REGIONAL BOUNDARIES AND NODAL PRICING

An Analysis of the Potential Impact of Nodal Pricing and Market Efficiency

Final Report

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IES
Intelligent Energy Systems

Table of Contents

1 Introduction

Intelligent Energy Systems (IES), in association with HARD software, was contracted by the Australian Consumer and Competition Commission (ACCC) to assist the ACCC with understanding the magnitude and materiality of the costs and benefits of implementing either a full nodal pricing regime for generators and customers or just full nodal pricing for generators alone.

1.1 Background

The Ministerial Council for Energy (MCE) is undertaking a review of regional boundaries and the related issue of management of network congestion. As part of that review process the MCE Standing Committee of Officials has invited comment on the paper, "NEM - Transmission Regional Boundary Structure" prepared by Charles River Associates (CRA). The CRA report investigates three options for managing network congestion:

- Nodal pricing,
- Dynamic regionalisation, and
- Evolutionary boundaries with congestion management and intra-regional pricing.

The 'dynamic regionalisation' corresponds to the current Code arrangements with the effective moratorium on boundary changes being removed. The 'evolutionary boundaries' option corresponds to a process that allows for only very gradual change in boundaries and the management of intra-regional congestion by constraint support pricing (CSP) and constraint support contracts (CSCs). From CRA's analysis, they conclude that the best option is the 'evolutionary boundaries' one combined with CSP and CSCs. In effect, if this option were taken to the point where all constraints were priced then it, basically, would be equivalent to nodal pricing for generators combined with nodal pricing for some network control ancillary services (NCAS). Thus the main differences between CRA's proposal for CSPs and CSCs and nodal pricing for generators is the degree to which all constraints are priced and the risk management and grandfathering arrangements for access by generators to their regional reference price.

While the benefits and costs associated with the implementation of a nodal pricing regime in the NEM have been discussed at some length, there have been limited attempts to quantify the costs associated with the implementation of a full nodal pricing regime (whether for generation alone or for both generation and load) in Australia.

The ACCC is seeking to understand the magnitude and materiality of the benefits and costs associated with the implementation of full nodal pricing and full nodal pricing for generators to consider its practicability.

1.2 Terms of Reference

The ACCC's terms of reference were as follows:

"The consultant is to prepare a report covering the issues specified below, with consideration to the findings and recommendations of the CRA report titled 'NEM – Transmission Region Boundary Structure' and dated September 2004 which was commissioned by the MCE.

Nodal pricing

In considering the applicability of full nodal pricing and full nodal pricing for generators in the NEM, the consultant is to:

- *Investigate and discuss the costs and benefits associated with the implementation of full nodal pricing and full nodal pricing for generators in the NEM. In undertaking this task, the consultant must identify those costs and benefits which are associated with transfer of wealth between participants of the NEM, and those costs and benefits which are a result of economic efficiency.*
- *Quantify the costs associated with the implementation of full nodal pricing and full nodal pricing for generators in the NEM, and discuss and outline the methodology and assumptions adopted."*

2 Overall Approach

2.1 Introduction

Given the limited time that IES had to undertake this project, IES investigated and attempted to quantify the benefits and costs associated with the implementation of full nodal pricing and full nodal pricing for generators in the NEM by:

- using a model that we had developed for QLD that has a ten zone network representation and the choice of one, four or ten pricing regions to estimate for 2005/06 what the wealth transfers and economic efficiency gains would be for a nodal pricing regime relative to a regional pricing one,
- comparing the outcomes of our modelling with the modelling work done by CRA to check on the consistency of our conclusions, and
- looking at how investments in generation and transmission may change under each regime, based on the results from the nodal pricing and regional pricing regimes for QLD.

2.2 Ten Zone QLD Market Model

IES's ten zone QLD model has the generator portfolios determining their offers into the spot market such that their profitability is maximised considering their portfolio of swap, cap, and FTR contracts. The different pricing regimes (nodal vs regional) cause the generators to offer different supply curves and hence result in different physical dispatches even though the physical network is the same for both models. From the dispatches the fuel and operating costs were calculated for both the regional and nodal models. The differences in these costs is a measure of the economic efficiency benefits/costs of the two regimes on dispatch costs. Estimates of wealth transfers were calculated from the nodal and regional price results combined with the generator dispatches and zonal loads. Although this modelling only relates to QLD it gives a reasonable qualitative/quantitative feel to what the dispatch benefits may be if nodal pricing were introduced.

2.3 Network Representation

The network model used for the dispatch of generation for both the regional and nodal pricing models was, in CRA terminology, a direct physical representation (DPR) model of the ten QLD zones. IES did this via an explicit network model that had each zone represented as a node or sub-region with explicit transmission connections between these nodes modelled as a DC load flow with losses related to the square of the flows on these elements. Thus, even though under the NEM's current regional model, the dispatch of generators is based on their fixed marginal loss factors, under this model the dispatch of generators for the regional model effectively uses dynamic loss factors. This was done to avoid the calculation of the benefits or costs for implementing a nodal regime getting mixed up (confounded) with the benefits or costs of having a full network model used for dispatch. Our modelling and analysis did not address the later. However, in section 7, there is a brief discussion of the benefits of a full network model versus an implicit model as currently used in the NEM.

2.4 Implementation Cost Analysis

Transitional arrangements and an effective FTR regime would be critical for the effective introduction of a nodal pricing regime. Without such arrangements there could be substantial reductions in contract liquidity and the ability of participants to manage their risks. These in turn would lead to inefficiencies in market outcomes. Consequently, when determining the implementation costs of a nodal pricing regime we have assumed that transitional arrangements are put in place and some form of FTR regime is agreed. Given this proviso, then the main implementation costs would be associated with IT systems and training.

To determine the IT cost of implementing nodal pricing for the NEM, HARDsoftware looked at the incremental system costs required for the market operator and retail, TNSP and generator participants from the following perspectives:

- Incremental bidding costs to be determined from additional nodal price requirements.
- Market information systems costs associated with the additional communication, storage and maintenance of the larger volumes of data.
- Settlement information costs associated with the additional data volumes and settlement methodologies.
- Additional communications network infrastructure required for the market.
- Other market information costs associated with changes to public market delivery systems and third part information providers.

These costs were approximately estimated by determining the additional data requirements of the market participants and the additional functionality associated with the implementation of nodal pricing. Some discussions were held with representative market participants and the results collated, analysed and discussed to determine the full incremental IT cost for an implementation of nodal pricing.

