Loy Yang Marketing Management Company Pty. Ltd.

AGL Hydro Pty. Ltd.

International Power (Hazelwood, Synergen, Pelican Point, Loy Yang B and Valley Power)

TRUenergy Pty. Ltd.

Flinders Power

Hydro Tasmania

InterGen (Australia) Pty. Ltd.

22 December 2006

Dr John Tamblyn
Chairman
Australian Energy Market Commission
Level 16
1 Margaret Street
Sydney NSW 200

Emailed: **submissions@aemc.gov.au**

Dear Sir,

Congestion Management Review – modelling of future efficiency gains

In our letter dated 3 November (to which you responded 17 November) we foreshadowed providing you an estimate of the forward-looking efficiency gains that available through a comprehensive approach to resolving matters of NEM congestion. We are pleased to provide you the attached report, produced by the well respected NEM consultants, Intelligent Energy Systems (IES) that provides such an estimate. We apologise for the delays in providing this to you.

IES' modelling shows significant long-term efficiency gains through the efficient location of new generation and commensurately lower transmission investment requirement when new generators are exposed to the full costs of congestion and/or new transmission that their investment causes. The efficiency gain available measured in one state alone over 15 years accrues an NPV in the order of $200m[1].

[1] Or around $550m if undiscounted (2006 dollars)

Background

As discussed in our letter, we are aware that the Commission is uncertain of the materiality of the transmission congestion issue and whether there would be significant efficiency gains to be had through congestion management. We agree that historical reviews of dispatch outcomes show small to moderate costs of congestion. Our contention is that the most likely gains are in the area of dynamic efficiency, largely through the locational decisions of future generators.

This view has been espoused by many commentators, including the Energy Reform Implementation Group, which stated "ERIG considers that it is crucial that signals are put in place for the efficient location of generation investment"[2] however there is little quantitative evidence available supporting the position. This work is intended to fill that gap.

Scope

This activity has been undertaken to demonstrate the level of net efficiency gain that is *potentially* available, compared to status quo, through a comprehensive solution implemented out of the Congestion Management Review. It does not propose nor critique any specific proposals. The consultants were tasked to presume an idealised solution that would accurately expose new entrant generators to the full cost of their locational decision. Because no specific solution is being proposed the report addresses neither related implementation complexity nor costs including effects on existing participants.

The contributors are not proposing a specific solution that would deliver these gains. Indeed, the undersigned have supported a number of different proposals in their previous submissions to the review. The reader should be cautious to avoid over-interpreting the modelling and its labelling as implying our support to any particular solution. It is our expectation that the Commission, having been made aware of the potential gains on offer, will now move to analyse several solutions to identify which of these can capture the most efficiency gain, net of cost. The contributors will be pleased to discuss potential solutions with the Commission, jointly and severally.

Approach

Modelling the sub-regional locational decisions of generators and the resultant impact on transmission spending is very challenging requiring a broad range of skills. IES was chosen as our consultant due to their experience in modelling both the new entry points of generation and the complexity of intra-regional networks. Their intra-regional network model and transmission knowledge was however developed robustly only for the Queensland region, for which they identified 11 nodes. In the interest of time, we have asked IES to apply the theoretical solution only to new generators in Queensland, and NEM-wide materiality can be assumed by extrapolation. Despite this

[2] ERIG Discussion Papers, Pg 144

limitation, Queensland represents an excellent case study as it comprises roughly half of the load and generation growth of the NEM, it is geographically large and these 11 nodes encompass a very wide range of new entrant costs, from the cheapest to the most expensive in the NEM.

The approach, in summary, was to model scenarios:

- A **base case** where generators receive income as expected by generators in the NEM under the current rules from 2006/7 through to 2020/21. New entrant generators are developed ideally, that is in response *only* to regional market prices and loss factors[3], using the new-entrant costs used by NEMMCO in its ANTS modelling. Queensland transmission begins with existing and committed[4] projects, however as demand grows and where generation is remote from that demand, new transmission is built as per the current Queensland transmission reliability criteria.

- **Scenario 1** models **locational pricing for new generators** where new entrants receive a locational marginal price where they have entered a congested area. This results in a sharper congestion incentive effect than the existing "bidding war" arrangements. To mathematically develop the correct new-entrant signal, IES has used their "nodal pricing" model for the 11 nodes. This should not be inferred to imply that nodal pricing is necessary to create this signal[5].

- **Scenario 2** models **locational pricing and transmission causer-pays for new generators** where new entrant generators would be required to fund any transmission augmentation directly or indirectly caused by their location. This requires the modeller to estimate the resultant transmission costs that would be incurred were large amounts of generation to locate at each of the nodes, and then amortise those costs into a operating charge upon new entrants at that node, effectively raising their marginal cost[6].

IES' model is NEM-wide, however as noted above the changed arrangements for scenarios (1) and (2) were only applied to Queensland. So that they were not counteracted by a response from the unchanged other regions, new entry (generation and transmission) in the other regions was fixed as per the base-case run.

The total industry supply cost, being an aggregate of:

- dispatch costs,

[3] The modelling does not factor in the effects of other drivers on the type, timing and size of new plant which would change the modelled locational price outcomes in Queensland's sub-regions. Also as per the current arrangements, congestion is resolved via a "bidding war" i.e. is equally shared between new entrants and incumbents.

[4] Being those planned to be develop in the upcoming 5 year period, although some of these are yet to pass the regulatory test.

[5] Other arrangements, such as widespread use of CSC/CSP, or a cross-generator compensation arrangement can be used to have a very similar economic effect to this nodal pricing model.

[6] See also the relevant comment in "Important Limitations" below

- capital cost in new generation,
- capital cost in new transmission, and
- unserved load (if any)

was compared between the scenarios. Any change is considered a change in net welfare and has been calculated as an NPV (discounted at 9%) to the current year.

Outcomes

Differences were marginal for the early years, 2006/7 to 2013/14. This is largely explained through the large level of transmission projects considered as committed[7], which provide unconstrained transport capacity in the short-term. The scenarios then show considerable divergence in the investment regime compared to the base case. The results lead to:

- In the scenarios, new entrant generation being located in more load-rich locations. As a result of differences in locational fuel availability, generation is of a different type and tends to be slightly deferred compared to the base case, without materially affecting reliability.
- Uncommitted transmission projects, which are required from 2017 in the base case being deferred in the scenarios.
- Dispatch costs increasing in the scenarios as the new plant mix has higher short-run marginal costs than the base. This is outweighed by their capital cost savings.

Despite the considerably delayed and discounted benefits, they remain material in 2006/7 with a present value at $195m and $222m for the respective scenarios 1 and 2 compared to base case. Without discounting, the total nominal benefit is $540m and $580m respectively in 2006 dollars.

Important Limitations

As noted above, the regime has been applied only to Queensland, and a NEM-wide effect must be extrapolated.

An area particularly difficult to model in the timeframe is that of estimating idealised "causer-pays" transmission costs to apply to new generators in scenario 2. This is because each transmission augmentation will be highly dependent upon the exact circumstances, size and type of generation investment that the model outputs, as well as the methodology of allocation. IES have estimated the cost of such augmentations on a simple geographical distance from the primary load centre to node basis, which is then amortised into a simple $/MWh transmission levy upon each new generator at that node. It is quite possible, depending on the incidence of load growth, that some generation could enter at these nodes without requiring augmentations.

IES has used only a "traditional" new entrant generation set, including coal fired plant, open and combined cycle gas turbines and liquid fuelled gas

[7] Note these include planned projects that have not yet passed the regulatory test. Were congestion management techniques to be implemented very quickly, it is possible that some of these could be deferred.

turbines. IES has advised that where liquid fuel plant is promoted, demand-side participation may be a cheaper and simpler substitute. Wind is not considered a realistic new-entrant in Queensland and was excluded from the modelling, however the same locational incentive logic would apply to wind generation. Some of our earlier submissions have drawn specific attention to poorly located wind generation that can cause congestion that is unlikely to be built out for reliability reasons.

Conclusion

We commend this report to the Commission and hope that it will provoke further investigation into solutions for providing a robust congestion management regime with a clear locational signal to new investors.

Further tabulated information and explanation can be provided on request. Please contact Roger Oakley (03) 9612 2211.

Yours faithfully,

……………………………………
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General Manager
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Hydro Tasmania

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Manager Public Policy and Regulation
Intergen (Australia) Pty. Ltd

MODELLING OF TRANSMISSION PRICING AND CONGESTION MANAGEMENT REGIMES

Report on the estimation of dynamic inefficiencies

22nd December 2006

FINAL

IES
Intelligent Energy Systems

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Summary of Findings

IES has undertaken modelling for a group of generators to estimate the impact on economic efficiency of relying upon the current NEM locational drivers for new generator investments and operation signalling. This group of generators comprises:

- Loy Yang Management Marketing Co;
- AGL Hydro;
- TRUenergy;
- International Power;
- Flinders Power;
- Intergen;
- Delta Electricity;
- Snowy Mountains Hydro; and
- Hydro Tasmania.

The objective of the modelling undertaken by IES was to assess the potential economic benefits to the market as a whole of locational signals incorporating both energy and transmission costs. The modelling compared the "current arrangements with two "hypothetical arrangements" which had varying degrees of locational signals.

The basis of the modelling study is the Queensland region[1] modelled using an explicit network model. The base time period is the fifteen-year period from 2006/07 to 2020/21. The key elements of the defined "hypothetical arrangement" compared to the "current arrangement" (current NEM pricing regime) are outlined as follows:

Current arrangements

The key features of the present NEM arrangements with respect to providing locational incentives for generation are:

- Regional pricing with an expectation of stability of the current regional boundaries;
- Static Marginal Loss Factors;
- Open access;
- The potential for generators to be constrained on or off without compensation which can result in intra-regional congestion rationing through a "bidding war"

[1] QLD was chosen due to the ready availability of information and the limited time frame in which this study was to be conducted.

process whereby generators offer their generation prices near the price floor; and

- The regulatory test for future transmission investment.

Hypothetical arrangements

The hypothetical arrangements reflect the use of a fully integrated congestion model of the NEM or an “idealistic generation/transmission planning” regime. Under this regime investment decisions would be approximated in a competitive market where investment is driven by the forecast price duration curve to determine the nature and timing of the investment whilst taking into account all fixed costs associated with the investment. This would mean that any new generation proposals would incorporate into the locational costing decision:

- The entire cost of congestion caused by the decision; or
- The likely cost of building out that congestion; whichever is lower.

To fully assess the economic impact of hypothetical pricing regimes, IES has undertaken modelling that addresses the following key aspects of cost to consumers over a 15 year period (2006-07 to 2020-21):

- Generators behaviour (offering different supply curves)
- Different physical generator dispatches even though the physical network is the same for the scenarios modelled until the point at which an option leads to a change in network investment;
- Different out turned spot prices; and
- Different investment incentives and decisions – generation and transmission.

The approach IES developed to meet these objectives has been designed to address the key issues and develop a suitable report within a limited timeframe. IES’s approach has been to model 2 cases to compare to the current framework as represented by a base or reference case. Each case has been modelled utilising an explicit network model that properly takes into account all material intra-regional constraints. An overview of the key parameters of each case and the results of the modelling is provided below.

