DIRECTLINK CONVERSION APPLICATION - REVIEW OF MARKET MODELLING

A report to the Australian Energy Regulator

17 October 2005

IES
Intelligent Energy Systems

Executive Summary

This report presents a review of the modelling exercise performed by TransÉnergie USA (TEUS) as part of the application by Directlink Joint Venturers (DJV) for Directlink to be converted to a regulated interconnector. The report was undertaken by Intelligent Energy Systems (IES) on behalf of the Australian Energy Regulator (AER).

This report follows the IES report "Directlink Conversion Application – Review of Interregional Market Benefits" of 26 April 2005 which reviewed the September 2004 DJV submission on the market benefits of Directlink.

The modelling study presented in this report was performed to address issues noted in the September 2004 submission. IES and TEUS worked together during this modelling study to align assumptions and methodology and to validate the modelling results as the modelling was performed.

As a first step a base case, using historical bidding and agreed assumptions and methodology, was modelled in parallel by IES and TEUS. Differences between the two sets of modelling, in particular the price outcomes and the profile of benefits were noted. These differences were found to be due to the different modelling software used and the resulting unavoidable small differences in modelling approaches. The agreement in the total benefits from the two sets of base case modelling gave confidence that the modelling performed was robust and that the results were valid.

TEUS then executed the following modelling cases:

- SRMC Bidding
- High Load Growth
- Low Load Growth
- High New Entry Costs
- Low New Entry Costs
- Alternative 3

IES analysed the results from the TEUS modelling and performed spot check modelling to confirm the new entry decisions and energy deferral benefits seen in the TEUS modelling. Discussions between IES, TEUS and the AER were held to clarify any issues with the modelling and additional explanations and results from TEUS were provided as requested.

IES is satisfied that the results from the TEUS 2005 modelling are reasonable and suitable for use in the ACCC regulatory test.

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1 Introduction

1.1 Background

In April 2004, the Australian Energy Regulator (AER) commissioned Intelligent Energy Systems (IES) to undertake a review of 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 review undertaken involved both a review of methodology and a review of the modelling undertaken and can be found in the IES Report "Directlink Conversion Application – Review of Interregional Market Benefits" of 26 April 2005 (IES Report).

As noted in that report the overall methodology was considered consistent with the 1999 regulatory test. However a number of issues with the modelling assumptions and detailed modelling results were identified.

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

To address these issues TransÉnergie United States (TEUS)/DJV agreed to undertake modelling of an agreed set of scenarios. The key issues to be addressed were as follows:

- Modelling of the interconnection capacity provided by the alternative project;
- Modelling of the market in a manner consistent with observed price outcomes and generator bidding and utilization;
- The use of recent estimates of new entry costs together with sensitivity analysis.

In April 2005, the AER commissioned IES to review the modelling undertaken and to provide opinion on the suitability of the modelling for its intended use. This involved a process that had IES working with TEUS/DJV throughout the modelling study to align assumptions, identify issues as they arose and to provide a cross check of the modeling results. IES was also asked to provide comment on the suitability of the sensitivity assumptions for the ACCC Regulatory Test.

This report details the modelling process undertaken and the results from this process. Refer to the April 2005 IES Report for details on the initial modelling and the review of the methodology in relation to the regulatory test.

1.2 Process Undertaken

The process involved the following:

- Agreement of modelling assumptions and process;

- Calibration of the historical bidding process;
- TEUS and IES parallel independent modelling of the historical base case;
- Discussion and analysis of the historical base case results;
- TEUS modelling of SRMC case.
- Discussion and analysis of SRMC results;
- TEUS modelling of the additional sensitivities cases and the alternative 3 case;
- Discussion and analysis of additional cases and alternative 3 results;
- IES developed this final report on its findings.

1.3 Outline of this Report

This report is structured as follows:

- Chapter 2 presents the modelling assumptions used in the study.
- Chapter 3 presents the approach used in the study.
- Chapter 4 presents the base case results and analysis.
- Chapter 5 presents the SRMC case results and analysis.
- Chapter 6 presents the additional case results and analysis.
- Chapter 7 presents the alternative 3 case results and analysis.
- Chapter 8 provides a comment on the suitability of the sensitivity assumptions for the regulatory test.
- Chapter 9 presents the conclusions of this review.

2 Modelling Assumptions

The first stage of the modelling study was the agreement of the assumptions to be used in the IES and TEUS modelling.

The modelling assumptions were for the most part the same as those used in the TEUS 2004 modelling as presented in Appendix G of the DJV submission dated 22 September 2004. Updated assumptions included generator supply developments, new entry costs and network topology. In addition the bidding was to be "historical bidding", which assumes that the current bidding patterns in the NEM continues over the analysis period.

2.1 Generator Developments

The generator projects that were included in the modelling and the timing for these projects are shown in Table 1 below. The selection and timing of these projects was determined from the 2004 NEMMCO Statement of Opportunities (2004 SOO) and latest information available in the market.

Table 1 Assumed Generator Developments

Development Name	Region	Details	Timing
Townsville Power Station (Enertrade)	ROSS	Conversion of current 165MW OCGT to 223MW CCGT	1/06/2005
Callide A (CS Energy)	CW	120MW return to service	1/01/2006
Braemar (Wambo)	SW	3 x 150 OCGT	1/06/2006
Kogan Creek (CS Energy)	SW	1 x 750MW coal fired	1/12/2007
Laverton (Snowy Hydro)	VIC	2 x 156MW OCGT	1/12/2006
Tallawarra Power Station (TXU)	NSW	400MW CCGT	1/01/2008
Quarantine (Origin)	SA	Conversion of current 96MW OCGT to 170MW CCGT	1/01/2008
Swanbank B	MS	500 MW Retired	1/07/2011

2.2 Loads

The loads used were those used by TEUS in the 2004 modelling as follows:

- Energy and maximum demands as contained in the 2003 SOO;
- 2003 regional load traces as published by NEMMCO;
- 2003 sub-regional load traces supplied by TEUS (from Powerlink and Country Energy).

Both the market modelling and the reliability modelling load forecasts were based on the medium economic forecast. The market modelling used the 50% Probability of Exceedence (POE) peak demand forecast, and the reliability modelling used the 50% POE, 10% POE and 90% POE peak demand forecasts[1].

2.3 Hydro

IES and TEUS use different methodology for modelling hydro generators.

IES use a marginal water value to model the hydro systems. The marginal water value is defined as the marginal opportunity cost of water, i.e., the best profit the generator can achieve in the market for every additional amount of generation it produces now or in the future using the water stored in the reservoirs or inflows. This marginal water value is then used when creating bids for the hydro generators.

The model TEUS used, Prosym, takes the input available energy on a monthly basis and the maximum capacity of each hydro facility to "level the load" prior to the thermal dispatch.

2.4 Wind

The IES and TEUS modelling did not explicitly model wind capacity in the NEM. Wind generators are classified as non-scheduled generators and hence the expected generation from existing and committed wind farms has already been subtracted from the expected load in the NEMMCO load forecasts. Explicitly modelling existing and committed wind farms would be effectively double counting this generation.

2.5 Other assumptions

Other assumptions used in the IES modelling, including generator capacities and forced and planned outage rates were based on those in Appendix G of the DJV/TEUS Report dated 22 September 2004.