3 Modelling and Analysis Approach

3.1 Introduction

Great care has to be given to how any potential regional boundary arrangements are modelled. The regional boundary arrangements are pricing and settlement arrangements. They do not necessarily reflect the underlying physical network. Thus comparisons between a model that had QLD as one region and another model that had QLD as ten regions would be quite erroneous if they did not have the same underlying physical network. Many models do not distinguish between the regional model used for pricing purposes and the model used to represent the physical network. The use of such a model would produce incorrect inferences regarding boundary changes or nodal pricing.

One minor problem that occurs when exactly the same underlying network model is used for dispatch for both the nodal and regional models is that, for the regional model, the generators effectively get dispatched based on dynamic loss factors rather fixed loss factors. Thus dispatch for the regional scenario will be slightly more efficient, given the set of bids and offers, than the dispatch would have been if fixed marginal loss factors were used. This minor disadvantage was thought to be more than compensated by the fact that using the same network model allowed a much more accurate comparison of how the pricing incentives of both regimes affected the bids of generators and the resulting dispatch costs. If the fixed loss factor dispatch regime were implemented then the dispatch costs for the regional regime are likely to go up because the dispatch is less efficient.

The modelling in this study was primarily aimed at estimating the changes in the costs of dispatch under regional and nodal pricing regimes in QLD. It was not aimed at providing price forecasts, though we were interested in looking at the differences between the underlying nodal prices for both the single region scenario and for the ten region scenario.

3.2 Spot market

IES modelled QLD using Powerlink's ten zone model of QLD rather than using the generic constraints that are used in NEMDE. The ten zone model also picks up intra-regional constraints that affect inter-regional flows such as the Tarong constraint.

Given that the aim of the modelling exercise was to determine what would be the economic efficiency benefits of going to a nodal pricing regime relative to the current regional pricing regime, market simulations based on SRMC bidding behaviour would not have been adequate. Under a SRMC bidding approach all the generator offers are based on their short run marginal costs. In this case the bids would be the same for the one and ten region scenarios and hence would result in the same dispatch for both as the same physical network representation is used for both scenarios. Thus if a SRMC bidding approach is used, it is impossible to detect how a nodal pricing regime may affect behaviour and hence be able to estimate the economic benefits of its introduction. The only way to estimate the economic benefits of a nodal pricing regime is to attempt to model how the nodal pricing incentives change behaviour relative to a regional pricing regime.

For the one and ten region models, the generators' offers were determined to maximise their profits given their portfolios of contracts and FTRs. The zonal prices were used to determine the relevant reference prices. For example, the single region prices were determined from the Moreton North zonal prices whereas the nodal prices were determined from the ten zonal prices.

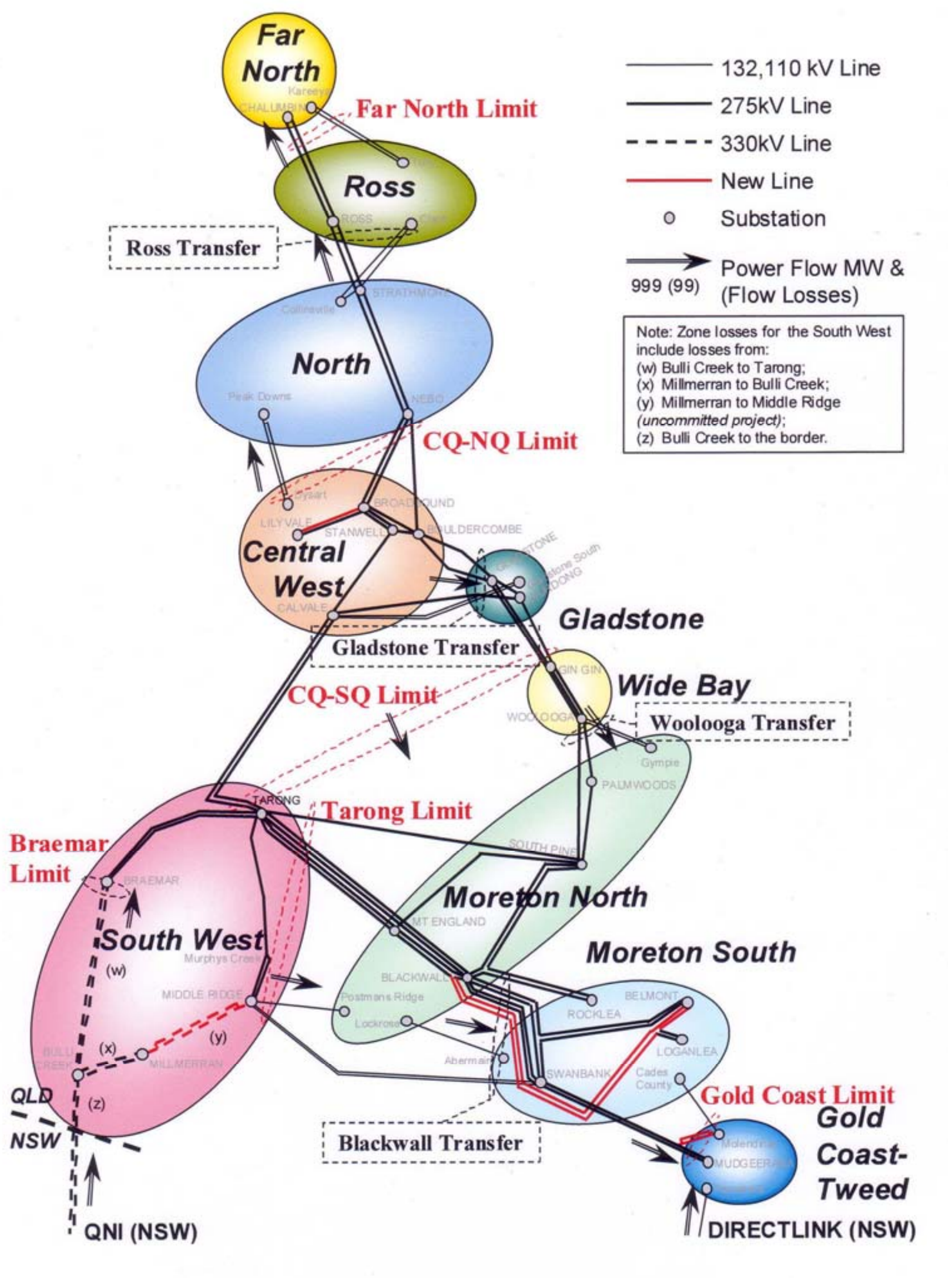
3.3 The Physical Model

Whether the NEM is modelled as regions or as a nodal model, the same physical network and security constraints need to be incorporated into the dispatch process. This could be done in a transparent manner via an explicit network model or in a less transparent way, such as the NEM currently does via regions and the 9000 odd generic constraints.

