DIRECTLINK CONVERSION APPLICATION - REVIEW OF INTERREGIONAL MARKET BENEFITS

A report to the Australian Competition and Consumer Commission

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IES
Intelligent Energy Systems

Executive Summary

This report presents a review undertaken by Intelligent Energy Systems (IES) for the Australian Competition and Consumer Commission (ACCC) on the assessment of interregional market benefits contained in the application by Directlink Joint Venturers (DJV) for Directlink to be converted to a regulated interconnector. The regulatory test used by DJV and upon which the review is based is that promulgated by the ACCC on 15 December 1999.

The review undertaken involved both a review of methodology and a review of the modelling undertaken.

The modelling study submitted by DJV in the assessment of interregional market benefits provided by Directlink closely followed the methodology that had been used in the application of the ACCC test to Murraylink, and which had been accepted by the ACCC in that application. The overall methodology was considered consistent with the 1999 regulatory test, including the calculation of reliability benefits that was slightly different to that used in previous application of the ACCC regulatory test.

A number of issues were noted that were also present in the Murraylink application, noting that in the case of Murraylink the decisions by the ACCC had been based on the test objective of determining the preferred project. These issues included:

- Absence of a market simulation that approximated actual market bidding and prices;
- No sensitivity testing on key assumptions such as new entry costs;
- No least cost planning scenario; and
- The use of a methodology that has an implied assumption regarding the continuation of post 2019 benefits.

The review of modelling assumptions and detailed modelling results showed a number of significant issues. These issues included:

- The service level provided by Directlink (and the other DC alternative projects) assumed that these projects provide an increase in the interconnection capacity of 180 MW from NSW to Queensland in the PROSYM market modelling. However, these projects provide no increase in northward flow;
- Unrealistic spot price outturns in the market modelling which would significantly impact the dynamics new entry generation and associated benefits;
- The use of unsupported assumptions on new entry costs. In particular a high implied WACC in the determination of annualized new entry capital

costs and an assumption of full CPI escalation of new entry capital costs from 2003 to 2005; and

- Levels of market generation deferral that does not accord with the service levels provided by Directlink (and the other DC alternative projects). For example the modelling had 200MW of market entry deferral in Queensland when Directlink (and the other DC alternative projects) does not provide any increase in interconnection capacity to Queensland;

It was also noted that since the time of the modelling, there have been a number of market developments that would result in significant changes to assumptions.

In IES's opinion the significance of the issues identified with the modelling means that the modelling results contained in the application cannot be relied upon for the purposes of the ACCC test.

A meeting was held between the ACCC, DJV and IES to discuss the findings contained in the IES draft report and to give DJV the opportunity to address the issues raised. While DJV did address some of the issues contained in the draft report, the matters listed above remained unresolved. To address these issues DJV/TEUS has agreed to undertake remodelling of an agreed set of scenarios.

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Glossary

AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
CCGT	Combined Cycle Gas Turbine
DC	Direct Current
DCF	Discounted Cash Flow
DJV	Directlink Joint Venture
FOR	Forced Outage Rate
HVDC	High Voltage Direct Current
IES	Intelligent Energy Systems
LRMC	Long Run Marginal Cost
MAR	Maximum Allowable Revenue
ME	Market Entry
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance
POE	Probability of Exceedence
PV	Present Value
QNI	Queensland NSW Interconnector
RE	Reliability Entry
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
TEUS	TransEnergie United States
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

1 Introduction

In April 2004, Directlink Joint Venturers (DJV) submitted an application to the Australian Competition and Consumer Commission (ACCC) requesting that the ACCC determine that:

- The network service provided by Directlink is a prescribed service for the purposes of the National Electricity Code; and
- For the provision of this prescribed service, DJV be eligible (subject to the performance incentive scheme proposed in section 6.5 of the application) to receive the maximum allowable revenue (MAR) from transmission customers (through coordinating network service providers) for a regulatory control period from the date of effect of the ACCC's final decision on the application to 31 December 2014.

As part of ACCC's inquiry into DJV's application, a review of DJV's application of the regulatory test is required. The regulatory test used by DJV and upon which the review is based, is that promulgated by the ACCC on 15 December 1999.

The ACCC commissioned two separate consultancies for this review. The first (stage 1) consultancy undertaken by Parsons Brinckerhoff Associates (PB Associates), established the suite of feasible alternative transmission augmentations relative to Directlink, their respective costs, and performance characteristics including any operational constraints associated with providing local area transmission system support. This work also undertook an assessment of the benefits Directlink and similar projects would provide by way of transmission development deferrals.

For the second (stage 2) consultancy, which is the subject of this report, the ACCC appointed Intelligent Energy Systems (IES) to provide advice on DJV's application in relation to the modelling and assessment of interregional market benefits.

1.1 Terms of Reference

The terms of reference for this review are as follows:

"The consultant is to review DJV's calculation of market benefits for the purposes of a regulatory test assessment. To this end the consultant is to:

- Comment on the inputs, methods and assumptions underlying DJV's calculation of market benefits for each of the alternative projects identified as part of its application, or re-configured alternative projects as the case may be, or other alternative projects identified during the assessment process by the ACCC's stage 1 consultants
- Comment on the DJV's treatment of committed, anticipated and modelled projects.

- Compare and contrast the calculation of market benefits in DJV's application with the calculation of market benefits in previous applications of the regulatory test. This should include, but necessarily be limited to, NEMMCO's assessment of SNI and SNOVIC 400, after considering the views of the NET and Victorian Supreme Court in relation SNI, the Murraylink Conversion Application and VENCorp's assessment of the La Trobe Valley to Melbourne 4th line augmentation;
- Review DJV's sensitivity analysis on the alternatives to test the robustness of inputs, assumptions and methods."

1.2 DJV Submission Documents Reviewed

The documents from DJV pertaining to the determination of interregional market benefits, and that are the subject of this report are:

- "Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to 30 June 2015 " dated 22 September 2004;
- Appendix D - Burns and Roe Worley Report – "Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" 22 September 2004;
- Appendix G TEUS Reports:
  - Part 1 – TransEnergie US Limited, Estimation of Directlink Alternative Projects' Market Benefits, April 2004;
  - Part 2 – TransEnergie US Limited, Estimation of Directlink Alternative Projects' Market Benefits – Supplementary Report, 15 September 2004;
- "Response to IES Questions on Directlink's Inter-regional Market Benefits" 18 August 2005;
- "Response to Questions from ACCC Staff Posed on 21 July 2004" dated 24 August 2005;
- "Supplementary Response to IES Question 12 on Directlink's Alternative Projects' Inter-Regional Market Benefits" dated 28 September 2004;
- "Response to IES Questions of October 25,2004" dated January 18, 2005
- Burns and Roe Worley – "Technical Advice to Assist TEUS in Answering IES / High Growth Case NSA and Dumaresq Line Support" 19 January 2005;
- Memorandum – "IES Draft Rport of 11 March 2005" dated 14 March 2005
- Response to the IES Report Reviewing Directlink's Interregional Market Benefits" dated 21 March 2005[1];
- TEUS spreadsheets containing detailed modelling results (these were provided in response to requests during the review period).

[1] This document contained comments on the first draft of the IES report.

The document “Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to 30 June 2015” dated 22 September 2004 is the principal document in the DJV submission. The key chapters of the report addressing the assessment of interregional market benefits are Chapter 2 - Directlink Network Service, and Chapter 4 – Application of the Regulatory Test. These chapters give a high level description of Directlink and the competing projects, as well as the approach and assumptions taken to determine market benefits. This document also contains details of modelling results that were not included in Appendix G.

Appendix G provides the details of the modelling work undertaken to determine the interregional market benefits of Directlink and the competing projects. Part 1 of this was the original submission in April 2004.

Part 2 contains updated modelling results based on revised information being used on loads in Northern NSW and Gold Coast areas, peak period transfer limits between the sub-regions in Queensland and Northern NSW, and the present value reference date and analysis period. This revised modelling related to that associated with reliability assessment only.

In addition, there were slight changes made to the market modelling results associated with the discount period. Quoting from page 3 of the supplementary report:

> “To achieve consistency within their revised application package to be lodged with the ACCC in September 2004, the Directlink Joint Venturers now wish TEUS to apply a present value reference date of 1 July 2005 to the dollar figures it calculates, and have market benefits calculated for the 40 years from 1 July 2005.”

Appendix G and accompanying spreadsheets formed the key documents to this review, with the “Response to IES Questions” documents providing clarification in requested matters.

1.3 Evaluation Process Undertaken

IES was retained by the ACCC in early 2004 in relation to stage 2 of the DJV submission review process. Since that time, the review process undertaken by IES has involved the following:

- Review of the April 2004 submission by DJV;
- Review of the PB Associates report for the purpose of understanding for Directlink and similar projects, the costs, transmission deferral benefits and required operating constraints, and the impact on interregional transfer capacity;
- Development of a list of questions to DJV following review of the April 2004 submission. IES also submitted other questions to DJV through the process. DJV responded with a question and answer session and with written responses to all the questions raised;

- Following issues raised by PB Associates and IES, DJV developed a revised submission that was delivered to the ACCC in September 2004. DJV also provided a response to the PB Associates report on the alternative projects.
- DJV provided a response to IES questions in January 2005;
- Draft report provided to DJV on 8 April 2005 for comment;
- Following this, DJV responded with a written submission on identified issues. A meeting was held between the ACCC, DJV and IES to discuss the approach used by TEUS in their modelling and the issues identified;
- With the final submission and response documents, IES developed this final report on its findings.

1.4 Outline of this Report

This report is structured as follows:

- Chapter 2 and 3 presents a review of the ACCC Regulatory Test and the modelling principles for evaluating interregional market benefits. This is presented as a background and reference for the review that follows. Issues addressed here include overall approach, simulation modelling and how the timing of future new generation is determined, and generator bidding.
- Chapter 4 presents an overview of the DJV submission. This is intended to put the more detailed review of the analysis in perspective.
- Chapter 5 considers the service level provided by Directlink and the competing projects, with emphasis on the key features that should be included in the modelling undertaken. Issues with the representation used by DJV in their submission modelling are identified.
- Chapter 6 reviews the validity of the assumptions used in the modelling and how these have changed since the modelling was undertaken in early 2004.
- Chapters 7 and 8 respectively review the modelling approach used in the market and reliability modelling, and identify potential issues.
- Chapters 9 and 10 take a close look at the modelling results produced. This analysis uses the detailed modelling results provided in the spreadsheets.
- Chapter 11 reviews the overall economic results presented. Issues considered here include the assessment of terminal value.
- Chapter 12 summarises the findings together with the conclusions of this review.

2 Application and Methodology of the ACCC Regulatory Test

Before considering the modelling issues associated with the regulatory test, this chapter reviews:

- The objectives of the test as a background to ACCC decisions on the application of the test to Murraylink (being the most recent application of the test and particular application issues associated with Directlink;
- The methodology for the application of the test; and
- The treatment of the least cost planning scenario.

2.1 Test Objectives

In section 4.5.5 of the ACCC decision on Murraylink, the ACCC say:

> The Commission notes that in response to its concern expressed in the Preliminary View regarding the uncertainty prevalent in estimating a single value of gross market benefits in a regulatory test assessment, MTC performed confidence interval estimates to demonstrate that it is appropriate to adopt a single value or expected value of the 'most likely' estimate. The Commission also notes concerns expressed by ESIPC which questions the calculation of a median market benefit rather than a "most likely" benefits with sensitivities to test the robustness of the results.
>
> The Commission notes that the regulatory test requires that both market development scenarios and sensitivity analysis be considered as part of a regulatory test assessment to test the robustness of the analysis to input parameter variability and behaviour of market participants. Furthermore the regulatory test does not refer to estimating a "most likely" or "median" estimate of the gross market benefits, but makes reference to the augmentation or proposals being assessed maximising the market benefits (that is the gross market benefits minus the costs) in most credible scenarios. Part (e) of the regulatory test states:
>
>> "(e) a *proposed augmentation* maximises the *market benefits* if it achieves a greater *market benefit* in most (although not necessarily all) credible scenarios;"
>
> The Commission considers that it is inconsistent with the regulatory test to derive a "most likely" or "median" estimate of the gross market benefits, given that it does not make reference to such outcomes.
>
> The gross market benefits of Murraylink and its alternative projects under different market development scenarios and sensitivities are presented in Appendix F.

This indicates that ACCC decisions on Murraylink need to be seen within the objectives of the ACCC test as expressed by the ACCC, this being to ascertain which of a number of projects passes the ACCC regulatory test. It is not to ascertain what would be the likely level of market benefits.

2.2 Overview of Methodology

The ACCC regulatory test states that:

"A new interconnector or an augmentation option satisfies the test if it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios."

Re-expressed, the 'market benefit NPV' as defined is equal to the NPV of the market benefits net of the project cost, optimised with respect to the project commencement date.

The test prescribes a cost benefit analysis where the economics of a transmission asset that is the subject of the test (referred to as the Project) is determined and compared to the economics of similar competing options (referred to as the Alternative Projects). The test says that augmentation options include, but are not limited to, generation, demand-side management (DSM), and network service provision. (These were the subject of the stage 1 review.)

The economics of the project (in this case Directlink) and alternative projects is determined through modelling the development (generation and transmission) and operation (generation dispatch and supply reliability) of the market for the following cases:

- Without the project or any of the alternative projects – this is referred to as the 'no project' or 'base' case;
- With the project assumed to be developed – this is referred to as the 'project case';
- With each alternative project in turn assumed to be developed – these are referred to as the 'alternative project cases'.

The economics of the project is given by the difference in total market costs between the project and base case. Likewise, the economics of each alternative project is given by the difference in total market costs between the respective alternative project case and base case.

Cost components that are subject to change in each year (and that consequently impact the economics of the project and each alternative project) include:

- The cost of the project and alternative projects – capital and annual operating costs;
- The costs of new and uncommitted investments in generation and transmission;
- The costs of generation production[2] - this is associated with the costs of fuel used and variable operation and maintenance (O&M) costs of all generators operating in the market (including the supply of transmission losses);
- The costs of ancillary services.

[2] Also called dispatch

From the annual change in market costs (capital and operations of generation and transmission) due to the presence of the project or each of the alternative projects, an NPV is calculated for the project and each of the alternative projects over their respective lives. The impact of varying project timing is also considered. This enables the economics of the project to be determined and compared to each of the alternative projects. The Project or one of the Alternative Projects that produces the maximum NPV satisfies the Regulatory Test.

In undertaking the simulation modelling the test specifies the following:

- That a suitable number of market scenarios be undertaken;
- The use of generator bidding that approximates actual market bidding and prices;
- Provision of a Short Run Marginal Cost (SRMC) market scenario;
- That regional reliability levels be maintained at the applicable standard in each scenario;
- Provision of a least cost planning scenario.

Although the test is not prescriptive in relation to modelling approaches, application issues key to the results obtained through modelling undertaken include:

- Representation of the project and alternative projects in the simulation modelling;
- Assumptions of generator bidding and the resulting spot price outturns;
- The economic criteria used for determining the timing and type of new generator entry.

These matters are discussed in the following chapter.

2.3 The need for the Least Cost Planning Scenario

The1999 ACCC Regulatory Test specifically asks that in addition to determining the economics of the project and alternative projects under a variety of market scenarios, the economics under a least cost planning scenario should also be done.

The regulatory test states:

> "Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.
>
> (a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs."

Given that a least cost planning scenario would have generators dispatched in SRMC merit order in the same manner as the SRMC bidding market scenario, there is a close connection between these two scenarios. However, there is no basis to assume that these two scenarios are necessarily the same.

Under the SRMC bidding market scenario, generator entry is determined by spot prices that result from SRMC bidding. As spot prices beyond marginal costs are determined by demand side bids and VoLL events, the results of this scenario result in low prices and low levels of generation entry until significant levels of unserved energy result. This results in high levels of reliability generation entry. This may not be the lowest cost development plan as would be developed under the least cost planning scenario.

ACCC Decision on Murraylink

The ACCC did not make specific mention of the absence of a least cost planning scenario in the Murraylink application.   The ACCC accepted the modelling presented.

3 Modelling Principles for the ACCC Regulatory Test

As background to the review and to ensure a common understanding of the issues that are the subject of this review, this chapter reviews the modelling principles involved in the assessment of interregional market benefits under the 1999 ACCC Regulatory Test. Common terminology is also presented.

This review is based on the published 1999 ACCC Regulatory Test and ACCC decisions in the application of the regulatory test to Murraylink.

As background to understanding the benefits provided by interconnection and how long such benefits may continue, Appendix 1 presents a description of the role of interconnection and benefits provided.

3.1 Simulation Modelling

This section reviews the principles of market simulation modelling in the context of the ACCC Regulatory test. These principles are based on reflecting outturns and costs as would occur in the actual market.

Market simulation modelling generally entails the use of models that represent the hour by hour (or half hour by half hour) physical and financial operation of the market. For each dispatch period, such models have generators offer prices for their energy (using pre-defined or model determined generator bids) and the level of demand being supplied, from which spot prices, generator dispatch levels and settlements (ie. generator revenues) are then determined. Through this process the operation of the market is modelled. The study period runs can vary from one day to say 20 years.

3.1.1 Key Features of Simulation Modelling

The key features usually incorporated into such models are:

- The regional structure of the NEM;
- Relevant transmission limits that exist between regions and within regions;
- The total customer demand in each region (and sub-regions if appropriate);
- The capacity of individual generators, their times of planned outages and the likelihood of each individual generator being out of service due to breakdown;
- Constraints on generator operation such as minimum generation levels;
- Generator cost structures;
- The grouping of individual generators into power stations and by ownership;
- Constraints on fuel use such as hydro power stations;

- Recognition of bought and sold contracts by generators in the market;
- The ability to specify the bids of generators, or have the model determine how generator portfolios would bid according to defined strategies (such as to maximize profit)[3]; and
- The ability to have the model report on issues such as regional spot price, interconnector transmission power flows, generator revenues etc.

The results of market simulations are the result of the input assumptions used. The most critical of these for multi-year simulation include the following:

- The level of customer load growth;
- The number of new generators committed to enter the market;
- The planned increase in interconnector capacity;
- The cost structure (capital and operating costs) of potential new entrant generators;
- Bidding behaviour of generators; and
- The economic criteria used by new merchant generators to enter the market.

The last two of these are particularly important to simulation modelling done for the ACCC Regulatory Test, as these determine the market dynamics by which new transmission impacts generator capital investment.

3.1.2 Approach to Determining Capital Investment

Given the significance of capital deferral benefits in the calculation of market benefits, this section reviews the economics and approach for the determination of investment timings undertaken in market simulations.

A key issue is the criteria used for new generators to enter the market. The usually practice is that new entry generators will enter the market when (spot) prices are sufficiently high for the generator to make a satisfactory return on investment. The prices required for the economic entry of new generation can be determined using the concept of 'spot price premiums'. This is explained below.