For the 2005 modelling, TEUS licensed Henwood Energy Systems current Australian Prosym database. TEUS retained as much of the database information as possible, including generator capacities and forced and planned outages rates, for use in the modelling exercise.

2.6 Historical Bidding

Historical bidding assumes the current bidding patterns seen in the NEM continue over the analysis period. This bidding attempts to represent the profiles

[1] Projected future demand levels out 10 years are published in the NEMMCO SOO. Future demands are established based on Low, Medium and High levels of economic activity, and for each of these the level of maximum demand is based on mild, average and extreme weather conditions (90%, 50% and 10% Probability of Exceedence (POE) projections respectively).

and interleaving of generator bids that occurs in the market, which neither SRMC or LRMC bidding does.

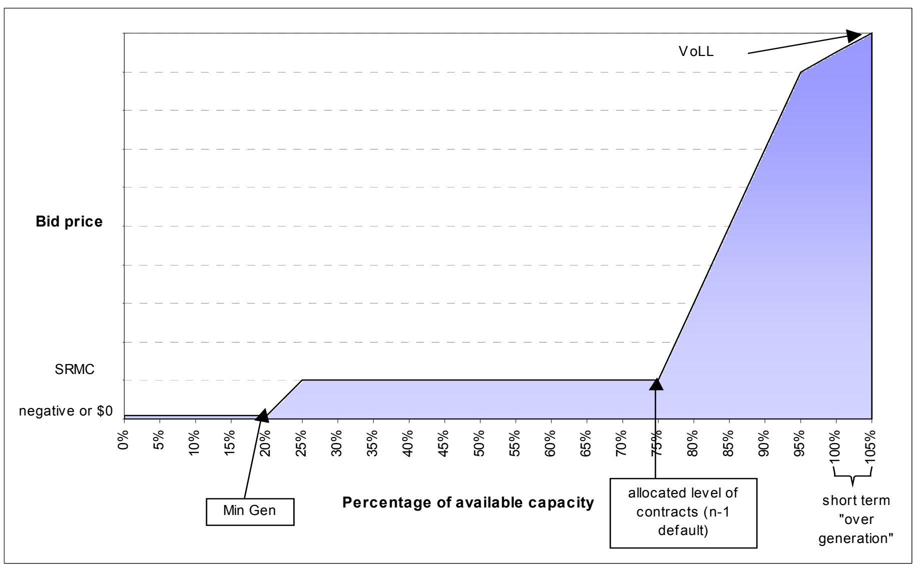
Historic bidding strategies are defined by contract levels, bid shapes and portfolio operation.

A typical bidding strategy employed by generators is:

- Bid the minimum generation MW requirement at or below $0/MWh;
- Bid the contract quantity MW around their short run marginal cost value; and
- Bid the residual at various steps up to VoLL.

An example of a typical supply curve is shown in Figure 1.

Figure 1 Typical Generator Bids in the NEM



IES modelling

To develop historical bidding strategies the minimum generation levels, contract levels of portfolios and supply curves shapes were developed as follows:

- Minimum generation levels were taken from NEMMCO's "2005 ANTS Data and Assumptions Consultation – Issues Paper" dated 15 February 2005.
- Contract levels are defined as a percentage of regional load and are estimated by analysing actual bids. The contracted percentage of the regional demand is then allocated to each business unit using a merit order priority process.
- The remainder of the supply curve shape, the quantity bid in between bid bands 3 to 10, is defined by supply curve parameters based on portfolio size and the costs of the individual plants in the portfolio.

- Supply curve parameters are developed using an iterative process; initial parameters are developed using actual bids and then tuned to give the required market outcomes: prices, price distribution and generation levels as seen by the different generators in the market.

Once these contract level and supply curve parameters are developed they remain the same throughout the modelling. However because these parameters are based on market conditions: regional load, portfolio size and plant costs, the bids are able to dynamically respond to changes in market conditions throughout the modelling process.

In addition portfolio operation has portfolios cover their contracts and offer supply curves at the minimum production cost. This has portfolio units increase output to cover forced and planned outages and the units within a portfolio operate within a cost merit order.

TEUS modelling

The Prosym model used by TEUS uses a 5-point bid curve. TEUS provided a description of the bid calibration process in their note of 14 June 2005.

> "In brief, TEUS classified each generator of one of four types:
>
> - Baseload
> - Base-intermediate
> - Intermediate
> - Peaking
>
> For each plant type, a 5-point bid curve was established using generic Prosym 'adders' (or 'subtractors') to different points on the units' heat rate curves. This allowed baseload plants to bid below their marginal costs to ensure they would be committed and operate continuously, and it allowed peaking plants to bid well above marginal cost. Different generic strategies were developed for each NEM region to replicate the 2005 regional results provided by IES."

2.7 Network Topology

To correctly model the service level of Directlink the Northern NSW sub region was explicitly included in the modelling. The limits between NSW, Northern NSW and QLD are shown in Table 2.

Table 2 Transfer Limits MW

	Positive Direction	Negative Direction
Northern NSW to NSW	1200	1200
QLD to Northern NSW via QNI	950	700
QLD to Northern NSW via DL	125	180

2.8 New Entry Costs

New entry costs were taken from the ACIL Tasman "Report on NEM generator costs", dated February 2005. The ACIL new entry cost information provides the following:

For coal, CCGT and OCGT generators:

- Capital cost in $/MWh at an assumed capacity factor
- Tax cost in $/MWh at an assumed capacity factor
- Fixed O&M in $/MWh
- Variable costs ($/MWh) – fuel and variable O&M.

3 Modelling Process

The second stage of the modelling study was the agreement of the modelling process to be used in the IES and TEUS market simulation modelling.

The principles of market simulation modelling in the context of the ACCC Regulatory test were reviewed in the IES Report dated 26 April 2005.

The market simulation modelling was performed to determine the market benefits with the project in place. 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.

The transmission network deferral benefits have been addressed in stage 1 of the DJV submission review and are not part of this study.

IES used the market model PROPHET to perform the simulation modelling. TEUS used one model, PROSYM, to estimate the energy benefits and the market plant entry, and another model, MARS to estimate the reliability benefits and reliability plant entry. The modelling process used by TEUS and IES was aligned to the greatest extent possible.

3.1 Market modelling

Modelling methodology used was as described in Appendix G of the DJV/TEUS report dated 22 September 2004 and is summarised below. IES and TEUS followed the same market modelling process.

The modelling used:

- Hourly time steps;
- 3 simulations for market modelling;
- Competitive new entry based on profitability after entry:
  - Potential new entrants added one at a time and the year remodelled until the next new entrant is no longer profitable;

- Profitability defined as when the new entrants energy revenues exceed its long – run marginal cost.

3.2 Reliability Modelling

The reliability modelling was undertaken to determine levels of unserved energy (USE) across the NEM, as well as the levels of reliability planting needed to keep levels of USE under the Reliability Panel's standard of 0.002% of energy consumed.

IES Modelling

The reliability modelling methodology used by IES for each year was as follows:

- Run 100 simulations of hourly time steps using the 50% POE load forecast;
- Add reliability new entry in 50MW increments to keep levels of USE under 0.002% criteria;
- After planting completed run 100 simulations of hourly time steps using the 50% POE load forecasts;
- Re – run 100 simulations of hourly time steps using the 10% POE load forecast;
- Weight the results from the 50% POE and 10% POE modelling.

