DIRECTLINK JOINT VENTURE

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9 December 2005

Mr Warwick Anderson
Acting General Manager, Access Branch
Australian Energy Regulator
470 Northbourne Avenue
CANBERRA ACT 2600

Dear Warwick

Re: Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to June 2015

The Directlink Joint Venturers welcome the Australian Energy Regulator's ('**AER's**') publication of its draft decision in relation to the Directlink conversion application. The draft decision confirms that Directlink is an asset with capability to provide very substantial benefits to the National Electricity Market. We are pleased to provide this response.

We very much support the AER's conclusions on the major points of principle and substance in the draft decision. In particular, the Directlink Joint Venturers supports the AER on the following:

- that Directlink satisfies the code's definition of transmission network for the purposes of conversion;
- the criteria and analysis used to support the AER's view that Directlink's network service may become a prescribed service;
- the use of an asset valuation methodology based on the Regulatory Test and Directlink's economic value;
- the choice of the alternative projects with which the AER has compared Directlink's costs and benefits;
- the capital costs that the AER has determined for each of the alternative projects;
- the choice of the low, medium and high load growth historical bidding cases as being the basis of credible market development scenarios;

- the AER's adoption of the load forecasts used by Burns and Roe Worley ('**BRW**') and TransÉnergie US ('**TEUS**') as the basis of their modelling and analysis;
- acceptance of the nature and timing of emerging constraints in the Queensland and New South Wales regions, and the transfer limits, put forward by BRW;
- recognition that Directlink can defer major network augmentations in Queensland and in New South Wales;
- that currently proposed embedded generators in northern NSW cannot be relied upon to provide network support;
- the AER's acceptance of TEUS's market modelling methodology and its modelling results for the estimation of Directlink's inter-regional benefits;
- that the substantial network deferral benefits Directlink can provide beyond 2014 should be recognised;
- that circuit availability is the appropriate measure of Directlink's performance and our proposed performance targets are appropriate; and
- that our request for a regulatory control period of 10 years is justified.

In the attached submission, we would like to provide further information to assist the AER gain a clearer understanding of some general points of detail within the draft decision, issues relating to network deferral and inter-regional benefits of Directlink and its alternative projects, and to Directlink's regulatory value and revenue.

The Directlink Joint Venturers appreciate the AER's efforts to reach a final decision as soon as practicable and we stand ready to provide any further information or assistance that the AER may require. We would be happy to meet with you, or make our consultants and advisors available, at times and places to suit the AER. Please feel free to contact Ms Sandra Gamble of The Allen Consulting Group for information or to make any arrangements on 0416 229 616.

Yours sincerely

Dennis Stanley
Directlink Joint Venture Manager

Encl.

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SUBMISSION IN RESPONSE TO THE AER'S DRAFT DECISION OF 8 NOVEMBER 2005

CONTENTS

GENERAL

1. Establishment of the transmission connection points

Issue:

The Australian Energy Regulatory ('**AER**') considers that Directlink satisfies the code's definition of transmission network for the purposes of conversion.

Response:

The DJV concurs that Directlink satisfies the code's definition of transmission network for the purposes of conversion. The AER's rationale is the same as that set down in our application and subsequent submissions.

The National Electricity Market Management Company ('**NEMMCO**') and Country Energy have advised the Directlink Joint Venturers that arrangements have been finalised for the formal establishment of the transmission connection points at Lismore, Dunoon, Mullumbimby and Terranora on the same day that Directlink's network service becomes classified as a prescribed service.

2. Notice of ceasing to be a market network service

Issue:

The AER expects to be notified by the Directlink Joint Venturers when Directlink's network service ceases to be a market network service.

Response:

When the Directlink Joint Venturers notify NEMMCO that Directlink's network service will cease to be a market network service, they would be pleased to provide the AER with a copy of their notification at the same time. In preparation, the Directlink Joint Venturers have already agreed with NEMMCO to wording of the cessation notification.

3. Version of the Regulatory Test

Issue:

The AER considers it appropriate to evaluate the Directlink Joint Venturers' application in accordance with the 1999 version of the Regulatory Test.

Response:

The Directlink Joint Venturers hold the view that the 1999[1] and 2004[2] versions of the Regulatory Test are the same in essence. Both are partial equilibrium cost/benefit assessment frameworks that take account of a similar set of costs and benefits. The 2004 version has some more clearly defined terms and a description of how competition benefits might be calculated. For this reason, the Directlink Joint Venturers have no strong preference as to which version of the test is used.

The choice or interpretation of one of the test versions should not lead to significantly different impact on the test result.

A key aspect in which the two versions vary from one another is in their acknowledgement of the value of unserved electrical energy, and the need for related sensitivity testing.

The 1999 Regulatory Test says:

> In determining the *market benefit*, the following information should be considered:
>
> (b) reasonable forecasts of:
>
> (ii) the value of energy to electricity consumers as reflected in the level of VoLL;

and

> the calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis.

The 2004 Regulatory Test says:

> In determining the market benefit, the analysis may include, but need not be limited to the following benefits: … (c) changes in involuntary load shedding caused through savings in reduction in lost load, using a reasonable forecast of the value of electricity to consumers, or deferral of reliability entry plant;

and

> The calculation of the costs or market benefits must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on, but not limited to, the following, and should be appropriate to the size and type of project:
>
> (a) Market benefits:
>
> (i) Using all reasonable methodologies; and
>
> (ii) Testing reasonable forecasts of the value of electricity to consumers.

[1] ACCC 1999, *Regulatory Test for New Interconnectors and Network Augmentations* ('**1999 Regulatory Test**'), 15 December, pp. 18-20.
[2] ACCC 2004, *Decision, Review of the Regulatory Test for Network Augmentations* ('**2004 Regulatory Test**'), 11 August, pp. 7-13.

These provisions are completely consistent with one another if they are interpreted in the light of sound economics. As outlined in one of our previous submissions[3], VENCorp has been able, in effect, to reconcile the two when it interpreted the Australian Competition and Consumer Commission's ('**ACCC's**') reference in its 1999 Regulatory Test to 'VoLL' to be a reference to the value of unserved energy to consumers, rather than the wholesale market price cap to avoid encouraging inefficiently low investment.

We discuss further the selection of a reasonable value of unserved energy in section 11 of this submission.

In applying either version of the Regulatory Test, the AER has the opportunity to interpret the meaning of particular parts in accordance with sound economic principles to achieve the most accurate and robust answers. Consequently, both versions should bear the same result.

4. Bounds of the asset valuation

Issue:

The AER has had regard to Council of Australian Governments' ('**CoAG's**') preference for using deprival value for asset valuation and concludes that the regulatory asset value of a converting asset should fall within:

- A lower bound set by the economic value—'the greater of disposal or salvage value (that is, net realisable value), or its value to users…'[4]; and
- An upper bound set by the replacement cost of the least cost option.

Response:

The Directlink Joint Venturers agree with the AER's rationale and principal conclusion on this issue, especially the need to be consistent with clause 6.2.4(c)(5) of the National Electricity Code, which requires that the AER must provide a fair and reasonable risk adjusted cash flow rate of return on efficient investment.

The AER having regard to CoAG's preference is also consistent with the new wording of clause 6.2.3(d)(4)(iv)(A) of the National Electricity Rules that requires the AER to have regard to the principle that deprival value should be the preferred approach to valuing network assets.

The Directlink Joint Venturers firmly support the AER's view that Directlink's asset value should not be set to zero. Directlink has the capacity to provide substantial benefits to the National Electricity Market ('**NEM**') over its life. It is appropriate that, if at the time of conversion, Directlink is not considered to be the optimal asset, its asset value should be set with regard to its economic value to the NEM.

[3] Directlink Joint Venturers 2004, *Response to stakeholder issues*, 24 August, pp. 15-6.
[4] New Zealand Commerce Commission 2002, *Review of Asset Valuation Methodology: Electricity Lines Business' System Fixed Costs, Discussion Paper*, 1 October, p. 50 quoted in the Directlink draft decision, p. 35.

The Allen Consulting Group's proposed asset valuation methodology[5] takes account of the possibility that the optimal and the least cost asset might have a different level of benefits to the one being valued. Where the optimal asset, the least cost asset, and the asset being valued have similar levels of service and benefits, AER's conclusion as to the upper and lower bound is in line with the ACG methodology.

5. Selection of the alternative projects

Issue:

The AER concludes that Alternative 1, 2 and 3 have the requisite level of similarity to Directlink to be considered as alternative projects under the Regulatory Test. These alternatives:

- potentially defer the augmentations described by Burns and Roe Worley ('**BRW**') as being parts of Alternative 5 for varying periods; and

- allow for the flow of electricity between regions of the National Electricity Market to different extents and with differing levels of controllability.

The AER has determined that Alternatives 4 and 6 are not valid alternative projects because of their technical and economic limitations.

The AER presents its view that Alternative 5 is not an alternative project but, instead, the reference case.

Response:

The Directlink Joint Venturers agree fully that Alternatives 1, 2 and 3 are valid alternatives for the purpose of the Regulatory Test.

Like all the alternatives that BRW identified for the Directlink application, a very substantial proportion of the benefits that these projects would provide come from their capability to address the emerging network constraints, to support the northern NSW and Gold Coast transmission networks and to enable Powerlink and TransGrid to meet the requirements of Schedule 5.1 of the Rules. A common feature among Directlink and Alternatives 1, 2 and 3 is that they would achieve this through their ability to transfer power between the NSW and Queensland regions and be controllable. In fact, in the case of Alternative 3, all its benefits are associated with its limited ability to address the emerging network constraints.

The Directlink Joint Venturers are of the view that the ability to transport power between the regions and to be controllable is not a necessary condition for a project to be a valid alternative. If it was, the asset valuation methodology would be more akin to an ODRC approach than one based upon the Regulatory Test.

If the AER is to employ a requisite level of similarity, the Directlink Joint Venturers submit that all the alternative projects should be just capable to varying extents of addressing the

[5] The Allen Consulting Group 2004, *Conversion of a Market Network Service to a Prescribed Service: Setting the Regulatory Asset Value*, October.

emerging network constraints, supporting the northern NSW and Gold Coast transmission networks, and enabling Powerlink and TransGrid to meet the requirements of Schedule 5.1 of the Rules. If this were the case, Alternatives 1, 2 and 3 would still clearly qualify as valid alternatives.