For a given spot price outcome, the 'premium' available to a potential new generator each settlement period is as follows:

Premium ($/MWh) = (Spot Price minus the SRMC of the new entry plant, when Spot Price > SRMC

= 0 when Spot Price < SRMC

This is referred to as the premium above SRMC (the value above which the premium is calculated is referred to as the strike price). The premium indicates the amount of cash available to a new entrant (by trading solely in the spot market) to service the capital cost of the plant. Clearly, no contribution to capital

[3] Generator bidding strategies that have generator portfolios competitively bid can be used to incorporate the impact of competition benefits.

costs is available until the premium is positive, ie. the spot price exceeds the fuel cost for the technology being considered.

When summed over a year, the premium provides the revenue available to the generator assuming it operates when the spot price is greater than its SRMC. The powerful aspect of the premium approach is that no assumptions are required in relation to the capacity factor of the generator, as it simply operates when economic.

Consequently, the level of premium available in the market provides the fundamental investment signal for new entry. When the premium, calculated at the SRMC of a certain generator technology, reaches or exceeds the generator capital cost (and assuming spot prices will continue to increase) it becomes economic for a new plant to enter the market (assuming it operates when spot price exceeds its SRMC).

The entry of a new generator will most likely have a depressing effect on spot price outturns (and the available premium). The extent of this impact will be influenced by the size and timing of the new entrant generator.

3.2 Market Benefits

The market benefit is calculated as the total net benefit of a proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). Net benefits are created by an augmentation option if it reduces the economic costs of meeting projected demand and/or unserved energy.

Market benefits accrue in the following areas:

- Reduction in system wide fuel costs;
- Deferral of capital costs in the areas of generation, DSM, and transmission;
- Reduction in unserved energy costs (measured by the reduction in the economic costs associated with reduced customer load shedding); and
- Reduction in ancillary services costs to the market as whole.

ACCC Decision on Murraylink

The above listed benefits have been used in other test applications, including Murraylink, and have been accepted by the ACCC. Quoting from the ACCC Decision in relation to the Murraylink application:

> "The Commission is of the view that there are 4 broad types of benefits that Murraylink and its alternatives can bring to the NEM. These are:
>
> - Energy benefits;
> - Deferred antry benefits;
> - Reliability benefits; and
> - Riverland deferral benefits.

> "The Commission considers that the methodology employes by MTC in the estimation of the market benefits of Murraylink and its alternative projects is not inconsistent with the principles set out in the regulatory test."

3.3 Characterisation of the Project / Alternative Projects

As the objective of the modelling is to determine the value of a particular project or alternative project, the accuracy of any assessment is particularly dependent on the characterization of the project or alternative projects in the modelling undertaken.

This is often not an easy task, as the asset in question may provide capacity that varies dynamically with a number of factors, such as regional demand, power flows on other transmission lines, etc.

Consequently, it is essential that any differences between the service level provided by the project and the representation of the project in the modelling be fully understood and transparent. It would be expected that any simplification would be based on capturing the performance level where most of the value would be expected.

For example, if a transmission line that was the subject of the test provided full capacity most of the time but was limited for some reason at times of high demand when its capacity would be most likely needed, then it would not be appropriate to ascribe full capacity to this transmission line all the time. The options might be to use a limited capacity that reflects availability at times of most value, or to dynamically model its capacity.

3.4 Scenario Development

In Section 5.1 of the ACCC Decision on Murraylink, the ACCC makes reference to the scenarios and sensitivities required. Quoting from that section:

> "In note 5 and 6, the regulatory test provides some guidance on the type of scenarios that need to be considered in a regulatory test assessment."

Note 5 of the regulatory test states:

> "In determining the *market benefit,* the analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project *commissioning* dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative *construction timetables* as nominated by the proponent. These scenarios should include projects undertaken to ensure that relevant reliability standards are met. These market development scenarios should include:
>
> (a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years *(committed projects)*;

> (b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years *(anticipated project*s);
>
> (c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant *(modelled project*s); and
>
> (d) any other projects identified during the consultation process."

The test recognises the uncertainty associated with key assumptions and future outcomes, particularly with market outcomes in terms of capital developments and future market behaviour, and requires that the economics of the project and alternative projects be examined under a variety of scenarios and sensitivities. The test also requires that appropriate sensitivity analysis be undertaken.

> "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;"

ACCC Decision on Murraylink

In Section 5.1 of the ACCC Decision on Murraylink, the ACCC make the following comments:

> "The role of sensitivity analysis is to test the variability of the gross market benefits to key assumptions. The role of market development scenarios is to capture the uncertainty which necessarily exists about the future of the electricity market, and to ensure that the project which passes the regulatory test is robust to different assumptions about the future development of the market."

The ACCC made no specific mention of the number of scenarios that would be required. The only conclusion that can be drawn from the Murraylink decision in relation to the scenarios modelling is that the modelling presented in that application was accepted by the ACCC.

3.5 Generator Bidding

The regulatory test states

> "The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price trends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes."

The assumptions around generator bidding are a critical factor impacting the results of the simulation modelling, because the nature of generator bidding determines the profile and average level of spot prices, which in turn determines:

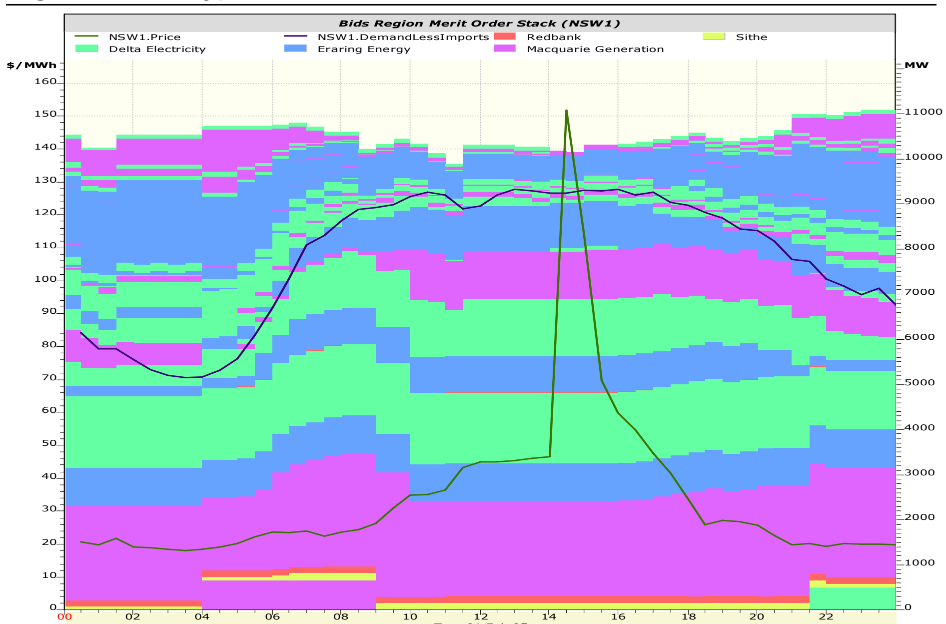
- The dispatch level of generators;
- The timing, location and type of new generators; and
- How the project would influence the above two outcomes.

The impact generator bidding can have on the economic assessment is recognised in the test by requiring that the modelling include various scenarios of generator bidding and that simulations be undertaken that reflect actual market bidding.

Realistic generator bidding profiles are particularly important, as the economic assessment of the proposed project and the alternative projects is determined by the pattern of generator bids 'on the margin'. This is very different from the average pattern of generator bids.

This is illustrated by Figure 1, which shows a 'merit order graph' for a typical day in NSW. In this figure, each colour represents a different NSW generator portfolio, with the merit order being developed based on generator bids. It is quite evident that generators 'interleave' their bids, and that on the margin, generator bids do not reflect a single merit order as would be determined through a merit order based on SRMCs.

Figure 1 Typical Profile of NSW Merit Order



The following generator bidding behaviours have often been used in market simulation modelling and have considered for use in modelling under the 1999 ACCC Regulatory Test:

- *Short Run Marginal Cost Bidding.* This assumes that each generator offers its capacity at short run marginal cost. Implicitly, this market behaviour assumes that there is perfect competition.
- *Bertrand Bidding* (or shadow bidding). This assumes that each generator bids close to the short run marginal cost of the next generator in the merit order. This results in generators maintaining their market share but increasing their revenue through increased spot prices. Inter-regional trading limits complicate the identification of the 'next' generator in the merit order.
- *Long Run Marginal Cost Bidding.* This assumes that generators bid in an attempt to recover their 'long-run' costs, based on replacing fixed assets plus variable costs. This can involve generators changing their bids on a regular basis so as not to under or over recover costs, which has the advantage of having the merit order change dynamically throughout a simulation. However, such bidding cannot be considered realistic, as it neither reflects the impact of competition nor the general shape of generator bid curves in the market.
- *Historical Bidding.* This assumes the current bidding pattern continues over the analysis period. Bidding by Generators is characterised into seasonal, day-type and peak-offpeak bidding patterns based on recorded bids. This has the weakness of being pre-defined, and as such does not incorporate the impact that changed market conditions, such as those brought about by the Project or Alternative Projects, may have on generator bidding behaviour. However such bidding does attempt to represent the profiles and the interleaving of generator bids that occurs in the market.

An advanced form of generator bidding and one that has not been used in ACCC test applications to date is to incorporate the impact of competition on generator bidding. This has been referred to as Dynamic bidding:

- *Dynamic Bidding.* This bidding is the most advanced of all the bidding scenarios presented. Here generator bids are automatically developed within the simulation in response to changing contract positions and market conditions. In this manner, the bids can be made to closely mirror the dynamic actually observed in the market.

ACCC Decision on Murraylink

The following extracts are taken from the ACCC Decision on Murraylink. The pertinent issues to the Directlink application are the reality of the LRMC scenario and the acceptance of this by the ACCC.

Section 4.5.4.2 - Submissions by other interested parties - Consistency with regulatory test application:

> "ESIPC suggests that a LRMC based bidding strategy to model the market creates far more rational results that reflect the true operation of the market. ESIPC highlights that MTC has purported to examine market development scenarios where the price is more reflective of current price outcomes, however this would appear to have been achieved by simply scaling the SRMC value for each generator. ESIPC submits that while this methodology will raise prices it does not resequence the generators into a merit order more consistent with the reality and effectively just maintains MTC's forecast level of benefits by scaling the entire market up."

Section 4.5.5 Commission's considerations:

> "While SRMC and LRMC modelling has been considered in Murraylink and other applications of the regulatory test, actual bidding under note 6b of the regulatory test has not been determined due to the difficulty of modelling such behaviour. As part of its review of the regulatory test and in particular the issue of competition benefits, the Commission is looking at this issue."

> "The Commission is therefore satisfied that SRMC, generation bids above SRMC and LRMC has been considered in the TEUS assessment of market benefits for Murraylink and its alternative projects."

Of note is that the ACCC did not comment on the realism of either bidding scenario or whether the bidding scenarios confirm with the ACCC Regulatory Test.

3.6 Economic Assessment

The regulatory test requires that the net present value (NPV) of the market benefits be determined. The NPV is the present value of the market benefits listed above, net of the project cost. The NPV calculations are based on annual savings in cash flow, with NPV given by the sum of:

- The present value of benefits accumulated during a forecast period, which has typically been a 10-year period; and
- The present value of benefits accumulated after the explicit forecast period.

Key issues here include the discount rate used and the treatment of market benefits post the forecast period.

Discount Rate

The regulatory test states:

> "(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector";

Terminal value

With projects having typical lives of 40 years and detailed simulation modelling usually limited to about 10 years, the methodology for incorporating the value of the project after year 10 is particularly important. This terminal value is also called the ‘residual’ or ‘continuing’ value.

When calculating the residual value, it is often assumed that the market benefits have reached a ‘steady state’ by year 10, and that an appropriate approach is to assume that the market benefits of year 10 or an average of the last 2 to 3 years continue into ‘perpetuity’.

This methodology can be problematical and care must be taken to confirm what benefits are likely to continue. For example, the deferral value determined during a period where an interconnection project is utilising surplus capacity to defer capacity (in an adjacent region) will decline as the surplus capacity reduces. While an interconnector project can provide significant perpetual deferral benefits this may not necessarily be the case, and consequently, any assumption that an interconnection project would provide perpetual capacity deferral benefits would need to be supported.

4 Overview of DJV Submission

The documents listed in Section 1.2 of this report form the basis of the review presented in this report. Based on that information, this chapter presents an overview of the approach used by DJV in the determination of the interregional market benefits of Directlink and the competing projects. The chapters that follow examine the key issues identified in more detail.

4.1 Basis of Economic Assessment

The overall methodology used by DJV follows that required by the 1999 ACCC Regulatory Test, this being to determine and compare the economics of Directlink with a number of competing projects that would provide a similar level of service. This was done using market simulation modelling over the 15 year period 2005 to 2019 to determine:

- How the market would develop without Directlink or any of the alternative (competing) projects;
- How the market would develop with Directlink but with none of the alternative projects; and
- How the market would develop with each one of the alternative projects.

For each of these cases, the following costs were obtained for each year of the market simulation:

- Energy costs - this is total dispatch cost (including the demand side);
- Market entry generation – the capacity of new generation that enters the market in response to economic prices;
- Reliability entry generation – the capacity of new generation that enters the market to ensure the reliability criteria is satisfied; and
- Unserved energy.

The annual net market benefit of Directlink and alternative projects were then determined by the difference in these costs between the relevant ‘with project’ and ‘without project’ cases. This gave the following annual interregional benefits for Directlink and alternative projects:

- Energy benefits - this is the change in dispatch costs (including the demand side);
- Deferred market entry generation – reduced capital and O&M costs from generation deferred due to changed spot prices;
- Deferred reliability entry generation – reduced capital and O&M costs from deferral of generation required to ensure the reliability criterion is satisfied; and

- Residual reliability benefits – reduced costs due to lower levels of unserved energy.

For the remaining period of the study, 2020 to 2044, the market benefits of each component were calculated by developing 5 patterns of benefits based on the benefits in the year 2014, then 2015 etc. The first of these assumed that post 2015 the annual benefits were those of 2015, the second assumed that post 2016 the annual benefits were those of 2016, the third assumed that post 2017 the annual benefits were those of 2017 and so on. The results for these cases were then averaged[4]. The reasoning for this is discussed in Chapter 11 of this report.

A review of the spreadsheet showed this to be implemented as described.

The final economic assessment of Directlink and the competing projects was calculated as the net present value (NPV) of the interregional market benefits plus transmission deferral benefits less project cost.

4.1.1 Terminology

The DJV application used terminology, which while clear and consistent, could potentially be confusing. For this reason it is clarified here.

The terminology used was that Directlink and all the competing projects were termed alternative projects:

- Directlink was Alternative Project 0;
- The 6 competing projects to Directlink were termed respectively Alternative Project 1, Alternative Project 2, Alternative Project 3 etc;
- Alternative Project 5 was where neither Directlink nor any of the competing alternative projects were assumed to enter the market. As this represented how the market would develop without Directlink or any of the (competing) alternative projects, it represented the no project or base case. This is the case from which the economics of Directlink and the alternative projects was calculated.

  By definition, the economics of Alternative Project 5 had an NPV of $0 (as it is being compared to itself).

For clarity, the naming convention used by DJV compared to that which has previously been used is shown in Table 1 below. This report primarily uses the traditional names as shown in this table.

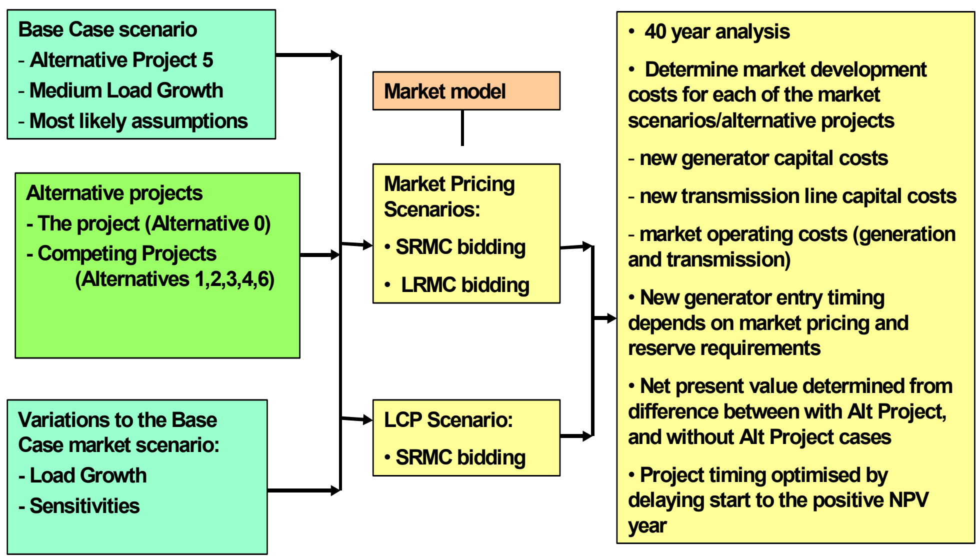
A diagrammatic overview of the approach is shown in Figure 2 below. Note that DJV assumed that the least cost planning scenario was identical to the SRMC bidding case.

[4] This is not equivalent to averaging the market benefits in the last 5 years of the simulation modelling period and assuming these benefits continue annually in the years post 2019.

Table 1 Naming Conventions

DJV Naming	Traditional Name	Asset
Alternative Project 0	Project Case	Directlink
Alternative Project 1 to 4,6	Alternative or Competing Projects	As described in the DJV reports
Alternative Project 5 or also referred to as the No Alternative Project (Appendix G)	No Project or Base Case	Grid augmentation in NSW and Qld

Figure 2 Overview of DJV Methodology



4.2 Competing Projects to Directlink

The DJV submission listed 6 alternative projects to Directlink. These were

- Alternative Project 1: DC link using HVDC Light technology;
- Alternative Project 2: DC link using conventional HVDC technology;
- Alternative Project 3: AC link using a power shifting transformer;
- Alternative Project 4: AC link using a conventional auto transformer;
- Alternative Project 5: State based AC augmentations in NSW and Queensland; and
- Alternative Project 6: Demand management and/or embedded generation.

The DJV submission reviewed these projects and discounted alternative projects 4 and 6 as not feasible, leaving as the competing projects to Directlink two DC link options and one AC link option. This conclusion has been confirmed by PB Associates in its review as reasonable.

PB Associates also confirmed that Alternative Project 5 is likely to proceed at some stage in the future, as these developments are needed to provide a long-term solution to transmission requirements in Northern NSW and the Gold Coast area in Queensland. The PB Associates report confirmed that Alternative Project 5 can be considered as the ’Reference Case‘ against which the market benefits of Directlink and the alternative projects can be compared.