The weighted results were developed using the recommended weighting factors from the IRPC Stage 1 Report Final on the Proposed SNI Interconnector, August 2001, as shown in Table 3.

Table 3 Weighting Factors

10% POE	16.7%
50% POE	66.6%
90% POE	16.7%

The 90% POE demand forecast was not modelled. Based on the moderate levels of these demand forecasts the 90% POE unserved energy was assumed to be zero for the reliability modelling.

TEUS Modelling

The process used by TEUS has been described in detail in Appendix G of the DJV/TEUS report dated 22 September 2004 and summarised here.

The MARS model used by TEUS, allows load uncertainty to be specified and modelled so that for each hour during the simulations the load is adjusted up or down based on specified load scaling factors and their associated probabilities. These load scaling factors and probabilities were developed using NEMMCO's 50% POE, 10% POE and 90% POE demand forecasts.

The reliability modelling methodology used by TEUS for each year was as follows:

- Run 300 simulations of hourly time steps using load uncertainty;
- Add reliability new entry in 50MW increments to keep levels of USE under 0.002% criteria;
- Re – run 300 simulations of hourly time steps using load uncertainty to determine final levels of USE.

3.3 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 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; 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 discount rates used were 7%, 9% and 11%.

Terminal value

IES and TEUS used different methods to determine the terminal value.

IES used the average of the last 4 years of the modelling (2016 to 2019) as the terminal value.

TEUS used a process that extrapolated the results of the year 2015 to 2019 as described 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”

3.4 Scenarios

The scenarios modelled in the 2005 modelling study are shown in Table 4 below, along with their load growth, bidding strategy and new entrant cost assumptions.

Table 4 Scenarios and Assumptions

Case	Load Growth	Bidding Strategy	New Entrant Cost
Base Case	Medium	Historical	100% of ACIL 2005
SRMC	Medium	SRMC	100% of ACIL 2005
High Load Growth	High	Historical	100% of ACIL 2005
Low Load Growth	Low	Historical	100% of ACIL 2005
High New Entry Costs	Medium	Historical	110% of ACIL 2005
Low New Entry Costs	Medium	Historical	90% of ACIL 2005
Alternative 3	Medium	Historical	100% of ACIL 2005

IES and TEUS modelled the Base Case in parallel. TEUS modelled the remaining cases.

For the first 6 cases shown above Alternative Project 5 and Alternative Projects 0, 1 and 2 were modelled. For the last case shown above Alternative Project 5 and Alternative Project 3 were modelled. The projects are defined as follows:

- Alternative Project 0: Directlink
- 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 5: State based AC augmentations in NSW and Queensland.

Alternative Projects 0, 1 and 2 (i.e. Directlink and two other DC technologies) shared the same modelling. Alternative Project 3 (AC link) required separate modelling. Alternative Project 5 can be considered the 'Reference Case' against which the market benefits of Directlink and the alternative projects can be compared.

3.5 Modelling Calibration

Initial modelling was performed to calibrate 2005 modelling outcomes to recent market outcomes. The IES and TEUS modelled 2005 annual price statistics for the Queensland region, with Directlink, are shown along with actual 2003 and 2004 price statistics in Table 5. The actual price statistics were developed from hourly prices. The 2005 modelled price statistics are from one of the three iterations modelled.

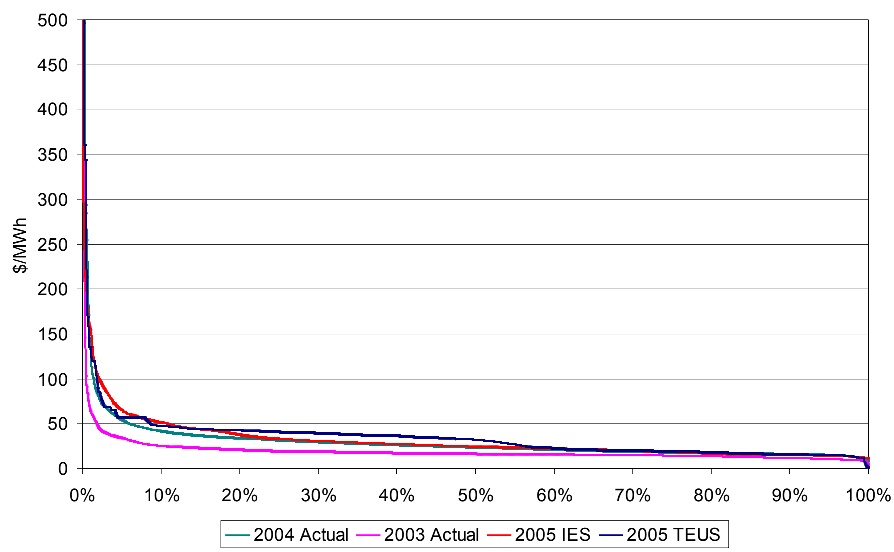
Table 5 Price Statistics ($/MWh)

	2003 Actual	2004 Actual	2005 IES	2005 TEUS
Average	34.55	22.52	33.69	35.15
Median	23.36	16.25	24.32	31.77
Max	8221.09	5351.33	7492.98	7146.73
Min	-65.38	-70.46	10.18	0
Standard Deviation	164.77	115.00	134.20	108.75

Figure 2 shows the same data in price duration format. Overall it can be seen that the TEUS price duration curve has more prices between $30/MWh and $40/MWh and IES has more prices between $50/MWh and $100/MWh than the actual curves. The TEUS bidding structure supported 5 bid bands only, rather than the 10 used in the market and in the IES modelling, and this is reflected in the pronounced steps seen in the TEUS curve. Another outcome of using 5 bid bands rather than 10 is that it is more difficult to replicate the volatile nature of the NEM, where prices are low for the majority of the time, with a small number of very high price incidents contributing to an average price significantly higher than the median price.

However both sets of modelling give a reasonable approximation of the spot price outcomes seen in the market. Thus it was concluded that TEUS satisfactorily modelled historical bidding.

Figure 2 Queensland Price Duration Curves



4 Comparison of IES and TEUS Modelling

The results of the Historical Bidding Base Case modelled by both IES and TEUS are presented below. The "With Directlink" results refer to Alternative projects 0,1 or 2 and the "Without Directlink" results refer to Alternative project 5.

4.1 IES results

The annual average pool prices for both cases are shown in Table 6.

Table 6 Annual Average Prices ($/MWh)

Year	With Directlink				Without Directlink			
	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2005	35.81	33.73	35.77	32.22	37.34	33.09	35.86	33.4
2006	36.16	34.08	36.18	29.34	36.54	33.67	35.98	29.69
2007	37.07	34.7	35.83	33.4	37.93	34.27	36.16	34.09
2008	36.46	31.57	36.26	33.29	37.67	30.08	36.63	34.38
2009	38.44	33.09	38.14	36.22	40.88	32.46	38.92	37.72
2010	39.08	35.8	41.79	38.01	40.68	35.55	42.52	38.99
2011	43.95	38.5	43.31	41.86	42.53	36.29	42.94	40.95
2012	41.76	42.05	42.74	41.58	42.64	41.99	42.7	42.38
2013	41.66	38.41	42.7	42.34	42.83	38.31	42.61	42.87
2014	38.75	40.5	43.91	41.37	39.44	41.01	44.4	42.05
2015	41.58	41.7	45.23	43.83	40.42	40.68	44.56	41.15
2016	38.02	38.4	46.68	40.01	38.66	37.76	46.77	40.45
2017	47.08	38.83	42.9	43.42	48.97	36.98	43.55	44.64
2018	41.43	40.21	40.83	41.72	42.21	39.44	41.25	42.05
2019	38.22	38.8	42.92	35.99	39.56	39	42.79	36.46
Average	39.70	37.36	41.01	38.31	40.55	36.71	41.18	38.75

The following tables show the new entry in the With and Without cases as well as the deferred new entry. In both 2011 and 2015, there was a 150MW OCGT unit deferred in NSW for one year.