In order to model the single pricing region versus nodal pricing (ten pricing regions) scenarios in QLD a physical network model needs to be set up that is common to all of the scenarios. This model does not need to be a perfect representation of the underlying network and security constraints but it has to be good enough to allow inferences to be made about different regional boundary arrangements.

To this end the ten zone model that Powerlink uses in its annual planning review was chosen. This model can be thought of as an approximation to a full network model. The ten node model consists of Far North QLD, Ross, North QLD, Central West QLD, Gladstone, Wide Bay, South West QLD, Moreton North, Moreton South and Gold Coast-Tweed and is illustrated in Figure 1.

Figure 1 Powerlink Ten Zone Model of QLD and Power Flow Limits (from Appendix A Powerlink Annual Planning Review 2004)



3.4 QLD Network Constraints

The physical network and system security constraints in QLD were approximated by Powerlink's ten zone network model, see Figure 1. 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.

Many of Powerlink's limit equations included terms concerning capacitor banks, whether units were on-line or not, whether some hydro units were in synchronous condenser mode etc. To model such limits we assumed that if the limit were going to bind all resources available, which could enhance the flow capabilities, would be dispatched. That is, if a hydro unit was not dispatched for energy then it could be used as a synchronous condenser, all capacitor banks would be utilised etc. The QLD network was modelled using a DC load flow approximation.

3.5 Modelling Generator Behaviour

The greatest challenge to simulation models is the incorporation of market behaviour. In particular the challenge is to address the issue of what offers generators may bid each day into the market and how these might change through each day during the simulation run. Most electricity markets are not perfectly competitive. Generally all the larger generating portfolios in a market have some degree of market power. Consequently, most of these larger portfolios do not bid all their plant at their short run marginal costs. They bid their plant to maximise their profits recognising that their generation faces a price versus volume trade off.

The most common approach to this in the Australian market has been for industry analysts to develop a set of generator bids prior to the start of a simulation model run. The bids would be developed based on assessments of competition levels, existing contracts and possibly recent bidding trends evident in the market[1]. 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 (eg. peak, offpeak 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 through the simulation. 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 represented in a static bid representation.
- The development of pre-determind generator bids, unlike structural issues, has a very subjective nature to it and consequently the outputs of a model

[1] 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.

can always be questioned as to whether they are a result of the modeller or a reasonable reflection of what may occur in the market.

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 does this by:

- computing the price sensitivies 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,
  - swap and cap contract portfolio, and
  - FTR contract portfolio.
- once the optimal changes in volumes have been determined, 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.

Because dynamic bidding was used, using the same parameter values for all of the simulation runs, IES believes that the dispatch costs and prices determined from the simulations for each of the scenarios should give reliable indications as to the likely directions of any efficiency and price changes from a one region scenario to a nodal pricing one (ten regions).

4 Modelling Assumptions

This section outlines the assumptions used in the base case modelling.

4.1 Modelling Period

The modelling was for the financial year 2005/06.

4.2 Demand Growth

Demand growth was modelled for each of the ten Powerlink zones using Powerlink's energy and demand projections in their 2004 Annual Planning Report. Regional demand growths for the rest of the NEM were based on the 50% Probability of Exceedence (POE) projections published in the 2003 NEMMCO Statement of Opportunities (SOO).

4.3 Load Traces

Load traces for the QLD zones and other NEM regions were based on three years (2000/01, 2001/02 and 2002/03) of historical half hour data scaled to give the annual energy and demand figures that were consistent with the Powerlink and NEMMCO forecasts yet maintained the half hourly statistical variations observed in the historical data.

4.4 New Supply Developments

A number of potential projects are identified in the 2003 SOO that may or may not eventuate. The projects that IES has identified as likely to proceed and the proposed timing for these projects are shown in Table 1 below.

Table 1 Supply Developments

Development Name	Region	Details	Timing
Basslink (Hydro Tas)	VIC/TAS	600MW/300MW Interconnection	1/1/2006
Tallawarra Power Station (TXU)	NSW	400MW CCGT	1/1/2008
Tomago (Macquarie)	NSW	790MW CCGT	When economic
Quarantine (Origin)	SA	Conversion of current 96MW OCGT to 170MW CCGT	1/1/2006
Kogan Creek (CS Energy)	QLD	750MW base load (coal fired)	1/7/2008
Townsville Power Station (Enertrade)	QLD	223MW CCGT using coal seam methane (an extra 60MW of generation resulting from OCGT to CCGT conversion)	1/7/2005

4.5 Network Outages

Forced and planned network outages were not modelled. The network was always modelled as being at its full capability. Consequently the modelling may underestimate to some extent the differences between the nodal prices in QLD.

4.6 Network Support Arrangements

Existing and future network support arrangements, such as those in Northern QLD, whereby a generator may be constrained on to manage loads were not explicitly modelled. However, the model of the market clearing and dispatch process would always dispatch high priced generation to meet local demand in constrained areas before any load curtailment would occur.

4.7 Contract Assumptions

4.7.1 Overview

For each QLD region, approximately 85% of the expected half hourly demands were hedged with swap contracts. Cap contracts were added to this to hedge peak demands. The amount of cap contracts was determined to be the difference between the maximum of the expected demands and the amount of swap contracts held at the same time but was also restricted to ensure that the total quantity of swap and cap contracts at any time never exceeded 115% of the average demand.

4.7.2 Swap Contract

The Queensland region was divided into ten zones. The generation business units were allocated swap contracts referenced to the ten zones depending on how much available baseload capacity they had and in which zones it was located.

The allocation of the swap contracts to generators was done in a way that aimed to meet the hedging requirements for the regional loads and to minimize the basis risk to generators of contracting. This was done as follows.

- Firstly, swap contracts were allocated for the load in zones in which business units owned baseload generation. For example, the Gladstone Power Station's generation covers Enertrade's risks associated with swap contracts for the Gladstone zone.
- For zones that did not have enough baseload generation in the zone to cover the required swap contracts, surplus generation from other zones was used. This was done by first choosing the generators with surplus un-contracted capacity in zones closest to the zone of interest and then choosing generation in further away zones until all the swap contract requirements were met. For example, Tarong, which owns the Tarong Power Station in the South West, was allocated swap contracts referenced to the Moreton North, Moreton South and Gold Coast-Tweed zones, as

well as the South West, since these zones are physically closer to Tarong's generating units than, say, Far North Queensland.