The Base Case

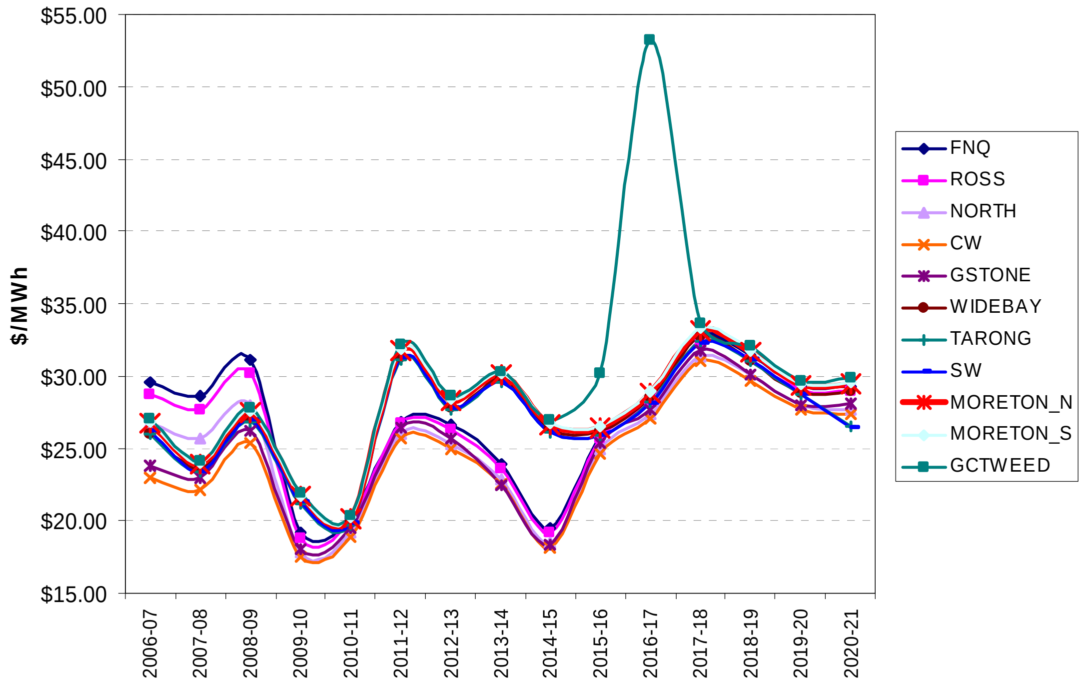
The Base Case has been designed to represent the current regulatory and market design framework. The case uses standard NEM regional pricing for generators and customers. Key assumptions for this case are as follows:

- Generator bids are determined in a manner that attempts to maximise the generator’s profits given contract and spot revenues, and are based on the regional reference price (RRP).

- The modelling incorporates committed network upgrades, new generation plant and plant upgrades as per the 2006 SOO and respective regional 2006 Annual Planning Reviews (APR).
- New entrant generation (other than committed as per the 2006 SOO) was determined using an automated new entry model that assumes market-driven merchant generation investment on the basis of the price duration curve that generators would receive – in this case the regional reference price. New entrant costs include locational fuel costs but do not include the cost of electricity transmission upgrades.
- Transmission expansions other than those deemed as committed from the respective 2006 APR have been made on the basis of reliability criteria i.e. the TNSP's build new transmission when congestion builds to a point that customer reliability criteria are impacted or when the network was excessively constrained.

The base case modelling undertaken has been done with all generators bidding to optimise their financial position against the QLD RRP – this is represented as the Moreton North price, the zone/node where south pine is located. The other prices in Figure 1 are nodal “shadow” prices and are used by IES in order to assess and value transmission constraints in a regime where the opportunity-cost value of those constraints is masked. These shadow prices (marginal costs) currently exist in the NEM as calculated values for individual constraints, and can be extracted from the NEMDE dispatch calculations published by NEMMCO. The nodal prices in IES’s modelling approximately represent the situation where all the network and security constraints that affect generation are incorporated into a CSP regime.

Figure 1 Base Case RRP and Nodal Prices



The forecast spot prices in Figure 1 are low, however that is a reflection of the cost of new entry as applied in the modelling. IES used the ACIL Tasman new entry costs as published in the 2006 SOO because they are publicly available numbers.

Transmission was upgraded to meet reliability criteria or where nodal prices consistently diverge in the modelling due to transmission constraints. The transmission upgrades undertaken on this basis are outlined in Table 1 as follows.

Table 1 Base Case Generic Transmission Upgrades

Year	Upgrade	Cost (AEC $M)
2017-18	500MW upgrade from Moreton_South to Gold Coast	$7.53
2017-18	1000MW upgrade from South West to Moreton_South	$46.58
2018-19	500MW upgrade from Central West to Moreton_North	$62.27

NB: AEC is annual equivalent cost.

The capital cost of 2,000MW of transmission upgrades required in this modelling case is $1.252 billion in current 2006 dollars.

Following the decision to undertake each transmission upgrade, anew sequence of new entrants was created to reflect the impact of transmission upgrades on the investors' decision to build. The resulting new entry generation schedule reflects the low cost of coal in south west Queensland. Post (NGAC) subsidy[2], the SRMC of coal-fired plant in this region is $5.56. Of the 2,500MW of generic plant added into the SW node 1,500MW is coal-fired plant. In effect a Kogan Creek B in 2013-14 and Kogan Creek C in 2019-20.

There is also 500MW of coal-fired plant scheduled for entry in Tarong in 2014-15, and in Gladstone in 2018-19. The remainder of the capacity (automatically) planted in the region is gas-fired GT or CCGT plant, primarily required to meet shoulder and peak requirements.

The estimated capital cost of the total construction required in the base case is $5.028 billion over the 15 year period modelled as follows:

Table 2 Base Case Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
5,028.00	108.75	405.00	608.00	0.00	2,031.25	1,875.00

Case 1: Locational Pricing for Generators

Case 1 assumes that generators are subject to a locational pricing regime, or nodal pricing for generators and a full regime of constraint support pricing.

Unlike the Base Case generators profit maximise based on spot market revenues derived from the locational price signal rather than the RRP, i.e. bids are now focussed on the price at the node in which the generator resides. When all constraints in the market are converted to Option 4 constraints and constraint support pricing is applied to each constraint then the net result will be, to a close approximation, nodal/locational pricing for generators. The differences between constraint support pricing and nodal pricing would be caused by losses being modelled as static loss factors in regions rather than dynamically (which would be the case under nodal pricing), and that some security constraints may not be able to be modelled as MW injections at specific nodes but may require the specific MW outputs of units or power stations in constraint support pricing In this case

Case 1 is designed to reflect the impact of this implementation of constraint support pricing across the NEM. This case could be considered an assessment of the impact of just short run (spot market) locational signals on timing and location of new entry.

Key assumptions for this case are as follows:

- New entrant generation in this case has been determined using the same automated new entry model as the base case, but using the nodal price duration curve rather than the RRP duration curve. Consistent with the base

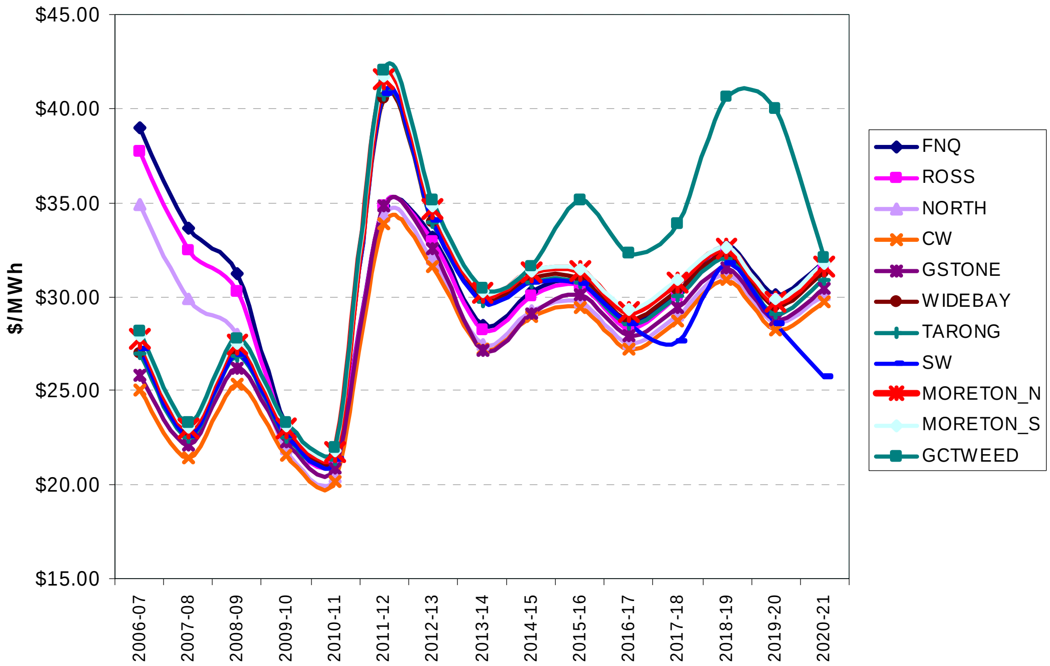
[2] IES has assumed that any new coal-fired generation will utilise technology that ensures it is below the NSW emissions benchmark, egg Kogan Creek.

case new entrant costs include locational fuel costs but do not include electricity transmission costs.

- Transmission expansion has been undertaken using the same methodology as applied in the Base Case.

The nodal/locational price results from this modelling show less divergence than the Base Case, with the exception of the Gold Coast area. This part of QLD is characterised by high demand growth forecasts and minimal capacity for new entry, i.e. limited numbers of locations/sites and a reliance on diesel fuel for any generation placed in the node.

Figure 2 Case 1: Locational Queensland Spot prices ($/MWh)



The significant differences between Case 1 and the Base Case come in the transmission upgrades required and the timing and placement of generic new entry. Case 1 required only one additional transmission upgrade between Moreton South and the Gold Coast, due to the cost limitations on new entry in that node. The capital cost of this generic transmission upgrade is $670 million.

The volume (and therefore cost) and type of generic new entry required when plant receives locational prices rather than regional prices is significant as shown by Table 3.

Table 3 Summary of Case 1 New Entry Differences by Plant Type

	Case 1	Base Case	Difference
GT	1,050	750	300
CC	1,340	640	700
Coal	2,000	2,500	-500
Total	**4,390**	**3,890**	**500**

To some extent the change in the pricing regime has resulted in (cheaper) generation replacing transmission upgrades. This is because in a nodal or locational pricing regime smaller and more flexible generation configurations have greater significance. The estimated capital cost of the total construction required in Case 1 is $5.033 billion over the 15 year period as follows:

Table 4 Case 1 Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
5,033.00	870.00	101.25	608.00	360.00	1,218.75	1,875.00

This compares favourably to the base case capital cost of $5.028 billion for 3,890MW of capacity. On a per MW basis the cost of capital in Case 1 is $1.15 million compared to the base case cost of $1.29 million, due solely to the change in the generation mix.

The overall benefit of this case as measured by the NPV is $194.65 million, driven for the most part by the change in the mix of new generation type. There has been an increase in the overall dispatch cost caused by increased generation from (relatively) more expensive plant, but this is offset by significant reductions in transmission and generation capital costs.

Case 2: Transferring the Cost of Transmission to Generators under a Locational Pricing Regime

Case 2 overlays the locational pricing regime investigated in Case 1 with a congestion cost levied upon new entrant generators that reflects long run locational costs based on future transmission costs. The case has been designed to locate new generation projects in locations optimal to the industry as a whole i.e. including TNSPs. This case has been referred to as the ‘hypothetical arrangement’.

New entrant generation in this case has been determined using the same automated new entry model as in Case 1, with new entry costs increased to account for the expected costs of network upgrades. The only transmission expansion not funded by increased new entry costs will be that required for reliability.

In this modelling IES assumes that once the generation investment has been made the transmission cost for the new generator remains fixed and hence unaffected by the generator's generation patterns. Therefore the generator's short run marginal costs (SRMC) are the same as for the Base Case and Case 1.

The levelised cost adders applied in Case 2 represent the costs of transmission upgrades relative to the distance from load centres. The locational costs applied to new entry in each node are shown at Table 5 below. These transmission costs could considerably improved with further work, but were felt to be adequate to give some idea of what the impact would be of a transmission charge for new generation investments on the economic efficiency of the market.