4.3 Simulation Modelling

Consistent with the requirements of the ACCC Regulatory Test that specifies that the assessment of market benefits shall be determined through market simulation modelling, the DJV submission presented a description and results of market simulation modelling undertaken as part of the evaluation of interregional market benefits.

The modelling used two simulation models, namely PROSYM that is suited to market modelling and MARS that is suited to reliability modelling.

The PROSYM model was used to undertake the modelling that determined spot price outcomes, the consequent level of market driven new generation, and generator dispatch levels. This is referred to as the market modelling. The modelling used an interpretation of the notional (meaning average) interconnector limits contained in the 2003 NEMMCO Statement of Opportunities.

The MARS model was used to determine the level of regional reliability resulting from the level of generator capacity that outturns in the market modelling. If the level of regional reliability was less than the reliability standard of 0.002% level of unserved energy, then additional ‘reliability generation’ was added until the 0.002% level unserved energy was reached. The interconnector limits used in the MARS modelling were more detailed than those used in the PROSYM modelling, which were based on limits at peak demand times between a number of Queensland sub-regions.

Both methodological basis of models were suitable for the tasks used.

4.3.1 Modelling Issues

Issues to be considered here include:

- The validity of notional limits used in the PROSYM modelling;
- The use of different limits between two models;
- The level of total generation and corresponding regional reserve levels derived through the MARS modelling; and
- The appropriateness of the generator bidding scenarios used.

4.4 Value of VoLL

The ACCC discussed the issue of the appropriate level of VoLL to be used in the regulatory test.

Section 4.5.5:

> "The Commission is of the view that the current wording of the regulatory test does not specify a value of VoLL to be applied for the calculation of the gross market benefits. The Commission concurs with interested parties that the VoLL specified in the code is a wholesale market price cap and does not necessarily reflect the real or true value of lost load to end user customers, which may vary from customer type and location. Therefore, the Commission is of the view that where an appropriate value of customer reliability has been determined for a region or sub-region, it would be not inconsistent with the regulatory test to be used in the calculation of the estimated benefits to endusers from greater reliability. In the absence of an accurate value for the value of customer reliability, the VoLL specified in the code should be used. However, the Commission notes that for the purposes of sensitivity analysis, it is appropriate for different values of VoLL to be tested.
>
> For the purposes of the regulatory test assessment for Murraylink, MTC has assumed a value of $29,600/MWh. The Commission notes that this value is consistent with the Victorian composite value of customer reliability determined by a CRA study commissioned by VENCorp. Furthermore, the benefits that the Murraylink interconnector provides are mainly attributable to the South Australian region, and in particular the Riverland region, therefore the Commission must consider whether a value of $29,600/MWh (an average for the Victorian system) is appropriate to be used to determine the gross market benefits of Murraylink, which provides benefits to the Riverland region. While a value of $29,600/MWh may be appropriate for Victorian customers, the Commission does not have a view as to its appropriateness in the case of interconnector alternatives that are expected to service the South Australian region, and in particular the Riverland region. Therefore the Commission believes that it is not inconsistent with a regulatory test assessment for the value of VoLL to be based on the current market price cap and/or a level of VoLL based on an objectively identified measure."

Given the potential sensitivity of the value of VoLL to the modelling results and the ACCC decision reproduced above, the validity of using $29,600/MWh for the value of unserved energy needs to be considered.

It is noted that the $29,600/MWh was based on a study for Victoria, and so the assumed value may not be applicable to the reliability impacts associated with Directlink. In particular, the type of customers that would be impacted by Directlink (no large customers) would need to be considered in the value of unserved energy used.

However, it is considered that the $29,6000/MWh would be a fair estimate of the value of unserved energy for this study, and it was the most recent data available. Furthermore, the range of VoLL prices used ($10,000/MWh to

$29,600/MWh) was sufficient for the purposes of the sensitivity testing as required by the test.

4.5 Scenarios

The modelling undertaken to test the economics of Directlink and the alternative projects was based on the information contained in the 2003 NEMMCO Statement of Opportunities. With these assumptions different market scenarios were developed from the following factors:

- Load growth – Low, Medium and High;
- Generator bidding – SRMC and LRMC.

  LRMC bidding was developed by adding $20/MWh to the SRMC bid of each generator unit.
- Economic discount rate – 7%, 9%, 11% (these are per year)
- Value of Unserved Energy - $10,000/MWh and $29,500/MWh

Only changes to the load growth and generator bidding assumptions required re-simulation using PROSYM and then MARS. The DJV submission indicates that MARS modelling was required in all the load growth / generator bidding cases as the disposition of new entry derived through the PROSYM modelling was different in each.

Of the 6 possible combinations of generator bidding and load growth assumptions, 4 scenarios were presented, these being:

- LRMC / Medium Load Growth
- SRMC / Medium Load Growth
- LRMC / Low Load Growth
- LRMC / High Load Growth

The application of the 3 discount rates was undertaken through an economic spreadsheet while the sensitivity of the cost of unserved energy was determined by applying the value of unserved energy to the unserved energy levels determined in the 4 ‘base’ scenarios.

Particular matters to be considered here include:

- The number of scenarios undertaken;
- Appropriateness of LRMC bidding (including the derivation of LRMC values used).

4.6 Assumptions

The assumptions used in the modelling by DJV were obtained from the following documents:

- 2003 Statement of Opportunities (published by NEMMCO);
- 2003 Annual Interconnector Review (published by the Interregional Planning Committee); and
- SRMC and LRMC of generators in the NEM (ACIL Tasman Report) (published by NEMMCO and the IRPC in April 2003).

The key assumptions here are:

- Load growth;
- Planned new generator commissioning dates;
- Interregional transmission limits;
- SRMC of existing power stations;
- Fixed and variable costs of new entrant generators; and
- Transmission losses.

It is noted that there have been a number of significant changes since the 2003 Statement of Opportunities was published, in particular the commitment to proceed with the 750 MW Kogan Creek Power Station in Queensland.

4.7 NPV Economic Calculation

The overall economic calculation presented a standard discounted cash flow (DCF) approach.

The costs and benefits of the DCF were the relevant project cost, benefits arising from the deferral of transmission development to support the North NSW and Gold Cost areas, and benefits associated with increased interregional transfer capacity. The project costs and transmission deferral benefits have been addressed in stage 1 of the DJV submission review and are not part of this study.

The review of discount rates used was beyond the scope of the review. However, the discount rates used were consistent with IES expectations in this area.

The only issue of note is the absence of any explicit examination of project timing, as is required under the ACCC Regulatory Test. However, from the context of the study, which entailed transmission and interregional benefits, the optimal development year was clear.

5 Characterisation of the Alternative Projects

As the objective of the modelling was to determine the value of the service level provided by Directlink and the competing projects, the representation of the respective service levels in the modelling is a critical aspect of the modelling.

The commonality of the service levels provided by Alternative Projects 0, 1 and 2 (ie. Directlink and two other DC technologies) meant that these shared the same modelling. Alternative Project 3 (AC link) required separate modelling.

This chapter reviews the transmission constraints that exist between NSW and Queensland and how these translate into interconnection limits between NSW and Queensland. With this background, the service levels provided by Directlink (and the other DC Link alternative projects) and Alternative Project 3 at peak demand times is presented. This is followed by a review and comparison of the representation of the respective service levels used in the PROSYM market modelling and the MARS reliability modelling.

5.1 Overview of NSW – Queensland Transmission Constraints

Before embarking on presenting the detailed service levels provided by Directlink and the (competing) alternative projects, this section reviews the constraints that apply in order that the service levels presented can be properly understood.

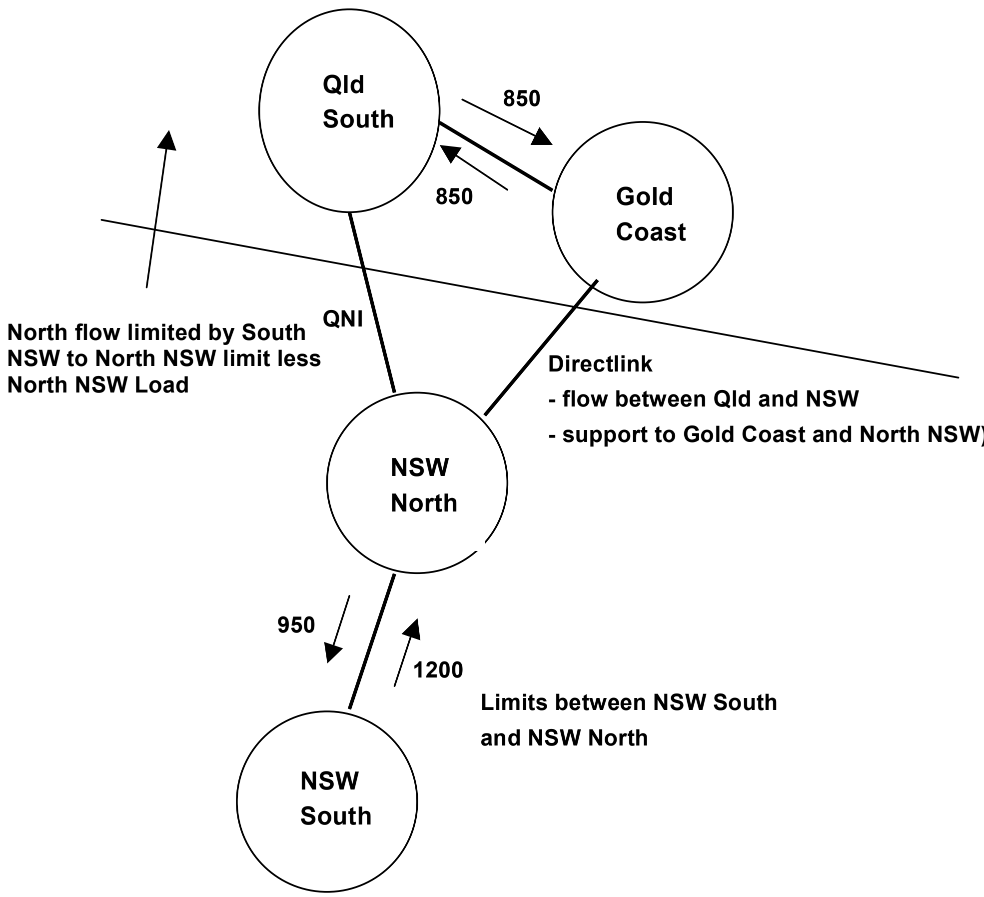
Figure 3 shows a diagrammatic view of the transmission arrangement between NSW and Queensland. The key issues are as follows:

- Four load regions – South Queensland, Gold Coast, North NSW and South NSW;
- The local regions Gold Coast and North NSW have supply constrained by constraints on connecting transmission;
- Directlink, which connects North NSW and the Gold Coast regions can provide support to these two regions;
- The southward flow limit Queensland to NSW is determined by flow limits on QNI and Directlink. The limit on the transmission between North NSW and South NSW does not bind for southward flow due to the large load in North NSW (which has the flow on the transmission North NSW to South NSW equal to the QNI + Directlink flow less the North NSW area load). The typical Queensland to NSW interconnection capacity is about 1000 MW; and
- The northward flow limit NSW to Queensland is determined by flow limits on the transmission between South NSW and North NSW. The reason for this is that for northward flow, the flow on QNI plus Directlink is the flow on the South NSW to North NSW transmission less the North NSW area load, which is always less than the capacity of QNI. The typical NSW to

> Queensland interconnection capacity is about 500 MW during average load conditions and about 300 MW during peak load conditions.

Figure 3 below shows that Directlink adds to the transfer capacity for southward flow but does not add to the transfer capacity for northward flow.

Figure 3 Transmission Network NSW - Queensland



5.2 Peak Demand Time Service Level Provided by Directlink

Appendix D of the DJV submission presents the report by Burns and Roe Worley "Directlink, Selection and Assessment of Alternative Projects to Support Conversion Application to ACCC" dated 22 September 2004. This report provided the service levels (and costs) of the alternative projects. The service levels were not disputed in an independent review undertaken by PB Associates for the ACCC.

The BRW report provided the transfer limits that would typically apply during peak load conditions. Reading from the BRW report Chapter 5 Page 49:

> " To assist TEUS to estimate the economic benefits of the alternative projects associated with deferring reliability entry generation plant and reducing unserved energy, BRW provided TEUS with transfer limits that would typically apply during peak load conditions."

This means that these are the limits that would be applicable to the assessment of generation levels required to ensure satisfactory reliability. These limits are given in tables 5.6(a) to 5.6(c) for the three load growth scenarios. They are also repeated in the Directlink Alternative Projects' Market Benefits – Supplementary Report dated 15 September 2004[5]. These limits are presented below for the 2006/07 year.

Table 2 BRW Report – Year 2006/07 - Comparison of No Alternative Project, Alternative Projects 0,1,2 and Alternative Project 3

Line and Limit Direction	Line name	No Alternative Project	Alternative Projects 0,1,2,	Alternative Project 3
NSW – North NSW		1200	1200	1200
North NSW - NSW		950	950	950
North NSW - GC	DL or other (north flow)	0	131	137
GC – North NSW	DL or other (south flow)	0	142	148
North NSW – South Qld	QNI (north flow)	300	300 – FF	300 – FF
South Qld – North NSW	QNI (south flow)	950	950	800
South Qld – GC		850	850	850
GC – South Qld		850	850	850
South Qld – North Qld		1750	1750	1750
North Qld – South Qld		1750	1750	1750

FF = flow from North NSW to GC (ie. flow on the alternative project)

The key factors for the no project case (Alternative Project 5), Directlink and the other DC alternative projects (Alternative Projects 0,1,2) and the AC option (Alternative Project 3) are described below. This discussion is supported by a diagrammatic representation of these limits.

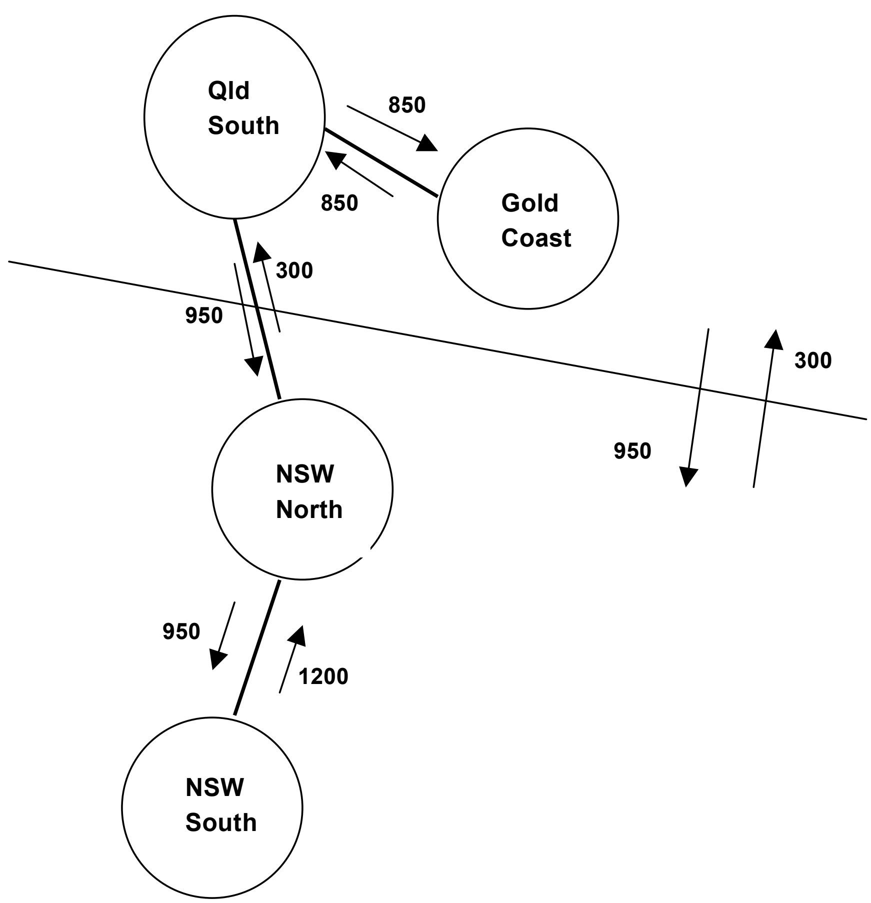
5.2.1 No Project (Alternative Project 5)

The (peak demand) limits for the no project case (ie. Alternative 5) are shown in the figure below. The key issues here are:

[5] These were not the same in 2005/06 for Alternative 3.

- The maximum flow (at times of high demand) from NSW to Queensland is 300 MW. While this is shown as associated with a capacity constraint on the North NSW to South Queensland line, the limit is actually associated with North NSW to South NSW line;
- For southward flows, the flow on the North NSW to South NSW line will be less than the net south flow QNI + Directlink. This is due to the substantial load in the North NSW area. This means that the North NSW to South NSW line will never constrain flow in the southerly direction.

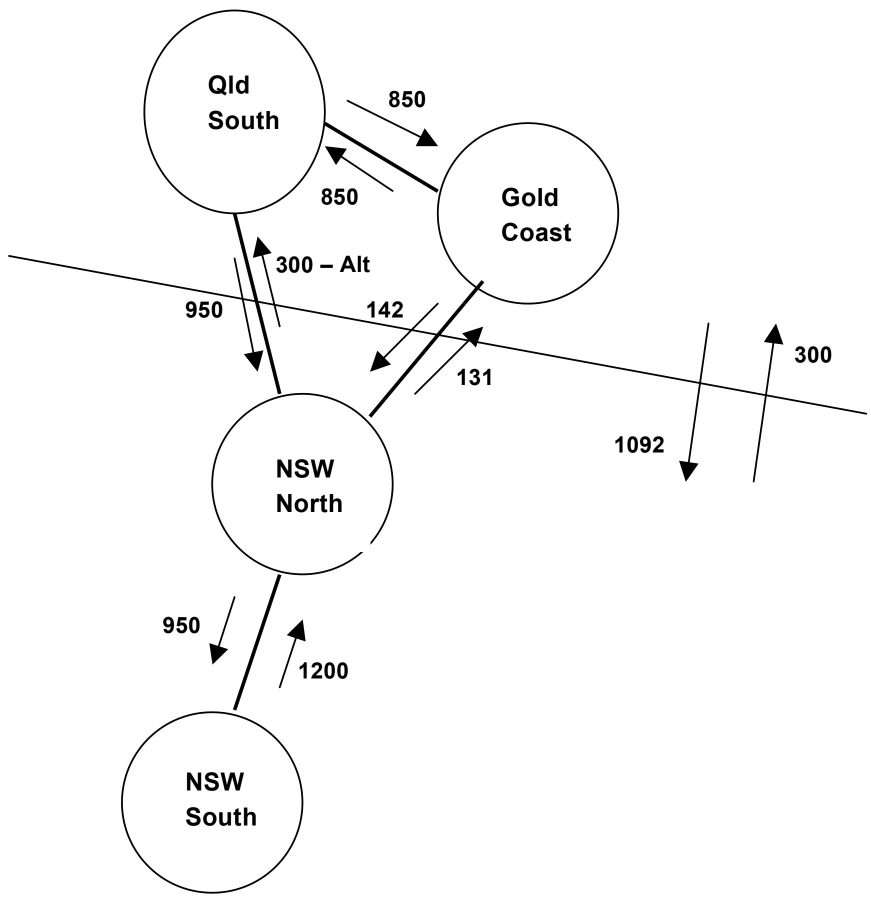
Figure 4 No Project (Alternative Project 5)



5.2.2 Alternative Projects 0,1,2

The (peak demand) limits for the Alternative 0,1,2 project cases are shown below.

