21th December 2006

Dr John Tamblyn
Chairman
Australian Energy Market Commission
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Dear John

Supplementary Submissions: National Electricity Amendment- Region Boundaries Rule (Ministerial Council of Energy) and Congestion Management Review

Macquarie Generation and Snowy Hydro asks that the Commission considers this supplementary submission on the Region Boundary rule change and the Congestion Management Review. Submission comprises a report on a study conducted by Firecone on the impact of locational pricing on the contract market.

Firecone concludes:

"…that an increase in locational pricing in the spot market, either as a permanent change or as a transitional measure, is likely to result in a greater level of inter-regional price risk, lower liquidity in contract markets, and greater difficulty in pricing the risks.
Conversely, a reduction in locational pricing in the spot market would be likely to increase liquidity in the contract market, possibly at the cost of some reduction in dispatch efficiency. Moreover, any gains through reduced costs will be shared with all market participants located in the region …

These factors suggest that the benefits from reduced transaction costs in the contract market are material enough to be an important element for consideration by policy makers."

Macquarie Generation and Snowy Hydro appreciate the opportunity to provide this supplementary submission.

Please contact Roger Whitby on (02) 9278 1885 or Russell Skelton on (02) 4968 7429 if you would like to discuss the issues outlined in this submission.

Yours sincerely,

Roger Whitby
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Snowy Hydro

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The impact of locational pricing on the contract market

A report by

Firecone Ventures Pty Ltd

November 2006

Disclaimer

EXECUTIVE SUMMARY

Purpose of the paper

There is substantial debate over the appropriate level of locational price signals in the National Electricity Market (the NEM). Much of that debate focuses on the extent to which the market Rules result in cost reflective prices (on the basis of bids and offers) at different transmission nodes.

The purpose of this paper is to set out why an increase in locational pricing will increase transaction costs in the contract market, and why this should be of concern to policy makers.

A focus on the effectiveness of price signals within the spot market is an inadequate framework for determining the level of locational pricing within the NEM. Commercial decisions, including new investment, are driven by the contract market. An increase in locational pricing will increase the transaction costs in the contract market. This is likely to lead to earlier generation investment than would otherwise be required, and may cause a 'regionalisation' of investment decisions with a consequent loss of dynamic efficiency.

This paper sets out why decisions on the level of locational pricing in the NEM should take account of the impact on transaction costs in the contract market. It does not attempt a quantitative assessment of the trade-off between this and other objectives. However, it does provide illustrative figures which suggest that this issue may be much more material than the impact of locational price signals on dispatch efficiency.

Appropriate consideration of the impact on transaction costs in the contract market is likely to lead to a lower level of locational pricing than if this issue is not considered. It may also create an argument for a reduction rather than an increase in the number of regions.

Price risk is managed through the contract market

The design of the National Electricity Market (the NEM) as a gross, energy-only market necessarily creates a high level of price volatility. In addition, there is significant variation in demand.

The regional structure of the NEM creates an additional risk of price separation between the regions, for market participants who are trading between regions. Price separation between regions is also highly volatile.

Although the spot market structure creates substantial risk, the risks are largely inverse between generators and retailers. As a result, market participants can reduce their risk through contracts. This is done directly, through brokers and through exchanges.

The risk of price separation between regions can also be hedged. When prices separate between regions, power flows from the low price region to the high price region, creating a settlement residue. The principal instrument for hedging the risk of price separation is the auction of these settlement residues.

A large increase in the number of regions would be required to ensure cost-reflective prices

The regions as currently defined include a number of transmission constraints. As a result, there are transmission nodes where the price at the node, under the current regional framework, differs from the marginal cost at the node on the basis of bids and offers. A paper by Darryl Biggar for AEMC has concluded that around 95 generator connection points have been mis-priced for 100 hours or more on average over the last three years. Around 70 regions would be required to remove this inefficiency. We recognise that Darryl Biggar and the AEMC have not advocated the creation of these regions.

An increase in regions would increase transaction costs in the contract market

The structure of locational pricing in the NEM affects the extent to which prices reflect the marginal cost of supply, for given bids and offers. It also affects transaction costs in the contract market. A substantial increase in the number of regions would increase transaction costs in the contract market by:

- Significantly increasing the risk of price separation between contracting parties, and the number of instruments required to hedge that risk
- Creating many nodes with low liquidity in the contract market, and
- Increasing the complexity in pricing inter-regional price risk, and asymmetry of information between sellers and buyers of contracts.