Table 7 New Entry MW– With Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	500	0	500	500	500	0	0	0	0	0
CCGT	0	0	385	0	0	0	385	385	1020	0	770
OCGT	0	0	300	150	150	0	150	150	150	0	300
Reliability	0	0	0	0	0	150	0	50	0	0	0

Table 8 New Entry MW– Without Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	500	0	500	500	500	0	0	0	0	0
CCGT	0	0	385	0	0	0	385	385	1020	0	770
OCGT	0	0	450	0	150	0	300	0	150	0	300
Reliability	0	0	0	0	0	150	0	50	0	0	0

Table 9 Deferred New Entry MW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	0	0	0	0	0	0	0	0	0	0	0
OCGT	0	0	150	0	0	0	150	0	0	0	0
Reliability	0	0	0	0	0	0	0	0	0	0	0

The total inter-regional market benefits are shown in Table 10 broken down into energy, reliability (change in residual USE), deferred market entry and deferred reliability plant. The energy benefits consist of the dispatch costs saving from thermal plants and the difference in the value of water stored in the reservoirs between the two cases.

The table shows the results with a 9% discount rate.

Table 10 Inter- Regional Market Benefits ($ million)

Value of Unserved Energy	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
$10,000/MWh	21.18	9.48	15.53	-	46.19
$29,600/MWh	21.18	9.48	45.98	-	76.63

4.2 TEUS results

The annual average pool prices for both cases are shown in Table 11.

Table 11 Annual Average Prices ($/MWh)

Year	With Directlink				Without Directlink			
	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2005	34.6	35.71	39.23	36.19	34.81	36.28	39.39	36.37
2006	37.33	41.78	42.01	38.73	37.76	42.75	42.57	39.16
2007	44.37	49.46	46.23	43.44	44.87	50.33	46.48	43.76
2008	46.31	43.66	47.68	45.44	47.65	43.07	48.95	46.22
2009	49.96	50.15	48.41	44.35	49.5	50.04	48.6	44.27
2010	49.57	46.72	49.71	43.91	50.88	48.14	52.4	46.06
2011	50.8	51.97	55.22	47.85	49.19	49.96	48.38	45.78
2012	45.72	47.76	51.27	46.38	46.42	47.71	51.92	46.95
2013	46.1	45.87	47.36	44.76	47.04	45.69	47.93	45.47
2014	48.26	47.93	47.74	43.42	49.87	47.81	47.76	43.93
2015	48.6	44.73	51.18	45.56	49.65	44.42	51.11	46.17
2016	47.5	44.56	53.12	46.04	48.6	44.05	53.89	46.81
2017	46.82	48.3	50.59	46.33	47.91	47.78	50.97	47.07
2018	45.36	43.86	50.86	43.75	46.86	43.6	50.62	44.24
2019	44.9	43.56	48.12	40.44	46.13	43.26	48.33	41.14
Average	45.75	45.73	48.58	43.77	46.48	45.66	48.62	44.23

The following tables show the new entry for the With and Without cases and the deferred new entry for the TEUS modelling. In 2009, there was a 150MW OCGT unit deferred in NSW for two years. In 2011, there was a 240MW CCGT unit deferred in SA for one year.

Table 12 New Entry MW– With Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	770	770	770	1010	1010	1155	770	770	1010	1540	1155
OCGT	0	0	150	0	0	0	0	0	0	0	0
Reliability	0	0	0	0	0	0	0	0	0	0	0

Table 13 New Entry MW– Without Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	770	770	1010	770	1010	1155	770	770	1010	1540	1155
OCGT	150	0	0	0	0	0	0	0	0	0	0
Reliability	0	0	0	0	0	0	0	0	0	0	0

Table 14 Deferred New Entry MW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	0	0	240	0	0	0	0	0	0	0	0
OCGT	150	150	0	0	0	0	0	0	0	0	0
Reliability	0	0	0	0	0	0	0	0	0	0	0

The total inter-regional market benefits are shown in Table 10. The table shows the results with a 9% discount rate.

Table 15 Inter- Regional Market Benefits ($ million)

Value of Unserved Energy	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
$10,000/MWh	2.18	23.46	14.79	-	40.43
$29,600/MWh	2.18	23.46	43.77	-	69.41

4.3 Comparison – Spot Prices

When comparing the IES and TEUS price outcomes it is necessary to look at both the average prices and price distributions.

From the average annual prices for the two sets of modelling, shown in Table 6 and Table 11, it can be seen that the TEUS annual prices are on average higher than IES annual prices. This is particularly pronounced after 2007, where the entry of Kogan Creek, a 750MW coal unit in QLD from December 2007, has a much greater effect on prices in the IES modelling than the TEUS modelling. Pool prices in the IES modelling are depressed from the entry of Kogan Creek until 2009 and no new market entry occurs until 2010. Market new entry first enters the modelling in 2009 in the TEUS modelling.

The ongoing differences in prices between the two sets of modelling are chiefly due to the different new entrant patterns, which can be traced back to the difference in price distributions. IES modelling has less new entry overall and more coal new entry than the TEUS modelling. This coal new entry depresses prices more than the CCGT new entry seen in the TEUS modelling. IES modelling also has a greater amount of OCGT new entry than the TEUS modelling. The higher prices in the TEUS modelling allow for more new entry overall.

To illustrate the differences in the price distributions, Figure 3 shows the price duration curves, average of 3 iterations, for the Queensland region in 2009 from both the IES and TEUS modelling with Directlink case. The price statistics for the same year's modelling are shown in Table 16.

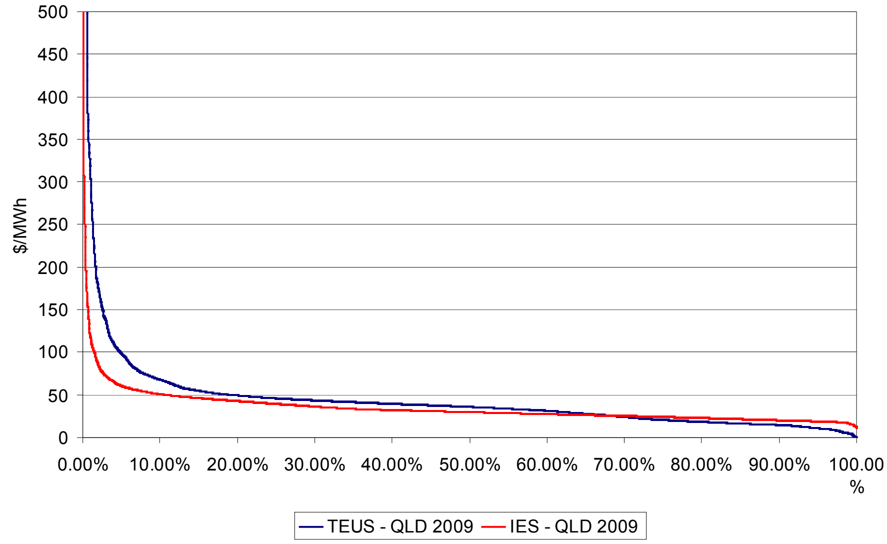
IES price duration curve shows prices under $51/MWh for 90% of the time, whereas TEUS has prices under $68/MWh for 90% of the time. The TEUS modelled price distribution has a greater number of price points between $50/MWh and $150/MWh, which support the entry of CCGT units.