Figure 5 Alternative Projects 0,1,2,



The DJV submission included the economics benefits of Directlink providing transmission support to Northern NSW and the Gold Coast areas (although not simultaneously), with the consequential benefits of deferring required transmission developments in these areas. This requires Directlink to be flowing power to the area being supported during the period support is being provided. This is termed pre-contingent power flow, as it is required in preparation for a potential contingency. Pre-contingent power flow is required as the technology for having Directlink respond after a contingency occurs was not included in the DJV submission.

Because Directlink requires pre-contingent flow associated with providing local area support, the NSW – Queensland interconnection limits need to be considered under 3 cases:

1. No pre-contingent flow on Directlink;

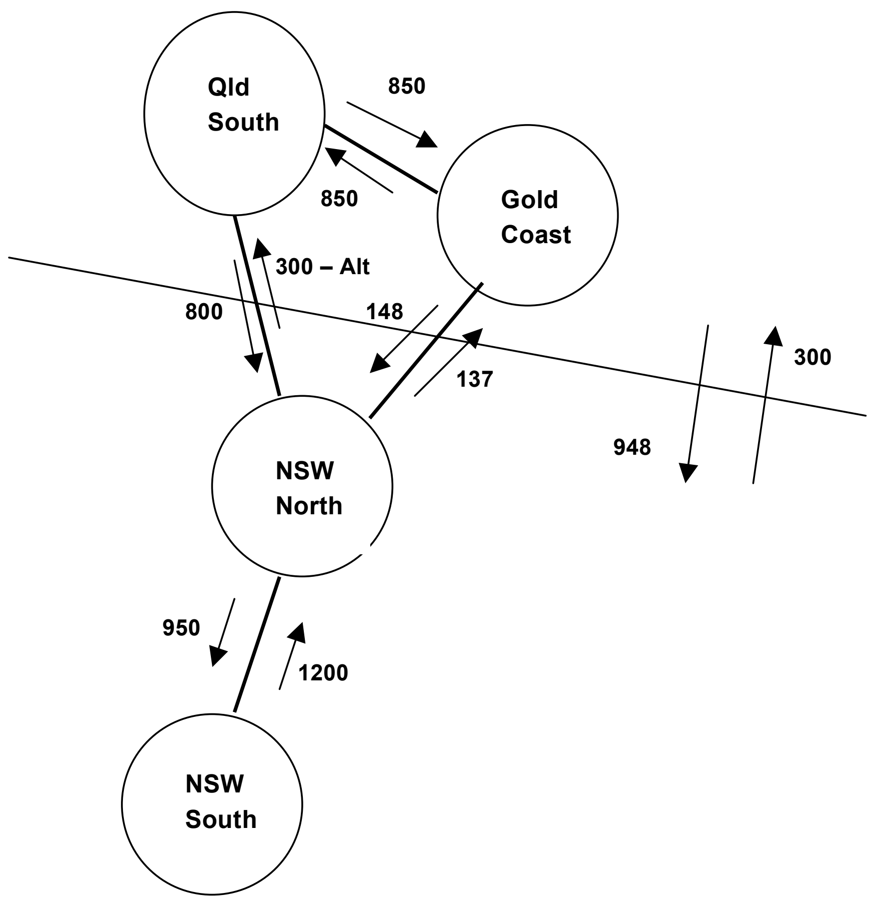
2. Pre-contingent north flow on Directlink to support GC; and
3. Pre-contingent south flow on Directlink to support north NSW.

Analysis showed that the requirement for pre-contingent flow did not impact the capability of Directlink to provide interregional benefits, based on a service level that did not enhance northward flow (ie. NSW to Queensland).

Thus the modelling assumption used by DJV that pre-contingent loading of Alternative Projects 0,1,2 would have no impact on the interregional benefits provided by these projects was considered valid.

5.2.3 Alternative Project 3

Figure 6 Alternative Project 3



Alternative Project 3 was the AC development option that contained a phase shifting transformer. This option had limited control over the flow on this AC link.

The limits associated with Alternative Project 3 are shown in Figure 6 above. Of note is that this alternative does not provide any increase in (peak demand) interregional capacity. This also applies at all other times.

The consequence of no increase in interregional transfer limits is that no increase in interregional reliability benefits would be expected from Alternative Project 3.

5.3 PROSYM Modelling

5.3.1 Alternative Projects 0,1,2

For the PROSYM market modelling, the current NEM regions were represented with interconnection limits based on the 'notional' interconnector limits contained in the 2003 NEMMCO SOO.

The rationale for this is explained in Appendix G, Chapter 3 - Calculation of Energy and Deferred Market Entry Generation Benefits, 3.1.3 Network Topology and Constraints, Page 13:

> " … does not provide a means of implementing dynamic constraints that change as a function of load or generation. Consequently, the detailed constraint equations have been represented within the PROSYM model with seasonal interface limits using information provided in the 2003 SOO. ….. TEUS has assumed the AC network will support power transfers over the various regional interfaces at the power transfer levels identified in the 2003 SOO. These are shown in Table 3.1."

Note: although this reads "the detailed constraint equations have been represented within the PROSYM model", this was clarified by DJV and it should have read "the detailed constraint equations have not been represented within the PROSYM model".

The limits as presented in the 2003 SOO and in Appendix G are shown in

Table 3 below. The 2003 SOO describes these limits as “notional inter-regional capacities”. The 2003 SOO also gives inter-regional capacities at high demand and identified interconnector capacity increases.

DJV used these notional interconnector limits in the PROSYM modelling as the capacity that is provided by QNI and Directlink for power flow between Queensland and NSW.

However, the notional limits as presented in the 2003 NEMMCO SOO were based on an arbitrary split in capacity between QNI and Directlink, and were not intended to be read as if Directlink provides increased transfer capacity for northward flows, as it does not. This means that using the limits in this manner would incorrectly depict Directlink as providing for **increased** transfer capacity for northward flow.

Table 3 “Notional” Limits presented in the 2003 SOO

Interface	Positive direction	Negative direction
Qld to NSW (QNI)	950	700
Qld to NSW (DL)	125	180
NSW to Snowy	1150 1150	2800 (summer) 3200 (winter)
Victoria to Snowy	1100	1900
Victoria to SA (Heywood)	460	300
Victoria to SA (Murraylink)	220	120

By assuming that Alternatives 0,1,2 provide an additional 180 MW transfer capacity for north flowing power (when there is no increase), the service level provided by these projects in the PROSYM modelling was overstated. This in turn would tend to overstate the change in market entry generation and generator dispatch benefits arising from the alternative projects. (Note that the generator dispatch benefits would be due to the average increase in transfer limit and not just that at peak time.)

Clarification Question to DJV

This issue was raised with DJV in a Question dated 25 October 2004. In summary this question asked whether not recognizing the limit between NSW South and NSW North was important to the PROSYM modelling. Its relevance is that this limit constrains northward power flows from NSW to Queensland, thus by excluding this limit the modelling would have incorporated an increase in northwards flow by the capacity of Directlink.

TUES responded in Question 1 – Response to IES Questions of October 25, 2004 dated January 18, 2005. The main points of the DJV response were based on two sets of analysis and findings.

The first was that an examination of the constraint equations that apply across the regional interfaces relevant to the PROSYM modelling, showed that using the simplified ‘notional limits’ for the purposes of estimating fuel costs and market entry has little or no impact on the estimates of interregional benefits. Quoting from Question 1 of the TEUS response:

> “In our supplementary report of September 15, 2004, “Directlink Alternative Projects’ Market Benefits - Supplementary Report”, we provided revised modelling results which recognised, among other things, more precise limits for our MARS modelling. On September 28, 2004, we provided the our findings of our examination of the constraint equations that apply across the regional interfaces relevant to our PROSYM modelling and we concluded that the modelling simplification of using “notional limits” for the purposes of estimating changes in annual fuel costs and market entry between With and Without cases has had little or no impact on its estimates of inter-regional market benefits.”

This was followed by PROSYM modelling with this limit included in the Alternative 0-1-2 Medium Growth LRMC Bidding case. This was reported as showing only minor differences to the timing and location of market entry combustion turbines, with the DJV conclusion that the original results are robust. Quoting from Question 3 of the TEUS response:

> "The PROSYM resimulation for Alt-0-1-2 Medium Growth LRMC Bidding case showed that the timing and location of market entry combustion turbines changed a small amount. This is to be expected. As described above, the revised topology will have little impact during low and moderate load conditions when peaking units would not be running in any event. By altering flows and prices during high load periods, the conditions that drive peaking unit market entry are altered, and the entry schedule changes in response. Compared to baseload coal units, the combustion turbine market entry units have much lower capital costs, higher marginal costs, and low capacity factors. As a result, the interregional market benefits are not greatly sensitive to changes in the peaking unit entry schedule. Furthermore, the MARS reliability analysis tends to compensate for lower peaker entry by adding additional reliability entry peaking units to ensure the 0.002% USE criteria is met. Similarly, higher market entry of peaking capacity results in a lower reliability need."

However, the responses by TEUS were not supported by analysis details that demonstrate the reasons why the incorrect assumption regarding the increase in NSW to Queensland interconnection capacity provided by Alternative projects 0,1,2 would only have a small impact on the modelling results.

5.3.2 Alternative Project 3

Although not stated, the PROSYM modelling presented in the April 2004 and September 2004 reports assumed that Alternative 3 used the same limits as Alternatives 0,1,2, as Alternative 3 had the same merchant entry capital deferral and avoided merchant entry O&M as Alternative 0,1,2.

This was corrected in a response by TEUS in Question 3 – Response to IES Questions of October 25, 2004 dated January 18, 2005. Here TEUS said:

> "TEUS confirms that, for its original analysis and supplementary report, the same interregional limits were used in PROSYM for Alternative 3 as were used for Alternatives-0-1-2.
>
> BRW has since advised TEUS that Alternative 3 effectively provides no increase in interregional transfer capability. When Alternative 3 is reevaluated assuming this, the energy and deferred market entry benefits become zero.
>
> TEUS has reestimated the reliability benefits of Alternative 3 (associated with deferring reliability-entry and reducing expected unserved energy) using the MARS model, and a market entry schedule for Alternative 3 identical to the market entry schedule developed with PROSYM for the Without case. As shown in the table below, in some scenarios Alternative 3 does still provide a small positive reliability benefit (primarily the LRMC Medium Growth scenarios), and in others the reliability

benefits are slightly negative. Averaged over all the Alternative 3 scenarios, the reliability benefits are close to zero."

Note: TEUS presented a table of Alternative 3 Interregional Market Benefits which is not shown here

"Alternative 3 is able to provide small reliability benefits in some of the scenarios, even if the total NSW to QLD transfer capability is not increased, because it provides an additional flow path between northern NSW and the Gold Coast. Under certain patterns of load and generator outages, this additional flow path may allow available generation to reach load that would be unserved in the Without topology. However, the MARS analysis showed these circumstances to be relatively rare, as reflected in the "close to zero" Alternative 3 reliability benefits shown above."

5.4 MARS

Setting aside the question of having different limits in the PROSYM and MARS modelling, the MARS modelling used limits appropriate to reliability assessment. These limits were those presented by BRW and as described in the above section.

6 Assumptions Used

This chapter reviews the assumptions used, their robustness and how these have changed since the time of the initial application.

The key assumption to the test and the ones reviewed here are:

- Committed generator capacity;
- Load growth;
- New entry generation costs.

6.1 Committed Generation

Generator developments assumed committed in the DJV modelling are shown in Table 4.

Table 4 DJV Modelling - Committed New Generator Capacity

Plant	Region	Capacity - MW	In service Date
Callide A1 – re-powering	Queensland	30	3/1//2005
Callide A2 – re-powering	Queensland	30	3/1//2005
Callide A3 – re-powering	Queensland	30	3/1//2005
Callide A4 – re-powering	Queensland	30	3/1//2005
Townsville Gas Turbine – re-powering	Queensland	Increase from 160 to 223	3/1/2005
Port Lincoln 2	South Australia	40	3/1/2007

The assumptions used are consistent with the information contained in the 2003 NEMMCO SOO with the exception of Port Lincoln increasing its capacity by 2 MW in 2007 (which would have a negligible impact).

Since that time, the 2004 NEMMCO SOO notes changes since the 2003 SOO. The key change noted is Kogan Creek Power Station, which has 750 MW committed by the summer of 2007/08. This would have a significant impact on market outcomes.

Further, there are a number of other publicly announced and advanced projects for new generation capacity in the NEM. The significant projects here are:

- Wambo Power Ventures Pty Ltd – 3 x 150 MW OCGT plant at Braemar in Queensland. This plant was indicated as advanced and publicly announced in the 2004 NEMMCO SOO.
- Texas Utilities – 400 MW gas-fired power station at Tallawarra in NSW. This plant was indicated as advanced and publicly announced in the 2004 NEMMCO SOO.

- Origin – Expand the existing Quarantine Power Station to 170 (conversion from 96 MW OCGT to 170 MW CCGT). This plant was indicated as advanced and publicly announced in the 2004 NEMMCO SOO.
- Snowy Hydro has announced the development of a 2 x 156 MW OCGT plant at Laverton in Victoria. While this plant was not noted in the 2004 NEMMCO SOO, it is noted in the 2004 Statement of Opportunities Update dated 31 January 2005.
- Delta Electricity – Increase in the summer rating of Vales Point Power Station from 1100 MW to 1320 MW. While this upgrade plant was not noted in the 2004 NEMMCO SOO, it is noted in the 2004 Statement of Opportunities Update dated 31 January 2005.

The total quantum of these projects would have a very significant impact on any assessment of NSW – Queensland interconnector economics.

6.2 Load Growth and Change in Demand/Supply Balance

The loads used in the DJV modelling are those contained in the 2003 NEMMCO SOO. While these were the most up to date projections at the time the modelling was undertaken, these have been revised in the 2004 SOO. The projections of maximum demand contained in the 2004 SOO and their increase compared to those contained in the 2003 SOO is presented in the table below. This is done for the Medium Load Growth 50% Probability of Exceedence (POE) demands.

Table 5 Increase in Maximum Demand Projections – 2004 Compared to 2003

Regional Maximum Demand Projections Summer Medium 50% POE Generator-terminal basis (MW)	Qld		NSW		Vic		SA		Tas		NEM-wide	
	Projection	Increase	Projection	Increase	Projection	Increase	Projection	Increase	Projection	Increase	Projection	Increase
2001/02 actual	7002		10990		7618		2506		1398		26321	
2002/03 actual	7082	80	12456	1466	8202	584	2788	282	1367	-31	28579	2258
2003/04 actual	7912	830	12216	-240	8572	370	2604	-184	1341	-26	29775	1196
2004/05	8187	275	12660	444	8997	425	3026	422	1457	116	31226	1451
2005/06	8587	400	13080	420	9274	277	3111	85	1488	31	33764	2538
2006/07	8847	260	13480	400	9509	235	3199	88	1504	16	34712	948
2007/08	9116	269	13770	290	9725	216	3296	97	1521	17	35556	844
2008/09	9411	295	14140	370	9981	256	3380	84	1547	26	36535	979
2009/10	9656	245	14550	410	10262	281	3472	92	1596	49	37560	1025
2010/11	9898	242	15010	460	10542	280	3567	95	1619	23	38603	1043
2011/12	10146	248	15470	460	10764	222	3659	92	1649	30	39603	1000
2012/13	10397	251	15930	460	10999	235	3750	91	1669	20	40608	1005
2013/14	10639	242	16370	440	11246	247	3852	102	1687	18	41604	996
2014/15					11553							

Of particular note is that the Queensland maximum demand projections have increased by about 260 MW and the NSW maximum demand projections have increased by over 400 MW over the period of the projections. By itself this would have the effect of reducing the surplus capacity in Queensland available to supply NSW (thus decreasing the interregional benefits that Directlink and the alternative projects can provide to NSW) and of moving forward the need for capacity support from Queensland.

However, to assess the impact of changed assumptions on market benefits, one needs to consider the changes to both demand and supply, as given through the noted changes to committed generation and demand.

The significant change to committed generation was noted as the 750 MW Kogan Creek Power Station. A number of other advanced projects in Queensland and NSW/Victoria were also noted.

Assuming only Kogan Creek is committed, the net change in the demand and supply balance is likely to be an increase in capacity surplus in Queensland, providing additional surplus capacity to support NSW. Depending on the situation in NSW, this would be expected to provide additional reliability benefits to Directlink.

It is noted that additional sensitivities and more detailed analysis of the proposed new generation would be required before firm conclusions can be drawn in this regard.

6.3 New Entry Generation Costs

As previously mentioned, new entry costs are a critical assumption, as these impact directly on the determination of generator capacity deferral benefits. The key assumptions here are those that are used to determine the annualized cost of the fixed costs associated with a generator unit, these being:

- Capital cost of construction;
- Fixed O&M costs;
- Project life over which the annualized cost is determined; and
- Weighted average cost of capital (WACC).

The TEUS submission report stated that new entry costs were assumed to be those contain in the ACIL Tasman report but it did not contain any details of the approach used to move from capital costs to annualized costs. TEUS provided an explanation of the approach they used to move from capital costs to annualized costs in their response to a follow-up question on this issue. The relevant response (Question 7 Response to IES Questions on Directlink's Inter-regional Market Benefits) is replicated below.