Table 5 Case 2 Transmission Upgrade Cost Adders

Node	km to primary load centre	Cost of Upgrade ($k/km)	Cost per km ($'000)	Fixed Costs ($'000)	Total Costs ($'000)	Capacity of Upgrade (MW)	Effective cost per kW	Effective cost in $/MWh	Levelised Cost Adder
Far North (FNQ)									
Ross	325	700	227,500	60,000	287,500	500	575	65.64	$6.10
North	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
Central West (CW)	871	700	609,875	60,000	669,875	500	1,340	152.94	$14.22
Gladstone	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
WideBay	290	700	203,000	60,000	263,000	500	526	60.05	$5.58
Moreton North (MN)									
Moreton South (MS)	30	700	21,000	60,000	81,000	500	162	18.49	$1.72
Gold Coast (GC)									
South West (SW)	286	1400	401,100	100,000	501,100	1000	501	57.20	$5.53
Tarong	266	1400	372,400	100,000	472,400	1000	472	53.93	$5.01

In this case therefore the cost of building coal in south west Queensland would be a fixed cost reflecting the capital cost of the plant plus a transmission fixed cost reflecting the $5.53 for future transmission expenditure

Similar to Case 1, the significant differences between Case 2 and the Base Case arise in the transmission upgrades required, and the timing and placement of generic new entry. However unlike Case 1, Case 2 required no additional transmission upgrades during the modelling period. The volume and type of generic new entry required in Case 2 is summarised in Table 6.

Table 6 Summary of Case 2 New Entry Differences by Plant Type

	Case 2	Base Case	Difference
GT	1,350	750	600
CC	1,440	640	800
Coal	500	2,500	-2,000
Total	**3,290**	**3,890**	**-600**

In addition to a change in the type and location of the new entry when compared to the Base Case, there has been a 600MW reduction in the overall volume of new entry required under this hypothetical arrangement. The estimated capital cost of the total construction required in Case 2 is $3.057 billion over the 15 year period modelled as follows:

Table 7 Case 2 Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
3,056.75	978.75	0.00	608.00	720.00	0.00	750.00

This compares favourably to the base case capital cost of $5.028 billion for 3,890MW of capacity. On a per MW basis the cost of capital in Case 2 is $0.93 million compared to the base case cost of $1.29 million.

The overall benefit of this case is $222 million, as measured by the NPV. Consistent with the Case 1 results, the change in new generation mix and location has driven the NPV benefit in Case 2; however the optimisation of new entry generation to include a transmission cost has resulted in both a reduction in the volume of new plant required, and the delay of all base case transmission upgrades.

The relative breakdown of the NPV variance is between Cases 1 and 2 shown in Table 8 below.

Table 8 Comparison of Benefits between Cases 1 and 2

	Dispatch Costs ($M)	Capital Costs (AEC - $M)	Transmission Costs (AEC - $M)	Total Costs ($M)
Case 1 Total $	-132.44	277.32	395.73	540.61
Case 2 Total $	-983.76	1,160.89	403.26	580.39
Case 1 NPV	-58.06	130.80	121.91	194.65
Case 2 NPV	-365.52	464.06	123.98	222.52

IES acknowledges that the calculation of the levelised cost adder in the manner undertaken for this case does not address transmission issues currently existing within the Ross and North regions of Queensland. The methodology used in calculating the adder is a great simplification of what a transmission charging regime for new generation might realistically look like. However, despite its shortcomings the hypothetical regime still shows net benefits for the market.

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1 Introduction

The AEMC is currently reviewing congestion management in the NEM. As part of this process a group of generators engaged IES to estimate the impacts on economic efficiency of relying upon the current NEM locational drivers for their impacts on new generator investments and operations. This group of generators comprises:

- Loy Yang Management Marketing Co;
- AGL Hydro;
- TRUenergy;
- International Power;
- Flinders Power;
- Intergen;
- Delta Electricity;
- Snowy Mountains Hydro; and
- Hydro Tasmania.

This group of generators will hereafter be referred to as the "Engagement Gens".

The objective of the modelling undertaken by IES was to assess the potential economic benefits to the market as a whole of locational signals incorporating both energy and transmission costs. The modelling compared the "current arrangements with two "hypothetical arrangements" which had varying degrees of locational signals.

Current arrangements

The key features of the present NEM arrangements with respect to providing locational incentives for generation are:

- Regional pricing with an expectation of stability of the current regional boundaries;
- Static Marginal Loss Factors;
- Open access;
- The potential for generators to be constrained on or off without compensation which can result in intra-regional congestion rationing through a "bidding war" process whereby generators offer their generation prices near the price floor; and
- The regulatory test for future transmission investment.

Hypothetical arrangements

The hypothetical arrangements reflect the use of a fully integrated congestion model of the NEM or an "idealistic generation/transmission planning" regime. Under this regime investment decisions would be approximated in a competitive market where investment is driven by the forecast price duration curve to determine the nature and timing of the investment whilst taking into account all fixed costs associated with the investment. This would mean that any new generation proposals would incorporate into the locational costing decision:

- The entire cost of congestion caused by the decision; or
- The likely cost of building out that congestion; whichever is lower.

1.1 Terms of Reference

The Terms of Reference provided to IES were as follows.

> *The consultant, using a market simulation, will estimate the resulting efficiency advantages, over an appropriate investment timeframe, such as 10 or 15 years if the hypothetical arrangements were adopted compared to the current NEM arrangements for congestion management and transmission pricing.*
>
> *The new generation entrants in the simulation would be driven by the price duration curves. That is the new entrants would be the most 'profitable' new entrant plant technologies based on the price duration curves.*
>
> *It is expected that a well developed NEM model with a new-entrant simulator can be used to propose new projects and that the consultant will:*
>
> - *In the base case allow these projects to locate in locations that appear optimal to the investor within the current regime.*
> - *In the hypothetical case locate these projects in locations optimal to the industry as a whole, i.e. the "idealist generator/transmission planning" approach.*[3]
>
> *The consultant will scope out the task and hold a phone conference with the proponents within one week of proceeding. Within 2 weeks of that date, the consultant will prepare a draft report and hold another phone conference. A final report is to be provided within 1 week of the draft report.*
>
> *Due to deadline concerns the proponents understand that the analysis will not be exhaustive and that a number of assumptions will be required and these should be outlined in the report.*

[3] The new entrant costs are adjusted to accommodate the higher total costs in the hypothetical case-which may alter the new entrant plant mix.

2 IES Modelling Approach

The objective of the modelling IES has undertaken is to assess the economic impact of hypothetical pricing regimes with and without transmission costs included versus the current regime of regional pricing in terms of:

- Generators behaviour (offering different supply curves)
- Different physical generator dispatches even though the physical network is the same for the scenarios modelled until the point at which an option leads to a change in network investment;
- Different out turned spot prices; and
- Different investment incentives and decisions – generation and transmission.

The approach IES developed to meet these objectives has been designed to address the key issues and develop a suitable report within a limited timeframe. IES's approach has been to model 2 cases to compare to the current framework as represented by a base or reference case. Each case has been modelled utilising an explicit network model that properly takes into account all material intra-regional constraints. An overview of the key parameters of each case is provided below.

The basis of the modelling study is the Queensland region[4] modelled using an explicit network model. The base time period is the fifteen-year period from 2006/07 to 2020/21.

2.1 The Base Case

The Base Case was designed to represent the current regulatory and market design framework. The case uses standard NEM regional pricing for generators and customers. The following assumptions have been made about generation and transmission over the 15 years modelled.

Generator bids are determined in a manner that attempts to maximise the generator's profits given contract and spot revenues, and are based on the regional reference price (RRP).

The modelling incorporates committed network upgrades, new generation plant and plant upgrades as per the 2006 SOO and respective regional 2006 Annual Planning Reviews (APR).

New entrant generation (other than committed as per the 2006 SOO) was determined using an automated new entry model that assumes market-driven merchant generation investment on the basis of the price duration curve that generators would receive – in this case the regional reference price. New entrant

[4] QLD was chosen due to the ready availability of information and the limited time frame in which this study was to be conducted.

costs include locational fuel costs but do not include the cost of electricity transmission upgrades.

Transmission expansions other than those deemed as committed from the respective 2006 APR have been made on the basis of reliability criteria i.e. the TNSP's build new transmission when congestion builds to a point that customer reliability criteria are impacted or when the network was excessively constrained.

2.2 Case 1: Locational Pricing for Generators

Case 1 assumes that generators are subject to a locational pricing regime, or nodal pricing for generators and a full regime of constraint support pricing.

Unlike the Base Case generators profit maximise based on spot market revenues derived from the locational price signal rather than the RRP, i.e. bids are now focussed on the price at the node in which the generator resides. When all constraints in the market are converted to Option 4 constraints and if constraint support pricing is applied to each constraint then the net result will be, to a close approximation, nodal/locational pricing for generators. The differences between constraint support pricing and nodal pricing would be caused by losses being modelled as static loss factors in regions rather than dynamically (which would be the case under nodal pricing), and that some security constraints may not be able to be modelled as MW injections at specific nodes but may require the specific MW outputs of units or power stations in constraint support pricing

Case 1 is designed to reflect the impact of this implementation of constraint support pricing across the NEM. This case could be considered an assessment of the impact of just short run (spot market) locational signals on timing and location of new entry.

New entrant generation in this case has been determined using the same automated new entry model as the base case, but using the nodal price duration curve rather than the RRP duration curve. Consistent with the base case new entrant costs include locational fuel costs but do not include electricity transmission costs.

Transmission expansion has been undertaken using the same methodology as applied in the Base Case.

2.3 Case 2: Transferring the Cost of Transmission to Generators under a Locational Pricing Regime

Case 2 overlays the locational pricing regime investigated in Case 1 with a congestion cost levied upon new entrant generators that reflects long run locational costs based on future transmission costs. The case has been designed to locate new generation projects in locations optimal to the industry as a whole i.e. including TNSPs. This case has been referred to as the ‘hypothetical arrangement’.

New entrant generation in this case has been determined using the same automated new entry model as in Case 1, with new entry costs increased to account for the expected costs of network upgrades. The only transmission expansion not funded by increased new entry costs will be that required for reliability.

In this modelling IES assumes that once the generation investment has been made the transmission cost for the new generator remains fixed and hence unaffected by the generator's generation patterns. Therefore the generator's short run marginal costs (SRMC) are the same as for the Base Case and Case 1.

2.3.1 Calculation of the Transmission Cost Levy

In order to calculate what the transmission costs per new entrant would be, IES has undertaken an assessment of the costs of grid augmentation. These have been converted to a $/MWh fixed cost that would be added to the generator's other fixed plant costs that would be considered in the investment decision.

No data is publicly available on the costs of specific augmentations, and the regional APRs do not present historic upgrade cost data. IES has therefore made the following assumptions that we believe are indicative of the costs of transmission options available in Queensland:

- 275 kV transmission costs of $700,000/km;
- 500 kV transmission costs of $1400,000/km;
- Central West to South East upgrade would require approximately 300 km of transmission infrastructure;
- Braemar to Tarong would require approximately 60 km of transmission infrastructure;
- Upgrades to the Tarong - South West – South East would be undertaken via 500 kV transmission;
- New substation cost of $60M;

IES has also assumed a very simple transmission pricing model that assumes that the transmission costs are based on the distance to an identified load location which represents a point at the end of the network, in this case Far North Queensland, Moreton North and Gold Coast.

Utilising the above assumptions, IES has established a standardised set of constraint upgrade cost adders that will apply to each node in QLD. These are shown in Table 2-1 below. These transmission costs could considerably improved with further work, but were felt to be adequate to give some idea of what the impact would be of a transmission charge for new generation investments on the economic efficiency of the market.