Although the contracts were referenced to the ten zones, they were priced according to the price-setting zone/s. For example, for the single region scenario there is only one price setting zone, Moreton North. In this case all of the contracts would have Moreton North's price applied to them.

Around 85% of the demand in each of the ten zones was contracted in the forecast year, 2005/06. This represented approximately 56% of available capacity in 2005/06. Table 2 shows the approximate percentage of available capacity contracted for each Queensland portfolio for each of the years. The figures for 2005/06 align reasonably with the historical analysis of quantities bid below the assumed SRMC compared to each business unit's capacity[2].

Table 2 Percentage of Portfolio with Swap Contracts

Business Unit	2005/06
CS ENERGY	57%
ENERTRADE	33%
INTERGEN	64%
STANWELL CORP	56%
TARONG ENERGY CORP	69%
Average	**56%**

4.7.3 Allocation of FTRs

FTRs were allocated to generators to cover any mismatch they had between their zonal contract portfolio and their physical generation portfolio. The amount of FTRs allocated depended on the amount of swaps contracted and to which zones they were referenced relative to the amount of generation each business unit had in each zone. Where a business unit was contracted in a zone where all of its generation did not cover the swap quantity, an FTR was set up. For example, in 2005/06, Stanwell Corporation has swap contracts in place for load in Gladstone and Moreton North zones but only baseload generation in Central West. Thus FTRs were created for Stanwell to hedge its contract quantities in Gladstone and Moreton North.

4.7.4 Cap Contracts

The allocation of swap contracts used the following principles:

- Cap contracts were allocated preferentially to peaking plant rather than baseload plant.
- The combined swap and cap contract quantities were limited to no more than 115% of the average load in a zone.

[2] Recently, Tarong and Millmerran/Intergen have bid all of their capacity at prices below SRMC but this is adjusted downwards for this modeling.

- The total allocation of cap and swap contracts to a portfolio was limited to be no greater than the portfolio's available generation minus the capacity of its largest unit.

For 2005/06, the cap amounts for each region are shown in Table 3.

Table 3 2005/06 Cap Contract Quantity by Zone

Zone	Cap Quantity
Far North Qld	40
Ross	72
North	51
Central West	68
Gladstone	176
Widebay	33
South West	45
Moreton North	176
Moreton South	233
Gold Coast/Tweed	84
TOTAL	**978**

5 Dispatch Costs for Regional and Nodal Pricing Regimes

5.1 Introduction

This section looks at the nodal prices and dispatch costs[3] for the 1 and 10 region scenarios. For this modelling the bids from all generators outside QLD were different from half hour to half hour but were static (preset) in the sense that they did not change in response to: generator behaviour in QLD, outages, unexpectedly high or low regional demands etc. This was done to remove any additional sources of variation that were not directly related to the incentives of the regional and nodal pricing regimes on QLD generator behaviour.

In the modelling the load was fairly highly contracted and the QLD generators were assumed to attempt to maximise in the short term rather than generate a little less to increase future contract prices. Thus the prices may appear to be a little low. However price forecasting was not the primary purpose of the modelling. The aim was to see if the different incentives of regional pricing versus nodal pricing were likely to induce differences in behaviour and hence differences in dispatch costs in the market.

In order to be able to benchmark how material were the benefits and costs of pursuing a nodal pricing regime, an unconstrained single QLD pricing region scenario was also constructed. This scenario had the same physical network as for the 1 and 10 region models but the flows on all network elements in QLD were unrestricted. However, the losses for flows were kept the same as for the 1 and 10 region models. In essence all the network flow constraint equations were relaxed so that they would never bind.

5.2 Nodal Prices and Regional Reference Prices

Table 4 presents the underlying nodal prices for both of the pricing scenarios and for the unconstrained (relaxed) single QLD pricing benchmark. The regional reference price for the single QLD region is the Moreton North price. These figures are the average of the three replicates (three single years of simulations using different random outages and load traces).

[3] Dispatch costs are the variable costs of generation and equal the fuel + O&M costs

Table 4

	1 pricing region	10 pricing regions	1 pricing region with unconstrained network
FNQ	59.07	29.12	21.89
ROSS	57.12	28.39	21.38
NORTH	53.55	26.69	20.12
CW	18.47	18.86	18.97
GSTONE	18.73	19.22	19.61
WIDEBAY	19.06	19.65	20.35
SW	20.55	20.75	20.26
MORETON North - Regional reference price	21.20	21.37	20.81
MORETON South	21.46	21.63	21.06
GCTWEED	21.89	22.06	21.45
QLD load weighted price customers would pay	21.20	21.97	20.81
NSW	25.94	26.01	25.82
Snowy	25.02	25.09	24.93
Victoria	27.95	28.02	27.86
Sth Aust	37.86	37.91	37.78
Tasmania	31.24	31.27	31.22

The patterns and magnitude of the zonal prices are similar to CRA's modelling, though prices are on average are a bit higher. This is a reflection of the fact that in our modelling the generators are not bidding at SRMC but are trying to profit maximise given their contract positions[4]. Table 5 presents the average number of hours per annum that various limits were binding in the simulations.

Table 5 Average hours per annum that constraints bind

	1 pricing region	10 pricing regions
ROSS to FNQ	94.2	58.8
North to ROSS	12.7	6.3
CW to NORTH	1884.5	1863.7
CW to Gladstone	0.3	0.3
CQ to SQ limit	0.0	0.0
Widebay to Moreton North	1597.2	1163.7
South West to Moreton North (Tarong)	0.2	0.2
Moreton North to Moreton South	2.3	2.7
Moreton South to GC/Tweed	26.7	24.7

From our analysis it is quite clear, for the modelled network capability, that some of the zonal prices within QLD are materially different from the regional

[4] Generators tend to offer their contracted quantities (swaps) around or below their short run marginal costs and as a consequence increasing the level of contracting tends to lower prices and decreasing the level of contracting tends to raise prices.

reference node prices. Thus given the presence of materially different zonal prices to those of the regional reference node it would be reasonable to expect that a nodal pricing regime would create different incentives for generators and hence differences in behaviour. This conclusion disagrees with CRA's conclusion about the pricing outcomes from a nodal model versus a regional regime.