IES modelling shows more price spikes than the TEUS modelling and hence supports the entry of OCGT units.

Table 16 2009 QLD Price Statistics ($/MWh) – With Directlink Case

	TEUS	**IES**
Average	50.15	38.79
Median	36.06	29.65
Max	3871.51	9204.41
Min	0.00	11.41
Standard Deviation	147.42	174.29

Figure 3 2009 QLD Price Duration Curve - With Directlink Case



4.4 Comparison – Profile of Benefits

The total interregional market benefits for the 9% discount rate are shown in Table 17. As can be seen the total benefits from both sets of modelling are close, with IES's modelling showing benefits around $7 million higher than those from TEUS's modelling. However the profile of the benefits are quite different, with the majority of IES benefits from energy savings and the majority of TEUS benefits from capital deferral.

Table 17 Inter- Regional Market Benefits ($ million)

	Value of Unserved Energy $k/MWh	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
IES	10	21.18	9.48	15.53	-	46.19
	29.6	21.18	9.48	45.98	-	76.63
TEUS	10	2.18	23.46	14.79	-	40.43
	29.6	2.18	23.46	43.77	-	69.41

The reliability benefits are close in both sets of modelling, with IES benefits slightly higher. This would be expected with the lower level of market entry in the IES modelling. The lower level of planting leads to more unserved energy, in both the With and Without cases, and also a greater difference between the levels of unserved energy between the cases. This is because the sensitivity of unserved energy to the level of installed plant increases as the level of installed plant decreases.

The higher levels of market deferral in the TEUS modelling, in particular the CCGT unit in 2011 in SA, are shown in the higher levels of market deferral benefits. During the analysis of the TEUS and IES modelling, particular emphasis was placed on the validation of the market deferrals seen in the modelling. In this particular case it was noted that in the IES modelling, in a similar time frame, there was a case in which a potential CCGT in SA was very close to being profitable in the Without Directlink case, and not in the With Directlink case. As the unit was not quite profitable it did not enter the market in either case and no market deferral was seen in the IES modelling. However it was easy to understand how the slightly higher prices in the TEUS modelling would have supported the unit in the Without case but not in the With case.

There are a number of reasons why the IES modelling showed higher energy benefits than the TEUS modelling. The first is that greater market entry deferral tends to lead to less energy benefits, as the case without the new entrant needs to use more expensive existing generation to cover load. In addition, as noted the IES modelling has greater resolution in the bidding structures and hence allows more interleaving of base load and peaking plant bids than the TEUS modelling. This allows the ability of the project to displace more expensive peaking plant to be better reflected in the modelling.

4.5 Conclusions

Given the differences in prices and market entry schedules the overall agreement in total benefits is very close, reflecting the balance between energy deferrals and capital deferrals in the market.

Considering that the two sets of modelling used different simulation models, slightly different assumptions and methodology the overall agreement in the total interregional benefits gives confidence in the robustness of the results. The analysis of the modelling also gave confidence that the stated methodology was being followed and that the modelling was an accurate portrayal of the potential benefits of the project.

5 SRMC Results

The results of the TEUS SRMC Bidding Base case are presented below. The "With Directlink" results refer to Alternative projects 0,1 or 2 and the "Without Directlink" results refer to Alternative project 5.

The annual average pool prices for both cases are shown in Table 18.

Table 18 Annual Average Prices ($/MWh)

Year	With Directlink				Without Directlink			
	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2005	16.93	16.25	26.31	20.86	17.03	16.29	25.82	20.90
2006	18.03	17.46	27.00	22.20	18.15	17.54	26.95	22.27
2007	19.92	18.16	29.09	24.94	20.06	18.19	29.05	25.00
2008	20.45	17.78	29.07	25.64	21.27	17.87	29.47	25.77
2009	25.00	21.06	30.87	28.48	26.06	20.93	30.95	29.03
2010	27.22	23.49	33.15	30.51	29.05	23.54	33.48	30.99
2011	39.27	38.12	35.29	34.39	33.64	32.45	35.25	33.83
2012	40.60	47.22	36.63	36.38	45.17	49.48	37.85	39.03
2013	44.44	48.57	41.59	41.17	49.04	51.98	42.19	42.39
2014	45.28	43.08	43.61	45.23	43.25	52.77	42.39	43.80
2015	44.00	52.36	45.67	45.36	45.19	43.96	46.70	48.68
2016	44.89	49.72	51.58	50.61	45.74	46.98	55.03	54.87
2017	48.98	53.66	54.15	47.96	46.21	50.67	53.18	46.46
2018	45.84	50.59	56.99	50.08	46.98	50.77	50.65	47.58
2019	47.11	57.29	54.67	49.49	46.18	54.81	51.68	45.93
Average	35.20	36.99	39.71	36.89	35.53	36.55	39.38	37.10

The following tables show the new entry for the With and Without cases and the deferred new entry for the SRMC modelling.

Table 19 New Entry MW– With Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	500	0	0
CCGT	0	0	0	385	385	385	0	770	385	1155	770
OCGT	0	0	300	150	450	300	750	150	300	150	150
Reliability	0	0	850	1200	1350	1550	1850	1950	1900	1650	1850

Table 20 New Entry MW– Without Directlink

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	500	500	0
CCGT	0	0	0	0	385	0	385	770	385	1010	385
OCGT	0	0	450	300	300	1050	450	150	150	0	450
Reliability	0	50	800	1350	1600	1450	1700	1800	1850	1400	1750

Table 21 Deferred New Entry MW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	500	500
CCGT	0	0	0	-385	-385	-770	-385	-385	-385	-530	-915
OCGT	0	0	150	300	150	900	600	600	450	300	600
Reliability	0	50	-50	150	250	-100	-150	-150	-50	-250	-100
Total	**0**	**50**	**100**	**65**	**15**	**30**	**65**	**65**	**15**	**20**	**85**

Table 22 shows the deferred new entry, market and reliability, by region.

Table 22 Deferred New Entry MW By Region

Region	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NSW	0	50	100	115	65	115	165	115	115	65	80
QLD	0	0	0	0	0	-35	0	0	-50	0	0
VIC	0	0	0	0	0	0	-50	0	0	15	165
SA	0	0	0	-50	-50	-50	-50	-50	-50	-60	-160

The total inter-regional market benefits are shown in Table 23. The table shows the results with a 9% discount rate.