Table 2-1 Case 2 Transmission Upgrade Cost Adders

Node	km to primary load centre	Cost of Upgrade ($000/km)	Cost per km ($'000)	Fixed Costs ($'000)	Total Costs ($'000)	Capacity of Upgrade (MW)	Effective cost per kW	Effective cost in $/MWh	Levelised Cost Adder
Far North (FNQ)									
Ross	325	700	227,500	60,000	287,500	500	575	65.64	$6.10
North	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
Central West (CW)	871	700	609,875	60,000	669,875	500	1,340	152.94	$14.22
Gladstone	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
WideBay	290	700	203,000	60,000	263,000	500	526	60.05	$5.58
Moreton North (MN)									
Moreton South (MS)	30	700	21,000	60,000	81,000	500	162	18.49	$1.72
Gold Coast (GC)									
South West (SW)	286	1400	401,100	100,000	501,100	1000	501	57.20	$5.53
Tarong	266	1400	372,400	100,000	472,400	1000	472	53.93	$5.01

In calculating the levelised upgrade cost adders IES have assumed a life of 40 years and a discount rate of 9%.

2.4 Scenario Management

The design of the market simulation experiments must take into account that whilst the differences in estimated total dispatch costs for the NEM between scenarios may be material they can be very small when compared to the market's overall dispatch cost. As such, it is important to rule out any sources of noise by ensuring the following:

- The same forced and unforced outage sequences to be used for all options;
- The same physical networks and constraints to be used for all options until the point at which an option leads to a change in network investment;
- Careful management of hydro plant and valuation of water in storage to ensure there are no spurious results obtained due to differing amounts of hydro generation over the study periods;
- For later years of the simulations, i.e. once new generation is required over and above what has been committed, the location and type of new entrant generation to be based on predetermined market criteria;
- The allocation of contracts to generator portfolios to be consistent for all options to ensure that the allocation of contracts does not bias the results for any option.

These criteria have been incorporated in the modelling undertaken for this assignment.

2.5 Measurement of Results

The deliverables from this modelling are:

- The quantification and comparison of the economic cost differences between the cases: dispatch costs, reliability/unserved energy costs, generation investment costs and transmission investment costs; and
- A comparison of the outcomes over a 15 year period on an NPV basis using an appropriate discount rate, and accounting for terminal values of any new assets using an annual equivalent cost approach. This includes the calculation of efficiency differences between scenarios.

In order to provide these deliverables IES has used a model of the NEM that is able to simulate generator bidding behaviour given different congestion management pricing regimes. This model is able to clear the market based on the physical network i.e. dispatch plant, and determine regional, zonal or nodal prices based on the actual physical network.

Fuel and operating costs have been calculated from the modelling results in each case and are used as a measure of the dispatch cost. This has been done for the NEM as a whole because the relative value of flows across QNI and Directlink into QLD cannot be separated from the dispatch of the other regions of the NEM. In order to minimise the impact of this change, modelling assumptions for all regions other than QLD i.e. new entry of generation plant, behaviour, outages etc, have been calibrated in the base case and are then held constant in all runs. Thus the difference in the dispatch costs between the cases is a good measure of the impact of the different QLD regimes on dispatch costs.

The differences in spot prices and hence spot market revenues caused by the different types of pricing regime will result in different market based generation investments, and therefore different transmission investments. These differences in the capital investment cost have also been captured in the benefit calculations and incorporated into the calculation of the NPV for each case.

The total dispatch costs were determined as follows:

- For thermal plant, dispatch costs were determined as generation x SRMC;
- For hydro plant, dispatch costs were determined as the difference in the value of water stored at end of the simulation with value of water stored at beginning of the simulation;
- For pumped storage plant, pumping costs were not directly calculated as these costs were captured by the increase in thermal plant costs and changes in hydro storage levels that were caused by changes in demand resulting from pumping; and
- For voluntary load shedding, the demand management costs were determined by the reduced demand x the value of power to the load (the bid price).

Calculating the differential NPV is very similar to that required for the regulatory test for transmission upgrades. Utilising an approach of this type also aligns with the market objective that the AEMC is obliged to account for when assessing the benefits of various Rule changes.

2.6 The simulation model

IES has used the PROPHET simulation model to undertake the simulations required to deliver estimates of benefits under the regimes outlined above. PROPHET is capable of modelling a full AC network (using a DC load flow approximation) or just a simple regional network like that currently used in the NEM with security constraints to manage the transmission system. NEMMCO uses PROPHET for its ANTS studies.

PROPHET is able to be used in this type of congestion management/regional boundary assessment work because it can be configured as a regional model for pricing/settlements and a full network model to represent the physical system and determine the actual dispatch of plant based on their bids and offers. This feature allows IES to estimate nodal prices, regional prices, constraint support prices (CSPs) and FTR payments or constraint support contract payments (CSCs) for power stations around a constraint and with respect to multiple constraints. It is this feature that enables the calculation of differential NPV values for the purposes of assessing the relative merits of the regimes outlined in Sections 2.1 through 2.3 above.

3 Detail of Modelling Assumptions

This section presents the principal assumptions used in the development of all Cases.

- The Queensland region was represented using a 10-node model that was adapted from the 2006 Powerlink Annual Planning Review (APR), with subsequent amendments.
- All cases were modelled with the majority of Queensland and New South Wales generation dynamically optimising their bidding behaviour for each half-hourly solve period, namely:
  - Intergen;
  - CS Energy;
  - Stanwell Corporation;
  - Tarong Energy Corporation;
  - Delta Electricity;
  - Eraring Energy; and
  - Macquarie Generation.

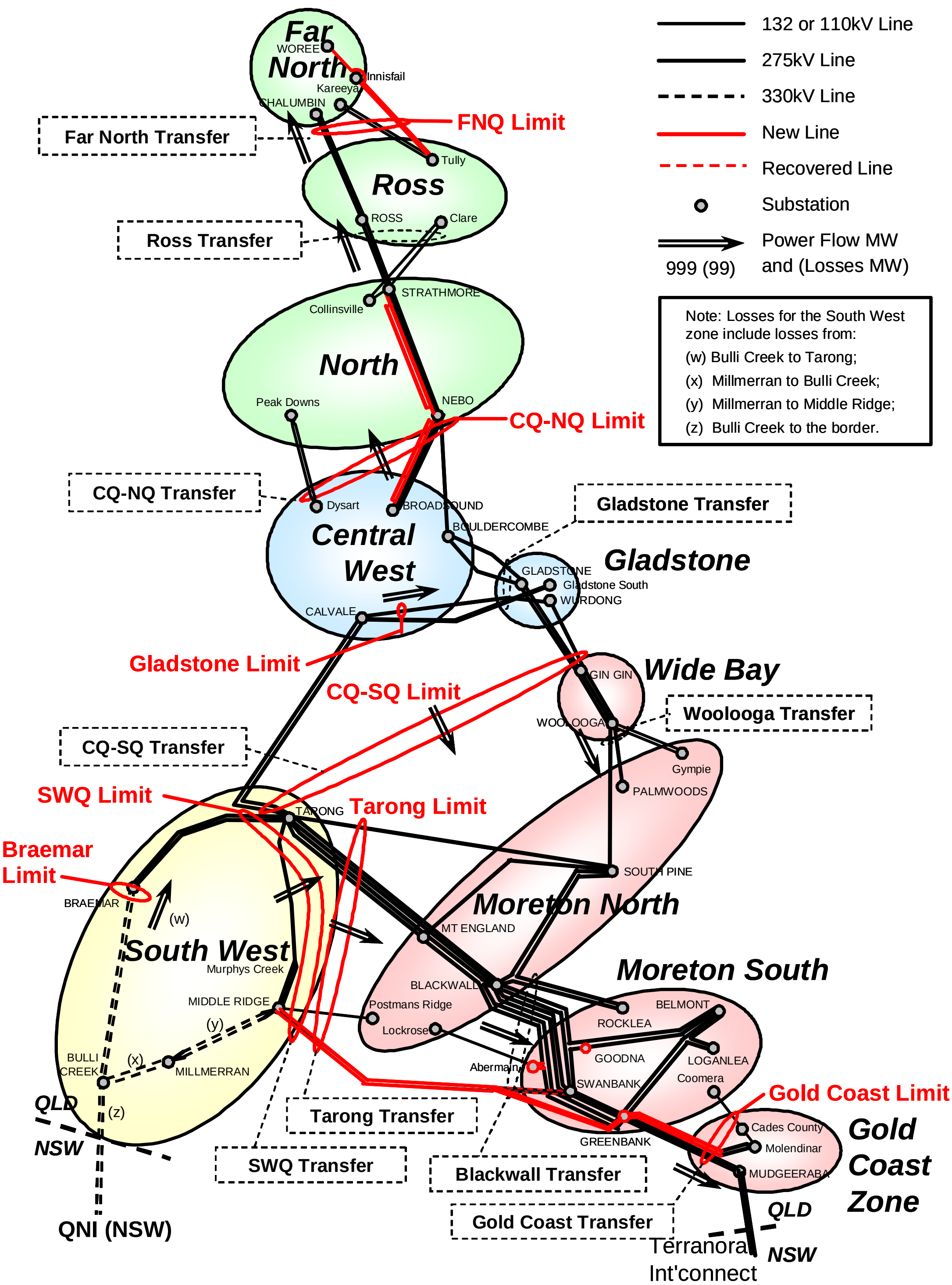
3.1 Transmission Topology

The topology used in the modelling is based on Powerlink's ten zone model of Queensland as shown in Figure 3-1.

This model has been extended to eleven zones with the South West zone split into south west and Tarong zones in order to better model the SWQ limit. In this model all of the major security constraints are managed by limits on cut set flows. The details of the limits can be found in Powerlink's Annual Planning Review. The use of this eleven-zone model ensures that the modelled generator bidding behaviour reflects intra-regional constraints. Updated versions of these constraints, and the formulation of these constraints after the committed augmentations, were provided to IES by Powerlink. The loss equations and admittances for each branch of the 11 zone QLD network were provided to IES by Powerlink.