> "Merchant entry generator costs were developed from information in the ACIL Tasman report on long run marginal costs. As the report did not provide annualized costs, and also did not provide recommended assumptions for WACC, etc., TEUS used the annualized costs previously published in the IRPC Stage 1 Report for the SNI evaluation, adjusted for the new unit sizes and fixed O&M estimates, and escalated to January 1, 2005. The calculation for each generator type is shown below:

		CCGT	OCGT	QLD Coal	NSW Coal	VIC Coal
Orig Size	MW	180	50	450	450	500
Capital Cost	$/KW	1031.00	500.00	1200.00	1200.00	1500.00
FOM	$/KW-Yr	10.31	5.00	12.00	12.00	15.00
Annualized Cost	$/KW-Yr	165.00	80.00	192.00	192.00	240.00
Annualized Capital Cost	$/KW-Yr	154.69	75.00	180.00	180.00	225.00
New Size	MW	385.00	100.00	450.00	500.00	500.00
New Capital Cost	$/KW	1000.00	500.00	1400.00	1400.00	1800.00
New FOM	$m/Yr	14.00	1.00	20.00	21.00	25.00
New FOM	$/KW-Yr	36.36	10.00	44.44	42.00	50.00
Ratiod Annualized Cap Cost	$/KW-Yr	150.04	75.00	210.00	210.00	270.00
Total Annualized Cost	$/KW-Yr	186.40	85.00	254.44	252.00	320.00
Inflation to Jan. 1, 2005		1.0778	1.0778	1.0778	1.0778	1.0778
Annualized Cost	$/KW-Yr	**200.90**	**91.61**	**274.24**	**271.61**	**344.90**

TEUS notes that the fixed O&M costs for some generator types have changed significantly from estimates used in the SNI evaluation. The ACIL Tasman report does not address the newer estimates were developed or explain the reason for any change."

There are three key issues to be considered in relation to the new entry costs used by TEUS. These are as follows:

- The level of assumed fixed costs;
- The validity of implied assumptions that must be made in order to translate the fixed capital cost to an annualised cost; and
- The 1.0778 escalation assumed to produce 2005 real prices.

Many views are expressed in the market over the fixed costs of new entry generators, and the ACIL reported figures should be seen as such. Sensitivity analysis should be used to address the uncertainty associated with the development of these numbers.

In relation to deriving annualized costs the following observations are made:

- Firstly, from this response it is evident that TEUS has taken the ratio of the fixed capital costs and annualized capital cost from the "IRPC Stage 1 Report Final Proposed SNI Interconnector" dated August 2001, and applied this ratio to the ACIL Tasman capital costs. A review of the required WACC over an assumed project lifetime of 30 years to obtain the annualized cost shown from the assumed capital cost, indicated this to be in excess of the level that would be expected. No justification is given for the implied use of a WACC that could result in increased annual capacity costs.

- Secondly, the assumption of full CPI increase in costs from the date of the ACIL Tasman report (April 2003) to 2005 has not been justified, and takes no account of recent assessments of new entry costs. To IES's knowledge, $1000/kW plus $36/kW.year for fixed operations for a CCGT plant would also be considered a high cost estimate in the current market.

An important consideration from the new entry prices discussed is the average spot price at which such new entrants would become economic. From the new entrant costs provided, the NSW and Queensland coal units would need a dispatch weighted price of about $40/MWh to be economic[6], on the assumption that these would be operated in a predominately base load role. Given that these units would operate as base load units, the average spot price at which these units would become economic is in the order of $40/MWh or slightly over.

It would be expected that the modelling would show average time weighted spot prices in the order of $40/MWh. The fact that this was not the case is discussed in later chapters of this report.

[6] The annualised capital cost translates to an energy cost of about $31/MWh. Adding the SRMC of about $9/MWh gives the dispatch weighted price of $40/MWh.

7 Market Modelling

The overall approach to simulation modelling was as follows. The PROSYM model was used to undertake the modelling that determined spot price outcomes and market driven new generation, and generator dispatch levels. This is referred to as the market modelling. The MARS model was used to determine the level of regional reliability resulting from the level of generator capacity that outturns in the market modelling. If the level of regional reliability is less than the 0.002% level of unserved energy, additional 'reliability generation' is added until the 0.002% level unserved energy is reached.

Noting the limitation of PROSYM in relation to modelling reliability, IES considers the approach adopted by TEUS as appropriate. This is supported by the limitation that NEMMCO attaches to the 'NEMMCO calculator', which states that the calculator has not been designed for use that involves changing transmission transfer capacities.

Having addressed issues associated with the assumptions used (in Chapter 5 of this report), the issues relevant to a review of the modelling undertaken include:

- The suitability of the project service level representation used;
- Representation of generator bidding;
- The dynamics of new generator entry;
- The relationship between the PROSYM and MARS modelling;
- Treatment of losses.

These are considered in turn below.

7.1 Project Service Level

The service levels used for Directlink and the alternative projects were described in Chapter 4, and issues were noted in relation to the service levels used in the PROSYM modelling.

The issue was that the PROSYM modelling used notional limits that did not recognise:

- The manner the NSW to Queensland limit varies through the day; and
- The impact Directlink and the alternative projects have on this limit.

For the NSW to Queensland limit, Table 6 shows a comparison of this limit for average and peak demand conditions and how this limit is impacted by Directlink. It is also noted that the peak demand limit on Directlink from North NSW to the Gold Coast is 131 MW in the year of this example.

The comparison clearly shows that the modelling has significant differences in this limit, particularly at peak demand times, and also that the modelling has significantly overstated the service provided by Directlink. In particular, the PROSYM modelling has assumed that Alternative Projects 0,1,2:

- Increase the interregional transfer limit from NSW to Queensland when this is not the case. This would impact the pattern of market driven generation as well as having the modelling overstate the energy saving benefits;
- Flows power freely with no pre-contingent power flow constraints associated with providing local area support. This would also have the modelling overstate the energy saving benefits in the year that support is provided.

This raises serious doubts about the validity of the market impacts of Directlink obtained through the PROSYM modelling.

Table 6 NSW to Queensland Interconnection Limit - Comparison of Actual Limits and that used in PROSYM (MW)

	Average Demand Conditions (MW)	**Peak Demand Conditions (MW)**
Without Directlink		
Actual	500	300
PROSYM	700	700
With Directlink		
Actual	500	300
PROSYM	880	880
Difference		
Actual	0	0
PROSYM	180	180

7.2 Representation of Generator Bidding

The 1999 ACCC Regulatory Test states that

> “The forecast of spot price trnds should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those likely to occur under actual system and market conditions”

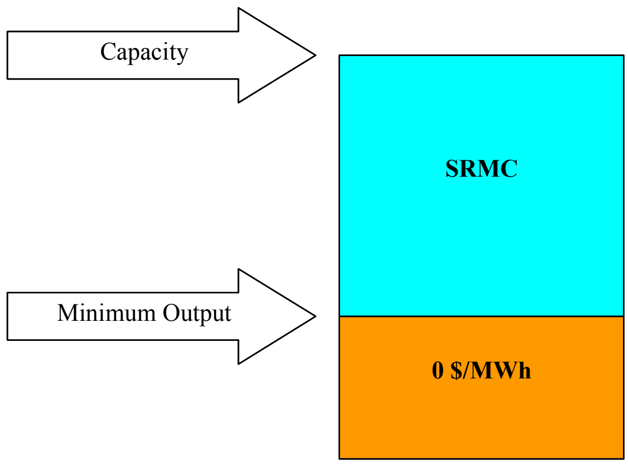
Two generator bidding scenarios were used, namely SRMC and LRMC bidding. Each of these is considered in turn below.

7.2.1 SRMC Generator Bidding

The test requires a scenario that uses SRMC generator bidding. The approach to this that would normally be applied is to have generators bid all of their capacity at SRMC while recognizing the constraints of minimum generation levels. This is shown in the figure below.

It is understood that the TEUS modelling had generators bid their minimum generation levels at $0/MWh and the rest of their capacity at SRMC. This is consistent with expectation.

Figure 7 SRMC Generator Bidding



7.2.2 LRMC Generator Bidding

As noted above, the 1999 ACCC test requires modelling scenario(s) that entails generator bidding that approximates actual market bidding. TEUS used LRMC bidding as the alternative to SRMC bidding.

Overview of LRMC Bidding

LRMC bidding is generally defined as having generators bid their capacity above minimum output at LRMC. Given that LRMC expressed in $/MWh is dependent on the capacity factor of operation, LRMC for each generator needs to be determined on the basis of the expected capacity factor of operation. However, given the uncertainty in the capacity factor of generator operation, such modelling is best implemented by having generators change their bids on a regular basis through a simulation in response to their changing LRMC ($/MWh). The modelling used can also recognise contract levels by having generators bid this level at SRMC. With all generators assumed to bid in this cooperative manner, generators should recover their LRMCs. This is shown in the figure below.

LRMC has no pretence of being realistic as it does not include any of the competitive tensions that exist in the market, nor does it recognise the 'opportunity cost' of generation. Also, this form of bidding may not convey the general shape of the bid curves as seen in the market. However, compared to SRMC bidding, LRMC bidding is possibly more realistic over a 10 year study period, as the higher level of resulting prices is more in line with that required to economically sustain generation, and the merit order can change in line with generators bidding changes.

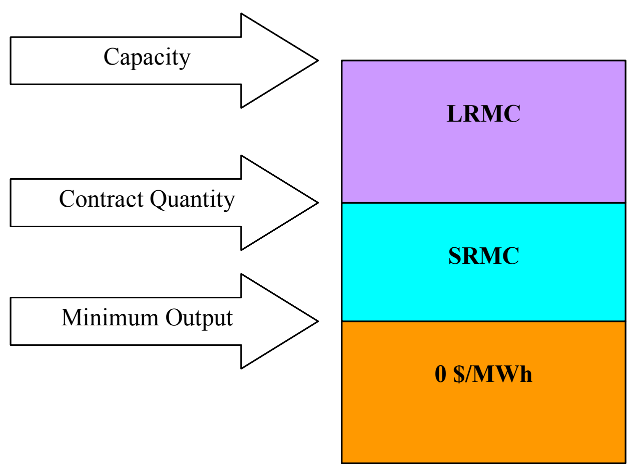
LRMC Bidding Used by TEUS

It is understood that the TEUS LRMC bidding scenario had generators bid their minimum generation levels at $0/MWh and the rest of their capacity at LRMC calculated as follows:

- For new entrants, using the new entrant calculated LRMC;
- For existing generators, calculating LRMC as the corresponding SRMC plus $20/MWh. TEUS recognised the $20/MWh method as a proxy given that it did not have the LRMC information of existing power stations.

TEUS made no comment on the realism of this bidding scenario in Appendix G, only stating that "This produced market prices sufficiently high to attract coal entry within the first 5 years of the analysis".

Figure 8 LRMC Bidding



In a follow-up question (Question 16 Response to IES Questions on Directlink's Inter-regional Market benefits) about the realism of the SRMC and LRMC bidding scenarios and the fact that the merit offers in the SRMC and LRMC bidding applied would be substantially the same, DJV replied as follows:

> "TEUS does not consider either the SRMC or LRMC bidding to be bidding strategies to be individually realistic, and does not understand that the Regulatory Test requires a proponent to construct their own view of "realistic bidding". Rather, TEUS believes these two bidding strategies produce results that likely bracket the results that would

> be produced by actual or realistic bidding behaviour, if it were possible to determine the true future bidding strategies of NEM generators."
>
> "IES has observed that the TEUS approach will not change the generator dispatch merit order. This was by design. TEUS believes any assumptions it made regarding which types of generators would adopt which approach to recovering their long run marginal costs would have been seen as arbitrary and potentially biased. Furthermore, TEUS believes that the discipline of a competitive market would restrain generators from deviating too much or too long from the dispatch order imposed by SRMC."

Observations

The "likely bracket of results" mentioned by TEUS is understood to mean bounds on the benefits that the projects modelled would receive. This may be the case, as it would be expected that the SRMC case would give low benefits and the LRMC case considerably higher benefits. The higher benefits of the LRMC case would be due to the increased amount of new generator entry that results from higher spot prices and generators bidding all capacity (above minimum generation levels) well above SRMC.

However, given that the LRMC bidding scenario is not representative of a realistic scenario, no conclusions could be drawn from such a scenario in relation to the performance of the projects under realistic market outcomes or the likely benefits that would be achieved.

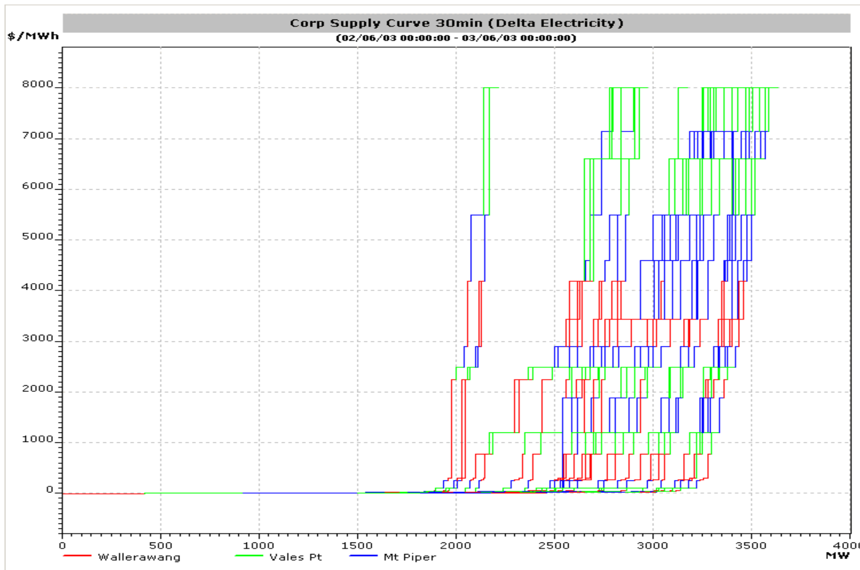
This conclusion is based on the following observations in relation to the LRMC bidding approach used by TEUS:

- The type of new entry plant that enters the market depends as much on the distribution of prices (ie. volatility) as on average price levels. Realistic price volatility can only be obtained in the modelling with generator bid shapes that represent those observed in the market. This is bidding at near SRMC to contract levels and then with quickly increasing bid prices. An example of the typical bid curve over a day (ie. 48 bid curves) is shown in the Figure 9 below. The TEUS modelling did not incorporate this characteristic.
- The $20/MWh added on to the SRMC is greater than the annualized fixed cost of many generator unit types, such as Queensland coal units. This means that the level of prices will be such that excess new generator entry[7] is likely to occur. This has the potential to significantly increase the sensitivity of generator capacity deferral due to increased interconnection.
- The saving in energy costs (ie. dispatch costs) due to increased interconnection depends not on the average merit order in the market, but on

[7] This can be understood as follows. New generators will enter the market when they can recover their fixed plus variable costs. The average price needed by a generator for its energy produced to be economic depends on the capacity factor it operates at. The higher the capacity factor the lower the average $/MWh needed as the fixed costs are absorbed by a larger quantity of energy. And vice versa.
If all generators were to increase their bids by a significant amount, then it would be economic for more generators to enter the market, and equilibrium would be reached at a higher average price level but with generators operating at lower capacity factors.

the merit order 'on the margin'. On the margin, the dispatch merit order can be significantly different and show greater variation than the dispatch merit order for the total market. The TEUS modelling did not incorporate or investigate this characteristic.

Figure 9 Example of Actual Generator Bids



ACCC Decision on Murraylink

In relation to the LRMC bidding scenario used by TEUS, and which was very similar to that used in the Murraylink application, the following are noted in relation to the ACCC decision on Murraylink:

- A submission had been made in relation to the LRMC bidding scenario being developed by simply scaling the SRMC bids, and that this did not result in a changed merit order;
- The ACCC determined that the SRMC and LRMC bidding scenarios were not realistic;
- No other bidding scenarios were required as the ACCC accepted that the range of benefits had been determined.

Final Comment

While none of the bidding scenarios undertaken can be said to be indicative of actual bidding (as specified in the test), the key issue is the confidence that the market benefits determined are suitable for the purpose being used. This requires consideration of the actual modelling results obtained, which is addressed in the following chapters.

7.3 Relationship between the PROSYM and MARS Modelling

As two models were being used to determine the manner the market would develop in total, there is an issue of the inherent connection between these studies. This was also the case in previous ACCC test modelling, where a generation reserve analysis was used instead of the MARS model[8].

There was a close connection between the market modelling (PROSYM) and reliability modelling (MARS) not present in previous modelling of this sort. The connection was the calculation of interconnector losses. Appendix G describes how the interconnector losses calculated in the PROSYM modelling was used in the MARS modelling, to overcome the absence of a quadratic loss calculation capability in the MARS model.

However, there appears to be an issue with using PROSYM determined losses in the MARS modelling, as the market conditions and interconnector power flows would be quite different on an hour by hour basis between the PROSYM and MARS model simulations. While the actual method used is not fully understood, any error here may not be significant.

[8] An example of this is the report on the economic evaluation of the proposed SNI interconnector by ROAM Consulting published on 19th September 2001.

8 Reliability Modelling

The 1999 ACCC Regulatory Test states that:

> "These scenarios should include projects undertaken to ensure that the relevant reliability standards are met"

This chapter overviews the approach used by TEUS in the reliability modelling, which involved the modelling undertaken using the MARS model. In particular, it considers whether the approach used by TEUS is consistent with the ACCC Test and whether the modelling undertaken was robust.

8.1 Validity of Approach Used

The approach to determining reliability benefits was slightly different from that used in previous regulatory tests and that used in the ACCC test application to Murraylink:

- ACCC test applications prior to Murraylink had used the NEMMCO reserve criteria to determine any required reliability generation, with any residual unserved energy valued at VoLL. Given that installing reliability generation to satisfy the NEMMCO reserve criteria resulted in very low levels of residual unserved energy, the results were quite insensitive to the value of VoL ;
- The Murraylink application had not installed reliability generation to satisfy reliability criteria, but simply valued all unserved energy at VoLL. In this case the study results were very sensitive to the value of VoLL;
- The Directlink application used the 0.002% unserved criteria to determine the amount of reliability generation required, with any residual unserved energy valued at VoLL. In this case the level of unserved energy was about 0.002% of total demand. The sensitivity of results to the value of VoLL lies between the two approaches listed above[9].

As previously mentioned, IES considers the approach used by DJV as an appropriate approach, as this satisfies the regulatory test in having plant enter the market to satisfy reliability criteria, as well as addresses the plant needed for reliability in the absence of a NEMMCO supported alternative.

ACCC Decision on Murraylink

Section 4.5 of the Murraylink decision:

> "The regulatory test does not provide a prescriptive means of calculating reliability benefits, although the issue of whether the regulatory test needs to be prescriptive is being considered by the Commission as part of the review of the regulatory test. The regulatory test currently states in regard to the calculation of market benefits for the purposes of reliability that:

[9] Valued at $10,000/MW, 0.002% of unserved energy equates to over $300M across the NEM.

"(1) In determining the market benefits, 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;

(5) In determining the market benefits, the analysis should include modelling a range of reasonable alternative market development scenarios….These scenarios should include projects undertaken to ensure that relevant reliability standards are met."

While the Commission prefers the approach adopted by NEMMCO for the determination of reliability benefits, the Commission considers that the approach of NEMMCO, VENCorp and MTC are not inconsistent with the current wording of the regulatory test."