It may be possible to offset any distributional impacts of a move to stronger locational pricing through allocation of rights to the settlement surpluses (although this has proved difficult in other markets). However, this would not affect the increase in transaction costs.

Experience in other electricity markets suggests that market participants would respond to this increase in transaction costs by avoiding inter-regional price risk. They could do this either by not trading between regions, or by ensuring that their generation and load portfolios are balanced, not just in scale but also in location.

This is likely to lead to higher costs due to greater risk premiums, a higher level of generation reserve as entry is made in response to higher prices in the contract market, and a regionalisation of investment decisions with a consequent loss of dynamic efficiency.

These costs may well outweigh any efficiency gains from locational price signals

We have not attempted to fully quantify the comparative materiality of impacts on efficiency in the spot market with contract market impacts. Similarly, we have not attempted to assess the impact on dynamic efficiency of differing locational signals under different models. However, analysis by the AER of the costs of constraints in the NEM concluded that they have been between $30m and $45m in 2004 and 2005. There is no reason to believe that greater locational pricing will cause this to diminish. Also, the relative insignificance of this cost in proportion to wholesale market sales of around $6bn suggests that there is not a material inefficiency with the existing arrangements.

The UK has consistently rejected stronger locational pricing due in part to the impact on liquidity in the contract market. New Zealand, which has introduced nodal pricing, suffers from an illiquid contract market.

Our conclusion is that policy makers should consider the impact of decisions on the regional framework of the NEM on the contract market. This will generally support the case for a lower level of locational pricing than if this impact is not considered.

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1 Introduction

1.1 Purpose

The development of policy in the National Electricity Market (NEM) and of the Rules for the NEM draws heavily on an economic framework.

This may encourage a strong reliance on price signals. The Rules for the spot market affect the extent to which prices reflect costs. Economists tend to assume that cost-reflective price signals (by definition) assist allocative efficiency. Price signals should also encourage static and dynamic efficiency. Where there is sufficient competition, price signals will reflect efficient costs. Where there is not – and prices are above efficient costs – then this will create a signal for market entry, encouraging dynamic efficiency.

Costs in the NEM can vary significantly by location. An analytic framework of this kind may therefore lead to an increase in the level of locational pricing in the NEM.

An increase in locational pricing may deliver benefits in the spot market, for the reasons outlined above. It will also have distributional impacts – to the benefit of some generators and detriment of others. Policy makers could ignore these distributional impacts as simply representing transfers rather than welfare gains or losses. Alternatively, the introduction of locational pricing could be accompanied by contracts (such as the CSCs currently used at one transmission node) which offset any distributional impacts, while leaving marginal price signals in place.

If there is no clear understanding of the costs associated with stronger locational pricing, there will therefore be pressure to move in this direction. However, the analytic framework outlined above is too simplified. It ignores transaction costs in the contract market.

Electricity markets are extremely volatile. Participants have to manage that volatility to reduce risks to acceptable levels, and do so through the contract market. Policy makers tend to focus on spot market design, as this is the instrument that they can control. However, it is the contract market which dominates commercial behaviour in the NEM and underpins new investment.

An increase in locational pricing will increase the transaction costs in the contract market and reduce its efficiency. This will be reflected in larger spreads in the contract market. It is also likely to be reflected in illiquid markets, where participants face difficulty in hedging locational risks.

Any increase in spreads in the contract market is not simply a distributional issue – that is, a transfer from parties paying premiums to parties receiving them. An increase in transaction costs in the contract market will lead to higher contract prices, earlier entry, and so less efficient levels of generation reserve.

If there is a reduced level of integration between the contract markets in different regions – due to an increased cost of hedging price separation between regions – this may also lead to a decline in dynamic efficiency across the NEM. Investments will be made against contract market signals within a single region. A significant increase in transaction costs and or reduction in the ability to obtain locational risk hedges would lead to greater regionalisation of the market. This would undo many of the gains achieved by the development of the NEM. At an extreme, it could lead to a situation where the NEM is, again, a set of State-based electricity markets rather than a unified market across the South and East of Australia.

Some other jurisdictions have considered and rejected a move to stronger locational pricing because of the possible impacts on transaction costs and liquidity in the contract market. In other cases, a high level of locational pricing has been introduced but has led to a reduction in contract market efficiency. Great Britain provides an example of the first approach, and New Zealand of the second.