On the basis of BRW's advice set out in our application, the Directlink joint Venturers also hold the view that Alternative 4 and 6 have substantial technical and economic limitations that disqualify them as valid alternative projects. These projects have been considered for inclusion as alternatives on the basis that they might have had some capability to address the emerging network constraints. They would not have considered as possible alternative projects had they been required to transfer electricity between regions of the NEM.

We have defined Alternative 5 as the expected network augmentations that would need to be in place from 2005-06 in the absence of Directlink's other alternative projects (including Alternative 0, Directlink itself) to satisfy network reliability standards in Queensland and New South Wales.[6] The major feature of Alternative 5 is the timing of these augmentations.

The Directlink Joint Venturers submit that Alternative 5 should be designated as an alternative project as well as the case used to determine the relative network deferral benefits of the other alternatives. We have not considered the true reference case—the do-nothing case—because, in this case, network reliability standards would not be met. The question for the Regulatory Test is which project, or timing of projects, will enable network reliability standards to be met and provide the best net benefits.

For the Regulatory Test to draw appropriate conclusions, all alternative projects—including Alternative 5—should be considered equally along side one another. It might then be found that Alternative 5 satisfies the test, or it might be found that one of the other alternative does. If Directlink does not pass the Regulatory Test, it is appropriate to value it on the basis of its economic value, as the AER has determined.

NETWORK DEFERRAL BENEFITS OF THE ALTERNATIVE PROJECTS

6. PB Associates' promotion of Port Macquarie deferrals

Issue:

The AER believes that it is the Directlink Joint Venturers' view that Directlink can defer the Port Macquarie 330 kV augmentations and notes that the Directlink Joint Venturers has provided insufficient substantiation for this.

Response:

On 8 February 2005, the Directlink Joint Venturers wrote to the ACCC and provided revised calculations of the network deferral benefits of Directlink and its alternative project based on PB Associates' advice to the ACCC in January 2005 (in relation to the deferral of the Port Macquarie augmentations) and BRW's advice on other matters. Our rationale for doing this

[6] Directlink Joint Venturers 2005, *Submission in response to the PB Associates Report of 26 November 2004*, 14 January, p. 22.

was that PB Associates based its view on material not available to us and that, if the ACCC accepted PB Associates' advice for its TransGrid decision, it would be appropriate for the same view to be recognised in the Directlink decision. The Directlink Joint Venturers concurs with CHC Associates' subsequently expressed view that PB Associates' advice was incorrect.

In its report to the ACCC on TransGrid's capital expenditure program PB Associates wrote[7]:

> Further studies performed by TransGrid at the request of PB Associates indicate that, if it is possible to implement the control scheme, the contingent overloads and low voltages could be managed via dispatch of generation at Lismore or import from Queensland through Directlink, and provision of some additional reactive support. At this stage, it is not certain that the control scheme will be able to be implemented although we do not see any significant technical difficulty with implementing a control scheme of this type.
>
> …
>
> To calculate a reasonable probability weighted capital expenditure to be allowed in the ex ante cap for the Mid North Coast project, PB Associates has assumed that the project could be deferred for up to two years with an equal probability.

This implied that PB Associates had information not available to the Directlink Joint Venturers that supported Directlink's deferral of the Port Macquarie augmentations.

BRW's advice attached to our letter of 8 February 2005 confirmed that BRW had not conducted analysis to support PB Associates' view.

> BRW's modelling has been based on the assumption that the 330 kV augmentation to Port Macquarie would be in commissioned on 2008/09 – this assumption was given by TransGrid in the consultations regarding the modelling assumptions. As this was an initial assumption, BRW has not carried out detailed modelling to investigate the voltage conditions at Port Macquarie. Currently capacitor banks at Port Macquarie and Taree support the voltage at Port Macquarie and the current development of the 330 kV supply to Coffs Harbour will also improve the voltage situation. The proposed 330 kV development to Port Macquarie will resolve this issue. Limited studies by BRW have indicated that Directlink can provide a degree of support to improving the voltage conditions at Port Macquarie prior to the 330 kV developments to Coffs Harbour and Port Macquarie.
>
> PB Associates has indicated in its TransGrid report that voltage control schemes based on coordination of the reactive plant and tap changers at the Lismore and Coffs Harbour substations and the dispatch of Directlink importing power from Queensland could relieve contingent low voltages and overloads in the Port Macquarie area. PB Associates also indicates that, based on studies carried out by TransGrid at PB Associates' request, the Port Macquarie 330 kV augmentation could be deferred by two years through such coordinated voltage control schemes. BRW understands from its consultations with TransGrid in relation to the modelling assumptions that, whilst PB Associates does not see any significant technical difficulty with implementing a control scheme of this type, TransGrid currently has some reservations about the use of such schemes in this application.
>
> BRW has included an estimate of the potential benefit of a two-year deferment of the Port Macquarie 330 kV augmentation as input into the overall analysis even though BRW has not

[7] PB Associates 2005, *TransGrid's Forward Capital Expenditure Requirements 2004/05 to 2008/09*, 27 January, pp. 71-2.

> carried out modelling of this condition to the same extent as PB Associates and TransGrid. BRW would only be able to independently confirm the two-year deferment identified by PB Associates after more detailed modelling and after having undertaken an assessment of the technical feasibility of the necessary voltage control scheme.

In the light of CHC Associates' advice, which was reflected in the ACCC's decision on TransGrid's revenue cap[8], the Directlink Joint Venturers readily accept that Directlink alone cannot defer the Port Macquarie augmentations. We understood that our current view had been communicated to the AER at a meeting on 12 April 2005, but this appears not to have been the case.

7. Ability of Directlink to flow south

Issue:

The AER is concerned that there are potential obstacles to Directlink flowing south during the summer of 2006-07. It believes it is not clear, for example, that the re-rating of lines in the Tweed will provide sufficient power in southern Queensland to flow south across Directlink. Further, it is uncertain about the impact of transformer capacity at Molendinar and the impact of load growth on power transfer capacity within Energex's southern Gold Coast network.

The AER received information on this issue from Country Energy late in the development of this draft decision and it did not have sufficient time to undertake consultation on this material before finalising its draft decision. Instead the AER is consulting with interested parties on this information as part of the draft decision consultation and will incorporate its findings into the final decision.

Response:

In our letter to the AER on 21 September 2005, the Directlink Joint Venturers explained the correspondence that Country Energy submitted to the AER and summarised the advice it had at that time from Country Energy, Powerlink and BRW in relation to the augmentations that will enhance Directlink's capacity to flow south in 2006-07.

Powerlink and Country Energy have agreed to allow the summer emergency rating to be used to relieve in the Tweed 110 kV network under contingency conditions and, based on current projections, this provides capacity to maintain an N-1 supply to Terranora though until 2008 and 108 MW of capacity through the Tweed network to Directlink in 2006-07. Further measures would be required by 2008 to supply the Terranora load. As we have previously advised the AER[9], one option is to install capacitor banks at Terranora (providing nominally one year's additional capacity) and then to upgrade the lines or create an additional supply to the Tweed area at the sub transmission or transmission level[10].

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[8] ACCC 2005, Decision, *NSW and ACT Transmission Network Revenue Cap TransGrid 2004/5 to 2008/9*, 27 April, p. 108.
[9] Directlink Joint Venturers 2005, *Potential Support of Northern NSW Network from Gold Coast Network*, 5 July, p. 5.
[10] The detailed arrangements for reinforcement of the supply to the Tweed area will be developed through joint planning between Powerlink, TransGrid, Country Energy and Energex.

Powerlink will undertake the Greenback augmentation and install a second 375 MVA transformer at Molendinar substation in 2006 and this will relieve the critical constraints the Queensland network. A remote change-over scheme will address the potential constraints in the Energex network that would arise if the two Molendinar transformers were energised at the same time.

In September 2005, after extensive interaction between Powerlink and Country Energy about opportunities to maximise utilisation of the inter-jurisdictional transmission network, Powerlink confirmed that it would bring forward the second Molendinar transformer and this augmentation would provide Directlink with 90 MW of southwards capacity. This capacity was confirmed to us by BRW's modelling, which used updated modelling inputs and assumptions—including load forecasts—agreed with Powerlink.

8. Network support payments

Issue:

If Directlink converts to a prescribed service after payments have been made to Directlink Joint Venturers under the network support agreement with Powerlink, then the payments should be subtracted from the estimated value of the deferral benefit for the Queensland augmentations.[11]

Response:

Prior to conversion, the Directlink Joint Venturers are being paid to provide network deferral benefits through monthly network support payments we receive from Powerlink. After conversion, the Directlink Joint Venturers will be paid to provide network deferral benefits through monthly payments of its regulated revenue. Both forms of payment will go towards covering our asset depreciation, cost of capital, operating and tax expenses incurred over the period. Under these arrangements, the Directlink Joint Venturers will avoid being paid twice for deferring the Greenbank augmentation in Queensland over 2005-06.

There is no need for network support payments to be subtracted from the estimated value of the deferral benefit for the Queensland augmentations and, in turn, be subtracted from the Directlink asset value. If this occurred, the Directlink Joint Venturers would effectively earn no income for providing network support in 2005-06 up to the date of conversion.

To the extent that the Directlink Joint Venturers are paid network support payments in advance for providing network support in a period after conversion, they will return that payment to Powerlink. However, this is contrary to the current payment terms of our network support agreement with Powerlink and, thus, is very unlikely.

[11] AER 2005, *Directlink Joint Venture Application for Conversion and Revenue Cap, Draft Decision*, 8 November ('**Directlink draft decision**'), p. 85.

INTER-REGIONAL BENEFITS OF THE ALTERNATIVE PROJECTS

9. Credibility of the LRMC bidding case

Issue:

The AER highlights that the Regulatory Test requires the consideration of scenarios where forecast prices tend to reflect a range of market outcomes, ranging from short run margin cost (SRMC) bidding behaviour to simulations that approximate actual bidding behaviour.

The AER considers that the use of a long run marginal cost ('**LRMC**') bidding case as a credible scenario may distort the rankings and outcomes of the test.

Response:

The Directlink Joint Venturers agree that the Regulatory Test specifies a range of scenarios that should be considered. We also understand that the AER has substantial discretion as to which types of scenarios it requires for the purposes of using the Regulatory Test to value assets such as Directlink.

The ACCC had the same discretion when it valued Murraylink. In that case, the ACCC explicitly required MTC to present modelling scenarios that demonstrated the impact of LRMC bidding behaviour as an extension to the range specified in the Test. The ACCC's view was that it was important to establish the 'most credible range' and the LRMC case was credible for this purpose.[12] The ACCC accepted that scenarios with actual bidding behaviour were not conducted due to the difficulty of modelling such behaviour.