Thus the conclusion of the ACCC is that the various approaches are within the words of the regulatory test (despite the ACCC test wording "these scenarios should include projects undertaken to ensure that relevant reliability standards are met.").

8.2 NEMMCO Requirements

Given the approach selected by TEUS and its suitability, a number of questions were put to NEMMCO to understand the robustness of modelling that would be required in assessing reliability issues. The key questions and responses from NEMMCO (28 July 2004) are presented below.

Question

Will NEMMCO continue to require (for reliability reasons) that minimum regional reserves levels be maintained?

NEMMCO Response

"Yes, for the time being. The minimum reserve level approach is compatible with other NEMMCO market systems such as MT PASA. The approach of translating the result of extensive probabilistic studies into an operational threshold is commonly used internationally. Note that NEMMCO no longer uses the largest single generating unit as a criterion to set minimum reserve levels. This is discussed in the report on the Queensland and New South Wales minimum reserve levels as published on the NEMMCO website [http://www.nemmco.com.au/operating/systemops/240-0008.htm]."

Question

Would an approach that directly modelled regional unserved energy as a method for determining regional capacity requirements be considered satisfactory?

NEMMCO Response

"Probabilistic analysis is used to establish the regional capacity requirement necessary to deliver unserved energy consistent with that required by the reliability standard. A minimum reserve level is used as an operational threshold to reflect the

> regional capacity requirements identified in the wide-ranging probabilistic studies. NEMMCO is aware of alternative approaches using probabilistic methods in the medium term and notes that adoption of such an approach would necessitate changes to MT PASA. To be consistent with the approach currently followed by NEMMCO in setting minimum reserve levels, an approach which directly compares the simulated USE to the reliability standard to assess generation adequacy, would need to incorporate sufficient sensitivity analysis to ensure the standard is achieved for reasonable variations in input data."

The response from NEMMCO indicates that the approach used by TEUS would not be considered acceptable by NEMMCO. The reason for this is that while the MARS modelling approach used by TEUS to determine the level of reliability generation is acceptable, the approach used did not include the "wide-ranging probabilistic studies" that NEMMCO refers to.

However, given the absence of a NEMMCO supported regime to determine the required level of generation to satisfy reliability levels under varying interconnector limits, the approach adopted by DJV is considered reasonable.

8.3 Expected Outcomes

Generation reliability refers to the technical capability of the generation system to supply customer demand. Given that this relates to the physical power system, generation reliability is principally determined by the amount of available generating capacity, the reliability of that generating capacity, and the level and profile of the customer demand to be supplied.

The reliability profile of generation is given by the assumptions of forced outage rates (FOR) for the existing[10] and new entry generation. This was the same in all the modelled cases.

With equivalent generation reliability profiles in the MARS modelling, the level of generating capacity needed to satisfy the reliability standard (of no more than 0.002% unserved energy), it would be expected that this would be very close for all the scenarios of equivalent load growth.

MARS modelling was undertaken for all the 4 scenarios of load growth and generator bidding. While generator bidding should not impact reliability for common assumptions of generators and load, Appendix G notes that this was done to account for the different patterns of new generation that can occur under the different generator bidding scenarios. This would ensure that any potential change in generation reliability resulting from a different makeup of generation would be accounted for.

[10] The forced outage rates are provided in Appendix 2 of Appendix G. This has forced outages ranging from 1 to 2% for most generators, and up to 4.5% for older generators.

9 Overview of Modelling Results

This chapter presents a review and 'sensibility check' on the modelling results provided by TEUS. This is done to understand the sources of project value and to verify the consistency of the modelling results with the described approach.

To do this, this chapter first overviews the summary modelling results provided. This is followed in the subsequent chapter by a detailed examination of one selected scenario - the Medium Load Growth LRMC bidding case – with and without Directlink in service. This scenario was selected because it represents the most likely load growth scenario and the only alternative to the SRMC bidding scenario.

Figure 10 presents the summary provided by DJV[11] of the NPV market benefits for all scenarios[12] undertaken at the 9% WACC. The 7% and 11% WACC results have the same pattern as shown here.

The total market benefits presented in this table, except for Alternative Project 3, correspond to the revised interregional market benefits presented in the TEUS report "Directlink Alternative Projects Market Benefits – Supplementary Report" dated 15 September 2004. The result for Alternative Project 3 is understood to be based on Question 3 of the DJV paper "Response to IES Questions of October 25,2004 dated 18 January 2005. .

Figure 10 Scenario Market Benefits – 9% WACC $M

Discount Rate	9.0%	Med-LRMC		High-LRMC		Low-LRMC		Med-SRMC	
		Value of Residual USE		Value of Residual USE		Value of Residual USE		Value of Residual USE	
		$10k	$29.6k	$10k	$29.6k	$10k	$29.6k	$10k	$29.6k
Alt 0-1-2	Energy	(96.9)	(96.9)	43.0	43.0	(150.8)	(150.8)	(61.2)	(61.2)
	Def ME	201.7	201.7	140.1	140.1	233.4	233.4	50.7	50.7
	Def RE	(10.9)	(10.9)	(1.2)	(1.2)	(14.4)	(14.4)	27.3	27.3
	Resid USE	13.9	41.1	5.2	15.3	(7.7)	(22.8)	13.7	40.5
	Total	107.9	135.1	187.0	197.1	60.5	45.4	30.4	57.2
Alt 3	Energy	-	-	-	-	-	-	-	-
	Def ME	-	-	-	-	-	-	-	-
	Def RE	(3.7)	(3.7)	(2.4)	(2.4)	9.4	9.4	(2.3)	(2.3)
	Resid USE	3.9	11.5	(1.7)	(5.0)	(4.6)	(13.6)	2.1	6.4
	Total	0.2	7.8	(4.1)	(7.5)	4.8	(4.3)	(0.1)	4.1

Question 3 (referred to above) revised the interregional market benefits down to zero based on a revision that had this option providing no increase in interregional capacity. (This replaced Table 3.1 in the TEUS report "Directlink Alternative Projects Market Benefits – Supplementary Report" dated 15 September 2004 has interregional market benefits for Alternative Project 3.) As the basis for the revised capacity is supported, this removes Alternative 3 as a

[11] The split of market benefits shown was provided by DJV on 24 January 2005.
[12] The September TEUS report did not break down the market benefits as shown in Figure 10 and had higher market benefits ascribed to Alternative Project 3.

viable project. Consequently no further discussion on Alternative Project 3 is presented in this chapter.

In relation to Alternative Projects 0,1,2, which share the same simulation modelling, the following observations, that require explanation, were made:

- Substantial negative energy benefits (apart from the High Load Growth / LRMC scenario);
- The NPV of deferred market entry (ME) generation is very large; and
- Inverse relationship between load growth and market benefits.

These are discussed in turn below.

9.1 Negative Energy Benefits

The results display substantial negative energy benefits (apart from the High Load Growth / LRMC scenario). This is most surprising because all things being equal, providing increased ability for interregional trade should provide for lower dispatch costs. IES reasoned that a possible (but unlikely) reason for this could be that there are substantial differences in the pattern of new entry generation development between the ’with and without project cases‘, and that consequently the results are somewhat different than simply comparing the impact of Directlink with no change in installed generation.

TEUS confirmed this explanation. In summary TEUS reasoned that the without Directlink case had earlier entry of coal units that give rise the lower energy costs in the without case but higher capital entry costs. The linkage between these resulted in a more stable pattern (than the separate components).

Quoting from TEUS in their note of 21 March 2005:

> The difference of a single large coal unit between the With and Without cases has a very large impact on the energy benefits for that year. The Without case will have lower energy costs because it has the additional coal unit. In the following year, the energy benefits often swing positive, as load growth drives prices in the With case high enough to support the entry of a new coal unit, although multiple units added in multiple regions over the period of several years can sometimes make the details confusing to trace.
>
> In every situation where the earlier market entry of a coal unit in the Without case (as compared to the With case) causes a large negative energy benefit, there is an offsetting upswing in the market entry capital deferral benefit. The With case gains the benefit of having deferred the expensive coal plant, even though it loses the benefit of the cheaper energy it would have provided. Furthermore, the earlier entry of the coal plant in the Without case tends to decrease the relative need for reliability entry plant in that case.
>
> This capital cost savings further offsets the negative energy benefit.

> TEUS generally found that while the separate benefit components exhibited substantial year to year volatility, the linkage between the components that comes out of the integrated modelling approach used caused the total benefit to follow a more stable pattern. These impacts occur when there is any difference in market entry between the With and Without cases, but effects are much smaller when the difference in generation is comprised only of CCGT and/or OCGT units.

TUES reasoning is supported by the CRA review of the ACCC Test application on Murraylink[13]. Quoting from a footnote 9 in that report:

> In an extreme case, the energy benefit may even be negative if the addition of interconnector actually defers part of the capacity addition that was contributing significantly to meet energy requirements which now needs to be met from relatively expensive sources of generation. Another issue which may add to lower/negative energy benefit is the "lumpy" nature of capacity addition – because new generators will be added to the system in relatively large chunks of MW, it is possible that addition of an interconnector will get rid of a similarly large block of capacity – thereby earning a large capacity deferral benefit, but possibly a lower/negative energy benefit that the displaced/deferred generator was contributing to. The interconnector would however be able to obtain a higher overall market benefit because capacity deferral benefits would typically supersede the decrease in energy benefits.

The above highlights the sensitivity the profile of generation entry as determined through the modelling has on the results, both on terms of capital deferral and energy benefits. This indicates the need for a reconciliation of the service level provided by Directlink, spot prices, and the ability of the Alternative projects to defer the entry of large generator units, in particular large coal units.

9.2 Significant Market Entry Deferral

The results of the modelling had the level of deferred market entry (ME) considerably larger than the capacity of Directlink, resulting in a significant NPV for this benefit. For the Medium Load Growth / LRMC scenario this is $201.7M[14], which is equivalent to the permanent deferral of over 300 MW of OCGT plant at the capital costs assumed by DJV. This is about twice the increase in southward capacity provided by Directlink, noting that Directlink does not provide for any increase in northward capacity.

This result does not appear to be plausible as the quantity of plant deferral is not consistent with the changed market needs.

TEUS provided an explanation to this in their note of 21 March 2005:

[13] "Assessment of Murraylink Market Benefits – Comments on TransEnergie US Study" dated 11 October 2002.
[14] See Figure 10.

"It is important to remember when reviewing the benefit cashflows that they represent the *difference* between two cases. It is not necessary to "permanently" defer market entry generation to create a permanent difference in the market entry schedules.

To illustrate the point with a simple example, suppose the Without case resulted in 100 MW of OCGT every year starting in year 5. Suppose further that in the With case, the first market entry occurs one year later in year 6, but 100 MW of OCGT capacity enters at that time and in every year thereafter. Including the interconnector in the With case did not permanently defer new generation – it only delayed it by one year. But in this example, it created a permanent difference of 100 MW in every year from year 5 on. Prices should be about the same in both cases, trending, as IES observes, toward new entry equilibrium levels, and from year 6 on both cases have identical market entry schedules."

9.3 Inverse relationship between load growth and market benefits

The modelling results showed that the low load growth scenario had greater market entry generation deferral benefits than the medium load growth scenario, and that the same relationship existed between the high and medium load growth scenarios.

This needs an explanation, as it would be expected that lower spot prices associated with lower load growth would reduce the level of market entry and thus the potential deferral benefits. The reason for expecting lower deferral benefits with lower load growth is that lower load growth would act to "stretch" the new entry pattern in both the without and with cases, so that the NPV of new entry costs is less in each. Expressed algebraically:

Med Load Growth:

$$\text{Deferral Benefit}_{Med} = NPV_{Med-Without} - NPV_{Med-With}$$

Low Load Growth:

$$NPV_{Low-Without} = Scale1 \times NPV_{Med-Without} \qquad (Scale1 < 1)$$

$$NPV_{Low-With} = Scale2 \times NPV_{Med-With} \qquad (Scale2 < 1)$$

$$\text{Deferral Benefit}_{Low} = Scale1 \times NPV_{Med-Without} - Scale2 \times NPV_{Med-With}$$

$$= Scale1\ (NPV_{Med-Without} - (Scale2/Scale1) \times NPV_{Med-With})$$

Given that the pattern of new entry would be "stretched" by the same amount in both the with and without cases, it would be expected that Scale1 would be approx equal to Scale2).

The CRA review of the ACCC Test application on Murraylink[15] also supported this view. Quoting from section 5 of that report:

[15] "Assessment of Murraylink Market Benefits – Comments on TransEnergie US Study" dated 11 October 2002.

> Further, the composition of benefit is likely to be quite sensitive to the underlying system conditions e.g., demand level. This is particularly true for the capacity deferral and reliability benefits. I present the 40 year NPV results for the base and the low economic growth cases in Table-3 [not shown here].
> As the comparison clearly shows, capacity deferral benefits diminish rapidly with lower demand. It may also be expected that the reliability benefit would also go down with lower demand.

TEUS in their note of 21 March 2005 gave the following reasoning:

> High prices are what trigger market entry. All other things being equal, higher load growth will cause prices to increase more rapidly than lower load growth. Prices rise more slowly in the With case, because the additional interconnector capacity allows a more efficient dispatch of NEM generation.
> This means we see market entry generation occurring first in the Without case. Once the new generation enters, it "knocks down the price". In the lower growth scenario, it takes longer for prices in the With case to rise to the point that they will support market entry. The slower growth of prices in the Low Growth scenarios means the period between the entry of a new plant in the Without case and the entry of the corresponding plant in the With case will tend to be greater. The greater the deferral period, the larger the deferral benefits will be.

Once again, this highlights the sensitivity that the profile of new generation entry determined through the modelling has on the results, both in terms of capital deferral and energy benefits, and the need to have this fully transparent.

9.4 Residual Energy

There is a substantial level of residual unserved energy benefits in all but the Low/LRMC scenario. As previously indicated, this is due to reliability generation be added to the 0.002% level of unserved energy and not the NEMMCO reserve criteria.

9.5 General Pattern of Results

In addition to the above noted issues, the results are also quite inconsistent with the expected components of Directlink benefit as expressed by DJV. This is discussed in the commentary of results in Section 5.3 of Appendix G. Quoting:

> "A simple PROSYM analysis indicates that, all other things being equal, a more efficient dispatch provides a benefit of about $40m over the period 2005-2044. A separate and straightforward spreadsheet analysis indicates the cumulative present worth of permanently deferring 100 MW of reliability entry is approximately $50m. These two benefits taken by themselves (i.e. ignoring the impacts of deferred entry and changes in unserved energy) amount to $90m CPW, and provide a reasonable check on the inter-regional market benefits that TEUS has estimated for the

> Directlink alternatives. This simple analysis makes it clear that, after allowing for the impacts of market entry changes, market benefits in the range $80m-120m are certainly credible and reasonable."

In summary, the pattern of results does not accord with the expected dynamics.

In response to a question on this matter, TEUS in their note of 21 March 2005 explained the difference through the following reasoning:

> As previously noted, the integrated modelling framework means the benefit components are closely linked, and as one element increases, it is generally offset by another element decreasing. Said differently, the total benefits are more robust than the individual components. TEUS did not mean to imply that all scenarios should provide energy benefits of $40m and deferred capacity benefits of $50m, but rather that the overall results should not be presumed to be unreasonable if they are in the neighbourhood of $90m.

10 Detailed Results – Medium/LRMC Scenario

To better understand the results presented in the previous section, this chapter reviews the detailed modelling results provided by TEUS for the Medium Load Growth / LRMC scenario.

The issues examined here are:

- The profile of annual benefits including the determination of benefits post 2019;
- The pattern of spot price outcomes on which formed the basis for new entry plant decisions;
- The pattern of new entry generation compared to the corresponding spot prices and the service level provided by the alternative projects;
- The total level of generation required as determined by reliability requirements;
- The determination of terminal value.

10.1 Profile of Benefits

The annual benefits (for the Medium load growth/LRMC/Alt012 scenario) in the various categories are shown in Figure 11 below[16], for the modelled period 2005 to 2019.

Figure 11 Annual Modelling Results - Medium / LRMS Scenario

Gross Market Benefit Annual Cashflow							
Year	Energy Savings	Merchant Entry Capital Deferral	Avoided Merchant Entry O&M	Reliability Benefit	RE Capital	RE O&M	Total
2005	325	0	0	237	0	0	562
2006	1701	0	0	894	0	0	2595
2007	2870	0	0	1139	0	0	4009
2008	4541	0	0	1116	27249	545	33451
2009	2905	0	0	722	-27249	0	-23622
2010	2791	0	0	508	0	0	3299
2011	2123	54498	1090	-321	0	0	57391
2012	-3893	163495	4360	-2157	-108997	-2180	50628
2013	1444	-54498	3270	2636	0	-2180	-49328
2014	7094	-54498	2180	911	81748	-545	36889
2015	1604	-108997	0	5145	27249	0	-74998
2016	-45297	468686	16241	780	0	0	440409
2017	-72670	403288	25069	2975	-108997	-2180	247485
2018	2287	-871974	0	-2117	217993	2180	-651631
2019	2791	108997	2180	864	-81748	545	33629

[16] These figures are cut form the spreadsheet provided by TEUS.

As explained in section 4.1 of this report, post 2019 the benefits of each component were calculated by developing 5 patterns of benefits based on the year 2015 benefits continuing, year 2016 continuing etc. and these five developed results were then averaged.

For the Medium load growth/LRMC/Alt012 scenario, the NPV results for the 5 'extrapolated' cases and the average of these 5 cases are shown in Figure 12 below[17].

Figure 12 Medium/LRMC/Alt012 Scenario – NPV Benefits for the 5 Extrapolated Cases and Average

Start Extrapolation	Energy	ME Capital	ME O&M	Reliability	RE Capital	RE O&M	Total
2016	22,536	24,393	5,681	28,982	(9,090)	(2,117)	70,385
2017	(180,161)	213,342	75,929	10,539	(9,090)	(2,117)	108,441
2018	(288,335)	362,501	110,695	19,145	(49,404)	(10,701)	143,901
2019	(20,558)	66,623	20,893	553	24,566	4,916	96,993
2020	(17,812)	100,554	27,990	10,276	(883)	(407)	119,719
Average	(96,866)	153,483	48,238	13,899	(8,780)	(2,085)	107,888

In relation to the benefits shown in Figure 12 the following are noted:

- The $107,888k corresponds to the interregional market benefit presented in the September 15, 2004 report "Directlink Alternative Projects Market Benefits – Supplementary Report". This demonstrates that the calculation of market benefits from the modelling results was undertaken correctly.
- The energy saving benefits is negative $96.8M, which corresponds to an annualized benefit of $9M (at a discount rate of 9%) over the 40 years. Assuming that the alternative projects provide an additional 100 MW of flow for 20% of the time (ie. when the link would have been constrained for southward flow) requires a negative price differential (between the with and without cases) of $51/MWh. A discussion on the reasons provided by TEUS for negative energy benefits is presented in section 9.1 of this report.
- The market entry capacity benefit is positive $153.5M. Based on the capital costs contained in section 3.1.5 of Appendix G of the DJV submission, this corresponds to about 285 MW of OCGT plant commissioned in year 1, or about 118 MW of coal generation in that year[18]. This assumes the market entry capital saving does not include operations and maintenance costs. The reasonableness of this is related to the service level provided by the alternative projects and how this corresponds to changed generation needs.
- The savings in market entry operations and maintenance costs correspond to 31% of the capital savings over the 40 year period, and 44% of the total

[17] These figures are cut form the spreadsheet provided by TEUS.
[18] Based on capital costs of $500/kW for OCGT and $1200/kW for coal plant escalated by 1.0778.

market benefit. This illustrates the sensitivity of the total benefits to the assumed O&M costs.

