINTENACE AND FIXED FUEL COSTS

A review has been undertaken of the inputs used by the IMO to calculate the fixed operation and maintenance costs and the fixed fuel costs for a generic 160MW OCGT peaking power plant.

3.1 OCGT OPERATION AND MAINTENANCE

The IMO have made some assumptions for the basis for calculating the costs. The assumed regime is given below:

- net capacity of approximately 160MW;
- duel fuel with natural gas as the primary fuel;
- 1% and 2% capacity factor;
- 4 hours running per start;
- 22 starts per annum for a 1% capacity factor;
- 44 starts per annum for a 2% capacity factor;
- no fast starts; and
- one full time load trip per annum.

SKM developed the costs of operating and maintaining a 160MW OCGT based on the above criteria for the IMO. The SKM basis for the costs was a single 160MW open cycle industrial gas turbine.

PB has subsequently reviewed the assumptions and calculation made by SKM and is of the opinion that they are appropriate given the overall level of accuracy required. In forming this opinion PB has used information obtained independently and although there are some differences the overall match is reasonable.

It should be noted that very few reference sites exist which have the exact configuration used as the base case. This means that operation and maintenance costs have to be extrapolated. This has caused some additional uncertainty in the calculations although we believe that the overall result is still likely to be within a tolerance of ±5%

PB has also checked that the inputs provided by SKM have been interpreted correctly by the IMO for the inclusion in their own report.

The initial assumptions provided by the IMO led to costs being evaluated on the basis of a single 160MW OCGT power station. There are other types of generating plant that, in many respects, are better suited to the provision of reserve capacity. However, they have been omitted from the evaluation as a result of this very specific criteria being applied. At some stage it may be appropriate to review the criteria to ensure that the generation plant is suited to the duty required.

3.2 FIXED FUEL COSTS

PB has assessed the assumptions and calculation made to establish the cost of the fixed fuel.

PB has reviewed the cost of on-site storage of liquid fuel and the assumptions and calculation made. We are of the opinion that these are appropriate given the overall level of accuracy required.

When assessing clause 4.16.4(e) we have been unable to identify any calculations or assumptions relating to the capital cost of installing a secondary fuel source, specifically a gas pipeline.

PB notes that the WEM Rule 4.16.4(e) requires that the capital cost for a pipeline is assessed for reasonableness. PB recommends that the capital cost for a gas pipeline as specified in clause 4.16.4(e) is established and reflected in the report.

4. INDUSTRY ESCALATION INDEX

In order to express the cost of the transmission line and the OCGT in June 2006 dollars, an index is applied. SKM has determined two indices, one to be applied to transmission assets and another for generation assets.

PB has undertaken a review of the industry escalation rates offered by SKM and used in the IMO report. Table 4-1 shows the indices as reported by SKM, and also the PB estimate.

SKM referenced publicly available indices from the following sources:

- Australian Bureau of Statistics;
- Electrical Trade Union of Australia;
- Industrial Relations Commission;
- Rawlinson's Australian Construction Handbook; and
- CRU Steel Price Index.

SKM also reference an internal database generated from its own surveys undertaken in the power industry.

PB has verified the publicly available indices and we have also used our own internal cost database as an additional reference. PB believes that the indices used in the IMO report are satisfactory.

Table 4-1 – Industry escalation rates

Inflation category	SKM escalation estimate	PB escalation estimate
Transmission	5.48%	5.72%
Generation	4.25%	4.38%

The PB view is that the IMO has correctly included the indices created by SKM and the figures generated by SKM are appropriate.

5. DETERMINATION AGAINST THE WEM RULES

PB has reviewed the use of the costs in the IMO final determination in order to present its view on the appropriateness of the IMO's final determination against the requirements of the WEM Rules. This section sets out the findings of this review.

5.1 CLAUSE 4.16.4(A) – ESTABLISH THE OPTIMUM SIZE OF OCGT

This clause of the WEM Rules requires the IMO to assess the appropriateness of connecting an optimum sized OCGT to the South West Interconnected System (SWIS) where the optimum size is expected to minimise the cost of energy to market customers.