Table 23 Inter- Regional Market Benefits ($ million)

Value of Unserved Energy	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
$10,000/MWh	14.49	56.61	0.97	-28.11	43.97
$29,600/MWh	14.49	56.61	2.87	-28.11	45.87

5.1 Analysis – Spot Prices

Initial observations after an analysis of the average price and price distributions from the SRMC modelling were as follows:

- The average annual prices were slightly higher than would be expected, particularly in Victoria in the early years of the study. Sub $20/MWh prices would be expected over the period 2006 to 2009 whereas the TEUS modelling had these rising to over $25/MWh during this period. This was quite different to the SRMC bidding case done by TEUS in 2004 which showed considerably lower prices.
- The price duration curves produced by the modelling were of the shape expected for SRMC bidding. The curves displayed “steps” corresponding to the SRMC of generators such as coal and gas, particularly in the longer term as new plant entered the market (and is increasingly the marginal price setting plant) as expected.
- The pattern of daily load shapes were “spikier” than would be expected and showed more prices over $30/MWh than would be expected.

- Prices that appeared above new entry costs were observed in a number of years, especially in South Australia towards the end of the study. However, this was not unexpected given the nature of SRMC prices and the methodology of requiring generators to be economic “on the pool” once entered.

To better illustrate the differences in the spot price profile resulting from the TEUS modelling and that expected by IES, the prices for a sample week in March 2006 are plotted and shown overleaf. Figure 4 shows the TEUS modelling results and Figure 5 shows the results from the IES check modelling using the same assumptions as the TEUS 2004 modelling.

As can be seen, the TEUS modelling exhibits higher volatility in prices than the IES modelling.

Figure 4 TEUS - March Week in 2006

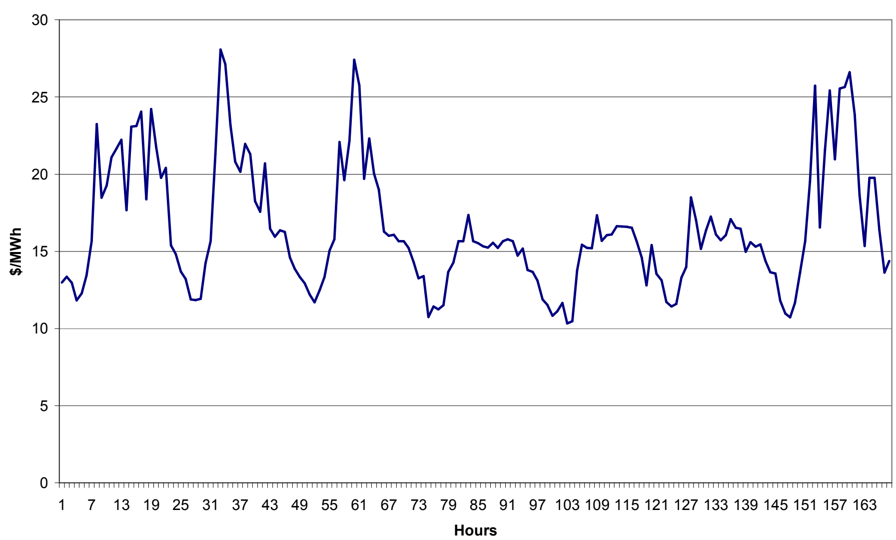
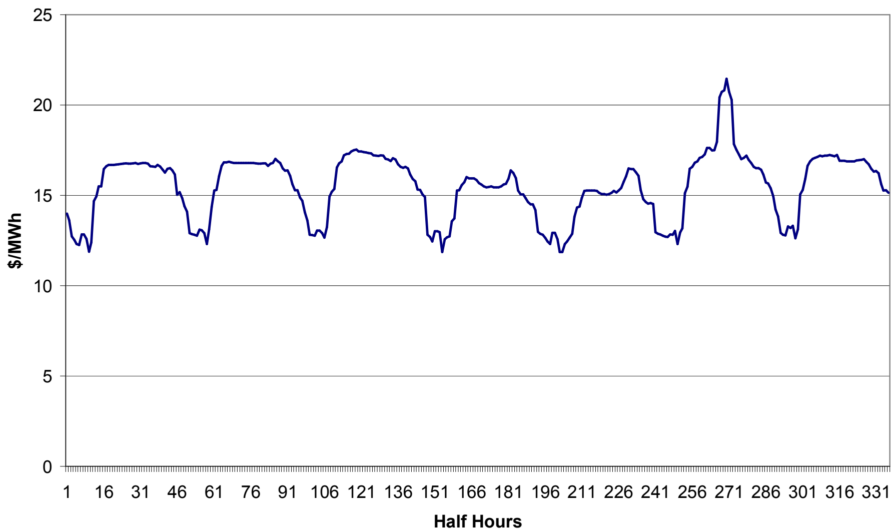


Figure 5 IES – March Week in 2006



TEUS in their note of 16 September 2005 discussed the reasons for the increase in the Victorian price between the 2004 and 2005 modelling. Briefly, the changes in the outage assumptions between the two sets of modelling changed the operation of the Victorian coal plants. In the 2004 modelling, the Victorian coal plants achieved capacity factors of around 95%, and in the 2005 modelling these capacity factors were around 2-6% lower. Given that in the 2004 modelling all the Victorian coal plants had the same forced outage rate of 1.86% and planned outage rates of 10 days per year, it is reasonable that the later modelling had increased outage rates for the older Victorian units, in particular the Hazelwood units.

These higher outage rates would lead to higher average pool prices, and explain the spikier nature of the price distribution as the intermediate and peaking plants run more frequently to meet load. It should be made clear that these comparisons relate to the two sets of TEUS modelling. The current SRMC modelling price distributions show significantly less prices over $30/MWh, and hence less operation of intermediate and peaking plant, than actual NEM outcomes, as would be expected from SRMC modelling.

5.2 Analysis – New Entry Deferrals

The market deferrals seen in the SRMC scenario are not as straightforward and easy to understand as those in the Historical Bidding base case, where small (150MW-240MW) OCGT and CCGT units were deferred for one or two years due to Directlink.

In the SRMC bidding scenario, there was a mixture of plant deferral and plant substitution, where the two cases, With and Without Directlink, supported different plant types. The With Directlink case tended to support less OCGT units and more CCGT units than the Without Directlink case. In the later years the Without Directlink case also supported an additional coal unit.

In the modelling from 2011 to 2017 the general pattern of market entry was the deferral of OCGT units in the With Directlink case in one year followed by the entry of additional CCGT units in the following year. This dynamic is expected, as the general effect of the interconnector is to damp out price volatility and hence defer peaking units. Load growth will then cause prices to increase in both cases, and the case without the additional peaking unit will tend now to have higher prices than the case with the unit.

For example, in 2011 there was a deferral of a 150 MW OCGT unit in NSW. The annual average pool prices in NSW in the previous year, 2010, were \$27.22/MWh with Directlink and \$29.05/MWh without Directlink. This price differential would have continued into the following year, and most likely would have increased if the planting in the two cases remained the same. However, the differential allowed the additional planting of the OCGT in the without case, leading to a higher annual average price in the case with Directlink in NSW in 2011, \$39.27/MWh, than in the case without Directlink, \$33.64/MWh.

In 2012 the higher prices in the With Directlink case, caused by the deferred OCGT unit, were able to support the entry of a 385MW CCGT in NSW, rather than the 150MW OCGT unit in NSW in the Without Directlink case.

A similar situation occurred in Victoria in 2018. In the Without Directlink case, a 500MW coal was found to be the most profitable new entrant, and in the With case a 385MW CCGT unit was the most profitable. IES performed spot check modelling to confirm this dynamic and the modelling supported the market entry decisions in the TEUS modelling.