5.3 Analysis of Nodal Prices and Intra-regional Constraints

In the CRA report it is argued that pricing outcomes from a full nodal model were not significantly different from those resulting from a regional pricing model. This conclusion was based on two analytic approaches: market simulation modelling using SRMC bidding and an analysis of historic constraint shadow prices.

For the market modelling, CRA concluded that the pricing outcomes from the nodal model were not significantly different from those of the regional regime and hence there is not a case to argue that a nodal pricing regime would produce better pricing signals. Though, CRA did state that this conclusion is highly sensitive to the level of network investment. For the QLD model they developed, the 10 zonal prices under their base power flows case differ very substantially from the single region price (the Moreton North price)[5]. These zonal price differences for their base case are not dissimilar to the results IES obtained from our modelling.

The CRA historical analysis of intra-regional constraints shows that there can be significant differences in prices that would be paid to generators under a nodal pricing regime relative to their regional reference prices. These differences are driven by a relatively small number of events. However, this is no different to average prices in the NEM being strongly influenced by a small proportion of dispatch periods. Thus the CRA statement that:

"Modelling has indicated that for the overwhelming majority of the time and for the foreseeable future, nodal spot market prices in the NEM are not expected to differ materially from likely regional spot prices."

is potentially misleading. The evidence is that the average nodal prices can be significantly different from the regional ones but that this is caused by a relatively small number of dispatch intervals.

5.4 Dispatch Efficiency Estimates

In order to get an idea of what may be the changes in dispatch efficiency of going from a regional pricing regime to a nodal pricing one, IES calculated the annual dispatch costs (fuel and variable operation and maintenance costs) for both regimes. These were done on a QLD and NEM wide basis. The NEM costs are the appropriate ones for estimating dispatch efficiencies as the

[5] Table 4 in CRA NEM Regional Boundary Issues: Modelling Report

regional and nodal regimes produced different flows over QNI and Directlink. Hence the changes in dispatch costs for the rest of the NEM needed to be considered.

In the case of hydro plant and pumped storages the following was done:

- Pumping costs were ignored as these were picked up via the increased loads at the time of pumping;
- Generation operations and hence bids were based on marginal water value functions that approximated the opportunity cost valuations of the water given the current storage levels;
- The starting water levels for each storage were set to be the same for each year's simulation;
- The water in each hydro storage was valued (based on the integral of its marginal water value function) at the start and end of each year's simulation to determine the cost of water used. These costs were added to the total NEM dispatch costs.

Table 6 NEM Dispatch costs for 1 region and nodal pricing regime

	1 pricing region ($M)	10 pricing regions ($M)	1 pricing region with unconstrained network ($M)	Benefit/Cost of nodal pricing ($M)	Total constraint costs ($M)	Benefit as % of constraint costs
Replicate 1	2360.2	2360.6	2355.5	-0.4	4.7	-9%
Replicate 2	2204.5	2200.0	2197.7	4.5	6.8	66%
Replicate 3	2217.5	2212.9	2210.1	4.6	7.4	62%
Average	2260.7	2257.8	2254.4	2.9	6.3	46%

Table 7 QLD Dispatch costs for 1 region and nodal pricing regime

	1 pricing region ($M)	10 pricing regions ($M)	1 pricing region with unconstrained network ($M)	Benefit/Cost of nodal pricing ($M) *	Total constraint costs ($M) *	Benefit as % of constraint costs *
Replicate 1	721.6	718.7	723.0	2.9	-1.4	-205%
Replicate 2	714.4	708.1	712.4	6.3	2.0	317%
Replicate 3	718.5	712.6	716.4	5.9	2.0	289%
Average	718.1	713.1	717.3	5.0	0.9	573%

* These costs are somewhat misleading as they do not include the impact of the increased costs for the rest of the NEM

Although not large when compared to the total dispatch costs, the average dispatch cost benefit of $2.9 million for pursuing a nodal pricing regime is quite large when compared to the total constraint costs in QLD. In fact it is estimated to be almost half the constraint costs. Consequently, on the basis of these estimates, this means that a change in the market rules from regional pricing to nodal pricing yields as much benefit to the market as the amount of transmission investment that would be required to eliminate half the dispatch costs due to intra-regional transmission constraints in QLD. However, it should be noted that there is quite a bit of variability between the replicates, consequently these results should not be treated as definitive. None the less they do indicate that there could be a material benefit in pursuing nodal pricing and this probably should be investigated further.

6 Impact on Generation Investment

6.1 Overview

In the competitive market environment, individual companies make decisions when to invest based on the economic signals of the market, the risk involved and the opportunity costs of capital. In simple terms, investments are made when the return on investment is perceived to provide a satisfactory rate of return over some period, accounting for the risks that exist in the market.

Spot prices reflect the value of energy during each settlement period at a particular location, such as a regional reference node. It is both the average level of prices and the distribution of prices that signal the economics of new generation in terms of timing and required service. In other words, it is the distribution of spot prices that determines whether base load, intermediate or peaking supply is required. This is central to the long-term dynamic efficiency of energy only markets.

Generator costs

The cost structure of a new generator is characterised by the cost of constructing the power station (ie. capital cost), fixed costs such as network connection charges and the cost of fuel and wear and tear when it is used to generate electricity (ie. variable cost). The cost of generating electricity over some period of time, normally a year, expresses the total costs incurred over the year for the electrical energy produced. Here the total cost in a year is the sum of the capital costs allocated to that year and the variable costs due to fuel used etc. The cost of generation is normally expressed in the units $/MWh.

As capital (and fixed) cost does not depend on the utilisation of a generator (but variable cost does) the average cost of generation depends on how much energy a generator produces. This means that generator utilisation is important when comparing generator costs.

The percentage of hours a power station operates in a year is termed its "capacity factor" of operation. Assuming a generator always operates at its rated output when it is generating, the amount of energy a power station produces in a year is directly proportional to its capacity factor of operation in that year. This can be expressed as:

Generated Energy in a Year (MWh) =
Rated Capacity (MW) x 8760 hours/year x Capacity Factor (%)

When capital cost is amortised over the economic life of a power station the cost of energy produced ($/MWh) in a year can be expressed as follows[6]:

[6] The cost calculated by this "annualised cost" approach is the same as that which would be determined using a simple NPV approach (where the capital expenditure occurs in year 0 and operations costs occurs in

$$\text{Cost of Energy (\$/MWh)} = \frac{\text{Annual Capital Cost (\$/pa)}}{\text{Energy Generated (MWh/pa)}} + \text{Variable Cost (\$/MWh)}.$$

As can be seen, the more a power station generates (ie. higher the capacity factor) the lower the capital component contribution to the cost of energy produced. This provides the basis for base load power stations to have high capital costs and low fuel costs and peaking power stations to have low capital costs and high fuel costs. Demand side management has very low capital costs but very high opportunity costs when used.