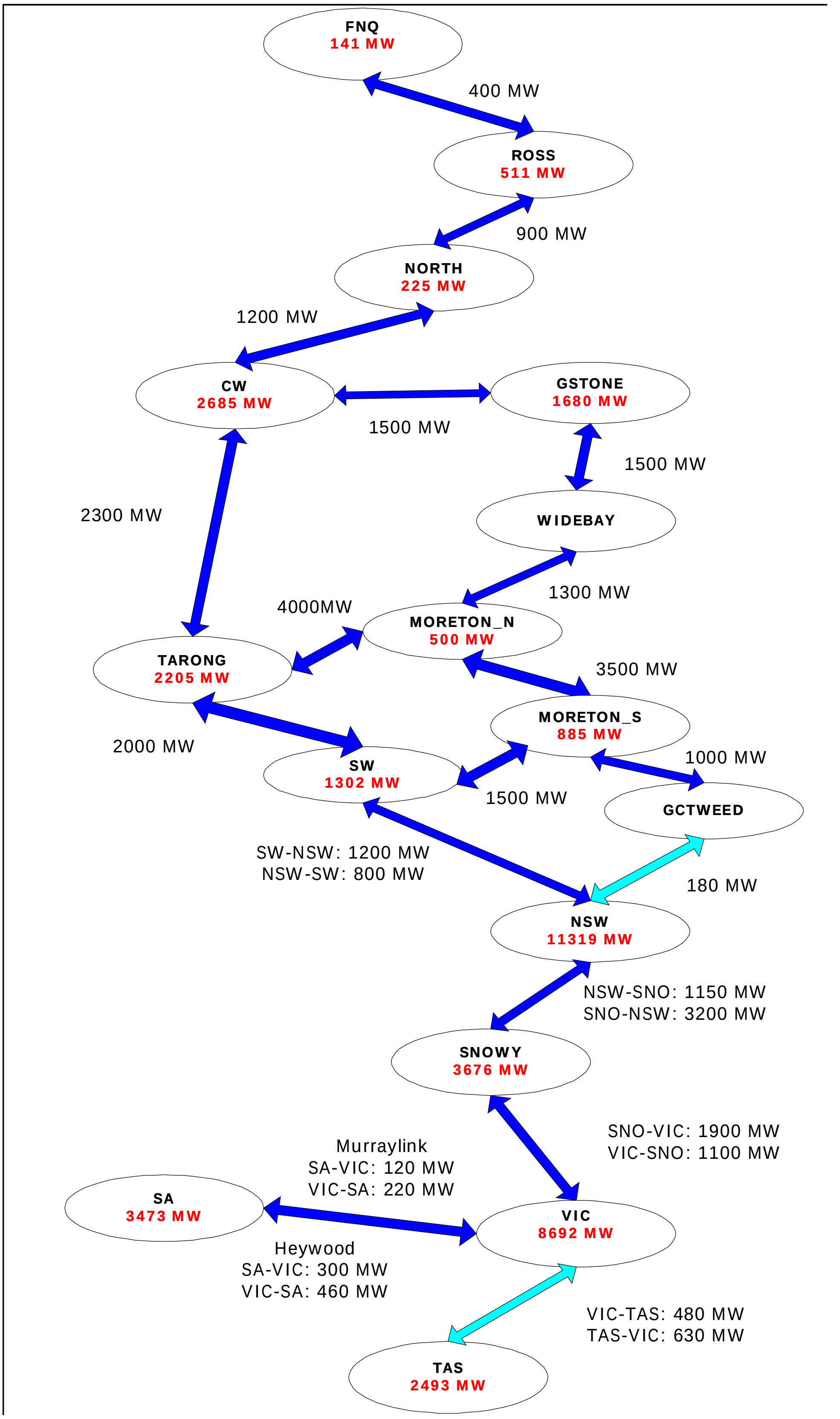
The 11 node Queensland model and the complete NEM model used together with constraint limits is shown in Figure 3-2.

Figure 3-1 Zonal QLD Network[5]



[5] Powerlink, "Annual Planning Report 2006", available from: www.powerlink.com.au

Figure 3-2 NEM Nodal Model



3.1.1 Transmission (Intra-connect) Augmentations

Committed network upgrades, as specified in the Powerlink APR and from discussions with Powerlink, will be included in the modelling. The limits on each of the lines over the modelling period are shown in Table 3-1. The line limits are the same in both directions.

Table 3-1 Simple Network Line Limits (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014 onwards
CW_GSTONE	1500	1500	1500	1500	1500	1500	1500	1500	1500
CW_NORTH	1200	1200	1270	1300	1590	1590	1590	1590	1940
CW_Tarong	1500	1500	1500	1500	1500	1500	1500	1500	1500
GCT_TWEED	300	300	300	300	300	300	300	300	300
GSTONE_WBAY	1500	1500	1500	1500	1500	1500	1500	1500	1500
M_N_M_S	3500	3500	3910	3935	4095	4255	4415	4575	4575
M_S_GCT	1000	1000	1115	1205	1205	1205	1225	1285	1360
NORTH_ROSS	900	900	970	1000	1290	1290	1290	1290	1640
ROSS_FNQ	400	400	400	450	450	450	450	460	460
SW_M_S	1500	1500	1910	1935	2095	2255	2415	2575	2575
SW_Tarong	2000	2000	2600	2600	2850	3000	3750	3750	3750
Tarong_M_N	4000	4000	4410	4435	4595	4755	4915	5075	5075
WIDEBAY_M_N	1300	1300	1300	1300	1300	1300	1300	1300	1300

Specific references to the upgrades assumed to occur in all cases, and reflected in the line limits in Table 3-1 above are outlined in Table 3-2 below.

Table 3-2 Detail of QLD upgrades included in all cases[6]

"Far North Queensland" Limit	**NQ -> FNQ**	**Source**	**APR Pg**
October 2008 (Second Chalumbin to Woree 275kV)	+50	Powerlink APR: Committed	p50
October 2012 (Woree 50MVAr capacitor bank)	+10	Powerlink	
October 2015 (Woree 50MVAr capacitor bank)	+10	Powerlink	
October 2016 (Ross to Woree 275kV)	+100	Powerlink	
"Central to North Queensland" Limit	CW -> NQ		
October 2007 (CQ-NQ reinforcement stage 1)	+70	Powerlink APR: Committed	p50
October 2008 (CQ-NQ reinforcement stage 2)	+30	Powerlink APR: Committed	p50
October 2009 (CQ-NQ reinforcement stage 3)	+290	Powerlink APR: Committed	p50
October 2013 (Stanwell-Broadsound string second side)	+350	Powerlink	
"Central to South Queensland" Limit	**CW -> TAR + GLAD -> WB**		
October 2008 (Woolooga SVC)	+100	Powerlink APR: Routine	p15

[6] Source: APR and discussions with Powerlink

"Tarong to Brisbane" Limit	**TAR -> MN + SWQ -> MS**		
October 2007 (Middle Ridge to Greenbank and capacitor banks)	+410	Powerlink APR: Committed	p50
October 2008 (Abermain TX)	+25	Powerlink APR: Committed	p50
October 2009 (Capacitor banks)	+160	Powerlink APR: Committed	p83
October 2010 (Capacitor banks)	+160	Powerlink APR: Committed	p83
October 2011 (Capacitor banks)	+160	Powerlink	
October 2012 (Capacitor banks)	+160	Powerlink	
"South West Queensland" Limit	**SWQ -> TAR + SWQ -> MS**		
October 2007 (Middle Ridge to Greenbank)	+600	Powerlink APR: Committed	p50
October 2009 (Upgrade 2nd Middle Ridge TX)	+250	Powerlink APR: Routine	p16
October 2010 (Millmerran series reactors)	+150	Powerlink APR: Routine	p16
October 2011 (Tarong to Braemar reinforcement)	+750	Powerlink APR: Routine	p16
"Gold Coast" Limit	**MS -> GC**		
October 2007 (Second Molendinar 275/110kV TX)	+115	Powerlink APR: Committed	p50
October 2008 (Capacitor banks)	+90	Powerlink APR: Routine	p17
October 2011 (Capacitor banks)	+20	Powerlink	
October 2012 (Capacitor banks)	+60	Powerlink	
October 2013 (Third Molendinar 275/110kV TX)	+75	Powerlink	

3.2 New Entry Generation – Approach and Costs

This section presents the approach to the economics of new entry generation and the assumptions of cost IES has applied in the modelling

3.2.1 New Entry Process

IES has developed an automated new entry feature for PROPHET that brings new generators on line based on the spot market price duration curve at nodal, zonal or regional locations.

In each year a premium curve, P(x), for each region, zone or node I produced. The premium curve for a year gives the average price above a specified price. That is:

$P(x) =$ average over year of $\mathrm{Max}(P_t - x, 0)$, where P_t is the spot price at time t

For a generator with a marginal cost of y ($/MWh), the premium curve point P(y) represents the average gross margin that the plant could obtain over the year if it generated at maximum capacity any time the price was over its marginal cost of y. P(y) represents the amount that the generator could earn from the spot, over and above its variable costs, which could contribute to it covering its fixed costs.

The premium curves and an input list of potential new generators are used to create a 'merit order' ranking of all plant with premiums which exceed their fixed costs, with optional threshold values applied. The process then trials the plant at the top of the rank and determines if the premiums still exceed the plant's fixed costs with the plant in the market. If the plant does not pass the test, the plant is taken out of the market and the next plant on the merit list is trialled. If the plant does pass the test the plant remains committed and a new merit list is created with the plant in the market. This process is continued until no more potential new entrants are available.

The input list of potential new generators includes known planned projects and generic new entrants. When there is more than one plant of the same type (same fuel type, node, variable and fixed costs) at the one location a pre-determined priority ranking is used to determine which plant enters the market first. A list of all the potential new plants – generic or otherwise, assumed by IES to be available to be planted in any Queensland node is shown in Table 3-3.

Table 3-3 QLD Potential New Generators

Node	Plant	Business Unit	Fuel Type	Size (MW)	Priority
South West	Spring Gully 1	Origin	CCGT	500	1
South West	Spring Gully 2	Origin	CCGT	500	2
South West	QLD_SW_CC_1	Generic	CCGT	500	3
South West	QLD_SW_CC_2	Generic	CCGT	500	4
South West	Braemer2_1	Wambo	OCGT	150	1
South West	Braemer2_2	Wambo	OCGT	150	2
South West	Braemer2_3	Wambo	OCGT	150	3
South West	Kogan Creek B	CS Energy	Coal	750	1
South West	QLD_SW_Coal_1	Generic	Coal	750	2
South West	QLD_SW_Coal_2	Generic	Coal	750	3
Tarong	Chinchilla	QGC	CCGT	240	1
Tarong	Tarong North 2	Tarong	Coal	500	1
Moreton South	Swanbank F1	CS Energy	CCGT	400	1
Moreton South	Swanbank F2	CS Energy	CCGT	400	2
Moreton South	QLD_MS_CC	Generic	CCGT	400	3
Moreton South	CS_MS_GT	CS Energy	OCGT	150	1
Moreton South	QLD_MS_GT_1	Generic	OCGT	150	2
Moreton South	QLD_MS_GT_2	Generic	OCGT	150	3
Central West	Stanwell Peaker_1	Stanwell	OCGT	150	1
Central West	Stanwell Peaker_2	Stanwell	OCGT	150	2
Central West	QLD_CW_GT	Generic	OCGT	150	3
Central West	CS_CW_CC	CS Energy	CCGT	400	1
Central West	QLD_CW_CC	Generic	CCGT	400	1
Central West	QLD_CW_Coal_1	Generic	Coal	500	1
Central West	Stanwell_CW_Coal	Stanwell	Coal	500	2
Central West	QLD_CW_Coal_2	Generic	Coal	500	3
Gladstone	QLD_Glad_CC	Generic	CCGT	400	1
Gladstone	QLD_Glad_GT	Generic	OCGT	150	1
Ross	AGL Townsville	AGL	CCGT	400	1

Node	Plant	Business Unit	Fuel Type	Size (MW)	Priority
Ross	Origin Townsville	Origin	CCGT	400	2
Ross	QLD_Ross_GT_1	Generic	OCGT	150	1
Ross	QLD_Ross_GT_2	Generic	OCGT	150	2
North	Stanwell_Coal	Stanwell	Coal	500	1
North	QLD_North_CC	Generic	CCGT	400	1
North	QLD_North_GT	Generic	CCGT	150	1

3.2.2 New Entry Costs - SRMC

New entry generation costs are comprised of Short Run Marginal Costs (SRMC) and Fixed Costs (FC). For the different locations in Queensland the SRMC are shown below. The information has been sourced from the 2005 ACIL Tasman report on NEM generator costs (Part 2). IES has adjusted these costs for subsidies from either the QGIC or GGAS scheme as applicable. IES has chosen to use ACIL Tasman numbers rather than internally developed costs because they are publicly available, and have been included in the 2006 SOO.

Table 3-4 SRMC of Coal, CCGT and OCGT Plant

Zone[7]	SRMC ($/MWh)	SRMC after subsidy ($/MWh)
	CCGT's	
NQ	$31.29	$15.79
CQ	$26.79	$11.29
SEQ	$25.86	$10.36
SWQ	$24.08	$8.58
NCEN	$32.92	$25.22
SWNSW	$30.98	$23.28
CAN	$34.78	$27.08
SNY	$31.75	$24.05
NVIC	$34.78	$27.08
LV	$25.94	$18.24
MEL	$27.65	$19.95
CVIC	$26.48	$18.78
NSA	$31.60	$23.90
ADE	$30.67	$22.97
SESA	$28.65	$20.95
TAS	$34.78	$27.08
	Coal Fired Plant	
NQ	$10.54	$8.04
CQ	$10.04	$7.54
SWQ	$8.06	$5.56
NCEN	$9.05	$6.55
SWNSW	$11.04	$8.54
LV	$7.35	$4.85
	OCGT's	
NQ	$55.66	$40.16
CQ	$48.49	$32.99

[7] Zone names have been abbreviated. Definitions are contained in Appendix A.