The total level of market deferral in MW ranged from –235MW (more plant in the With case) to 270MW in the Without case. The average level of market deferral from 2011 to 2019 was 100MW. This level of market deferral seems reasonable given the service level of the project.

Due to the low prices in the SRMC bidding scenario, levels of market entry were not high enough to keep the levels of USE under the 0.002% standard. Reliability planting was necessary in the SRMC case from 2010 onwards. When there was more market entry in the With Directlink case, there tended to be more reliability entry needed in the Without Directlink case, causing an overall net deferral of plant with Directlink in place.

Including the reliability plant, the total level of new entrant deferral in MW ranged from 15MW to 100MW, with an average of 50MW from 2010 to 2019.

5.3 Analysis – Profile of Benefits

The annual benefits, for the \$10,000/MWh value of lost load, are shown in Table 24. As can be seen there are large swings in the benefits in the different categories and in the different years. This is due to the lumpy nature of the new entry and the effect the new entry deferrals have on the other benefits.

Table 24 Annual Modelling Results ($ million) – SRMC Scenario

Year	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
2005	0.22	0.00	-0.02	0.00	0.20
2006	1.05	0.00	-0.04	0.00	1.01
2007	1.21	0.00	0.03	0.00	1.24
2008	2.21	0.00	0.19	0.00	2.40
2009	2.65	0.00	0.59	0.00	3.24
2010	3.18	0.00	-0.06	26.10	29.22
2011	0.39	78.30	-1.02	-51.83	25.84
2012	18.33	-245.71	-0.16	104.03	-123.50
2013	23.19	-81.01	-0.58	53.31	-5.09
2014	55.32	64.22	0.49	-180.86	-60.83
2015	36.37	163.71	-2.11	-26.84	171.12
2016	29.94	-0.49	-1.64	-1.11	26.71
2017	25.95	-78.79	2.24	51.09	0.49
2018	-110.74	762.30	0.20	-104.77	546.99
2019	-89.55	-156.57	5.27	76.45	-164.41

The NPV results for the 5 extrapolated years, and the average of these 5 years are shown in Table 25. These are for the 9% discount rate sensitivity and the $10,000/MWh value of lost load sensitivity. The method of averaging the extrapolation of the last 5 years of the modelling smoothes out the swing in benefits caused by the lumpy nature of the new entry.

Table 25 NPV Benefits ($ million) for the 5 Extrapolated Cases and Average – SRMC Scenario

Start Extrapolation Year	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
2016	228.40	-32.80	-10.18	-30.72	154.71
2017	200.94	-32.80	-8.22	-30.72	129.20
2018	184.28	-65.72	7.09	-8.77	116.89
2019	-305.24	237.40	0.01	-48.99	-116.82
2020	-235.92	176.97	16.15	-21.35	-64.15
Average	14.49	56.61	0.97	-28.11	43.97

5.4 Conclusions

Although there were differences in the price outcomes between the TEUS SRMC modelling and what IES expected it was found that the levels of market and reliability new entry deferral and the size of the total benefits found in the modelling were reasonable.

6 Additional Case Results

The additional cases modelled by TEUS were:

- High Load Growth
- Low Load Growth
- High Market Entry Cost
- Low Market Entry Cost

The high load growth and the low load growth were based on the 2003 SOO high and low economic forecasts, respectively. The Northern NSW forecasts were developed from information in TransGrid's 2003 Annual Planning Review.

The high market entry (ME) cost scenario used new entry costs of 110% of the 2005 ACIL Tasman costs, and the low ME cost scenario used new entry costs of 90% of the ACIL Tasman costs. The ME cost scenarios used the medium load growth forecasts.

All 4 cases used historical bidding.

6.1 Results

The market benefits for the additional cases are shown in Table 26. These results are for the 9% discount rate sensitivity. The base case results are shown for comparison.

Table 26 Inter- Regional Market Benefits ($ million)

Case	Value of Unserved Energy $k/MWh	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
Base Case	10	2.18	23.46	14.79	-	40.43
	29.6	2.18	23.46	43.77	-	69.41
High Load Growth	10	583.16	-405.41	-8.81	5.12	174.06
	29.6	583.16	-405.41	-26.09	5.12	156.78
Low Load Growth	10	-5.37	32.49	1.46	-5.75	22.84
	29.6	-5.37	32.49	4.33	-5.75	25.70
High ME Cost	10	-4.78	-6.08	30.46	-3.69	15.91
	29.6	-4.78	-6.08	90.15	-3.69	75.60
Low ME Cost	10	340.07	-249.96	-1.54	-8.72	79.86
	29.6	340.07	-249.96	-4.55	-8.72	76.84

It can be seen that in general the total benefits increase as the load growth increases, and decrease as the market entry cost increases.

For the high load growth and the low ME cost there are large energy benefits, partially offset by large negative market deferral benefits. Reliability benefits in both cases are relatively small.

The magnitude of the energy and deferred market entry benefits in the high load growth scenario and the low ME cost scenario may initially look surprising. However these results provide a good illustration of the dynamic between the individual components of the total benefits.

In both these scenarios the project initially deferred OCGT and CCGT units in the With Directlink case, causing positive market deferral benefits and small or negative energy deferral benefits. However as time progressed, the deficiency of CCGT/OCGT units in the With Directlink case meant that this case could support coal units that the Without Directlink case could not. This caused the large negative capital deferral benefits seen, along with the large energy benefits.

IES performed spot checks of the TEUS modelling, in particular to verify the new entry decisions made and the magnitude of the energy benefits seen. In both cases the IES modelling agreed with the TEUS modelling.

As shown in Table 27 and Table 28 below, the total level of deferred MW was generally positive in both these scenarios, so the expected reliability benefits with Directlink in service were cancelled out by the additional plant in the Without Directlink case giving overall negative reliability benefits.

The high load growth scenario had one instance of deferred reliability plant in 2017, causing a positive deferred reliability plant benefit. The low ME cost scenario needed extra reliability plant in the case with Directlink in 2018, causing a negative deferred reliability plant benefit.

Table 27 Deferred New Entry MW - High Load Growth

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	-500	-500	-500	-1000	-1000	-500	-500	-500	-500
CCGT	0	0	770	530	385	1155	1155	145	385	385	770
OCGT	0	150	150	150	150	150	0	150	150	150	0
Reliability	0	0	0	0	0	0	0	0	100	0	0
Total	**0**	**150**	**420**	**180**	**35**	**305**	**155**	**-205**	**135**	**35**	**270**

Table 28 Deferred New Entry MW - Low ME Cost

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	-500	-500	-500	-500	-500	-500	-500	-500
CCGT	0	385	385	625	770	385	625	385	625	770	770
OCGT	0	0	0	0	0	0	0	0	0	0	0
Reliability	0	0	0	0	0	0	0	0	0	-200	0
Total	**0**	**385**	**385**	**125**	**270**	**-115**	**125**	**-115**	**125**	**70**	**270**

In the high ME cost scenario the reliability benefits are large and positive, and the energy and capital deferral benefits are relatively small and negative.