The importance of transaction costs in the contract market has not been well understood in the policy debate to date. The MCE transmission statement of May 2005 concluded that "no material efficiency benefits would be gained from a nodal pricing approach at this stage of market development", but did not articulate clearly why it reached that conclusion. The CRAI report on criteria for regional boundary change, which formed the basis of that conclusion, considered the efficiency impacts of nodal pricing, stating:

> *"Nodal prices meet short-term efficiency objectives, since they reflect the marginal cost of electricity at any time and location by incorporating the effect of network constraints, as well as the cost generating electricity at each location. However, the offer prices on which dispatch is calculated may not be efficient when market power is being exploited."*[1]

While these points are correct, they focus on spot rather than contract market impacts (although other parts of the report recognised that impacts on contract market liquidity could lead to a higher cost of capital for market participants).

The purpose of this paper is to set out why an increase in locational pricing will increase transaction costs in the contract market, and why this should be of concern to policy makers.

Our objective is not to argue for any particular regional structure for the NEM. The impact on transaction costs in the contract market needs to be weighed up against other criteria, and we have not attempted to assess those trade-offs. However, a clearer recognition of the impact on transaction costs will lead to a lower degree of locational pricing in the NEM than if this factor is not taken into account. In addition, a focus on transaction costs in the contract market may support arguments for integration between regions – that is, a reduction in the number of regions – which may not necessarily be supported by a focus simply on spot market impacts.

1.2 Structure

The paper is structured as follows. Section 2 provides a brief background on the structure of the spot market in the NEM, including its current locational structure, and approach to pricing in the NEM.

Section 3 outlines the impact of this structure on price volatility. It looks first at volatility within the NEM as a whole, and then considers price volatility between regions – that is, how often prices separate between regions and to what extent.

[1] CRAI, Transmission Region Boundary Structure, September 2004

Section 4 describes how market participants manage this volatility through the contract market. It first describes the contract market in general, and then looks at approaches to hedging the risk of price separation between regions.

Section 5 outlines a hypothetical change in the level of locational pricing in the NEM, and discusses the impact on transaction costs in the contract market. Section 6 briefly summarises experience in Great Britain and New Zealand.

Finally, section 7 sets out our conclusions.

2 Pricing in the NEM

The National Electricity Market (NEM) is a gross market: all generators with capacity of 30 MW or above must sell their output through the NEM. It is also an energy-only market. There is no separate payment for capacity, and fixed costs are recovered by the quasi-rent when prices exceed variable operating costs.

The market operator, NEMMCO, dispatches generators to ensure a balance between supply and demand at all points within the NEM, and to minimise the costs of meeting demand within defined security criteria.

Generators submit offers to generate a day ahead, indicating the quantities they are offering in ten ascending bands. These price bands cannot be changed. The quantities available within bands can be varied through rebids, subject to constraints on rebidding behaviour. The offer price cannot be below - $1,000, or above $10,000 per MWh.

NEMMCO dispatches the market using NEMDE, to minimise the cost of meeting demand for energy and ancillary services. This is done in each region by stacking generation offers, and determining the least cost generation needed to meet an incremental unit of demand at the regional reference nodes, taking account of transmission constraints. Dispatch allows for constraints on generator rate of change (ramp rates). It also ensures demand can be met within security criteria applicable to the transmission system.

NEMDE produces a five minute (dispatch) price. The market is settled on a half-hourly, weighted average price, known as the 'traded interval price'.

The NEM has six regions. The price at each region reflects the marginal cost of a 1 MW variation in demand, on the basis of bids and offers. The spot price for each region is set at a single node, the Regional Reference Node. For regions other than Snowy, the Regional Reference Node is close to the major demand centre.

Each generator is located within one of the six regions. Each generator within a region is subject to a marginal loss factor. MLFs are based on a forward-looking estimate of losses associated with generation at the node concerned. Generator offers are adjusted by the MLF. Each generator is paid for energy sent out, times the price at the Regional Reference Node, adjusted by the marginal loss factor which is calculated at each node.

Losses within regions are reflected in static, marginal loss factors. Losses between regions are reflected in dynamic loss factors. Dynamic loss factors are calculated by NEMDE for each dispatch interval. These loss factors lead to small price differences between regions.