While preparing their application, the Directlink Joint Venturers were guided very much by the ACCC's view in the Murraylink case. We instructed TransÉnergie US ('**TEUS**') to prepare the types of scenarios that the ACCC considered to be required and credible, and we examined the rankings of the alternative projects under each one.

We would like to clarify that we did not put forward any scenario as being the one that would determine a point estimate[13] of Directlink's market benefits. In our application, we highlighted one scenario (Scenario 5) as an example of how we had combined network deferral and inter-regional benefits, but it was not our intention that this scenario, or any of the others we prepared for the application, would provide a point estimate. TEUS confirmed this in its response to the Intelligent Energy Systems ('**IES**') report *Directlink Conversion Application – Review of interregional market benefits* of 26 April 2005.[14]

The ACCC's selection of credible scenarios was designed to match its approach to the Regulatory Test for Murraylink. We understand from the draft decision that the AER has taken a slightly different approach in which it wishes to make a point estimate of the market benefits for Directlink and its alternative projects to determine their economic value. We

[12] ACCC 2003, *Decision: Murraylink Transmission Company Application for Conversion and Maximum Allowable Revenue* ('**Murraylink decision**'), 1 October, pp. 80, 83, 86-9.
[13] Directlink draft decision, p. 101.
[14] TEUS 2005, *Response to the IES Final Report Reviewing Directlink's Alternative Projects' Interregional Market Benefits*, 16 May, pp. 21-3.

have prepared a number of additional modelling scenarios with historical bidding behaviour as the AER has requested, and we acknowledge that the AER will use these to derive a point estimate.

We note also that the AER has used TEUS's original LRMC bidding cases as sensitivity tests.

10. The NSW-NNSW intra-regional constraint

Issue:

The AER will adopt BRW's transfer limits for the purposes of the market modelling.

The AER considers that it is necessary to recognise in the market modelling the NSW-NNSW intra-regional constraint north of Liddell.

Response:

The Directlink Joint Venturers concur with the AER that the peak load transfer limits that BRW calculated for the market modelling be adopted, including those for the NSW-NNSW intra-regional constraint.

The AER is correct that the topology that TEUS employed for the market modelling it prepared for the Directlink conversion application did not include the NSW-NNSW intra-regional constraint. In January 2005, TEUS provided additional modelling to demonstrate that, for one scenario (LRMC bidding, medium load growth), the impact of the constraint was minor.

Table 1

COMPARISON OF MODELLING RESULTS (JAN 2005)

			Discount rate			
	Scenario	Value of USE ($ per MWh)	7%	9%	11%	Average
Original topology	Sensitivity	10,000	108.4	107.9	102.9	106.4
	Credible	29,600	143.3	135.1	124.8	134.4
Revised topology	Sensitivity	10,000	128.0	101.9	84.1	104.7
	Credible	29,600	146.1	116.7	96.6	119.8
Change in IRMB	Sensitivity	10,000	19.7	(6.0)	(18.9)	(1.7)
	Credible	29,600	2.8	(18.4)	(28.3)	(14.6)

Source: TEUS 2005, *Response to IES questions of October 25, 2004*, 18 January, pp. 2-5.

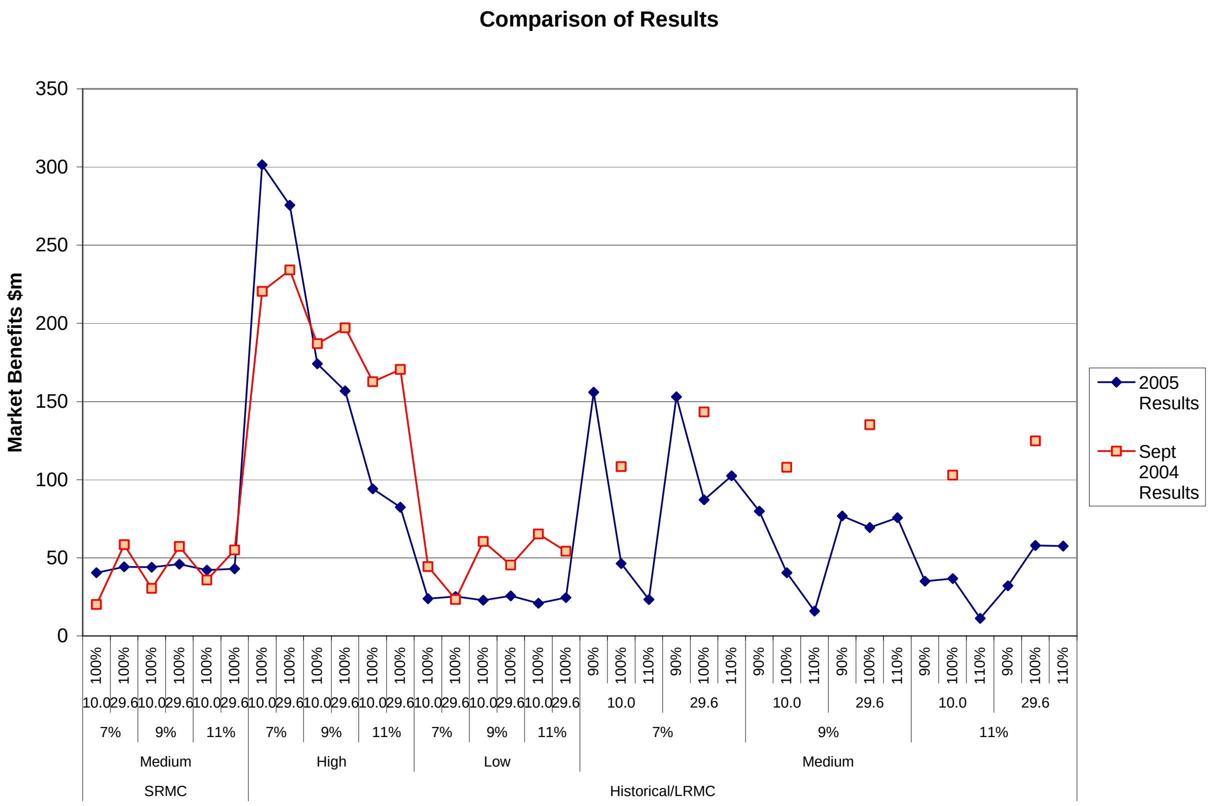
These changes shown in Table 1 indicate the original results are robust. Although the average decrease is larger for the cases where the value of unserved energy is deemed to be $29,600 per MWh, the original value of market benefits for these cases was also higher.

Market modelling results are clearly sensitive to the selection of modelling inputs and assumptions. TEUS's 2004 and 2005 results support the view that they are more sensitive to the selection of bidding behaviour than they are to more incremental changes such as recognising the NSW-NNSW intra-regional constraint or applying 2005 new entrant generation cost inputs.

For scenarios with SRMC bidding behaviour, the results of 2005 TEUS's market modelling (that used the revised topology and 2005 generation inputs) were very similar to the results of 2004 TEUS's market modelling (that used the original topology and 2004 generation inputs)—as shown in Figure 1. The results for LRMC and historical bidding behaviour are different to one another as expected.

Figure 1

COMPARISON OFMODELLING RESULTS (SEP 2005)



Source: TEUS 2005, *Directlink's Alternative Projects' Inter-regional Market Benefits, Summary of Additional Modeling and Results*, 22 September, p. 17.

In the cases assuming historical bidding, the modelled generation dispatch, prices and interconnectors flows are materially different to the LRMC cases. This produced different patterns of new generation entry and changes in unserved energy in all regions including Queensland. TEUS's additional modelling does not support a view that the recognition of the NNSW-NSW intra-regional constraint alone would have a major impact on the pattern of new generation entry.

11. Determining a credible estimate of the value of unserved energy

Issue:

The AER considers that $29,600 per MWh and $10,000 per MWh are both credible values for the unserved energy and that they be given equal weighting.

We note that the AER's view is based on IES's opinion that[15]:

> … both the market price cap and the value of reliability to the customer need to be considered for the purposes of the regulatory test. Without any evidence to the contrary, it seems reasonable to give an equal weighting to the two values of unserved energy.

Response:

The value of unserved energy for customers in the NEM is an important input to the Regulatory Test when determining the reliability benefits of an interconnector. In our previous submissions, we have emphasised this point and provided substantiation of the estimate we have used.[16] The following material reinforces our position.

Unserved energy throughout the NEM

The modelling using historical bidding behaviour conducted by TEUS for the AER in 2005 identified the potential for Directlink and its alternative projects to change the expected unserved energy across all regions of the NEM. Table 1 of the TEUS report attached to this submission provides the estimated change in expected unserved energy in each region for the historical bidding scenarios. For the medium and low load growth cases, the largest change occurs in New South Wales. For the high growth case, the largest change occurs in Victoria, with second largest change in New South Wales.

Equal weighting

The Directlink Joint Venturers submit that the NEM wholesale market price cap of $10,000 per MWh does not need to be considered for the purposes of the Regulatory Test because it is in no way an estimate of the value of unserved energy or a value of lost load to customers. The market price cap is set solely to achieve a balance between the need to protect generators and retailers from high spot prices and the need to maintain the market signals necessary to attract reliable supply.[17] Further, there is substantial public domain evidence to suggest that any credible estimate of the value of unserved energy across the NEM is significantly greater than $10,000 per MWh.

[15] IES 2005, *Directlink conversion application – Review of market modelling*, 17 October, p. 34.
[16] For example in Directlink Joint Venturers 2004, *Response to stakeholder issues*, 24 August, pp. 15-6, and in Directlink Joint Venturers 2005, *Letter to AER*, 23 September, pp. 2-3.
[17] Reliability Panel 2005, *VOLL and the cumulative price threshold, Final report*, March, pp. 4-5.

VENCorp has recognised this when it determined the value of unserved energy that it now uses for transmission planning when it concluded[18]:

> As noted in Section 4.1 above, if "reliability increases" are valued at a level below the marginal cost to consumers of unserved energy (the VCR), then the resultant level of supply reliability delivered to consumers will be inefficiently low. In light of this consideration, it is VENCorp's view the value of "reliability increases" must be assessed with reference to the VCR.
>
> Any over-riding considerations of competitive neutrality give rise to a further need to ensure that the VCR is consistent with the fundamental driver of reliability levels in the wholesale market, which is the Reliability Panel's reliability standard. As noted in Section 4.1 above, the VoLL implied by the Reliability Panel's reliability standard is not less than $26,500 per MWh. This value is consistent with the VCR determined during the recent study commissioned by VENCorp.