In our review the IMO final report, PB has not been able to establish how the optimum size of the OCGT was established at 160MW.

5.2 CLAUSE 4.16.4(B) – CAPITAL COSTS OF AN OCGT BASED ON APPENDIX 4

We have identified several discrepancies in the formulas stated in Appendix 4 of the WEM Rules when applied to the values as set out in the IMO Final report. Details of these are set out below.

Discrepancies in calculation

PB has identified two calculated discrepancies in the calculation of the price cap.

In calculating the value PC[t] using the formula in Appendix 4 of the WEM Rules a small discrepancy has been identified. Table 5-1 shows the figures as set out in the IMO report and the figure calculated by PB.

Table 5-1 – Discrepancy in the calculation of PC[t]

	IMO final report	PB calculation	variance
PC[t]	$517,103	$517,011	< 1%

A small discrepancy has also been identified in the calculation of the value CAPCOST[t] using the formula in Appendix 4 of the WEM Rules. Table 5-2 shows the figures as set out in the IMO report and the figure calculated by PB.

Table 5-2 – Discrepancy in the calculation of ANNUALISED_CAPCOST[t]

	IMO final report*	PB calculation	variance
ANNUALISED_CAPCOST[t]	$15,316,608	$15,028,387	-2%

* Note that the figure reported in the IMO Final Report is $13,947,700. After consultation with the ERA this was corrected to the figure in Table 5-2.

Expression of units

PB has identified two instances where the units used in the calculations are inconsistent with those stated in the Rules. The two inconsistencies are described below.

1. In the calculation of CAPCOST[t], the term PC[t] is stated in Appendix 4 of the WEM Rules as being expressed in *"Australian dollars in year t per MW*". But for the calculation to be mathematically consistent this term should be expressed in million Australian dollars in year t per MW.

2. CAPCOST[t] is stated in Appendix 4 of the WEM Rules as being expressed in *"million Australian dollars in year t",* but for the calculation of PRICECAP[t], CAPCOST[t] must be expressed in Australian dollars in year t to be mathematically correct.

Commonwealth Bond Rate

PB has identified two anomalies relating to the Commonwealth Bond Rate that affect the calculation of the MRCP figure.

The first relates to the number of days used to estimate the interest rate. The figures in Table 5-3 are taken from Appendix A of the IMO final report.

Table 5-3 – Calculated days used to generate the interpolated interest rate

	IMO final report	PB calculation	variance
Delta Days (days)	1,827	1,817	< 1%

The second anomaly relates to the range of rates used as the base for the interest rate.

In the IMO Final Report the real interest rate has been found by interpolating between the indicative mid rates of the Commonwealth Government Securities with maturity dates of 20 August 2015 and 20 august 2020. Whilst the headings in Appendix A of the IMO Final Report refer to those dates, the data used appears to cover the period 20 August 2010 to 20 August 2015.

Table 5-4 shows the affect on the interpolated rate used to calculate the interest rate.

Table 5-4 – Affect of using the Bond Rate

	IMO final report	PB calculation	variance
Interpolated rate	0.0241	0.0214	-11%

The total affect on the interest rate is given in Table 5-5.

Table 5-5 – Overall affect on the interest rate by correcting for the discrepancies

	IMO final report	PB calculation	variance
Interest Rate "D"	0.0391	0.0364	7%

5.3 CLAUSE 4.16.4(C) THROUGH TO 4.16.4(D)

PB examined the processes use by IMO in assessing the appropriateness of these values. In our view, the processes used by IMO are adequate to ensure that the requirements of the WEM Rules are met.

5.4 CLAUSE 4.16.4(E) – CAPITAL COST OF A PIPELINE

This clause requires the assessment of the capital cost of a pipeline of reasonable length to connect to a main gas pipeline to allow for duel fuel capability.