Spot price premiums and the economics of new entrant generators

The economics of a power station is based on a return on investment, which is given by the recovering the variable costs of production and an adequate contribution to capital. Given that a generator offers to sell energy at a price to at least cover its variable costs, the level of spot prices above its variable operating cost is the determining factor in the economics of new generation (ignoring the impact of take-or pay fuel contracts and financial hedging contracts). The level of prices above its variable operating cost is often termed the spot price premium. The sum of all hourly prices above a defined strike price in a year is expressed as $/MW/year, and dividing this by 8760 (the number of hours in a year) yields the spot price premium, a $/MWh figure. Expressed in terms of premiums, typical new entry costs for gas and black coal generation are as follows:

- Black coal: $25/MWh premium at a strike price of $12/MWh
- Combined cycle: $13/MWh premium at a strike price of $30/MWh
- Open cycle: $8/MWh premium at a strike price of $50/MWh

Impact of ignoring transmission constraints

Having some transmission constraints not being considered in the price setting process may result in “clipping” of the price distribution, at some locations, which in turn has the potential to influence the economics of new generation in terms of timing, type and location. For example, 2.5 hours of prices averaging about $10,000/MWh is sufficient to pay about half the capital costs of an open cycle gas turbine plant. This means that, if such a price signal were absent, as may be caused by removing a transmission constraint from the prices that a

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years 1 to 30). This equivalence is demonstrated as follows:

NPV Model:
NPV = K (capital cost) + C (annual O&M + fuel) $\{1/(1+r) + 1/(1+r)^2 + ...\}$
= K + C.A where A = {....}
Hence $/MWh = (K + C.A) / G.A where G = annual generation

Levelised Cost Model:
$/MWh = K / (G.A) + C / G where 1/A is the annuity factor applied in the initial analysis
= (K + C.A) / G.A where G = annual generation

This shows that plant costs are ranked same in both approaches and that the approaches are equivalent.

generator sees, the new entry economic signal could be distorted in terms of both timing and plant type.

6.2 Initial Qualitative Assessment

From the modelling undertaken for this report, which considers the impact of moving from one to ten regions in Queensland, this section considers how significant a move to ten regions would be to the efficiency of new generation investment. This is done by illustrating how investment decisions might change, depending on whether a single region or nodal pricing regime were present. To this end we have assumed that the qualitative characteristics of the nodal prices versus the single region prices would persist.

Modelling - 2005/06

Table 8 shows, for the single pricing region regime, the underlying nodal spot price results for the year 2005/06, expressed as premiums at various strike prices. These price reflect the nodal prices that would be seen if the dispatch engine that cleared the single region regime also produced nodal prices for each of the ten QLD zones.

Under the single region regime, investments will be driven by the regional reference node prices, i.e. the Moreton North nodal prices. In this case there is no indication that any generation would enter the market, as the premiums for all of the types of plant are well below those required to break even. On the other hand if the underlying nodal prices were looked at, then the results show a vast difference in the spot price premiums across the nodes and that all types of generation could be justified in northern QLD with OCGTs being the most economic. Consequently, if there were a CSP regime in northern QLD that only affected northern QLD generators at the margin, then this might attract some new entrant OCGTs.

Table 8 Estimated Spot Price Premiums for 1 Region Regime for 2005/06

Node	Strike price at $12	Strike price at $30	Strike price at $50
FNQ	47.07	36.67	33.94
ROSS	45.12	35.11	32.55
NORTH	41.55	32.50	30.11
CW	6.47	0.16	0.03
GSTONE	6.73	0.18	0.03
WIDEBAY	7.10	0.24	0.03
SW	8.55	0.49	0.08
MORETON North - Regional Reference Node	9.20	0.63	0.09
MORETON South	9.46	0.68	0.09
GCTWEED	9.89	0.79	0.11

Table 9 shows, for the ten pricing regions regime, the nodal spot price results for the year 2005/06, expressed as premiums at various strike prices. Under this regime the premiums for northern QLD are much higher than the premiums for the regional reference node in the single region regime. However, they are nowhere near as high as the premiums for the corresponding nodes in the single region regime. Under the nodal pricing regime, only OCGTs are anywhere near being economic.

Table 9 Estimated Spot Price Premiums for 10 Region Regime for 2005/06

Node	Strike price at $12	Strike price at $30	Strike price at $50
FNQ	17.12	6.90	6.11
ROSS	16.39	6.61	5.94
NORTH	14.69	6.03	5.53
CW	6.86	0.17	0.03
GSTONE	7.22	0.21	0.02
WIDEBAY	7.67	0.29	0.03
SW	8.74	0.49	0.06
MORETON North - Regional Reference Node	9.37	0.63	0.07
MORETON South	9.64	0.68	0.07
GCTWEED	10.06	0.79	0.08

While any reasonable analysis of new entry generation investment needs to consider the impact of new entry capacity due to the lumpiness of the investment, it is evident that the zones of Far North Queensland, Ross and North have prices that clearly signal that any new generation would be better located in these zones. With the strongest signal being for peaking type plant since the premium for this type of plant is closest to its economic threshold. The dampening of this signal in the 1-region model is due to some of the high peak period prices being absent.

While not signalling new entry at this stage, the differences in spot price premiums at the other nodes, compared to the Moreton North price for the one region model, also indicates that the investment signals would be different for a nodal regime as compared to single region regime. Further, when the single region model does signal the need for new entry, this is likely to encourage base load generation near the cheapest fuels rather than peaking plant at specific locations, as the 10-region model is signalling.

7 Network Model Used for Dispatch

7.1 Dispatch and Constraint Formulation

In CRA's report, they recommended that dispatch be based on a direct physical representation of the network. By this they meant a representation that directly represents the physical characteristics of the network. This form of constraint representation will deliver the most efficient dispatch given the sets of bids and offers made by participants.

Two forms of direct physical representations of constraints have been canvassed previously. These are as follows.

- The option 4 type of constraint representation - a regional model combined with network and security constraints where all dispatchable terms are put on the left hand side of the constraint equation. This approach is effectively a regional model combined with an implicit network model.
- The option 5 type of constraint representation – a full network model that explicitly represents the network with regional reference prices being determined from the nodal prices of the regional reference nodes.