That is, the use of a value substantially difference from the actual value of unserved energy can distort the outcomes of the Regulatory Test.

Credible estimate of the value of unserved energy

In our application, the Directlink Joint Venturers put forward $29,600 per MWh as a reasonable estimate in the NEM. This figure was sourced from VENCorp's transmission planning criteria[19] and a value of customer reliability based on a survey of Victorian customers conducted in 2001. VENCorp and many of its stakeholders have noted that $29,600 is supported by an estimate of $28,890 per MWh made by Monash University in 1997[20]. A similar study conducted by Monash for TransGrid in 1998 indicated a value of $20,560 per MWh[21] (in 1998 dollars) or $25,000 per MWh (in 2005 dollars) for New South Wales.

Determining a reliable single estimate for the value of unserved energy can be difficult because of the need to take account of:

- sectors of the economy such as the residential, agricultural, commercial and industrial sectors;
- the timing of possible outages during the day, week or year;
- the duration of the outage; and
- a variety of other factors, including whether customers have received advanced notice.

[18] VENCorp 2003, Response to submissions, *Final report, Value of unserved energy to be used by VENCorp for electricity transmission planning*, 23 May.
[19] VENCorp 2003, *Electricity Transmission Network Planning Criteria*, July, p. 2.
[20] Centre for Electrical Power Sector Engineering, Monash University 1997, *Value of Lost Load Study, Report prepared for the Victorian Power Exchange*, p. 20.
[21] Centre for Electrical Power Sector Engineering, Monash University 1998, *Report on Consultancy, Value of Lost Load Study for TransGrid*, July, p. 21, quoted in Macquarie Generation 2005, *System restart ancillary services, Submission to the AEMC in response to proposed rule change*, 14 October, p. 15.

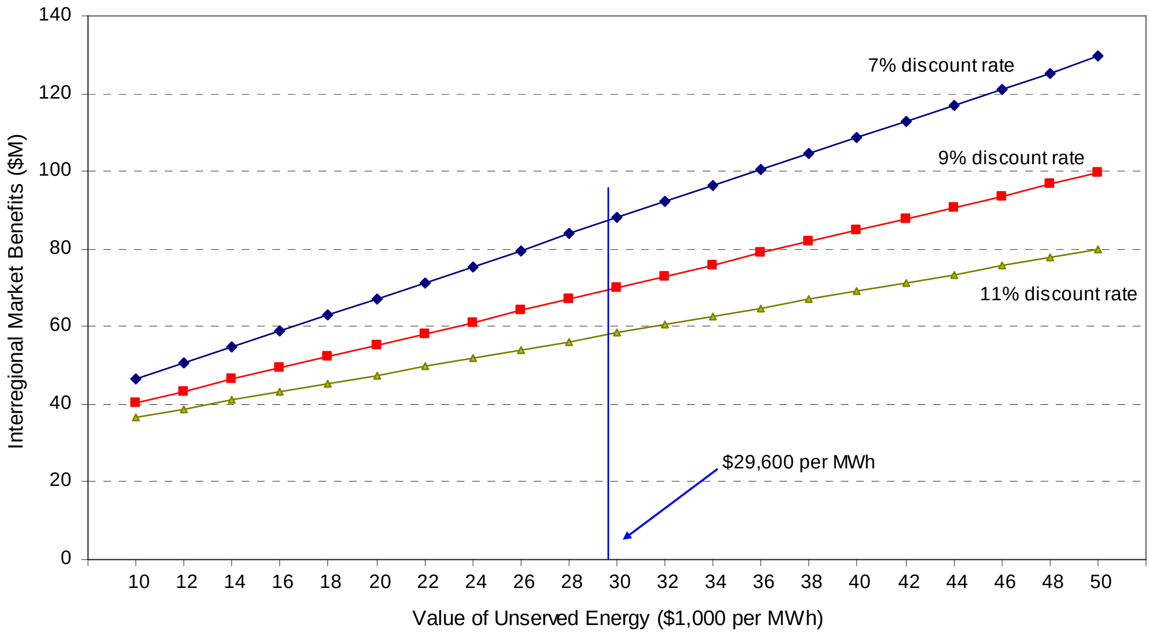
Surveys in Australia, Canada and Great Britain indicate that the value of unserved energy varied according to these factors, but is 'potentially very high—up to and above $100,000 per MWh'.[22]

Figure 2 shows the variability of the inter-regional market benefits of Directlink and Alternatives 1 and 2 with regard to the value of unserved energy in the historical bidding case with medium load growth.

The conclusion that one could draw from Figure 2 is that the inter-regional benefits of Directlink and its alternative projects are sensitive to the estimate selected for the value of unserved energy. The credibility of the benefits depends very much on the credibility of the value of unserved energy.

Figure 2

INTER-REGIONAL BENEFITS OF DIRECTLINK AND ALTERNATIVES 1 AND 2 (IN THE HISTORICAL BIDDING CASE, MEDIUM LOAD GROWTH): VARIATION WITH THE VALUE OF UNSERVED ENERGY



Source: TEUS 2005, *Impact of the Value of USE on Interregional Market Benefits*, 9 December, p. 6.

The Directlink Joint Venturers remain of the view that it is appropriate to assume that the value of unserved energy in Victoria is reasonably similar to the value in the other Australian regions and that $29,600 per MWh is the credible estimate. This view is implicitly supported by TransGrid and Powerlink who used $29,600 per MWh as the value of unserved energy in

[22] Charles River Associates (Asia Pacific) Limited 2004, *New Zealand's Transmission Regulatory Framework*, 29 October, p. 25.

their QNI Upgrade Report[23] and by the Monash University study of NSW customers for TransGrid. Consideration of $10,000 per MWh as a sensitivity case may be useful, but it is outside the credible range.

Sensitivity testing

In the light of the Australian and international evidence presented in this submission, we submit that if might also be valid to consider both $10,000 and $50,000 per MWh as sensitivity cases.

Our recommended credible and sensitivity case results for the historical bidding scenario are shown in Table 2.

Table 2

INTER-REGIONAL BENEFITS OF DIRECTLINK AND ALTERNATIVES 1 AND 2 (IN THE HISTORICAL BIDDING CASE): CREDIBLE AND SENSIVITY CASES

			Discount rate		
	Scenario	Value of USE ($ per MWh)	7%	9%	11%
Low load growth	Sensitivity	10,000	23.8	22.8	21.0
	Credible	29,600	25.2	25.7	24.6
	Sensitivity	50,000	26.7	28.7	28.3
Medium load growth	Sensitivity	10,000	46.4	40.4	36.8
	Credible	29,600	87.1	69.4	57.9
	Sensitivity	50,000	129.5	99.6	80.0
High load growth	Sensitivity	10,000	301.5	174.1	94.0
	Credible	29,600	275.5	156.8	82.3
	Sensitivity	50,000	248.6	138.8	70.1

Source: TEUS 2005, *Impact of the Value of USE on Interregional Market Benefits*, 9 December, p. 8.

[23] TransGrid & Powerlink Queensland 2004, *Benefits of upgrading the capacity of the Queensland – New South Wales Interconnector (QNI), A preliminary assessment* ('**QNI Upgrade Report**'), 19 March, p. 27.

DIRECTLINK'S REGULATORY VALUE AND REVENUE

12. Factors that indicate that Directlink's benefits could be understated

Issue:

The AER recognised that the Directlink Joint Venturers have not attempted to estimate the competition benefits that might be provided by the alternative projects.

Response:

There are a range of benefits that the Directlink Joint Venturers have not included in their assessment of Directlink:

- competition benefits; and
- other types of technical support;.

This confirms that AER may have understated Directlink's rather than overstated them, and as such the AER can have a level of comfort that Directlink can achieve its economic value.

Competition benefits

The 2004 Regulatory Test describes competition benefits as the benefits that arise from a change in generator bidding brought about by a change of market power after the implementation of the option. While the 2004 Regulatory Test defines the concept of competition benefits, the 1999 Regulatory Test does not preclude them being taken into account.

By establishing an additional inter-regional connection between the Queensland and NSW regions, Directlink operating as a regulated asset could deepen competition within the NEM and bring about changes to generators bidding strategies. This benefit was not estimated as TEUS and IES used the same bidding strategies With and Without Directlink and its alternative projects in place.

Other types of technical support

On the basis of work BRW have conducted since the preparation of our application, BRW have indicated to us that Directlink could be configured to provide ancillary benefits to the National Electricity Market, in addition to providing its prescribed services, as follows:

- System power oscillations—Directlink could control inter-regional power flows between Queensland and New South Wales specifically to dampen system power oscillations and prevent system separation between Queensland and New South Wales after a power system event; for example, a system fault or a large load/generation failure.
- System restart capability—Directlink could provide continuous power to local loads at either terminal. This is a useful feature in the event of a power system failure at either end of the link because it allows supplies to be quickly restored.

- Fast reactive support—Directlink provides independent voltage control or reactive power control at each individual terminal giving it similar capabilities to two independent static VAr compensators.

These benefits could be developed cost effectively over time adding to the value of that Directlink could provide.

13. Use of the median or the mean as a means of making a point estimate of market benefits

Issue:

The AER believes the use of a median value is appropriate given the range of estimates and the skewed distribution. The median is considered to be better measure of central tendency.

Response:

The DJV questions the statistical validity of the use of the median of the sample of six 'credible scenarios' as the best estimate of the market benefits.

The DJV submits that the mean of the sample is more statistically valid than the median of the sample, for the following two reasons:

- the use of the mean minimises the risk of estimation whereas the use of the median does not; and
- sampling for the mean has a lower error rate than sampling for the median.

Our detailed reasoning is set out below.

Mean more appropriate statistic than the median

The AER needs a single point statistical estimate of the market benefits to use as its estimate of the economic value (EV) of Directlink and Alternatives 1 and 2.

The AER has chosen to use the median, citing the following explanation:[24]

> The AER considers that the best balance to determine an EV that is representative of the credible scenarios is to use the measure of central tendency. Given the range of estimates and the skewed distribution, using a mean to determine a single value is not appropriate because the mean is more affected by extreme values and is therefore not a good measure of central tendency. The median is less sensitive to extreme ranges and this makes it a better measure than the mean for skewed distributions.

It is important to note that the median of the sample is being used as an estimate of the median of the population, which is the point above or below which there is equal likelihood of occurrence of an observation taken at random. The AER appears to believe that the best estimate of the economic value is the point which has equal probability of understating or overstating the economic value.