Other issues pertinent to the review are spot price outturns, new entry response to spot prices and the profile of deferred generation. These are discussed below.

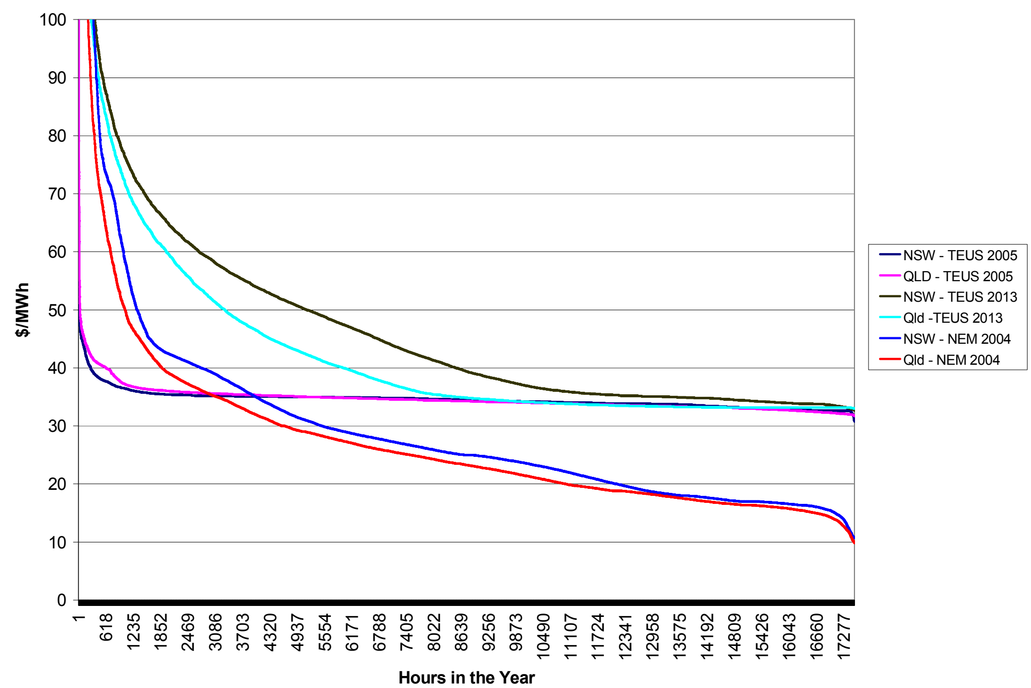
10.2 Market Modelling – Spot Price Outcomes

This section presents the pattern of spot prices produced by the modelling for the Medium Load Growth / LRMC scenario, and compares this to the pattern that has actually been observed in the NEM. This provides an indication of the level of realism in the modelling undertaken. The appropriate modelling of spot prices is fundamental to modelling generator dispatch levels and the dynamics of new entry generation.

To illustrate this, Figure 13 below presents the price duration curves[19] for NSW and Queensland for the following:

- TEUS modelled prices for the years 2005 and 2013; and
- The actual spot outcomes in the NEM for 2004.

Figure 13 Comparison of TEUS Modelled Spot Prices to Actual NEM Spot Price Outcomes



[19] A price duration curve is established by ordering the price outcomes for a year from the highest to the lowest prices. This provides a convenient manner to view prices over a period such as a year.

The comparison of spot prices above shows the following:

- The TEUS price pattern is very different from that observed in the actual NEM. Prices never fall below about $31/MWh in the TEUS modelling, whereas actual prices reflect considerable periods of low prices (typically in the low demand offpeak periods);
- TEUS modelled prices reflect the LRMC bidding assumption of SRMC + $20/MWh for existing plant and LRMC for new plant which is very different from the example bid curves illustrated in Figure 9;
- The TEUS modelled prices present a different economic signal to the market than the spot price patterns actually observed. The flatter and higher price profile developed in the TEUS modelling would increase the relative economics of base load generation compared to intermediate and peaking generation. However, if base load generators are not bidding predominately at SRMC (as they do in the actual market), then it is likely that there would be an oversupply of base load power stations, with these stations operating at lower than expected capacity factors.

These issues have the potential to significantly impact the type and timing of new entry generation and associated benefits.

10.3 Market Modelling – New Entry Dynamics

This section considers the dynamics of market entry generation in relation to the response of new capacity to price signals. To undertake this analysis, Figure 14 overleaf presents for NSW, a summary of the NSW spot price premiums and the market entry that occurred in NSW. The intent of this presentation is to explore the criteria used to model new generation entry, and the consistency of how this criteria was used through the simulation.

An explanation of spot price premiums was presented in Section 2.2 of this report. To recap, the spot price premium at a defined strike price can be thought of as the contribution to average annual spot price through the component of spot prices above the defined strike price.

From Figure 14 the following are noted:

- Average spot prices over the period increase from $35/MWh in 2005 to $64/MWh in 2019 (the average price is given by the spot price premium at a strike price of $0/MWh). The price levels reached towards the middle and end of the modelling were significantly higher than required by a new entrant.
- Assuming a CCGT generator has a SRMC of $30/MWh and is operated whenever spot price is above this level, then it would be able to obtain a return of over $24/MWh commencing in 2011. This corresponds to a return on capital invested of over $210/kW[20] and increasing from 2011. This should

[20] The translation of $/MWh to $/kW is obtained by dividing by 1000 to obtain $/kWh and then multiplying by 8760 to obtain $/kW.

imply market entry until spot prices decrease to a level where economic entry was not achievable. The reason why this has not occurred is possibly related to the assumed bidding of generators that has all generators bidding at SRMC+$20/MWh. The higher price outturns associated with such bidding would increase the level of generation capacity that is economic, but with generators operating at somewhat lower capacity factors than would be expected otherwise.

- Market entry has not occurred in 2014, which is a year of very high spot prices. This is inconsistent with the lower prices in other years when entry has occurred. This conclusion recognizes that while spot prices will decrease with the entry of new capacity, the extremely high level of spot prices in the year 2014 would be expected to provide for at least 100 MW of entry.

This brief review suggests that there are substantive serious issues with the results of the market modelling, and given the significance of market entry deferral in the total benefits obtained, these need to be properly explained and understood.

Figure 14 Spot Price Premiums (at shown strike price) and Market Entry – Medium/LRMC Scenario

	Strike Price $/MWh										Market
	0	10	20	30	40	50	100	300	1000	5000	Entry MW
2005	35	25	15	5	0	0	0	0	0	0	0
2006	35	25	15	5	0	0	0	0	0	0	0
2007	37	27	17	7	2	1	1	1	0	0	0
2008	38	28	18	8	3	2	2	1	0	0	0
2009	42	32	22	12	6	5	4	3	1	0	0
2010	50	40	30	20	14	12	11	9	3	0	0
2011	54	44	34	24	17	15	13	11	5	0	200
2012	48	38	28	18	10	7	4	3	1	0	400
2013	58	48	38	28	21	17	12	10	6	0	300
2014	62	52	42	32	25	21	16	14	9	1	0
2015	57	47	37	27	20	16	10	9	5	0	450
2016	57	47	37	27	19	16	12	10	6	0	550
2017	60	50	40	30	22	19	14	12	7	1	200
2018	64	54	44	34	26	21	13	9	6	1	300
2019	64	54	44	34	26	22	14	11	6	0	550

10.4 Level of Generation Deferral

The analysis presented here relates to the level and costing of market and reliability entry generation deferral. To support this analysis, Figure 15 presents the cumulative level of generation deferral due to Directlink (or the alternative projects)[21]. This is presented for market entry, reliability entry and total for each region. Appendix 2 presents the annual generation entry profiles that Figure 15 is based on[22].

This figure shows the pattern of generation entry and how this is influenced by the presence of Directlink. Initial observations show:

- The annual differences in capacity 'wanders about'. This characteristic is not totally unexpected, due to the lumpy nature of generation; and
- The pattern of generation deferral is consistent with the annual benefits profile shown in Figure 11.

Figure 15 Market Entry – Medium/LRMC Scenario

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Deferred Market Entry															
NSW	0	0	0	0	0	0	0	100	0	0	-100	50	-200	0	-100
QLD	0	0	0	0	0	0	100	100	100	100	100	100	100	100	200
VIC	0	0	0	0	0	0	0	200	200	200	200	100	600	100	100
SA	0	0	0	0	0	0	0	0	0	-100	-200	-200	-200	-200	0
Snowy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	100	400	300	200	0	50	300	0	200
Deferred Reliability Entry															
NSW	0	0	0	0	0	0	0	0	0	0	0	0	200	300	450
QLD	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50
VIC	0	0	0	0	0	0	0	-200	-400	-550	-750	-750	-1200	-1250	-1350
SA	0	0	0	0	0	0	0	0	0	100	300	300	350	500	500
Snowy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	50	50	50	50	-150	-350	-400	-400	-400	-600	-400	-350
Total deferred															
NSW	0	0	0	0	0	0	0	100	0	0	-100	50	0	300	350
QLD	0	0	0	50	50	50	150	150	150	150	150	150	150	150	250
VIC	0	0	0	0	0	0	0	0	-200	-350	-550	-650	-600	-1150	-1250
SA	0	0	0	0	0	0	0	0	0	0	100	100	150	300	500
Snowy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	50	50	50	150	250	-50	-200	-400	-350	-300	-400	-150

However, there are a number of inconsistencies and oddities that place doubt in the veracity of the modelling undertaken. These include:

- Queensland has 200 MW of deferred market entry generation. This would not be expected due to the fact that Directlink does not increase the interconnection limit for northward flow. This could be explained by the assumptions used in the PROSYM modelling that assumed that Directlink increases the northward interconnection limit by 180 MW. However, this is

[21] These values were determined by IES based on the spreadsheets provided by TEUS.
[22] This appendix shows two tables (1) for Directlink (or the alternative projects) NOT in service the annual level (NOT cumulative) of market entry and reliability entry generation for each region, and the total level of market entry and reliability entry generation that was installed over the period. The other table shows the same for Directlink (or the alternative projects) in service.

somewhat at odds with the explanation provided by TEUS that the assumed northward increase in interconnection limit assumed in the PROSYM modelling had only a minor impact.

- NSW has an additional 100 MW of market entry generation due to Directlink. This would not be expected due to the fact that Directlink does increase the interconnection limit for southerly flow only. As above, this could be explained by the assumptions used in the PROSYM modelling that assumed that Directlink increases interconnection flow in both directions.
- Victoria has an additional level of 1250 MW of capacity due to Directlink (100 MW less of market entry and 1350 MW additional of reliability entry). This is not consistent with the service level provided by Directlink. Although it can be argued that location issues are not relevant but only capacity in total, this raises issues in relation to the modelling processes used. In particular, the results suggest that the modelling processes used were different in the without and with project cases.
- Recognising that market entry generation deferral could result in some additional reliability generation entry, the level of reliability generation is substantial. While this deducts from the value of Directlink, it is not clear why Directlink would result in an increase in the level of installed capacity to satisfy the reliability criteria.
- The average difference in generation levels over the last 5 years of the simulation modelling due to Directlink was an increase of 320 MW. While this does not appear consistent with the significant deferral benefits ascribed to Directlink, timing and plant type issues can impact the benefits determined.

11 Terminal Value

A critical aspect of the DCF approach to the determination of total interregional market benefits is the treatment of the value post 2019, referred to as the terminal value.

The determination of the terminal value was described by TEUS in Appendix G - Chapter 3 Calculation of Energy and Deferred Market Entry Generation Benefits, Section 3.1.1:

> "By sometime after 2014, the modelling of the NEM is anticipated to have reached or be oscillating around a long run equilibrium condition. Results for all following years, excluding any further capital costs or savings for market entry or reliability entry plant, are assumed to replicate the termination year results on a monthly basis. Because of the large size and high cost of market entry coal plants and their impact on energy costs, the termination year results can be sensitive to the timing of coal plant entry. The estimated inter-regional market benefits, therefore, reflect an average of estimates based on the last 5 different termination years, 2015 through 2019. TEUS believes this provides a robust and unbiased estimate of the long run equilibrium outcomes"

The market benefits for the period 2005 to 2019 were determined through simulation modelling, and the benefits post 2019 were determined through a process that extrapolated the results of the year 2015 to 2019. This was previously described in section 4.1 of this report.

To gain an appreciation of value associated with benefits post 2019 and the stability of these benefits, Figure 16 overleaf shows for the Medium load growth/ LRMC bidding/Alt012 case the following:

- The present value (PV) of benefits associated with the annual benefits to the end of 2019. This is the PV of benefits determined through the simulation modelling;
- The PV of benefits for the 40 year study period based on extrapolating the results for year 2016 to 2045 (which is the end of the study period);
- The PV of benefits for the 40 year study based on the average of the 5 extrapolated cases.

From this figure the following are noted:

- The terminal value contains over 50% of the total benefits;
- The pattern of the benefits in the average case is very different than in the benefits determined to 2020. The volatility in the benefits determined in the 5 extrapolation cases is evident in Figure 12.

Figure 16 Total and Terminal Market Benfits

	Energy Savings	Deferred Entry - Capital	Avoided O&M on Deferred Entry	USE Reliability Benefit	Def RE Plant Capital	Avoided RE Plant O&M	Total
2020	17,844	24,393	5,681	14,424	-9,090	-2,117	51,134
2045	22,536	24,393	5,681	28,982	-9,090	-2,117	70,385
Average	-96,866	153,483	48,238	13,899	-8,780	-2,085	107,888

The reason for the volatility in extrapolated benefits is due to the extreme differences in benefits that resulted from the modelling in the years 2015 to 2019. The instability in the extrapolation and the significance of the terminal value to total value indicates the introduction of considerable uncertainty into the benefit calculation.

12 Summary of Issues and Conclusions

The application of modelling required under the ACCC Regulatory Test requires a methodology that is both transparent and objective. This in turn requires:

- A study program that addresses the requirements of the ACCC Regulatory Test;
- Robust economic evaluation methodology;
- A transparent description of the service level provided by the project and (competing) alternative projects, and any simplifications assumed in the modelling;
- Robust modelling including the establishment of stated criteria for the manner the modelling is to be conducted, such as the economic rule for market entry generation to enter the market;
- A clear description of the modelling results and an explanation for the results obtained. This is particularly important if the pattern of results do not outturn as anticipated; and
- Use of up to date assumptions.

Methodology

The modelling study submitted by DJV in the assessment of interregional market benefits provided by Directlink closely followed the methodology that had been used in the application of the ACCC test to Murraylink, and which had been accepted by the ACCC in that application.

The overall methodology was considered consistent with the 1999 regulatory test, including the calculation of reliability benefits that was slightly different to that used in previous application of the ACCC regulatory test.

A number of issues were noted that were also present in the Murraylink application, noting that in the case of Murraylink the decisions by the ACCC had been based on the test objective of determining the preferred project. These issues included:

- Absence of a market simulation that approximated actual market bidding and prices;
- No sensitivity testing on key assumptions such as new entry costs;
- No least cost planning scenario;
- The use of a methodology that has an implied assumption regarding the continuation of post 2019 benefits.

Modelling

In addition to a review of the stated methodology, the review included an examination of the modelling assumptions and detailed modelling results. Of these the key issues noted were as follows:

- The service level provided by Directlink (and the other DC alternative projects) assumed that these projects provide an increase in the interconnection capacity of 180 MW from NSW to Queensland in the PROSYM market modelling. However, these projects provide no increase in northward flow;
- Unrealistic spot price outturns in the market modelling which would significantly impact the dynamics new entry generation;
- The use of unsupported assumptions on new entry costs. In particular a high implied WACC in the determination of annualized new entry capital costs and an assumption of full CPI escalation of new entry capital costs from 2003 to 2005;
- Levels of market generation deferral that does not accord with the service levels provided by Directlink (and the other DC alternative projects). For example the modelling had 200MW of market entry deferral in Queensland when Directlink (and the other DC alternative projects) does not provide any increase in interconnection capacity to Queensland.

It is also noted that since the time of the modelling, there have been a number of market developments that would result in significant changes to assumptions.

Conclusions

From the perspective of determining the preferred project, the significant differences in the service levels provided between the DC and AC options and the equivalent service levels provided by the DC options, means that despite the significant issues associated with the modelling undertaken, the identification of preferred project was clear.

However in IES's opinion, given the observed sensitivity of market benefits to the outturn profile of new entry generation, the significance of the issues identified with the modelling means that the modelling results cannot be relied upon for the purposes of the ACCC test.

To address these issues requires re-modelling that:

- Properly models the interconnection capacity provided by the alternative projects;
- Models the market in a manner consistent with observed price outcomes and generator bidding and utilization;
- Uses recent estimates of new entry costs together with sensitivity analysis.

13 Future Modelling

A meeting was held between the ACCC, DJV and IES to discuss the findings contained in the IES draft report and to give DJV the opportunity to address the issues raised.

While DJV did address some of the issues contained in the draft report, there remained a number of unresolved matters. These included:

- The incorrect assumption regarding the interregional capacity provided by Directlink and the alternative projects that well overstated the service levels of these projects;
- The absence of any scenarios that contained realistic generator bidding behaviour and realistic spot price outturns;
- Unsupported new entry costs with no sensitivity analysis.

DJV/TEUS has agreed to undertake remodelling of an agreed set of scenarios that will address the issues identified.

14 Appendix 1 Benefits of Interconnection

This appendix is provided to provide a background to understanding the benefits provided by interconnection, and the benefit profile that could be expected from increased interconnection, such as Directlink.

The benefits of interconnection are essentially that it provides for a larger pool of suppliers and customers to operate in a unified market. This supports and drives capital and operating economies in generation and demand-side management and also helps drive energy prices down to competitive levels. It is useful to categorise benefits in more detail as follows.

- Capital cost saving benefits;
- Energy operating cost saving benefits (mostly fuel);
- Ancillary service benefits;
- Reduction in transmission losses; and
- Competition benefits including reduced price volatility.

Taking each of these categories in turn, this section explains, by way of example, the benefits of interconnection and the issues associated with optimal interconnection development.