Though in theory the two forms of constraints are equivalent, in practice the full network model has many advantages over the option 4 representation and is likely to lead to a more efficient use of the network and hence a more efficient dispatch based, for a given set of bids and offers. This issue is discussed further in section 7.2.

7.2 Full Network Model for Dispatch

One very important issue that can be separated from the issue of nodal pricing, to a large extent, is the choice of the network representation used in the dispatch process. CRA quite reasonably recommended that NEMMCO should use the Direct Physical Representation (DPR) form for all network constraints.

As mentioned earlier, this approach combined with the NEM's current regional dispatch model and generic constraints, theoretically, could produce the same outcomes as a full network model, combined with the DPR form for constraints not explicitly managed in the full network model. However, based on IES's work with NECA on the project 'Optimising Combined Secure and Economic Dispatch', we think that there are potentially substantial efficiency gains to be made by having NEMMCO use a full network model for dispatch.

Our conclusion is based on the fact that the regional model is not very good at managing many intra-regional flow limits and the whole process of determining constraint equations from the power system modelling to the statistical estimation of limit equations and their conversion to constraint equations is much more difficult when intra-regional network flow terms and nodal demands and injections cannot be used. The generic constraints that are used in the current dispatch formulation only use interconnector flows and generator dispatch terms yet they may be managing a relatively simple flow limit.

For example, the Central QLD to North QLD dynamic stability limit requires the flow from Central QLD to North QLD to be less than 985 MW – 10x(number of Barron Gorge and Kareeya units on-line in synchronous condenser mode) MW. Now with a full network model this limit can be readily formulated yet with the current regional model the flow between Central QLD and North QLD would have to be calculated from the QLD regional demand, QNI and Direct Link flows, and QLD generator dispatches. To ensure the same level of security as the full network model, the generic constraint that corresponds to this limit in the regional model would have to be more conservative than what is required for the full network model because this constraint would have to be constructed on the basis that there is a degree of uncertainty as to how the total QLD demand is spread geographically across QLD.

The current approach to system security is to manage the flows on the network via approximately 9000 security constraints (called generic constraints in NEMMCO's dispatch software). This approach is unsustainable in the long term and is already leading to inefficient dispatch. That is, either the network is being under-utilised or the market is being exposed to system security risks. Consequently, in the longer term, NEMMCO really needs to use a full network model for dispatch.

8 IT Costs of Implementing Nodal Pricing

IES attempted to get an initial preliminary estimate of the IT costs that would need to be incurred if nodal pricing were introduced. Given the shortage of time to make these estimates and the fact that we were not able to discuss the costs with all of the key players, these estimates should be viewed as being around the right order of magnitude and no more accurate than that.

8.1 Methodology for estimating IT costs

To determine the IT cost of implementing nodal pricing for the Australian NEM, IES looked at the incremental system costs required for the market operator and retail, TNSP, and generator participants from the following perspectives:

- Incremental bidding costs associated with additional nodal price requirements.
- Market information systems costs associated with the additional communication, storage and maintenance of the larger volumes of data.
- Settlement information costs associated with the additional data volumes and settlement methodologies.
- Additional communications network infrastructure required for the market.
- Other market information costs associated with changes to public market delivery systems and third part information providers.

This report seeks to estimate these additional IT costs for both full nodal pricing and just generator nodal pricing by determining the additional data requirements of the market operator and participants and the additional functionality required for the implementation of nodal pricing. Some discussions were held with representative market participants and the results collated, analysed and discussed to estimate the full incremental IT cost for the nodal pricing implementation.

8.2 Assumptions for estimating IT costs

Many of the effects of a nodal pricing regime on market participants can be estimated by comparison with the New Zealand electricity market model. Although a much smaller energy market than Australia, the NZ Electricity Market (NZEM) arguably presents the closest direct comparison to a potential nodal market model, with a similar business and social culture.

The NZEM consists of 10 major participants and 244 nodes and has been operating in various forms since 1996. Some observations can be made of the NZEM that have direct relevance to a potential Australian nodal market.

- Only about 10 nodes are regularly reported in the NZEM market reports, and are located in all of the major load centres in the North and South Islands.
- Over The Counter (OTC) contracts are usually only available for a limited number of these common reference nodes and with very low liquidity levels and range of instruments.
- Participants in the market are usually both generators and retailers, which is in direct contrast to the present composition of the Australian NEM.
- There was no transition from a regional competitive market to a full nodal market model.

Therefore whilst the NZEM does share a number of common characteristics with a potential nodal market, there is no equivalent of the proposed generator nodal market nor is there the more distinct separation of generation from retail participants that is a feature of the Australian NEM.

From consideration of the key features of the proposed nodal market models and comparison with the NZEM, and from discussions with market participants, a number of assumptions have been formulated to provide a framework for estimating the incremental IT costs associated with the potential nodal market models.

- Most participants would only collect and be interested in a small subset of the available information. Namely, generators would be expected to be interested in generation nodes, retailers with their connection nodes and all organisations, both participants and interested non-participants, would continue to collect key nodal data from the main load reference centres.
- OTC swap, cap, option and futures contracts would continue to be priced and sold based upon the regional reference nodes. As well as these nodes, a few large or important load bases such as Canberra/Southern NSW, Central Queensland and Northern Queensland may also be included, but very limited numbers of contract offers and bids would be expected if there was not an effective FTR regime.

8.3 Market operator IT costs

The market operator NEMMCO, as the sole provider and source of energy market information, would have the single largest IT cost associated with the implementation of either of the nodal pricing market models. Unfortunately, NEMMCO was not available to discuss any possible IT costs associated with either of the nodal pricing models. This made the task of estimating the possible incremental IT costs for NEMMCO, a key organisation, very difficult. In the absence of their contribution, many assumptions and imprecise estimates have had to be made for this part of the report.

During the initial establishment of the Australian NEM and also for significant market revisions such as the introduction of dispatched Ancillary Services, the resources and the time required for the design, development, testing and acceptance by the market participants of the NEMMCO IT systems virtually dictated the implementation dates for each major version of the market. The resource and time requirements were severely underestimated in the planning of each of the market implementations and adversely affected all of the market implementation project plans, milestones and commitments.

Any proposed commencement of a nodal pricing market would be significantly constrained by the costs and availability of suitable IT resources required to create and modify the NEMMCO IT systems to implement the nodal pricing markets.