[24] AER 2005, *Directlink draft decision*, p.129-130

However the median does not minimise the risk of determining an inaccurate estimate, as measured by the variance. Rather, the risk is minimised by using the mean of population as the point estimate.[25] This result is true for finite and infinite populations.

Table 3 illustrates this for a finite population of six observations with a median 150.6 and a mean 176.5. Table 3 shows that the variance from the median of six observations is 20 635, which is 25 per cent greater than the variance from the mean of 16 589. Hence the median, as a point estimate, has a greater risk of being wrong than the mean.

Table 3

VARIANCE FROM THE MEDIAN AND MEAN

Market benefit ($ million)	Weight	Variance from median (unweighted)	Variance from mean (unweighted)
128.9	0.167	468.7	2267.3
131.8	0.167	351.6	1999.6
136.1	0.167	208.8	1633.5
165.0	0.167	208.8	132.6
240.0	0.167	8001.3	4,030.1
257.3	0.167	11,395.6	6,525.9
Total	1.0	20,634.8	16,589.1

The DJV submits that minimising the risk of inaccuracy is more appropriate than having equal likelihood of under-stating or over-stating value. For this reason, the mean of a population is a more appropriate statistic than the median of a population.

Sampling

In effect, the AER has selected a sample of six ‘credible scenarios’ from the full underlying (infinite) population of all possible market benefits in all cases. It is important to estimate the error in sampling because the mean or median of the sample is only an estimate of the mean or median of the underlying population statistic, so the estimate with lower sampling error is preferred.

Statistical sampling theory enables an estimate of the error, although technically only when samples are selected at random. The AER has concluded that six scenarios are ‘credible’; presumably meaning that the six scenarios should be more representative of the underlying population than had they been chosen purely at random. Credible scenarios should therefore enable better estimates of the underlying population and have lower errors than a purely random sample.

[25] Freund J. and Walpole R. 1987, *Mathematical Statistics*, 4th ed., p. 146.

The AER's sample of credible scenarios should satisfy the statistical theorems for the sampling distributions of both the mean and median, which are shown in Box 1 and Box 2, respectively.

Box 1

CENTRAL LIMIT THEOREM

If x_1, x_2, …, and x_m constitute a random sample from an infinite population having mean μ, and variance σ^2, then the limiting distribution of $z = \frac{\bar{x} - \mu}{\sigma / \sqrt{m}}$

as $m \to \infty$, is the standard normal distribution.

Source: Freund J. and Walpole R, 1987, *Mathematical Statistics*, fourth ed., Theorem 8.3

Box 2

SAMPLING DISTRIBUTION OF THE MEDIAN

Suppose x_1, x_2, …, and x_{2n+1} constitute a random sample from an infinite population for which the population density (f) is continuous and non-zero at the population median ν.

For large n, the sampling distribution of the median for random samples of size 2n+1 is approximately normal with the mean ν and the variance $\frac{1}{8[f(\nu)]^2 n}$

Source: Freund J. and Walpole R, 1987, *Mathematical Statistics*, fourth ed., Theorem 8.16

The above theorems imply that sampling distributions of the mean and median both tend towards normal as the sample size increases but the error associated with sampling the median is greater than the error in sampling the mean. The precise difference between sampling errors of the median and mean depends on the underlying distribution—for the gamma distribution, which can be used to approximate the distribution of market benefits, the sampling error of the mean is less than 60 per cent of the sampling error of the median. [26]

The size of sample used to estimate the median therefore needs to be 60 per cent larger than the size of the sample used to estimate the mean, to achieve the same sampling error.

The DJV submits that the sample mean is a better estimate than the sample median, because the sampling error is less for the same size sample.

[26] Freund J. and Walpole R. 1987, *Mathematical Statistics*, 4th ed., p. 302.

Conclusion

The DJV submits that the population mean is a more appropriate value for the EV than the population median, and that the mean of a sample of scenarios gives a better estimate than the median of the sample.

The sample mean would provide sound point estimate of the expected economic market benefits of Directlink and Alternatives 1 and 2, and it would be consistent with the other reasoning in the AER's draft decision.

The DJV has noted in section 11 of this submission that $10,000 per MWh is not a credible estimate of the value of unserved energy. A paper by McLennan Magasanik Associates states that market benefits for low and high demand scenarios should have the same weight as for median demand growth.[27]

14. Directlink's O&M costs

Issue:

The AER believes that a comparison between the operating and maintenance ('**O&M**') costs of Directlink and Murraylink is not valid because benchmarking is not appropriate.

Response:

The estimate of Directlink's O&M costs contained in our conversion application was developed with regard for the actual circumstances of the project, independently reviewed by BRW, and compared with Murraylink for the purposes of establishing its reasonableness and efficiency.

As operators of Directlink, Country Energy prepared an initial estimate of its expected annual O&M costs, with detailed estimates for general management, operating management, operation, commercial/regulatory, financial management, maintenance costs, audit fees, legal fees, insurance, energy, communication, corporate overheads and other costs.

For the Directlink conversion application, BRW reviewed these costs and incorporated them into its report of the selection and assessment of Directlink and its alternative projects.[28]

In its November 2004 report, PB Associates considered the same set of costs and significantly underestimated the efficient costs of operating and maintaining a HVDC installation.[29]

In the light of comments made by PB Associates, the Directlink Joint Venturers benchmarked their costs of general management, operations, commercial/regulatory and

[27] McLennan Magasanik Associates 2002, *Assessment of NEMMCO's 2001 Calculation of Reserve Margins*, Final report to the Reliability Panel, Appendix B.
[28] BRW 2004, *Directlink Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC* ('**BRW report**'), 22 September, 67.
[29] PB Associates 2004, *Review of Directlink Conversion Application – Final Report* that the 26 November, p. 35-7.

financial management with the actual costs incurred by Murraylink Transmission Company ('**MTC**'), which shares resources with TransÉnergie Australia. Under its regulatory cap, MTC has a substantial incentive to incur efficient O&M costs, which are reflected in MTC's regulatory accounts.

Making a comparison with MTC has stronger relevance than benchmarking costs across a range of transmission network owners ('**TNOs**'). MTC's business is very like that of the Directlink Joint Venturers'—a level of likeness not shared by any other two Australian TNOs. MTC owns and operates a very similar asset from the same manufacturer. This makes its O&M costs highly comparable.

Comparing the costs of MTC with those estimated for Directlink by Country Energy has confirmed the estimates of the O&M costs for Alternative 0/1/2 presented in the BRW report to be reasonable and efficient.

15. The debt margin used to determine the cost of capital

Issue:

To determine a benchmark cost of debt, the AER proposes to calculate a short term average of the relevant bond yields. For the purposes of Directlink draft decision, the AER has found that the 10 day moving average benchmark debt margin over the government bond yields, for A rated corporate bonds with a term of 10 years, is 84 basis points.

From the AER's commentary, we understand that the AER has used the CBASpectrum information service as its source of market data.

Response:

Since the Directlink Joint Venturers lodged their application in September 2004, new research has come to light that examines the reliability of the market data available through information services such as CBASpectrum and used to determine debt margins.

The Energy Networks Association ('**ENA**') submitted this research—conducted by National Economic Research Associates ('**NERA**')—to the Essential Services Commission of Victoria ('**ESCV**') for the purposes of its recent determination of electricity distribution prices.[30] NERA found that:

> Many regulators have relied on CBASpectrum which provides estimated yields on 10 year debt. The CBASpectrum estimation procedure does not determine the best fit to the available data. The CBASpectrum estimation procedure is such that CBASpectrum estimated yields are expected to be, and in practice are, on average, less than actual yields for long dated, low rated bonds. Between 30 June 2003 and 10 May 2005, actual yields on Australian bonds with more than 6 years to maturity and ratings of A or below averaged 17.1 basis points higher than CBASpectrum estimated yields on such bonds. For bonds with more than 8 years to maturity and ratings of A or below, the difference has averaged 22.2 basis points.

[30] NERA 2005, *Critique of available estimates of credit spread on corporate bonds*, May, attached to a letter from the ENA to the ESCV dated 8 July 2005, available at www.esc.vic.gov.au.

> On this basis, we consider that the **minimum** reasonable adjustment to CBASpectrum estimates by regulators seeking to estimate the cost of debt on 10 year low rated debt is 22.2 basis points. Using only data from CBASpectrum, our best estimate of the appropriate adjustment to CBASpectrum estimates of yields on 10 year debt rated A or below is to add 25.6 basis points.
>
> The regulator might consider relying on a different data source such as Bloomberg. Bloomberg's estimation procedure will not induce an expected difference between actual and estimated yields.

The NERA report explained why it would be expected that the estimation methodology employed by the CBA Spectrum service would understate the yields on low rated, long dated corporate bonds. That is, it found that the CBASpectrum methodology would be expected to produce estimates of the yields for these bonds that are downward biased. It also examined an alternative methodology for calculating yields that is employed by the Bloomberg service and found that this methodology would be expected to generate unbiased estimates of the yields.

The ESCV's own analysis had also found that CBASpectrum yields are likely to understate bond yields by a material amount and the data provided by NERA supports the ESCV's findings.[31]

In Table 4, we show the current difference between the debt margins derived from Bloomberg and CBASpectrum information.

Table 4

FAIR YIELD MARGIN OVER COMMONWEALTH BOND, 10 DAYS TO 3O NOVEMBER 2005

Market information service	Credit rating	Bond term	Debt margin (basis points)
Bloomberg	A	10 years	104.6
CBASpectrum	A	10 years	83.9
		Difference	20.7

Note: These debt margins are based on a risk free rate of 5.45%

On the basis of research conducted by NERA and accepted by the ESCV, the Directlink Joint Venturers submit that either:

- the AER adds 25.6 basis points to any proposed debt margin based on information from the CBASpectrum service, being NERA's best estimate of the downward bias in the CBASpectrum estimate of the yield for a low rated (A or lower) 10 year bond; or

[31] ESCV 2005, *Electricity Distribution Price Review 2006-10 Final Decision, Volume 1, Statement of Purpose and Reasons*, October, pp. 366-72.

- the AER bases its estimate of a benchmark debt margin upon information from the Bloomberg service, which NERA found to use a methodology that would be expected to provide an unbiased estimate of the yields for these bonds.