Zone[7]	SRMC ($/MWh)	SRMC after subsidy ($/MWh)
SEQ	$47.01	$31.51
SWQ	$44.16	$28.66
NCEN	$58.23	$54.33
SWNSW	$55.21	$51.31
CAN	$61.13	$57.23
SNY	$56.34	$52.44
NVIC	$61.13	$57.23
LV	$47.12	$43.22
MEL	$49.85	$45.95
CVIC	$48.03	$44.13
NSA	$56.12	$52.22
ADE	$54.64	$50.74
SESA	$51.45	$47.55
TAS	$61.13	$57.23

IES has assumed that the GEC subsidy is no longer applicable to new entrants from 2011 onwards because the 13% target has been exceeded by this time.

3.2.3 New Entry Costs – Capital Costs

The capital costs assumed, based on a real pre-tax discount rate of 9%, are shown in Table 3-5 below. The number applied in the IES modelling is the levelised cost expressed as $/MWh.

Table 3-5 Fixed Capital Costs[8]

	OCGT	OCGT (brownfield)	CCGT	CCGT (brownfield)	Black Coal	Black Coal (brownfield)	Brown Coal
Capital Cost ($/kW)	725	675	950	900	1625	1500	2049
Life	25	25	30	30	30	30	30
Annual Equivalent Cost ($/MW per year)	73,810	68,719	92,470	87,603	158,172	146,005	199,450
Levelised Capital Cost ($/MWh)	8.43	7.84	10.56	10.00	18.06	16.67	22.77

3.3 Generator Behaviour

A key impact on the modelling results is the effect that a different pricing regime has on "rational generator" bidding behaviour. This effect will feed through into pool prices, dispatch patterns and the economic timing of new entry generation. The approach to modelling generator behaviour applied by IES is described below.

3.3.1 Overview of PROPHET Dynamic Bidding

The current structure of the NEM is such that it is not perfectly competitive; there are a number of larger generating portfolios that are able to exert some degree of market power. Consequently, most of these larger portfolios do not bid all their

[8] In Real July 2006 dollars

plant at their short run marginal costs, but bid their plant to maximise their profits recognising that their generation faces a price versus volume trade-off.

The most common approach to modelling these behaviours in the Australian market has been for analysts to develop a set of generator bids prior to the start of a simulation model run. The bids are generally developed based on assessments of competition levels, existing contracts and possibly recent bidding trends evident in the market[9]. This would most likely be done on a time sector basis, with different bid patterns assessed and entered in the model for each season and time sector (e.g. peak, off-peak and shoulder periods). Some of the problems with this approach are:

- When market conditions change, the bids are "static" and do not respond. An example of this is a highly contracted generator portfolio that suffers a generator outage. In the actual market, the portfolio would recast its bids so that the remaining generators covered the contract position.
- In the market, generator spot trading managers are constantly searching for opportunities to improve their profitability (either short term or long term) through changing their bids. This action is not captured by a static bid representation.

The development of pre-determined generator bids can be subjective.

To overcome these issues, IES used the dynamic bidding feature of the PROPHET model. This module automatically optimises the generator portfolio bids each half hour. In essence it achieves this by:

- computing the price sensitivities to changes in generator output at each of the portfolio's nodes (connection points),
- grouping the nodes into similar price volume relationships through an analysis of which constraints are binding,
- using a heuristic to optimise the changes in generator and/or pumping volumes such that the portfolio's profits are maximised considering:
- marginal generator costs,
- price volume relationships, and
- swap and cap contract portfolio,
- adjusting the unit offers/bids to match the new optimal outputs and the corresponding clearing prices at the unit connection points. These connection prices may differ from the regional reference prices if there are intra-regional constraints that are binding in the network model.

[9] Competition levels might be assessed through the demand/supply balance, the number of generator portfolios, the size of the individual portfolios and the level of contracting.

3.3.2 Modelling the Market Impact of Generation Portfolios in the NEM

All IES modelling undertaken utilises the PROPHET Dynamic Bidding module as described above. This bidding form allows the units residing within a portfolio to have their dispatch optimised for that portfolio.

Most generators in the NEM are of sufficient size to be able to influence the spot price in their region by changing the amount they generate. Thus if a generator were seeking to maximise its profits it would have to consider the expected impact on its total revenue of a change in quantity of generation offered to the market. This change in total revenue for a small change in output (generation) is called the marginal revenue and is defined as the change in total revenue for a unit change in output.

Profit is maximised in the short run when marginal revenue equals marginal cost. Consequently, a generator should try to bid into the market in such a way that its expected marginal revenue for each half hour is equal to its marginal cost of generation.

3.3.3 Allocation of Contracts to Generation Portfolios

Contracts are allocated to generation portfolios on the following basis. An overall level of contracting for each region is established. That is, the proportion of the expected demand that is contracted is determined for each region. Being based on an expected profile of load, conditions that move actual demand outcomes away from the expected, most notably weather conditions produce periods of high and low “spot exposure”. This is a key ingredient to spot price volatility.

The total level of contracts in the market is specified in terms of the percentages of retail load contracted in defined time sectors, usually in the peak period and off peak period. Once the overall level of contracting has been determined then any predetermined contacts are allocated to the relevant portfolios. The remainder of the contracts are allocated in proportion to the expected generation of each portfolio adjusted for the already committed contracts.

Once the overall positions for the portfolios are established, the Dynamic Bidding Module undertakes the following process:

- For each generation portfolio, create offer prices that reflect marginal costs, cap and floor contract prices and a range of high and low prices for managing generation.
- Create the static ‘total bid’ for the portfolio based on the portfolio’s offer prices and computed quantities for these offer prices using the simple generator bid model.
- Allocate the portfolio's total bid to bids for individual units within the portfolio.
- Perform sensitivity analyses for each region for the last trading interval (half hour or hour depending on the modelling time interval chosen) to determine the spot price vs. changes in generator output curve.

- For each generation portfolio selected to dynamically bid, perform a sensitivity analysis to determine its optimal output and corresponding market clearing price.
- Use each generator's optimal output and market clearing price to adjust the quantities in the portfolio’s static total bid.
- From the new dynamic bid for the portfolio adjust the unit bids to create dynamic unit bids.

It is in this manner that the optimal operation (i.e. the most profitable) of the units residing within each Queensland portfolio has been modelled.

In all cases modelled IES has assumed that active retailers in Queensland will contract their overall load with swaps to 90% of total demand with the remainder of the retailers’ positions covered with cap contracts struck at $300, excluding those contracts written for GEC’s and accounted for separately. At no time does the overall contract level in Queensland exceed 105% of demand.

3.4 Demand Assumptions

Demand growth is modelled for each of the eleven Queensland nodes using the published energy and demand projections from the Powerlink 2006 Annual Planning Report (APR) with additional data supplied from Powerlink for the South West and Tarong nodes.

The half hourly load traces for the 04/05 financial year have been used and are scaled to give the annual energy and demand figures that are consistent with the Powerlink forecasts, yet maintain the half hourly statistical variations observed in the historical data.

The 04/05 financial year was chosen as the reference year because the Queensland summer daily average temperatures in that year were close to the Bureau of Meteorology (BOM) long term climate averages; and being a recent year it would contain more of the effects of the increase in air-conditioning loads than previous years.

3.5 Supply Assumptions

3.5.1 Existing Generators

Generator capacity will be based on the 2006 NEMMCO Statement of Opportunities (NEMMCO SOO). Generator fuel costs will also be updated to reflect ACIL’s Feb 2005 Report on Generator costs. Minimum output levels, planned and forced outage rates will be based on the 2006 NEMMCO ANTS Data and Assumptions Consultation – Issues Paper. Maintenance schedules for all generators are set up to approximate planned maintenance schedules observed in the market. That is, most maintenance is scheduled to correspond to times of lower loads and expected prices. Plant forced outages are set up so that they can be aligned between different scenarios to remove any noise.

Assumptions about the characteristics of existing generators such as:

- MW capacity;
- Auxiliary usage;
- Marginal loss factors (MLFs);
- Marginal costs;
- Planned maintenance; and
- Forced outage rates,

have been provided under separate cover.

3.5.2 Committed Supply Developments

The planned generation projects which will be included in the modelling are shown in Table 3-6. These projects are classified as committed in the 2006 NEMMCO SOO.

Table 3-6 Supply Developments

Development Name	Region	Details	Timing
Kogan Creek (CS Energy)	QLD	750 MW base load (coal fired)	1/10/2007
Tallawarra	NSW	400MW CCGT	1/07/2008

The 480MW Swanbank B power station will be retired on 1 July 2011.

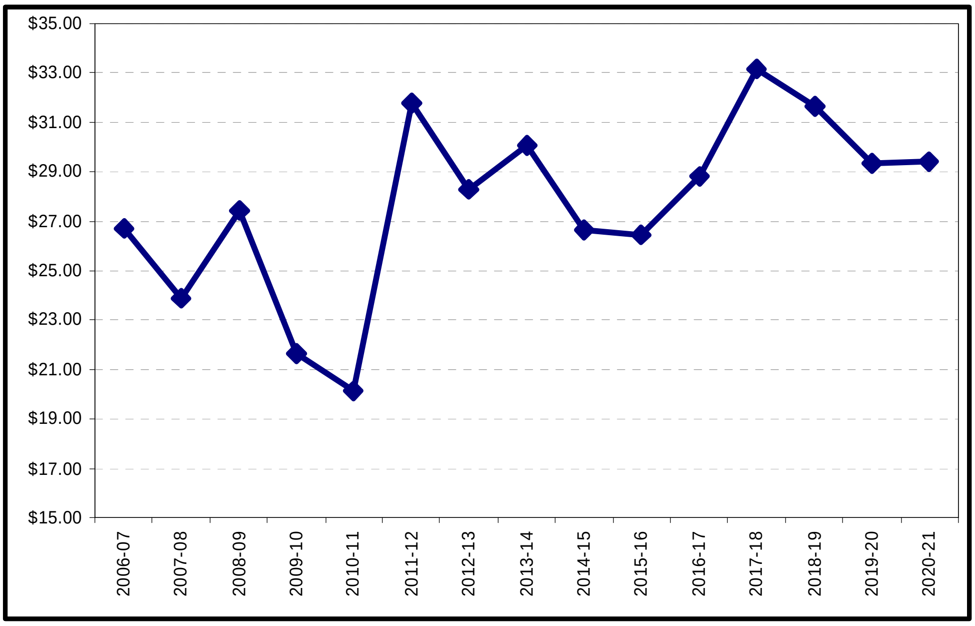
4 Modelling Results

All forecast prices are in real July 2006 Australian dollars. Years are financial years.

4.1 Base Case Modelling Results

The Base Case modelled represents the status quo (current regulatory and market design framework) of the market as outlined in Section 2.1. The results of this modelling are presented in Figure 4-1 below.

Figure 4-1 Base Case - Annual Queensland Spot price ($/MWh)



These spot price numbers are extremely low, however this is a function of the level at which ACIL Tasman have set new entry (SRMC) prices. As outlined in Section 3.2, IES have used these numbers in preference to alternate new entry costs because these numbers have been published in the 2006 SOO, and can therefore be considered an industry accepted set of numbers.