The general pattern seen in the modelling for this scenario was the higher prices in the Without Directlink case would support a 385 MW CCGT unit one year earlier than in the With Directlink case. The lower prices in the With Directlink case, which could not quite support the larger CCGT unit, would still be able to support 300MW of OCGT plant. This meant that a total of 85MW of plant would be deferred giving a positive capital deferral benefit and a negative energy benefit. However the entry of the CCGT unit in the With Directlink case in the following year would swap the benefits to a negative capital deferral benefit and a positive energy benefit. The overall level of market deferral from 2009 to 2019 varied from –300MW to 85MW and averaged –53MW. This caused the overall negative capital deferral benefit. The energy benefit was also negative overall because even though the Without Directlink case averaged less new entry, the new entry it did have was CCGT plant rather than the more expensive OCGT plant.

The main consequence of the higher levels of planting in the case With Directlink was the relatively large positive reliability benefits seen in the modelling.

As can be seen in Table 29 the last year of the modelling, 2019, was an exception to this general pattern – the case without Directlink had a higher level of new entry than the case with Directlink – causing the need for additional reliability plant in the With Directlink case and hence a negative reliability capital deferral benefit.

Table 29 Deferred New Entry MW - High ME Cost

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	385	0	0	385	0	385	0	0	0	0	-240
OCGT	-300	-300	-300	-300	-300	-300	-150	0	0	150	300
Reliability	0	0	0	0	0	0	0	0	0	0	-100
Total	**85**	**-300**	**-300**	**85**	**-300**	**85**	**-150**	**0**	**0**	**150**	**-40**

In the low growth scenario the deferred market benefits are large and positive, the reliability benefits are small and positive and the energy benefits are small and negative.

In this scenario there was no deferred capital entry until 2017, as shown in Table 30. In 2017, in the case without Directlink a 385MW CCGT unit in Victoria was the most profitable new entrant and in the case with Directlink a 240MW CCGT unit in South Australia was the most profitable new entrant. This meant that Directlink effectively deferred 145MW of CCGT plant. Directlink deferred an additional 385MW CCGT unit in NSW in 2018. An additional OCGT unit was then needed in the case with Directlink by 2019 due to the higher prices caused by the shortage of CCGT capacity in this case.

The deferrals in 2017 and 2018 caused the large positive market capital deferral benefits seen and also the negative energy benefits. The negative energy benefits were relatively small due to the positive energy benefits in the years prior to 2017, when the levels of new entry were the same in both cases.

The differential in planting also caused additional reliability plant to be needed in the With Directlink case in 2017 and 2018, and in the case Without Directlink in 2019. Overall there was more reliability plant needed in the With Directlink case causing the negative reliability capital deferral benefit seen.

As expected by the total levels of deferred new entry in the two cases shown below, the reliability benefits were positive in the years prior to 2017, negative in the years 2017 and 2018, and positive again in 2019, averaging to a small positive benefit.

Table 30 Deferred New Entry MW – Low Load Growth

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	0	0	0	0	0	0	0	0	0	0	0
CCGT	0	0	0	0	0	0	0	0	145	385	0
OCGT	0	0	0	0	0	0	0	0	0	0	-150
Reliability	0	0	0	0	0	0	0	0	-50	-200	150
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**95**	**185**	**0**

6.2 Conclusions

The large swings in the different categories of benefits seen in the additional cases are largely due to the size of the new entry, 150MW for OCGT, 385MW for CCGT and 500MW for coal. These sizes were modelled because it was not thought to be realistic to model 50 or 100MW increments of CCGT or coal units.

In the modelling, when applying the new entrant rule, it is common that a plant will be just profitable in one case and just not profitable in the other case, so that even a small change to the modelling assumptions can change the new entrant selection. The relatively large size of the new entrant plants means that the addition or absence of a new plant will have a large effect on the modelling outcomes and benefits – dispatch costs, spot prices and reliability. This will in turn affect the following year's new entrant decisions and outcomes, so that two scenarios with even small differences in initial assumptions can end up looking very different.

The analysis of the TEUS modelling of the additional cases showed that the differences in the cases could be traced back to the first new entrant selections made and the flow through effect that these had. Analysis of the TEUS spot prices and spot check modelling performed by IES satisfied it that the new entrant rule had been applied correctly in the TEUS modelling. In addition, the magnitude of the individual benefits, energy, reliability and market and reliability capital deferral, were found to be reasonable and the individual benefits balanced out to give total benefits in the range expected.

7 Alternative 3 Results

The Alternative 3 scenario modelled the AC link using a power shifting transformer.

The total inter-regional market benefits resulting from the TEUS modelling are shown in Table 31. The table shows the results with a 9% discount rate.

Table 31 Inter- Regional Market Benefits ($ million)

Value of Unserved Energy	Energy	Deferred Market Entry	Reliability	Deferred Reliability Entry	Total Benefits
$10,000/MWh	-	-	-2.61	-	-2.61
$29,600/MWh	-	-	-7.73	-	-7.73

This alternative project effectively provides no increase in interregional transfer capacity between NSW and QLD and the limits in the Prosym modelling in the With Directlink case remained the same as for the Without Directlink case so the energy and market deferral benefits are zero.

The limits provided by BRW for the MARS reliability modelling were slightly lower in the southward direction for the Alternative 3 project than in the reference case (the without case). This led to the negative reliability benefits.

In both the With and Without cases the levels of unserved energy were under that specified by the reliability standard so no reliability entry was necessary and the deferred reliability entry benefits were zero.

7.1 Conclusions

Given that Alternative 3 (With Case) gives no additional usable interregional capacity in either direction compared to the Without Case, IES agree that the total benefits from this scenario would be negligible as shown by the TEUS modelling.

8 Review of Sensitivity Assumptions

The scenarios modelled by TEUS and that were thus available for review were as follows:

- Historical Bidding
- SRMC Bidding
- High Load Growth
- Low Load Growth
- High Market Entry Cost
- Low Market Entry Cost

For each of these six scenarios 3 discount rate sensitivities, 7%, 9% and 11% and 2 value of unserved energy sensitivities, $10,000/MWh and $29,600/MWh were developed, giving a total of six scenarios for each of the above cases.

IES have been asked to give a view on the suitability of these sensitivities for the purposes of the regulatory test. As discussed in the April 2005 IES Report, the current wording of the regulatory test does not specify what value of lost load (VoLL) should be used in the determination of market benefits. In the Murraylink decision, both the market price cap value of VoLL ($10,000/MWh) and an estimated value of reliability to the customer were used ($29,600/MWh). This estimated value of reliability is the same as that used by VENCorp in their transmission studies and is an average for the Victorian region. To IES's knowledge, no detailed studies of the value of reliability to customers in the other NEM regions exist.

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

The review of discount rates used was beyond the scope of the review. However in IES's experience a discount rate of 9% seems reasonable.

9 Conclusions

IES and TEUS followed a modelling process for the purposes of providing a set of modeling results suitable for use in ACCC regulatory test for Directlink. This process involved the agreement of the modelling assumptions and methodology used, as well as validation of the TEUS modelling results as the modeling was performed. IES performed independent modelling of the base case as well as spot check modelling of the additional cases.

The different market modelling software used along with some variation in the historical bidding processes used by IES and TEUS caused differences in the base case results. However both sets of modelling provided realistic results and the overall market benefits shown were in agreement.

After analysis and spot checking of the additional TEUS modelling cases, IES is of the opinion that the modelling followed the stated methodology and that the results for these cases were reasonable and valid.

In conclusion, IES believes that the TEUS 2005 modelling results can be relied upon for the purposes of the ACCC test.