16. Performance incentive scheme

Issue:

In section 14 and appendix I of the Directlink draft decision, the AER analysed the relevant issues and accepted that:

- circuit availability is the only appropriate measure of Directlink's performance;
- the performance incentive scheme proposed by the Directlink Joint Venturers is consistent with the AER's current Service Standard Guidelines[32] and the CIGRÉ Protocol for calculating and reporting the availability of HVDC transmission systems[33];
- the Queensland public holiday in May should be included the peak period; and
- the performance targets we proposed are appropriate.

Response:

The Directlink Joint Venturers agree that its proposed performance incentive scheme is consistent with the current AER's service standard guidelines and the CIGRÉ protocol. However, we note that the AER has expressed Directlink's performance incentive scheme using different wording to that we proposed.

The Directlink Joint Venturers submit that its proposed wording for Directlink's performance incentive scheme is more suitable because it is structured as a comprehensive document that contains the definitions, formulae, and processes necessary to efficiently employ the scheme with a high degree of certainty. It does not implicitly cross-reference the AER's service standard guidelines that may change from time to time.

For convenience, we have included our proposed scheme wording as Attachment 3 with this submission with some amendments to the version we submitted on 17 November 2004:

- to reflect the inclusion of the May Queensland public holiday in the Peak Period;
- to remove some redundant and potentially inconsistent wording in our Table A3.1—words describing 'unit of measure';

[32] ACCC 2003, *Guidelines, Statement of Principles for the Regulation of Transmission Revenues, Service standard guidelines*, 12 November, contained in AER 2005, *Compendium of Electricity Transmission Regulatory Guidelines*, August ('**Service standard guidelines**').
[33] **CIGRÉ** Study Committee 14 CD Links 1999*, Protocol for reporting the Operational Performance of HVDC Transmission Systems*, February ('**CIGRÉ protocol**').

- to include S factor coefficients and formula tables, which are the same as the AER's Tables I.4, I.5 and I.6[34] with a modification to reflect that Circuit Availability is a percentage; that is, a number between 0 and 1;

- to refer to the formula the AER will use to determine the penalty/reward adjustment for our revenue (see also section 17 of this submission);

- to clarify the Directlink's Circuit only includes those assets used to provide prescribed services; that is, it excludes unregulated assets;

- to recognise the establishment of the AER and the Australian Energy Market Commission; and

- to define more precisely the process and timetable implied in the National Electricity Rules and sections 4 and 5 of the AER's service standard guidelines[35] so that the Directlink Joint Venturers can meet their obligations to provide information on their MAR to TransGrid—the New South Wales region coordinating network service provider—in accordance with its revenue collection agreement[36].

The central targets we have designated for Directlink are challenging but realistic. It will be especially challenging, if not impossible, for Directlink to secure its full 1% reward benefit.

To put beyond doubt how our proposed performance incentive scheme would operate, we include below three examples of how Directlink's S factors would be determined.

Table 5 shows a scenario in which Directlink comes very close to meeting its exact targets for each sub-measure.

[34] Directlink draft decision, pp. 234-6.
[35] Service standard guidelines. p. 2-3.
[36] Timeframes set down in our revenue recovery agreement are designed to enable TransGrid to conduct its transmission pricing process and publish its prices by 15 May each year.

Table 5

CALCULATION OF CIRCUIT AVAILABILITY AND S FACTORS FOR 2006 AND MAR ADJUSTMENT FOR 2007-08 – EXAMPLE 1

Sub-measure	Hours of Total Capacity Available				Hours of Total Capacity Unavailable in the Period	Total Circuit Hours in the Period	Circuit Availability	S factors	
	100% (3 units)	67% (2 units)	33% (1 unit)	0% (0 units)					
Scheduled	8616	144	0	0	48	8760	99.45%	S_1	0.00001
Forced peak	3708	87	0	0	29	3795	99.24%	S_2	0.00003
Forced off-peak	4851	114	0	0	38	4965	99.23%	S_3	0.00002
Total								$\mathbf{S_C}$	0.00006
					MAR_{t-2} ($M)	MAR_{t-1} ($M)	MAR_t Adjustment ($M)		
					12.10	12.30	**0.001**		

Note: MARs from the Directlink draft decision are used in this example for illustrative purposes only.

Table 6 shows a scenario in which Directlink exceeds its targets for the two forced outage sub-measures and meets its target for scheduled outages.

Table 6

CALCULATION OF CIRCUIT AVAILABILITY AND S FACTORS FOR 2006 AND MAR ADJUSTMENT FOR 2007-08 – EXAMPLE 2

Sub-measure	Hours of Total Capacity Available				Hours of Total Capacity Unavailable in the Period	Total Circuit Hours in the Period	Circuit Availability	S factors	
	100% (3 units)	67% (2 units)	33% (1 unit)	0% (0 units)					
Scheduled	8616	144	0	0	48	8760	99.45%	S_1	0.00001
Forced peak	3748	47	0	0	16	3795	99.59%	S_2	0.00164
Forced off-peak	4951	8	6	0	7	4965	99.87%	S_3	0.00289
Total								$\mathbf{S_C}$	0.00455
					MAR_{t-2} ($M)	MAR_{t-1} ($M)	MAR_t Adjustment ($M)		
					12.10	12.30	**0.055**		

Note: MARs from the Directlink draft decision are used in this example for illustrative purposes only.

Table 7 shows a scenario in which Directlink does not reach its targets for two of the sub-measures, but exceeds its target for the third.

Table 7

CALCULATION OF CIRCUIT AVAILABILITY AND S FACTORS FOR 2006 AND MAR ADJUSTMENT FOR 2007-08 – EXAMPLE 3

Sub-measure	Hours of Total Capacity Available				Hours of Total Capacity Unavailable in the Period	Total Circuit Hours in the Period	Circuit Availability	S factors	
	100% (3 units)	67% (2 units)	33% (1 unit)	0% (0 units)					
Scheduled	8616	180	0	0	60	8760	99.32%	S_1	-0.00074
Forced peak	3708	50	0	0	17	3795	99.56%	S_2	0.00152
Forced off-peak	4851	200	0	0	67	4965	98.66%	S_3	-0.00264
Total								$\mathbf{S_C}$	-0.00185
					MAR_{t-2} ($M)	MAR_{t-1} ($M)	MAR_t Adjustment ($M)		
					12.10	12.30	**-0.023**		

Note: MARs from the Directlink draft decision are used in this example for illustrative purposes only.

17. The AER's final decision

Issue:

The AER has expressed its final decision in terms of a nominal revenue path and has provided a series of formulae to describe the determination of its revenue and adjustment for inflation in Appendix K.

Response:

For the purposes of achieving regulatory and commercial certainty, the Directlink Joint Venturers are eager for the AER's revenue decision to be described in the plainest terms possible. We submit that this can be achieved by the AER deciding just three things:

1. MAR_1 = the maximum allowed revenue for year 1, 2005-06
2. X = a percentage that determines the rate by which the base annual revenue falls in real terms, determined by the AER in accordance with the building blocks revenue requirement

3. The revenue formula for the maximum allowable revenue in year t:

$$MAR_t = MAR_{t(\text{base})} + (MAR_{t-1(\text{base})} + MAR_{t-2(\text{base})}) \times 0.5 \times S_{ct} + P_t$$

for $t = 2, 3 \ldots 10$

where:

$MAR_{t(base)}$ = $MAR_{t-1(\text{base})} \times (1-\Delta CPI) \times (1-X)$

ΔCPI = is the annual percentage change in the All Groups Consumer Price Index (Average of the Eight State Capitals) published by the Australian Bureau of Statistics from March in year t-2 to March in year t-1

S_{ct} = the service incentive adjustment factor determined in accordance with Directlink's performance incentive scheme

P_t = any pass through amount/s the AER has determined for year t in accordance with the pass through rules

We acknowledge that the revenue to which we will be entitled to during 2005-06 and 2014-15 will be a pro-rated amount of MAR_1 and MAR_{10}, respectively, to recognise that the regulatory control period only covers part of those years.

ATTACHMENT 1

Letter from Rod Touzel of BRW to Dennis Stanley of the Directlink Joint Venturers of 8 December 2005.

Burns and Roe Worley

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8 December 2005

Directlink Joint Venture Manager
PO Box 518
Port Macquarie
NSW 2444

Attention: Dennis Stanley

Re: AER Directlink Draft Decision

Dear Dennis

BRW has reviewed the AER Draft Decision of 8 November 2005 and provides the following advice in relation to additional benefits that could be realised with Directlink beyond those forming part of the DJV's submissions for regulatory conversion.

Directlink could be configured to provide ancillary benefits to the NEM as follows:

- Control of inter-regional power flows between Queensland and NSW specifically to dampen system power oscillations and hence prevent system separation between Queensland and NSW after a power system event (e.g. a system fault or a large load/generation failure).

- System restart capability - Directlink can provide continuous power to local loads at either terminal. This is a useful feature in the event of a power system failure at either end of the link because it allows supplies to be quickly restored.

- Fast reactive support - Directlink provides independent voltage control or reactive power control at each individual terminal giving it similar capabilities to two independent static VAr compensators.

These benefits could be cost effectively developed over time adding to the value of Directlink.

Yours sincerely
Burns and Roe Worley

R McD Touzel
General Manager Consulting

Burns and Roe
Worley

ATTACHMENT 2

TransÉnergie US 2005, *Impact of the Value of USE on Interregional Market Benefits*, 9 December.

December 9, 2005

Impact of the Value of USE on Interregional Market Benefits

Prepared for

The Allen Consulting Group

By

TransÉnergie US Ltd.

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Contents

Executive Summary

This report provides additional information on two aspects of Directlink's interregional market benefits relating to unserved energy (USE):

- The geographic distribution of changes in USE caused by Directlink and its alternative projects
- The sensitivity of interregional market benefits to the value of USE

1 Geographic Distribution of Changes in USE

The impacts of Directlink and the alternative projects include changes in market prices, which in turn affect the timing and location of new market entry plant. The presence, or absence, of market entry plant in a particular regions will, combined with regional loads and interregional transfer capabilities, mitigate to a greater or lessor degree the need for reliability plant to achieve the 0.002% unserved energy criterion. The amount and location of any residual USE not eliminated by market entry and reliability entry is very much affected by the specific pattern (timing and location) of generation entry that develops in response to changes in market prices.