After allowing for GEC subsidy, the SRMC of a generic CCGT in the south west of Queensland is $8.58. From 2011 IES has assumed that the GEC subsidy no longer applies to new entrants because the 13% target has been reached, therefore the value of the GEC is reduced to a floor price because the volume of gas-fired new entry is greater than the set target. The resultant impact on the spot price can be seen clearly in 2011-12 where the regional reference price (RRP) moves toward un-subsidised SRMC levels.

Details of the base case spot prices are shown in Table 4-1 below.

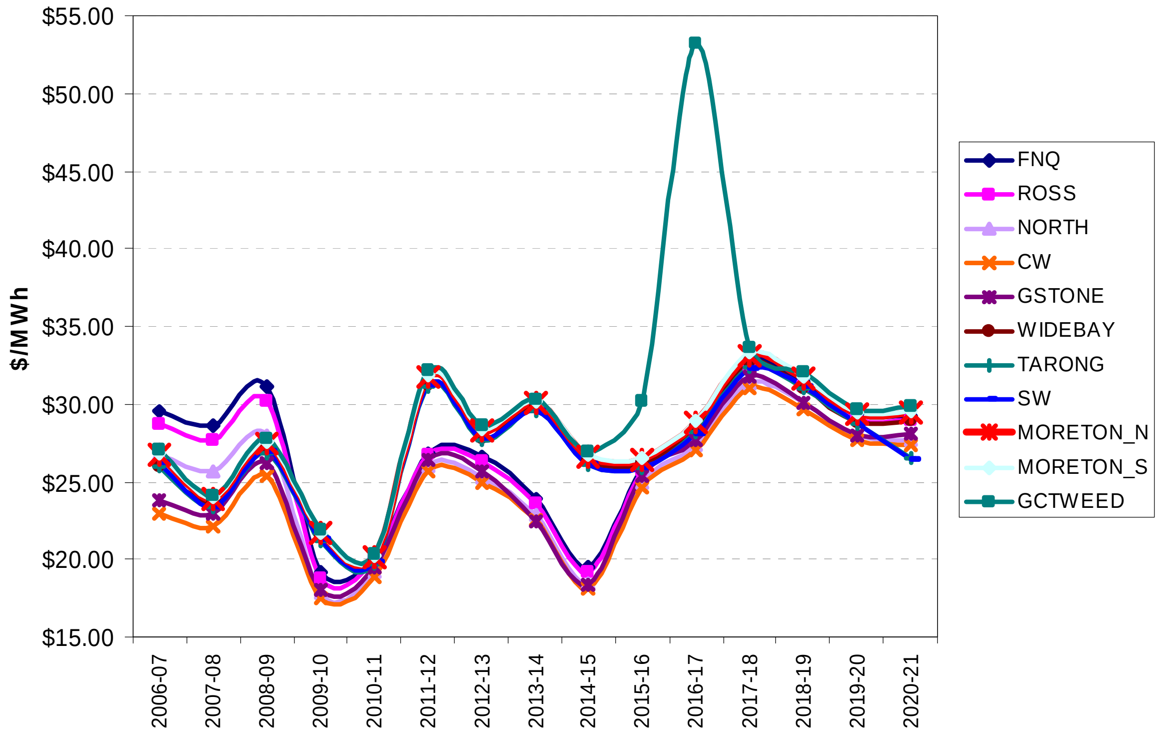
Table 4-1 Base Case Spot Prices

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
FNQ	29.6	28.57	31.15	19.14	20.17	26.81	26.58	23.88	19.48	25.93	28.46	32.75	31.45	29.39	29.26
ROSS	28.71	27.69	30.2	18.79	19.98	26.69	26.33	23.63	19.22	25.67	28.21	32.41	31.13	29.06	28.91
NORTH	26.68	25.63	28.01	17.79	19.16	26	25.3	22.82	18.44	24.96	27.36	31.37	30.04	27.99	27.72
CW	23	22.16	25.38	17.51	18.88	25.68	24.95	22.55	18.19	24.68	27.06	31.01	29.71	27.65	27.36
GSTONE	23.77	22.94	26.22	18.08	19.53	26.46	25.73	22.42	18.32	25.34	27.7	31.78	30.05	27.96	28.07
WIDEBAY	26.02	23.57	27.02	21.47	19.96	31.18	27.75	29.74	26.32	26.16	28.48	32.72	31.06	28.82	28.97
TARONG	26.02	23.34	26.85	21.18	19.73	31.13	27.7	29.55	26.08	25.89	28.21	32.34	31.07	28.71	26.5
SW	26.2	23.42	26.93	21.24	19.79	31.19	27.75	29.54	26.1	25.84	28.1	32.32	31.08	28.68	26.38
MORETON_N	26.7	23.86	27.46	21.65	20.13	31.76	28.28	30.07	26.63	26.43	28.8	33.13	31.67	29.31	29.44
MORETON_S	26.85	23.96	27.58	21.73	20.19	31.89	28.4	30.15	26.73	26.51	28.91	33.28	31.79	29.42	29.55
GCTWEED	27.08	24.15	27.79	21.92	20.36	32.16	28.65	30.33	26.93	30.19	53.19	33.62	32.05	29.68	29.82

The base case modelling undertaken has been done with all generators bidding to optimise their financial position against the QLD RRP – this is represented as the Moreton North price, the zone/node where south pine is located. The other prices in Table 4-1 are nodal "shadow" prices and are used by IES in order to assess and value transmission constraints in a regime where the opportunity-cost value of those constraints is masked. These shadow prices (marginal costs) currently exist in the NEM as calculated values for individual constraints, and can be extracted from the NEMDE dispatch calculations published by NEMMCO. The nodal prices in IES's modelling approximately represent the situation where all the network and security constraints that affect generation are incorporated into a CSP regime[10].

The divergence of the underlying nodal prices from the QLD RRP for the 15 years modelled is illustrated in Figure 4-2 below.

Figure 4-2 Base Case RRP and (Nodal) Shadow Prices



Transmission was upgraded to meet reliability criteria or where nodal prices consistently diverge in the modelling due to transmission constraints. The transmission upgrades undertaken on this basis (over and above those transmission upgrades outlined in Table 3-2), are generic as per the assumptions outlined in Section 2.3.1. The generic transmission upgrades in the base case are outlined in Table 4-2 as follows.

[10] IES' modelling is approximately equivalent to assuming system normal conditions.

Table 4-2 Base Case Generic Transmission Upgrades

Year	Upgrade	Cost (AEC $M)
2017-18	500MW upgrade from Moreton_South to Gold Coast	$7.53
2017-18	1000MW upgrade from South West to Moreton_South	$46.58
2018-19	500MW upgrade from Central West to Moreton_North	$62.27

NB: AEC is annual equivalent cost.

The capital cost of 2,000MW of transmission upgrades required in this modelling case is $1.252 billion in current 2006 dollars.

Following the decision to undertake each transmission upgrade, a new sequence of new entrants was created to reflect the impact of transmission upgrades on the investors' decision to build power stations. The final (generic) new entry required in the base case modelling is shown in Table 4-4 over the page.

The new entry generation schedule reflects the low cost of coal in south west Queensland. Post (NGAC) subsidy[11] the SRMC of coal-fired plant in this region is $5.56. Of the 2,500MW of generic plant added into the SW node 1,500MW is coal-fired plant. In effect a Kogan Creek B in 2013-14 and Kogan Creek C in 2019-20.

There is also 500MW of coal-fired plant scheduled for entry in Tarong in 2014-15, and in Gladstone in 2018-19. The remainder of the capacity in the region is gas-fired GT or CCGT plant, primarily required to meet shoulder and peak requirements.

The estimated capital cost of the total construction required in the base case is $5.028 billion over the 15 year period modelled as follows:

Table 4-3 Base Case Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
5,028.00	108.75	405.00	608.00	0.00	2,031.25	1,875.00

[11] IES has assumed that any new coal-fired generation will utilise technology that ensures it is below the NSW emissions benchmark, egg Kogan Creek.

Table 4-4 Base Case Generic New Entry

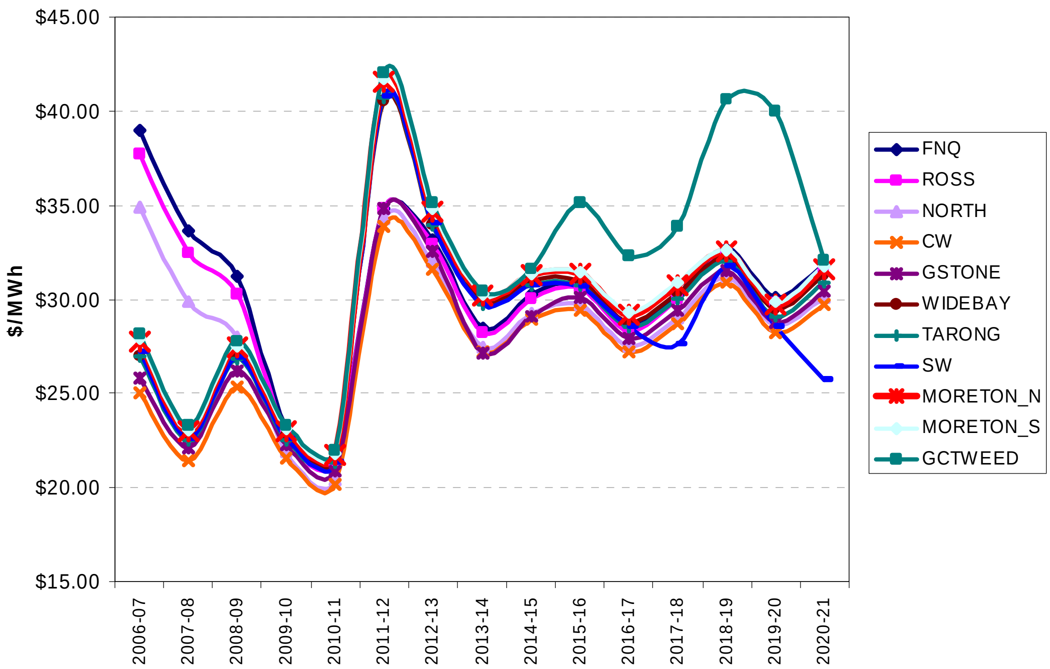
	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total
FNQ	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROSS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSTONE	0	0	0	0	0	0	0	0	0	0	0	0	500	0	0	500
WIDEBAY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TARONG	0	0	0	240	0	0	0	0	500	0	0	0	0	0	0	740
SW	0	0	0	400	0	0	0	750	0	0	0	300	300	750	0	2,500
MORETON_N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MORETON_S	0	0	0	0	0	0	0	0	0	0	0	0	0	150	0	150
GCTWEED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total QLD	**0**	**0**	**0**	**640**	**0**	**0**	**0**	**750**	**500**	**0**	**0**	**300**	**800**	**900**	**0**	**3,890**

4.2 Case 1 Results: Locational Pricing for Generators

As outlined in Section 2.2 this case is designed to reflect the impact of Option 4 constraint formulation on the market, and a full regime of constraint support pricing.

The nodal/locational price results from this modelling show less divergence than the Base Case, with the exception of the Gold Coast region. This area of QLD is characterised by high demand growth forecasts and minimal capacity for new entry, i.e. limited numbers of locations/sites and a reliance on diesel fuel for any generation placed in the node.

Figure 4-3 Case 1: Locational Queensland Spot prices ($/MWh)



The significant differences between Case 1 and the Base Case come in the transmission upgrades required and the timing and placement of generic new entry. Case 1 required only one additional transmission upgrade between Moreton South and the Gold Coast, due to the cost limitations on new entry in that node. The capital cost of this generic transmission upgrade is $670 million.

The generic new entry schedule for Case 1 is shown at Table 4-5 over. The volume (and therefore cost) and type of generic new entry required when plant receives locational prices rather than regional prices is significant and is summarised in Table 4-6.