PB are unable to confirm that the determination adequately meets this clause as the capital cost of the pipeline has been deemed…

> *"…not a necessary component of the least-cost OCGT power station."*[4]

PB also notes that the method of setting the MRCP, set out in Appendix 4 of the WEM, does not explicitly allow for the capital cost of a pipeline to be included in the price methodology.

5.5 CLAUSE 4.16.4(F) THROUGH 4.16.4(H)

PB examined the processes use by IMO in assessing the appropriateness of these values. In our view, the processes used by IMO are adequate to ensure that the requirements of the WEM Rules are met.

5.6 CONCLUSION

PB has assessed the affect that each of these discrepancies had on the overall MRCP and the result is given in Table 5-6.

Table 5-6 – Total change in MRCP by correcting for the discrepancies

	IMO final report	PB calculation	variance
PRICECAP[2007]	$142,200	$139,814	-1.7%

PB believe that clause 4.16.4(e) needs to be revisited to ensure that the capital cost of a gas pipeline has been adequately provided for.

4 IMO: final Report: Maximum Reserve Capacity Price Review for the 2009/10 Reserve Capacity Year; page 12.

6. REVIEW OF THE PUBLIC SUBMISSIONS

PB has undertaken a review of the three submissions received by the IMO on the Draft report on the MRCP. Submissions have been received from the following interested parties.

- Alinta Sales;
- Eneabba Gas Limited; and
- Beacon Consulting International.

PB notes that the IMO has already made comment on the responses received from the stakeholders and has included them in the final report.

Alinta recommends that the IMO reviews the requirement to use the lowest cost gas turbine price to establish the MRCP on the basis that the manufacturer may not be able to deliver. PB is of the view that the risk involved with taking the lowest cost is factored into the price by the doubling of the price to establish the Gas Turbine Price GTP [t-x]. We believe that is adequate at this stage of the process.

Alinta also believes that the process to establish the transmission connection price does not meet the WEM Rules. Clause 4.16.4(c) (i) of the WEM Rules states

> *"…the cost of electricity transmission assets required to connect an open cycle gas turbine power station to the SWIS…"*

Alinta believes that the cost of outages, and any system augmentations, needed to accommodate a new generator should be included in the connection cost. In PB's view, this is not an unreasonable point as the impact to the MRCP may be significant.

Furthermore, Alinta submit that the cost of including a lateral pipeline should be included in the cost when determining the MRCP. In the final report the IMO comment that this cost has not been factored into the Fixed Fuel Costs as it not seen as necessary. The WEM clause 4.16.4(e) states that

> *[... the IMO must assess the appropriateness of the following values…]*

> *"The capital cost of a pipeline lateral of reasonable length to connect to a main gas pipeline (so as to allow for duel fuel capability)"*

In the view of PB, the Alinta view is not unreasonable. PB believe that in the IMO Final Report it is not clear why the capital cost of a pipeline was not factored into the Fixed Fuel Costs and has been deemed an unnecessary component for a least-cost OCGT power station.

Alinta also believes that the factor applied to insurance is too low and there is insufficient information to derive a value. PB is of the view that there is insufficient detail to be able to make an independent assessment in this regard.

On reviewing the submissions two respondents shared a concern relating to the transmission costs. Alinta and Beacons Consulting International regard the current market price for the 330kV transmission connection is greater than those used by SKM, PB concurs with this view that the price in the IMO report is lower than the market price.

Alinta also state concerned that the switchyard costs are not reflective of the current market cost. PB believes that the cost used by SKM is lower than the current market price.

Alinta and Eneabba Gas Limited articulate concerns regarding the detail in the process implemented by the IMO. Specifically, the submissions reflect concerned with the lack of detail to support the IMO's decision.

The two respondents also made comment on the volatility of the historic value of MRCP and are concerned that this instability may cause uncertainty with the project proponents and investors.

Alinta and Eneabba Gas limited have included suggestions within their response on how they believe the process may be changed to improve the ability to analyse the results.