Previous TEUS submissions have shown that market entry and reliability entry are affected by Directlink in all four of the NEM regions with customer loads. This causes changes in USE in all of the regions. Table 1 below indicates the change in USE over time by region for the credible scenarios;

Table 1

	Reduction in USE Caused by Directlink and Alternative Projects (MWh)														
	Med Growth					Low Growth					High Growth				
Year	NSW	QLD	SA	VIC	Total	NSW	QLD	SA	VIC	Total	NSW	QLD	SA	VIC	Total
2005	0.6	-8.3	0.0	0.0	-7.7	0.6	-14.0	0.0	0.1	-13.3	0.9	-7.0	0.0	0.0	-6.1
2006	2.6	-3.9	0.0	0.0	-1.3	1.7	-2.4	0.0	-0.2	-0.9	6.5	-5.5	0.0	0.4	1.4
2007	8.0	-1.3	0.0	0.0	6.7	4.0	-0.1	0.0	0.0	3.9	29.5	-1.5	-0.2	0.3	28.1
2008	26.2	-3.5	-0.1	0.0	22.6	8.8	-0.7	0.0	0.0	8.1	93.3	0.0	0.0	3.4	96.7
2009	-14.9	-9.8	-1.2	-4.4	-30.3	21.3	-2.2	0.0	0.1	19.2	44.1	-0.6	0.0	1.3	44.8
2010	-22.6	-8.7	-0.3	-6.6	-38.2	62.5	-4.7	0.0	0.6	58.4	75.8	-4.1	0.0	3.7	75.4
2011	33.0	-18.9	-10.6	-19.2	-15.7	132.1	-2.3	0.3	2.4	132.5	-286.0	2.8	-3.2	-38.5	-324.9
2012	60.6	-10.8	-0.2	-0.5	49.1	186.7	-47.5	0.1	3.2	142.5	36.3	-1.4	11.5	-15.4	31.0
2013	158.5	3.5	0.6	12.0	174.6	133.7	-2.2	-0.7	-2.1	128.7	205.8	-1.2	2.5	23.8	230.9
2014	136.0	-4.4	-0.1	-3.6	127.9	152.9	-30.3	-0.5	-2.3	119.8	-251.7	-0.5	-8.2	-93.9	-354.3
2015	205.9	-0.5	-1.3	-3.5	200.6	150.8	2.8	-0.5	-0.7	152.4	-165.9	-1.7	5.8	51.8	-110.0
2016	234.2	-6.7	-1.5	7.9	233.9	134.6	-38.0	0.3	1.8	98.7	340.6	-4.8	34.0	-209.1	160.7
2017	336.5	-8.6	1.6	38.3	367.8	-68.9	84.4	11.0	-287.4	-260.9	176.2	-1.3	-26.2	-364.6	-215.9
2018	319.7	-6.8	1.5	18.3	332.7	-328.3	-27.5	-4.4	-95.8	-456.0	-247.8	-12.7	2.9	103.9	-153.7
2019	257.0	-7.1	1.1	26.7	277.7	153.3	-3.7	-0.6	-41.9	107.1	-362.0	-11.7	-34.5	-493.6	-901.8
Ave 2005-19	116.1	-6.4	-0.7	4.4	113.4	49.7	-5.9	0.3	-28.1	16.0	-20.3	-3.4	-1.0	-68.4	-93.2

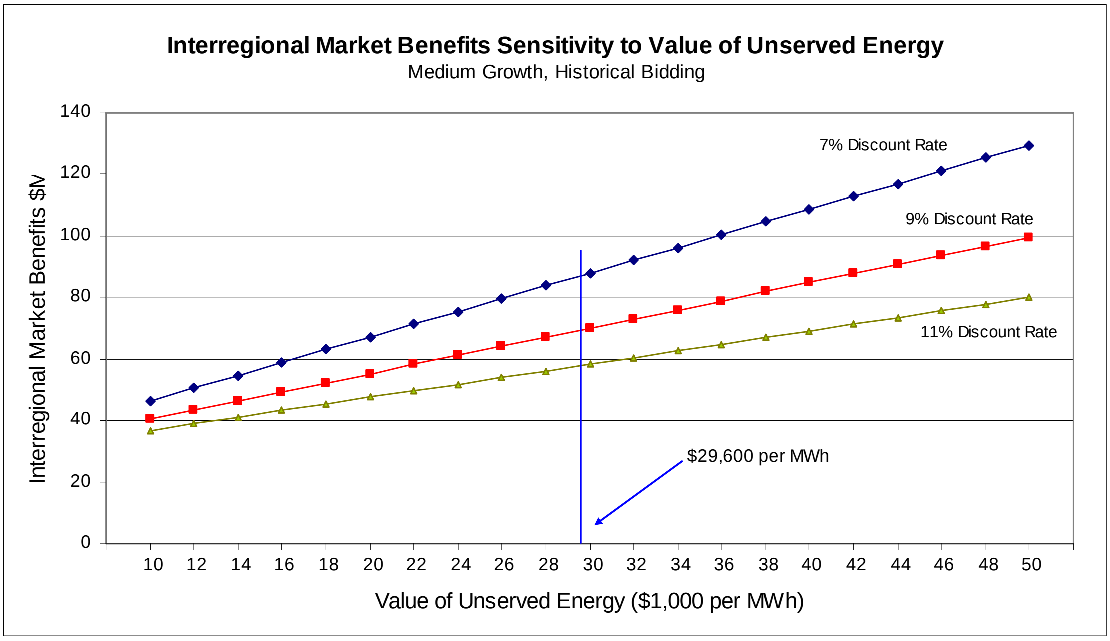
In the Medium and Low Growth cases, the largest change occurs in NSW. In the High Growth case, the largest change is seen in VIC. In all three cases, the smallest change occurs in SA. Depending on the particular patterns of market entry, changes may be positive or negative. The important point to note is that the changes are not limited to NSW and QLD, the two regions interconnected by Directlink, but occur throughout the NEM.

2 Interregional Market Benefits Sensitivity to the Value of USE

Directlink's interregional market benefits are composed of four elements – reductions in energy costs, deferred market entry costs, deferred reliability entry plant costs, and reductions in residual unserved energy. A review of the results previously provided by TEUS[1] indicate that for the credible scenarios with unserved energy valued at $29,600/MWh, reductions in residual unserved energy account for between 17-63% of the total interregional market benefits.

As a result, total interregional market benefits are clearly sensitive to the value assigned to unserved energy. Charts 1, 2, and 3 illustrate how the credible scenario market benefits vary for values of unserved energy between $10,000 and $50,000 per MWh. Table 2 provides a summary of these results.

Chart 1



[1] TEUS Summary of Additional Four Case Results, September 7, 2005, page 5.

Chart 2

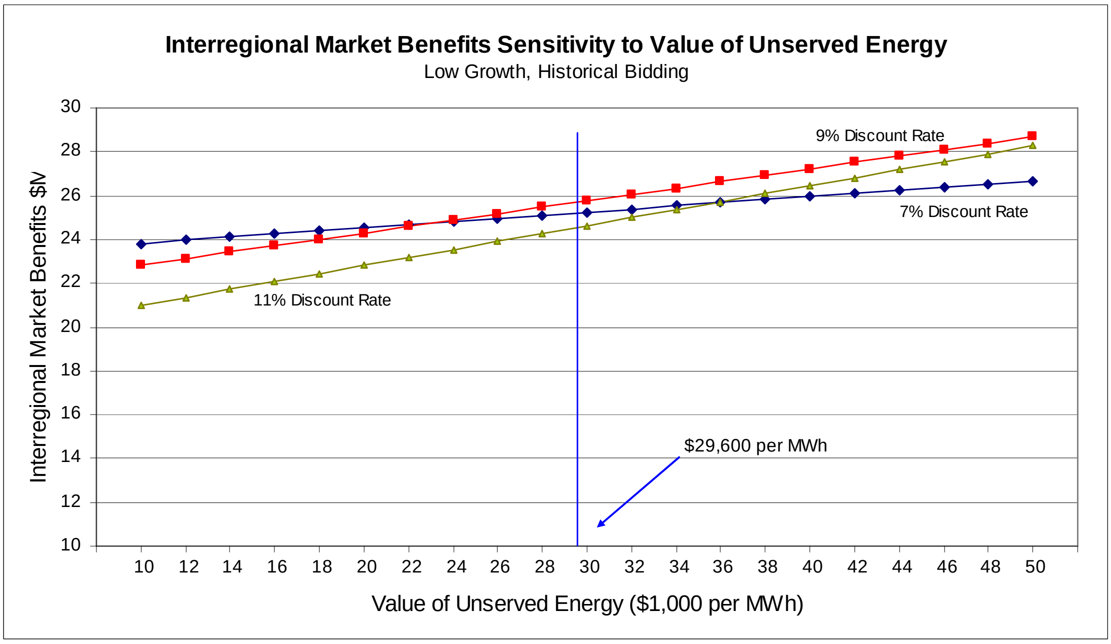


Chart 3

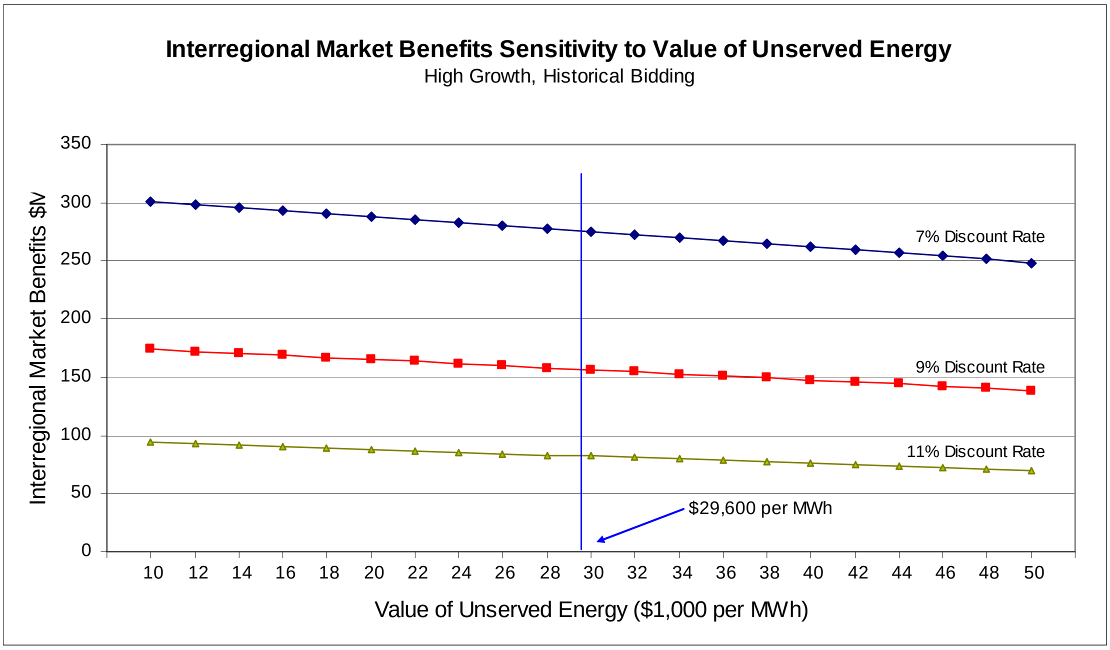


Table 2

Interregional Market Benefit Sensitivity				
Historical Bidding				
Discount Rate	Value of Unserved Energy $/MWh	Medium Growth $M	Low Growth $M	High Growth $M
7%	10,000	46.4	23.8	301.5
7%	20,000	67.2	24.5	288.2
7%	30,000	88.0	25.2	275.0
7%	40,000	108.8	26.0	261.8
7%	50,000	129.5	26.7	248.6
9%	10,000	40.4	22.8	174.1
9%	20,000	55.2	24.3	165.2
9%	30,000	70.0	25.8	156.4
9%	40,000	84.8	27.2	147.6
9%	50,000	99.6	28.7	138.8
11%	10,000	36.8	21.0	94.0
11%	20,000	47.6	22.8	88.1
11%	30,000	58.4	24.6	82.1
11%	40,000	69.2	26.4	76.1
11%	50,000	80.0	28.3	70.1