The significant market operator systems that are directly affected by the proposed nodal market models have been identified to include:

- Scheduling, pricing and dispatch.
- Energy settlements.
- Inter-regional settlements.
- Market information.
- Metering.

NEMMCO has estimated that the costs to setup the initial market systems for the entire Australian NEM cost around $30 to $50 million dollars. Although no estimates for the incremental costs associated with nodal market implementations have been provided by NEMMCO, given the substantial nature of the changes necessary for the market operator, the estimates for the incremental capital cost of the IT systems are:

- full nodal pricing $4 to $6 million.
- generator nodal pricing $3 to $5 million.

These estimates are indicative only and have been made with little available information and therefore should be interpreted with caution. These costs include a full network model for dispatch. Thus, if NEMMCO were likely to proceed with a full network model for managing system security, irrespective of whether a nodal market is to be implemented or not, then the above incremental costs would be lower.

The ongoing costs associated with nodal pricing relate mainly to the additional dispatch and pre-dispatch calculations and increased volumes of nodal data. There are technologies available that would reduce the amount of network data communication between NEMMCO and participants, such as data broadcasting and peer to peer data sharing, that were briefly investigated at the commencement of the market but not adopted for the implementation of that market, that could reduce the operational costs of the market operations with increased volumes of nodal data.

However, assuming the existing network, communications and information database query design, the increased IT operational costs / year are estimated to be:

- full nodal pricing $500K to $1 million.
- generator nodal pricing $350K to $800K.

8.4 AER and AEMC costs

The successors to NECA, the AER and AEMC, between them would continue NECA's role in monitoring the performance of the market and so would have a similar market information requirement as the market operator, as they may need to collect data for every node in the network, but more likely a substantial number of key nodes.

Either of the nodal pricing models would result in an estimated $100K to $200K of capital costs with possible some increased ongoing costs of around $50K / year, if measurable at all.

8.5 Generator costs

Each of the generators, for either of the nodal market models, would require IT enhancements to the following systems.

- Additional market information requirements for each generation node in the generator's power station portfolio.
- Possibly additional market information for key nodes that are not presently collected.
- Additional wholesale settlement functionality to accommodate generation nodes, additional inter-nodal residual calculations and a larger range of reference nodes.
- Bidding system modifications if generation portfolio is on more than one node and to remove the present regional loss factor calculations.
- Increased capability of risk management systems to cope with the additional nodal implications that determine market contract positions and portfolio valuation.

The costs for the increased IT functionality for the nodal markets are significantly determined by the number and locations of the generation units, the amount of speculative trading participation and the nature of generation (ie. slow and/or fast start plant portfolio).

For the larger Australian generators with a diverse portfolio of a large number of generators, the incremental costs for implementing either of the nodal market models would be estimated to be $300K to $600K capital costs and up to $100k operation costs / year. A medium size generator with a small and homogenous range of generators would be $100K to $250K capital costs and up to $50K / year, and a small one or two unit generator would be up to $100K capital costs and only a small increase in operational costs.

8.6 Retailer costs

The retailer incremental costs for IT systems are only significant for the full network nodal market model. As most of the large retailers have interests in a wide and diverse area of the market, the nodal data volumes would increase significantly for the following IT systems:

- Additional market information requirements for each node in the retailer's market.
- Possibly additional market information for key nodes that are not presently collected.
- Additional wholesale market settlement functionality to accommodate connection nodes, additional inter-nodal residual calculations and a larger range of reference nodes.
- Bidding system modifications for dispatched load (not presently used much in the Australian market).
- Increased capability of risk management systems to cope with the additional nodal implications to determine market contract positions and portfolio valuation.

As can be seen from the above list, the additional requirements for the retailers is similar to the requirements identified for the generators, but it should be noted that the additional nodal market information collected for the retailers is likely to be much larger than for the generators. Conversely, it is likely that most retailers would not have any significant bidding system modifications as these are not used by many participants and the changes would be minimal if required.

The estimate is also complicated by the fact that many small retailers outsource their billing, customer relations, contract management and settlements to third party organisations. It is expected that the changes required for the implementation of the IT requirements for the full nodal market would be charged back to the retail participant in the form of either higher fees or single payments depending on their individual out-source agreements. Also the capital costs of the IT changes may be shared between multiple out-source customers using a single IT provider and thus reduce the overall cost to each of the individual retail participants.

It is estimated that the large retail participants, with all internal IT systems, would have an incremental IT capital cost of $400K to $750K and increased operational costs of up to $150K / year. A medium size retail participant $150K to $200K capital costs and increased operational costs of up to $100K / year, and a small participant up to $100K capital costs and up to $50K / year operational cost depending on how many IT systems are out-sourced or standard products.

8.7 Total IT costs

By taking the previous incremental capital and operational cost estimates, the total IT costs can be estimated for the entire market for each of the nodal market models. Note that it is difficult to determine if there are any ongoing incremental operational costs associated with either of the market models for most participants, and therefore the range of estimates for the operational costs are especially relatively wide.

For the full market model the capital and operational costs for the entire market have been estimated to be:

- Capital IT costs: $13.7 million to $27.4 million.
- Operational IT costs: $0.5 million to $6.1 million.

Similarly, the IT capital and operational costs can be estimated for the generator only market model:

- Capital IT costs: $7.2 million to $14.9 million.
- Operational IT costs: $0.35 million to $2.4 million.

9 Conclusions

Given all the qualification stated earlier in this report, IES's modelling of the QLD regional pricing scenarios indicates that:

- there are likely to be significant price differences between various nodes and the regional reference node in the immediate future;
- given that there are materially different nodal prices within QLD, a nodal pricing regime is likely to induce different generator behaviour and this may have material benefits in terms of the NEM's dispatch costs (mainly fuel costs);
- a nodal pricing regime is likely to provide different investment signals to that of a regional pricing regime and this is likely to lead to different locations, timings and types of generation investment;
- on the basis of our estimates of dispatch costs for 2005/06, a change in the market rules from regional pricing to nodal pricing yields as much benefit to the market as the amount of transmission investment that would be required to eliminate half the dispatch costs due to intra-regional transmission constraints in QLD; and
- our rough estimates of the costs of moving to nodal pricing show that these costs are likely to be much lower than the costs of major transmission upgrades.

Consequently, we feel that (a) it is probably premature to reject any movement of the NEM to a more nodal regime and (b) further investigation of the benefits and costs of such a move is likely to be worthwhile.