14.1 Generation Reserve Sharing

One of the greatest benefits obtained through interconnection arises through the ability to utilise spare generating capacity in one region when another connected region is in deficit. This is termed generator reserve sharing. The associated benefits are the savings in generator capital costs through a reduction in the required level of installed generation.

The level of reserve sharing provided by interconnectors is impacted by a number of factors, these primarily being the size of the largest generator unit, the level of demand diversity between regions and the reserve criterion used by the system operator (ie. NEMMCO) in assessing generator adequacy. These fairly complex issues are considered in turn below.

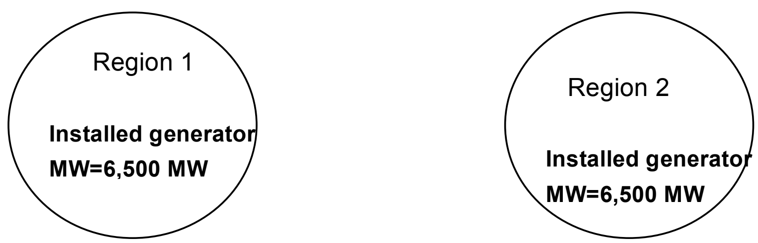
14.1.1 Load Diversity

Consider a single region (with no internal transmission constraints) where the size of the largest unit is 500 MW and that has a maximum demand of 10,000 MW. Also assume that the system operator requires that any region must have access to sufficient (generator or demand side) capacity in order to be able to supply the maximum demand with the largest generator unit out of service (ie. generation reserve criteria). Then this region has the need to have 10,500 MW of installed generation.

Now assume that for some reason this region is divided into two unconnected regions and that the largest unit in each region is 500 MW. Further, the individual maximum demands of these two regions occur at different times (ie. non-coincident) and that the sum of these maximum demands is 12,000 MW. The non-coincident nature of regional demands is referred to as load diversity, which can be expressed as the ratio of the system (ie. non-coincident) maximum demand and the sum of the respective regional maximum demands. In this case the load diversity ratio is 10,000 MW divided by 12,000 MW, which equals 0.83.

This situation is illustrated in Exhibit 1. The table within the exhibit shows three levels of demand that can occur, these being demand during average weather conditions and the respective regional demands at the time when demand in each of the two regions is at its maximum. The table also shows the amount of installed generator capacity over load (i.e. generating reserve) within each region for the three load conditions.

Exhibit 1 Example Two Unconnected Regions



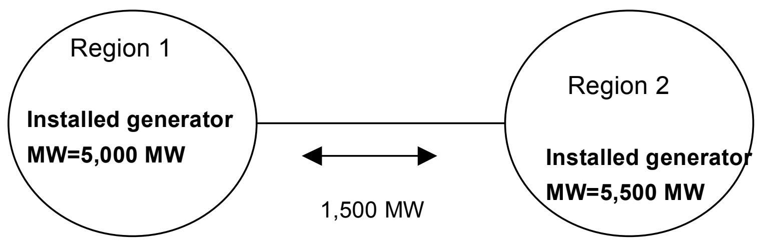
Market Conditions	**Region 1**		**Region 2**	
	Demand MW	*Reserve MW*	*Demand MW*	*Reserve MW*
Average	3,000	3,500	3,500	3,000
Time of Max Demand in Region 2	4,000	2,500	6,000	500
Time of Max Demand in Region 1	6,000	500	4,000	2,500

As each region is required to have access to 500 MW of reserve at time of maximum demand, the amount of total generator capacity required for the two (unconnected) regions is 13,000 MW.

Assume now that the two regions are to be joined by an interconnector, and that the interconnector is to be sized so that the amount of total generation required is a minimum (ie. 10,500 MW as for a single region). Consider a 1,500 MW interconnector. This situation is illustrated in Exhibit 2.

At the time of total maximum demand, there is a range of possible generator dispatch patterns depending on where reserve is to be maintained. Exhibit 3 below shows for the time Region 2 has its maximum demand, three potential generator dispatch cases and the corresponding dispatch after the largest generator unit is lost in the region indicated.

Exhibit 2 Example Two Connected Regions



Market Conditions	Region 1		Region 2	
	Demand MW	*Reserve MW*	*Demand MW*	*Reserve MW*
Average	3,000	2,000	3,500	2,000
Time of Max Demand in Region 2	4,000	1,000	6,000	- 500
Time of Max Demand in Region 1	6,000	-1,000	4,000	1,500

Of note is that through appropriate selection of generator dispatch, the maximum flow on the interconnector can be maintained at 500 MW before the loss of a generator unit. However, 1000 MW interconnector flow (into Region 2) is required if a unit is lost in Region 2.

Now consider the situation when Region 1 has its maximum demand. In the same manner as above, Exhibit 4 shows three potential generator dispatch cases and the corresponding generator dispatch after the largest generator unit is lost in the region indicated. Of note is the minimum flow on the interconnector is now 1,500 MW into Region 1 after the loss of a 500 MW generator unit in Region 1.

The interconnector has reduced the total amount of generation capacity required by 2,500 MW (to the level needed for a single region). This is the maximum amount of avoided generation achievable. Note that in this example this is greater than the capacity of the interconnector.

This example illustrates that the maximum reserve sharing obtainable from an interconnector is influenced by the amount of load diversity and the largest generator unit size.

The unsymmetrical nature of the interconnector flows at the times of regional maximum demand reflects the need to maintain reserves in only one of the regions. The region that is not holding the reserves requires a greater level of import capacity than the region that is holding the reserves.

The size of the interconnector required to minimise the total generation is also influenced by the disposition of generation in the two regions. For example, if Region 1 had 4,000 MW and Region 2 had 6,500 MW, a 2500 MW interconnector would be required to supply Region 1 at the time of its maximum demand (and still maintain reserve).

Exhibit 3 Example Potential Generator Dispatch Patterns at Time of Region 2 Maximum Demand

	Region 1 Generation	Region 2 Generation	Interconnection Flow into Region 2	Region holding Reserves
Before a 500 MW unit is forced out of service				
Case 1	5,000	5,000	1,000	Region 2
Case 2	4,500	5,500	500	Region 1
Case 3	4,750	5,250	750	Region 1 & 2
After a 500 MW unit is forced out of service in Region 1				
All cases	4,500	5,500	500	-
After a 500 MW unit is forced out of service in Region 2				
All cases	5,000	5,000	1,000	-

Exhibit 4 Example Potential Generator Dispatch Patterns at Time of Region 1 Maximum Demand

	Region 1 Generation	Region 2 Generation	Interconnection Flow into Region 2	Region holding Reserves
Before a 500 MW unit is forced out of service				
Case 1	5,000	5,000	- 1,000	Region 2
Case 2	4,500	5,500	-1,500	Region 1
Case 3	4,750	5,250	-1,250	Region 1 & 2
After a 500 MW unit is forced out of service in Region 1				
All cases	4,500	5,500	-1,500	-
After a 500 MW unit is forced out of service in Region 2				
All cases	5,000	5,000	-1,000	-

14.1.2 Largest Generator Unit Size

Now assume that there is no load diversity between the two regions, in other words that the maximum demands occur at the same time. As before, without the interconnector, the total amount of generation required is 13,000 MW.

Under this situation, an interconnector will enable reserves between the two regions to be shared. A 500 MW interconnector would reduce the total generation required by 500 MW to 12,500 MW, the level that would be required if the two regions were a single region. An interconnector of greater size would not result in any additional reduction in total generator capacity.

14.1.3 NEMMCO Reserve Criteria

The NEMMCO regional generating reserve criteria specifies the amount of generating capacity required to ensure supply reliability is maintained. This criterion requires that each region have access to sufficient generator or demand side capacity such that all demand in that region can be met with the largest generator unit in that region out of service. In the past, NEMMCO has expressed this requirement on the assumption that regional maximum demands occur at the same time[23] (i.e. coincident), although it is understood that NEMMCO is moving to express this requirement recognising that regional maximum demands do not occur at the same time.

[23] This is the manner generating reserves are expressed in the NEMMCO Statement of Opportunities documents.

In the above example, the NEMMCO regional reserve criterion translates to Region 1 requiring access to 6,500 MW of capacity (at the time of its maximum demand) and Region 2 access to 6,5000 MW (at the time of its maximum demand).

The example illustrates that the treatment of regional demand diversity strongly influences the 'assessed' level of reserve sharing that an interconnector would provide, and consequently interconnector economics.

Assuming no load diversity between regions, the amount of avoided generation capacity through reserve sharing is set by the largest generator unit. In the example this was 500 MW. Accounting for load diversity between regions increases the amount of avoided generation capacity through reserve sharing by the level of load diversity. In the example the amount of avoided generation was 2,500 MW when load diversity of 2000 MW was accounted for.

It should be noted that while the example has considered only generating capacity for simplicity, demand side capacity is equally relevant.

14.1.4 Generator Capacity Costs

Also fundamental to the economics of interconnector reserve sharing benefits is the cost of avoided (generation or demand side) capacity. Much has been written on the issue of generation capacity costs. Such costs depend on many factors such as technology and technology improvements, generator unit size, exchange rate, availability of units, interest rates, location etc.

Indicative lowest cost capacity options are likely to be those associated with second hand open cycle gas turbines. The all up cost of these has been assessed to be in the range $350/kW to $600/kW, with a likely achievable cost around $400/kW or a little higher.

The cost of generation or demand side capacity sets the benchmark that an interconnector would need to approach to be economic, noting that interconnectors also provide other benefits in addition to avoided capacity needs. However, in making such comparisons, it should be understood that interconnectors can (but may not) avoid capacity needs on both sides of the interconnector, thereby having a 'doubling up' effect.

14.1.5 Summary

The analysis above has demonstrated that interconnectors provide reserve sharing between regions equal to the sum of the amount of load diversity between regions and the largest generating unit or higher. Additional reserve benefits are achievable if a region has spare generating capacity that an interconnector would make available to a neighbouring region.

Given that the NEMMCO generating reserve criterion sets the amount of capacity needed, the treatment of load diversity in the NEMMCO definition of required reserves is consequently fundamental to the assessment of interconnector economics.

14.2 Saving in Operating Costs

Through providing access to lower cost generation, interconnectors also act to reduce generator operating costs.

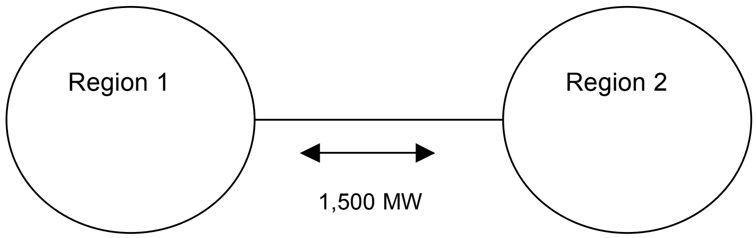
Continuing the example of a two-region market shown in Exhibit 2, Exhibit 5 shows:

- The percentage of time that the three market conditions apply;
- The average interconnector power flows associated with lower priced generation in one region being used to replace higher priced generation in the other region for the three market conditions;
- The cost of the marginal generator unit in each of the two regions. The marginal cost in each region is the operating cost (fuel and variable operating and maintenance costs) of the most expensive generator unit that would be required to supply that region if there were no interconnection. In this example it is assumed that generators bid (or price) their generation at their marginal operating costs. (This assumption is discussed later.)

The saving in generator operating costs under average conditions is about $21M per year and at the times of high demand about $12M, giving a total savings over the year of $33M. The magnitude of the cost savings is proportional to the total energy transfers and the production cost differences between the associated generators. In this example, the high average flow level was mainly responsible for the quantity of operating cost savings.

Alternatively, for an interconnector that would experience low utilisation (such as an increase to the capacity of the Snowy to Victoria interconnector), the associated savings in generator production costs would be small, and considerably less than the saving in generator capacity costs.

Exhibit 5 Example Two Region Market



Market Conditions	% of time	Average Flow	Marginal Generator Cost	
			Region 1	*Region 2*
Average	96%	500 MW	$10/MWh	$15/MWh
Max Demand Region 1	2%	1,250 MW	$50/MWh	$25/MWh
Max Demand Region 2	2%	750 MW	$50/MWh	$100/MWh

It should be noted that as an interconnector increases in capacity, the marginal utilisation of its capacity could be expected to decrease. Consequently, the saving in generator dispatch costs of additional interconnector capacity would be expected to be less than the average saving. In the two-region example above it is very likely that additional interconnection capacity (further to the 1500 MW) would result in only minor changes to power flows, and the impact to generator operating costs would be minor.

Noting the above and looking forward in the NEM, the potential saving in generator operating costs due to increased interconnection is not expected to be significant. This is due not only to the fact that all states are already interconnected, but that the growing availability of gas in all States is tending to minimise the likelihood of significant marginal fuel cost differences in future, although very cheap coal is still a contender in some regions. Also, without knowledge of contractual details it may be difficult to separate the fixed and variable costs of fuel.

14.3 Transmission Losses

An important cost component of interconnector flows are the power losses associated with power transfers, which typically average about 5% of the power flow, although higher average losses are possible. The marginal loss of power flows, which is the loss associated with the last MW of flow, can typically be over 15% to 20% for high interconnector power flows. While this can impact the capacity support available during periods of high link flows, for interconnectors that only provide capacity support, losses are not normally a significant issue. However, losses could become a more significant issue if a shift in the fuel and operating costs of generation between states resulted in a tendency for bulk energy transfers.

In the above example, the cost of losses based on an average loss on the interconnector of 5%, is about $2M per year. In this case the economics of transmission development to reduce losses appears limited. However, there may be cases where transmission development to reduce losses is economic.

14.4 Optimal Interconnector Development and Whole of Life Benefits

Continuing with the example two-region market, let's now assume that there are several options available to increase interconnection capacity as shown in Exhibit 6.

Exhibit 6 Interconnector Upgrade Options in Example Two-Region Market

Option	Capacity Provided	Cost	Annual Cost	$/kW
A	500 MW - both directions	$200M	$30M	$600/kW
B	400 MW - Region 2 to Region 1	$50M	$5M	$125/kW

As previously noted, additional interconnection is unlikely to be economically justified for the situation shown in Exhibit 2 (eg. ACCC test). This is because increased interconnection would not reduce the amount of generator capacity required to satisfy regional reserve levels and would not have any substantial impact on generator operating costs.

Assume now that the situation is modified and that a new 1000 MW generator station is built in Region 2, and that the load in Region 1 will increase by 1000 MW over the next year. The revised situation is shown in Exhibit 7.

Exhibit 7 Example Two-Region Market 1000 MW of Additional Generation in Region 2

Market Conditions	Region 1 Reserve	Region 2 Reserve
	Current Year	
Average condition	2,000	3,000
Time of Region 1 Max Demand	-1,000	2,500
Time of Region 2 Max Demand	1,000	500
	Next Year	
Average condition	1,000	3,000
Time of Region 1 Max Demand	-2,000	2,500
Time of Region 2 Max Demand	0	500

Additional interconnection in the first year has limited capacity benefits as both regions already satisfy their respective regional reserve criteria. The value of increasing interconnection capacity in this year would rely on generator operating cost savings and/or the impact to competition levels. Increased competition levels could have a substantial impact on Region 2.

Upgrading the interconnector by the end of the next year would provide an alternative to new generator capacity in Region 1 as Region 2 has sufficient generator capacity to support Region 2 at the time of its maximum demand.

Note that the level of interconnection would be greater than that given by load diversity and the largest generator unit. The economics of interconnection upgrade in this situation is due to the surplus of generation in Region 2.

However, as with any investment, an investment is only economic if the benefits are sufficient to cover all costs. Unless the payback period is quite short, this would usually require the economics to be considered over the whole of life of the project, which for an interconnector would typically be 30 years or more. Over such a long period, the issues would be the period of time that existing surplus capacity in one region is available to provide reserve sharing benefits and the expected development pattern of future generation. The later would be strongly influenced by the location cost of generation (esp. fuel costs) and transmission pricing.

An analysis of this example would need to account for the period of time that Region 1 requires support and the period of time that Region 2 has sufficient spare support capacity. Assuming that this is 7 years, Option B is economic on capacity benefits alone, while Option A is not economic on capacity benefits.

In relation to competition benefits, with the amount of generation now in Region 1, increased interconnection capacity from Region 1 to Region 2 is unlikely to have any significant impact to Region 2. However, there are likely to be substantial competition impacts from increased interconnector capacity from Region 2 to Region 1. With the two interconnector options having about the same capacity for transfers to Region 2, the impact on competition benefits is not likely to be significantly different.

15 Appendix 2 Pattern of Generation Entry – Medium Load Growth / LRMC Scenario

Figure 17 Market and Reliability Generation Entry – Without Directlink - Medium Load Growth / LRMC Scenario

Region	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL
NSW	Market Entry	0	0	0	0	0	0	200	400	300	0	450	550	200	300	550	2950
	Reliability Entry	0	0	0	0	0	0	0	0	0	0	0	0	200	300	300	800
QLD	Market Entry	0	0	0	0	450	450	550	450	450	450	0	450	450	200	650	4550
	Reliability Entry	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	50
VIC	Market Entry	0	0	0	0	0	0	0	200	100	500	0	0	500	0	100	1400
	Reliability Entry	0	0	0	0	0	0	0	50	150	0	200	400	250	450	550	2050
SA	Market Entry	0	0	0	0	0	0	0	0	0	0	0	385	0	0	200	585
	Reliability Entry	0	0	0	0	0	0	0	0	100	200	300	0	50	150	100	900
Snowy	Market Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Reliability Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	Market Entry	0	0	0	0	450	450	750	1050	850	950	450	1385	1150	500	1500	9485
	Reliability Entry	0	0	0	50	0	0	0	50	250	200	500	400	500	900	950	3800

Figure 18 Market and Reliability Generation Entry – With Directlink - Medium Load Growth / LRMC Scenario

Region	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL
NSW	Market Entry	0	0	0	0	0	0	200	300	400	0	550	400	450	100	650	3050
	Reliability Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	200	150	350
QLD	Market Entry	0	0	0	0	450	450	450	450	450	450	0	450	450	200	550	4350
	Reliability Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIC	Market Entry	0	0	0	0	0	0	0	0	100	500	0	100	0	500	100	1300
	Reliability Entry	0	0	0	0	0	0	0	250	350	150	400	400	700	500	650	3400
SA	Market Entry	0	0	0	0	0	0	0	0	0	100	100	385	0	0	0	585
	Reliability Entry	0	0	0	0	0	0	0	0	100	100	100	0	0	0	100	400
Snowy	Market Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Reliability Entry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	Market Entry	0	0	0	0	450	450	650	750	950	1050	650	1335	900	800	1300	9285
	Reliability Entry	0	0	0	0	0	0	0	250	450	250	500	400	700	700	900	4150