ATTACHMENT 3

PERFORMANCE INCENTIVE SCHEME

The AER will assess the performance of the Circuit after the end of each Year and adjust the MAR with a reward or penalty for the following financial year in accordance with the measures, targets, methodology and process set down in this performance incentive scheme.

A3.1 Measures

The AER will measure the Circuit's performance for a Year in terms of its Availability with regard for Forced Outages Events during Peak and Off-peak Periods and for Scheduled Outage Events, as described in Table A3.1.

Table A3.1

PERFORMANCE INDICATOR DEFINITION – CIRCUIT AVAILABILITY

Sub-measures	Circuit Availability (Scheduled) Circuit Availability (Forced Peak) Circuit Availability (Forced Off-peak)
Definition	The proportion of hours the Circuit is Available during the Circuit Hours in a given Period each Year divided by the total Circuit Hours in the Period in the Year, weighted by Unit.
Source of Data	Directlink Outage Register and Disturbance and Outage Report
Formula	$\textbf{100\% -} \dfrac{\text{Hours of Total Capacity Unavailable in the Period in the Year}}{\text{Total Circuit Hours in the Period in the Year}}$
Exclusions	The calculation of Circuit Hours and Circuit Availability will not include any time in which the Circuit is not Available as the result of an Excluded Event.

A3.2 Performance targets

The targets to achieve the rewards for achieving higher performance, and the penalties for achieving lower performance are set down in Table A3.2.

Table A3.2

TARGETS AND INCENTIVES FOR EACH PERFORMANCE SUB-MEASURE

	Circuit Availability Sub-measure		
	Scheduled	**Forced Peak**	**Forced Off-peak**
Type of Outage Event	Scheduled	Forced	Forced
Period	Peak & Off-peak	Peak	Off-peak
Maximum Circuit Hours in the Period[37]	8760	3795	4965
Maximum penalty (% MAR)	0.30%	0.35%	0.35%
Performance for maximum penalty	98.90%	98.47%	98.47%
Target for no reward or penalty[38]	99.45%	99.23%	99.23%
Performance for maximum reward	100.00%	100.00%	100.00%
Maximum reward (% MAR)	0.30%	0.35%	0.35%

A3.3 Calculation of S factors

The Circuit's actual circuit availability for a Year and its performance targets are the basis for calculating S factors for each performance sub-measure in accordance with the equations in Tables A3.3, A3.4, and A3.5.

Table A3.3

S FACTOR FOR SCHDEULED CIRCUIT AVAILABILITY (S_1)

Circuit Availability (Scheduled)	Formula for S_1
100.00%	0.00300
Less than 100.00% and greater than 99.45%	0.54545 x Circuit Availability (Scheduled) – 0.54245
99.45%	0.00000
Less than 99.45% and greater than 98.90%	0.54545 x Circuit Availability (Scheduled) – 0.54245
Less than 98.90%	-0.00300

Source: Directlink draft decision, p. 234.

[37] Maximum Circuit Hours in the Period are calculated as the number of hours in the Period in the year commencing 1 January 2006 and are presented for illustrative purposes only.

[38] Performance targets for Peak and Off-peak Periods are calculated as percentages of Peak and Off-peak Periods rather than percentages of total time.

Table A3.4

S FACTOR FOR FORCED PEAK CIRCUIT AVAILABILITY (S_2)

Circuit Availability (Scheduled)	Formula for S_2
100.00%	0.00350
Less than 100.00% and greater than 99.23%	0.45455 x Circuit Availability (Forced Peak) – 0.45105
99.23%	0.00000
Less than 99.23% and greater than 98.47%	0.46053 x Circuit Availability (Forced Peak) – 0.45698
Less than 98.47%	-0.00350

Source: Directlink draft decision, p. 234.

Table A3.5

S FACTOR FOR FORCED OFF-PEAK CIRCUIT AVAILABILITY (S_3)

Circuit Availability (Scheduled)	Formula for S_3
100.00%	0.00350
Less than 100.00% and greater than 99.23%	0.45455 x Circuit Availability (Forced Off- Peak) – 0.45105
99.23%	0.00000
Less than 99.23% and greater than 98.47%	0.46053 x Circuit Availability (Forced Off-Peak) – 0.45698
Less than 98.47%	-0.00350

Source: Directlink draft decision, p. 235.

The S factor for the Circuit for the Year is the sum of the S factors for each measure:

$$S_{ct} = S_1 + S_2 + S_3$$

A3.4 Calculation of the penalty/reward adjustment to the MAR

The AER will determine an adjustment to the TNSP's MAR for the financial year t—commencing 1 July after the end of the Year in accordance with the formula set down in its decision.

A3.5 Annual timetable

The TNSP and the AER will conduct their responsibilities for the implementation of this performance incentive scheme in accordance with the following timetable.

Table A3.6
TIMETABLE

Task Name	Due date
AER to advise the TNSP of the nature of the Circuit's annual operating performance information the AER requires the TNSP to collect for the Year and submit to the AER for the purposes of clause 6.2.5(a) of the National Electricity Rules	1 December of the previous Year
TNSP to submit the Circuit's annual operating performance information for the Year	31 January of the following Year
AER to advise the TNSP of its MAR adjustment as determined by this performance incentive scheme for the financial year following the Year	15 April of the following Year

A3.6 Definitions

In this performance incentive scheme, capitalised terms have the following meanings.

AEMC means the Australian Energy Market Commission

AER means the Australian Energy Regulator

Authority means NEMMCO, AER, AEMC and any:

(a) government or regulatory department, body, instrumentality, minister, agency or other authority; or

(b) body which is the successor to the administrative responsibilities of NEMMCO, AER, AEMC, department, body, instrumentality, minister, agency or authority.

The Circuit is **Available** in proportion to the extent to which one, two or three of its units are available.

Available Circuit Hours means the Total Circuit Hours in the Period in a Year minus the number of hours in the Year that the Circuit is not Available due to a Forced Outage Event or a Scheduled Outage event, as appropriate.

Circuit means the Directlink HVDC transmission asset (converter stations, cables and substation equipment, etc.) between and including the connection points set down in the TNSP's connection agreement with Country Energy and used for the purpose of providing a prescribed service.

Disconnection means to operate switching equipment or to remove or alter assets so that electricity is unavailable to be supplied to or received from the Circuit.

An **Excluded Event** is any event that causes the Circuit to be not Available and that is shown to be the result of:

(a) a fault, other event or capacity constraint on a Third Party System (e.g. inter-trip signal, generator outage, reaching a thermal power flow or voltage limit, failure of SCADA or other communications system);

(b) an instruction or direction from an Authority;

(c) Disconnection, Interruption or Works by Country Energy, TransGrid or Powerlink Queensland;

(d) damage to the Circuit's cable or equipment that results from action by a third party that, in the opinion of the Commission, the TNSP's best endeavours were unable to prevent; or

(e) Force Majeure Events.

Forced Outage Event means the actual or imminent occurrence of an event, other than an Excluded Event, that poses or has the potential to pose an immediate threat to the safety of persons, hazard to any equipment or property or a threat to power system security, and that results in the Circuit being not Available.

Force Majeure Event includes any event, act or circumstance or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the TNSP and that results in the Circuit being not Available, which event, act or circumstance may include, without limitation, the following:

(a) fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature;

(b) action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same);

(c) strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing; or

(d) acts or omissions (other than a failure to pay money) of a party other than the TNSP which party either is connected to or uses the high voltage grid, or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid, where those acts or omissions affect the ability of the TNSP to perform its obligations under the service standard by virtue of that direct or indirect connection to or use of the high voltage grid.

To avoid doubt, a Force Majeure Event specifically includes an event when the outcome is:

(e) The loss of or damage to 11 or more control or secondary cables;

(f) The loss or damage to two or more transformers and capacitor banks, either single or three phase, connected to a bus; or

(g) The loss or damage to a transformer, capacitor bank, or reactor, which loss or damage is not repairable on site according to normal practices.

This is not intended to limit the definition of force majeure rather to provide guidance in its application.

Interruption means that electricity is temporarily unavailable to be supplied or received from the Circuit.

MAR means the maximum allowable revenue determined for the TNSP by the AER under the National Electricity Code or the National Electricity Rules.

Peak Period is between 7.00 am to 10.00 pm on weekdays excluding public holidays in New South Wales.

Off-peak Period is all times other than Peak Period.

SCADA means supervisory, control and data acquisition system.

Scheduled Outage Event means the actual occurrence of an event, other than an Excluded Event or a Forced Outage Event, which results in the Circuit being not Available.

Third Party System means the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers together with associated connection assets, owned or operated by a party other than the TNSP.

Total Capacity Unavailable Hours means the number of hours in the Period in the Year minus the number of hours in the Year that the Circuit is not Available due to an Excluded Event.

TNSP means the entity or entities that are each registered as a transmission network service provider with NEMMCO and whose network contains the Circuit.

Unit means one of the three units of the Circuit that each provide one third of its total transfer capability.

Works means installation, construction, commissioning, augmentation, extension, removal, inspection, testing, undertaking of repairs, undertaking of maintenance or connection of another network user to the Third Party System.

Year means a year commencing on 1 January, or part thereof, within the regulatory control period.