Table 4-5 Case 1 Generic New Entry

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total
FNQ	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROSS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSTONE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300
WIDEBAY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150
TARONG	0	0	0	0	0	0	0	240	0	0	500	0	0	0	0	740
SW	0	0	0	0	0	0	0	750	0	0	0	0	150	750	0	1,650
MORETON_N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MORETON_S	0	0	0	400	0	0	0	0	0	150	0	0	400	300	0	1,250
GCTWEED	0	0	0	0	0	0	0	0	0	0	100	100	0	100	0	300
Total QLD	**0**	**0**	**0**	**400**	**0**	**0**	**0**	**990**	**0**	**150**	**600**	**100**	**550**	**1150**	**450**	**4,390**

Table 4-6 Summary of Case 1 New Entry Differences by Plant Type

	Case 1	Base Case	Difference
GT	1,050	750	300
CC	1,340	640	700
Coal	2,000	2,500	-500
Total	**4,390**	**3,890**	**500**

To some extent the change in the pricing regime has resulted in (cheaper) generation replacing transmission upgrades. This is because in a nodal or locational pricing regime smaller and more flexible generation configurations have greater significance.

The estimated capital cost of the total construction required in Case 1 is $5.033 billion over the 15 year period modelled as follows:

Table 4-7 Case 1 Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
5,033.00	870.00	101.25	608.00	360.00	1,218.75	1,875.00

This compares favourably to the base case capital cost of $5.028 billion for 3,890MW of capacity. On a per MW basis the cost of capital in Case 1 is $1.15 million compared to the base case cost of $1.29 million, due solely to the change in the new entry generation mix.

The overall benefit of this case as measured by the NPV is shown in Table 4-8 below.

Table 4-8 Case 1 NPV Benefit

Year	Dispatch Costs ($M)	Capital Costs (AEC - $M)	Transmission Costs (AEC - $M)	Total Costs ($M)
2006-07	-1.18	0.00	0.00	-1.18
2007-08	0.12	0.00	0.00	0.12
2008-09	0.04	0.00	0.00	0.04
2009-10	-10.10	22.19	0.00	12.09
2010-11	2.35	22.19	0.00	24.54
2011-12	-4.73	22.19	0.00	17.47
2012-13	-4.66	22.19	0.00	17.53
2013-14	1.17	0.00	0.00	1.17
2014-15	-47.90	73.00	0.00	25.10
2015-16	-40.12	61.93	0.00	21.81
2016-17	11.82	-18.45	0.00	-6.64
2017-18	0.49	-5.22	54.11	49.39
2018-19	-22.75	49.14	116.38	142.77
2019-20	-14.74	30.68	116.38	132.32

Year	Dispatch Costs ($M)	Capital Costs (AEC - $M)	Transmission Costs (AEC - $M)	Total Costs ($M)
2020-21	-2.25	-2.53	108.85	104.07
Total	**-132.44**	**277.31**	**395.72**	**540.6**
NPV Benefit	**-58.06**	**130.80**	**121.91**	**194.65**

The change in the mix of generation type has driven the NPV value in this case. There has been an increase in dispatch cost caused by increased generation from (relatively) more expensive plant; however this is more than offset by reductions in transmission and generation capital costs.

4.3 Case 2 Results: Locational Pricing with Transmission Levy

As outlined in Section 2.3 this case is designed to reflect the combined impact of Option 4 constraint formulation and a full CSP regime (nodal pricing regime for generators) on the market and a congestion cost levied upon new entrant generators.

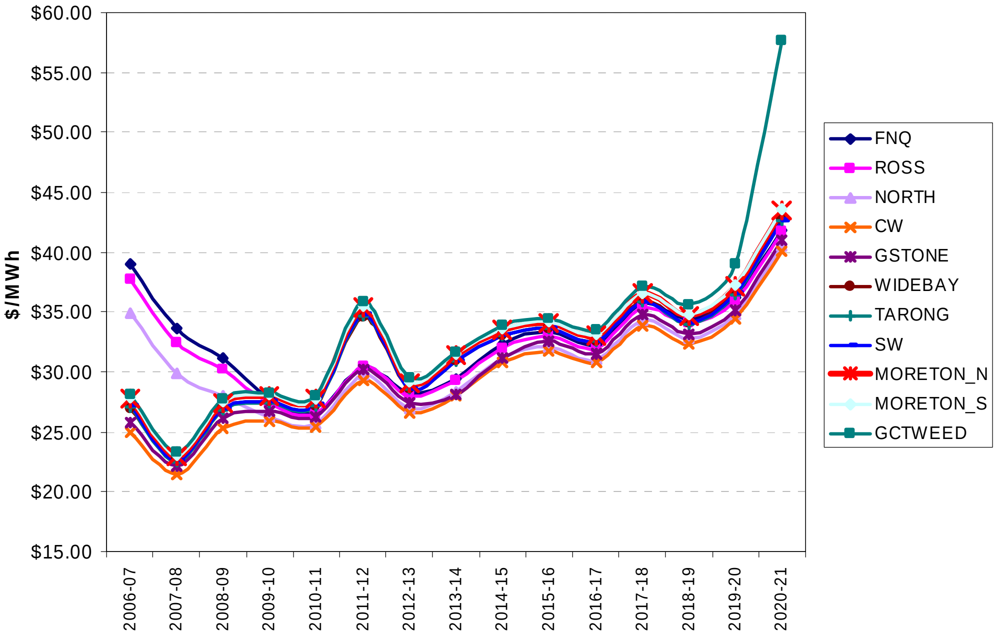
The levelised cost adders applied in Case 2 represent the costs of transmission upgrades relative to the distance from load centres. The calculation of locational costs applied to new entry in each node is outlined at Section 2.3.1, and the costs reproduced in Table 4-9 below.

Table 4-9 Case 2 Transmission Upgrade Cost Adders

Node	km to primary load centre	Cost of Upgrade ($000/km)	Cost per km ($'000)	Fixed Costs ($'000)	Total Costs ($'000)	Capacity of Upgrade (MW)	Effective cost per kW	Effective cost in $/MWh	Levelised Cost Adder
Far North (FNQ)									
Ross	325	700	227,500	60,000	287,500	500	575	65.64	$6.10
North	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
Central West (CW)	871	700	609,875	60,000	669,875	500	1,340	152.94	$14.22
Gladstone	540	700	378,000	60,000	438,000	500	876	100.00	$9.30
WideBay	290	700	203,000	60,000	263,000	500	526	60.05	$5.58
Moreton North (MN)									
Moreton South (MS)	30	700	21,000	60,000	81,000	500	162	18.49	$1.72
Gold Coast (GC)									
South West (SW)	286	1400	401,100	100,000	501,100	1000	501	57.20	$5.53
Tarong	266	1400	372,400	100,000	472,400	1000	472	53.93	$5.01

In this case therefore the cost of building coal in south west Queensland would be a fixed cost reflecting the capital cost of the plant plus a transmission fixed cost reflecting the $5.53 for future transmission expenditure Under this regime the locational prices are presented in Figure 4-4 below. These prices average $4.47 more than the base case over the modelling period.

Figure 4-4 Case 2 – Locational Queensland Spot prices ($/MWh)



Consistent with the results from Case 1, this pricing regime results in less divergence between regions than the Base Case, however unlike Case 1 the divergence of prices in the Gold Coast region is delayed until the final year of the modelling period. This is because small GT's were economic to install in the Gold Coast area under this pricing regime. Similarly to Case 1, the significant differences between Case 2 and the Base Case arise in the transmission upgrades required and the timing and placement of generic new entry. However unlike Case 1, Case 2 required no additional transmission upgrades during the modelling period.

The generic new entry schedule for Case 2 is shown at Table 4-11 over. The volume (and therefore cost) and type of generic new entry required when plant receives locational prices rather than regional prices is significant and is summarised in Table 4-10.

Table 4-10 Summary of Case 2 New Entry Differences by Plant Type

	Case 2	Base Case	Difference
GT	1,350	750	600
CC	1,440	640	800
Coal	500	2,500	-2,000
Total	**3,290**	**3,890**	**-600**

Table 4-11 Case 2 Generic New Entry

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Total
FNQ	0	0	0	0	0	0	0	0	0	0	0	0	0	300	0	300
ROSS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSTONE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WIDEBAY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TARONG	0	0	0	0	0	0	0	0	0	0	0	0	500	240	0	740
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MORETON_N	0	0	0	0	0	0	0	0	200	0	0	100	0	0	0	300
MORETON_S	0	0	0	0	0	550	0	400	0	0	400	0	150	150	0	1,650
GCTWEED	0	0	0	0	0	0	0	0	300	0	0	0	0	0	0	300
Total QLD	**0**	**0**	**0**	**0**	**0**	**550**	**0**	**400**	**500**	**0**	**400**	**100**	**650**	**690**	**0**	**3,290**

In addition to a change in the type and location of the new entry when compared to the Base Case, there has also been a 600MW reduction in the overall volume of new entry required under this hypothetical arrangement. The estimated capital cost of the total construction required in Case 2 is $3.057 billion over the 15 year period modelled as follows:

Table 4-12 Case 2 Total Cost of (Generic) New Entry

Total cost ($M)	New OCGT $M	Brownfield OCGT $M	New CCGT $M	Brownfield CCGT $M	New black coal $M	Brownfield black coal $M
3,056.75	978.75	0.00	608.00	720.00	0.00	750.00

This compares favourably to the base case capital cost of $5.028 billion for 3,890MW of capacity. On a per MW basis the cost of capital in Case 2 is $0.93 million compared to the base case cost of $1.29 million.

The overall benefit of this case as measured by the NPV is shown in Table 4-13 below.

Table 4-13 Case 2 NPV Benefit

Year	Dispatch Costs ($M)	Capital Costs (AEC - $M)	Transmission Costs (AEC - $M)	Total Costs ($M)
2006-07	-1.18	0.00	0.00	-1.18
2007-08	0.12	0.00	0.00	0.12
2008-09	0.04	0.00	0.00	0.04
2009-10	-27.57	59.18	0.00	31.61
2010-11	1.10	59.18	0.00	60.28
2011-12	-3.46	13.07	0.00	9.61
2012-13	-3.96	13.07	0.00	9.11
2013-14	-71.39	87.53	0.00	16.14
2014-15	-104.59	123.63	0.00	19.04
2015-16	-106.81	123.63	0.00	16.82
2016-17	-100.12	86.64	0.00	-13.48
2017-18	-111.35	99.87	54.11	42.64
2018-19	-98.39	115.50	116.38	133.50
2019-20	-168.13	189.80	116.38	138.04
2020-21	-188.08	189.80	116.38	118.10
Total	**-983.77**	**1160.9**	**403.25**	**580.39**
NPV Benefit	**-365.52**	**464.06**	**123.98**	**222.52**

Consistent with the Case 1 results, the change in new entry generation mix and location has driven the NPV benefit in this case; however the optimisation of new entry generation to include a transmission cost has resulted in both a reduction in the total capacity of new plant required, and the delay of all base case transmission upgrades.

IES acknowledges that the calculation of the levelised cost adder in the manner undertaken for this case does not address transmission issues currently existing within the Ross and North regions of Queensland. The methodology used in calculating the adder is a great simplification of what a transmission charging regime for new generation might realistically look like. However, despite its shortcomings the hypothetical regime still shows net benefits for the market.

Appendix A: Zonal Definitions for New Entry

Zone Name	Regional Location
ADE	Adelaide
CAN	Canberra
CQ	Central Queensland
CVIC	Central Victoria
LV	Latrobe Valley
MEL	Melbourne
NCEN	North / Central NSW (includes Sydney)
NQ	North Queensland
NSA	Northern South Australia
NVIC	Northern Victoria
SEQ	South East Queensland
SESA	South East South Australia
SNY	Snowy
SWNSW	South West NSW
SWQ	South West QLD