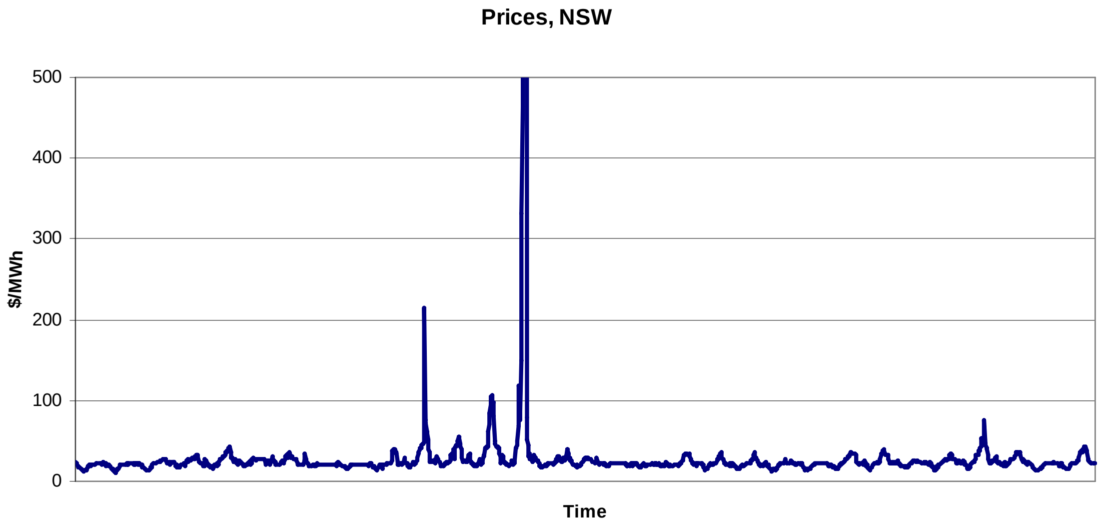
When transmission lines constrain, the marginal generator(s) able to supply the regional reference node will vary between regions. This can result in major price differences between regions.

3 Volatility in the NEM

3.1 Spot market

The NEM has a high level of price volatility in comparison with other, reasonably similar, electricity spot markets. This is due to the design of the market, and to volatility in demand. Figure 1 shows prices for the NSW region during January 2005. Prices averaged just under $40/MWh. The median level was $25 (that is, prices were above $25 for half the price periods in the month, and below for the other half). However, on several occasions prices exceeded $100 per MWh, and the maximum level was $6,277 MWh.

Figure 1: Price volatility within a region



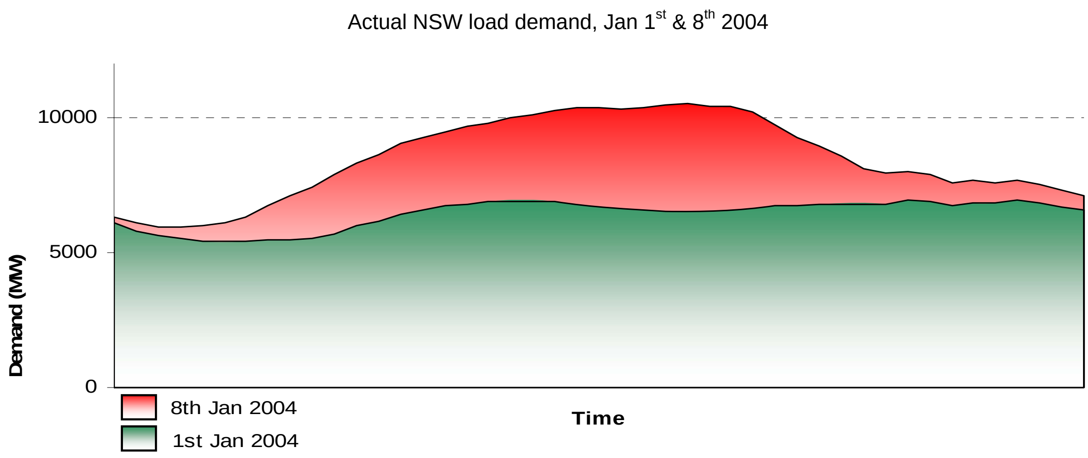
More generally, prices in the NEM average around $35-40 per MWh. Prices rarely drop below $7 per MWh, but can rise as high as $10,000 per MWh. As a result, prices can rise much higher above average than they fall below average. This results in a very skewed price distribution.

A price distribution curve for the NSW region is shown in Figure 2. This shows how often the NSW price was at or below a given level. For all periods (that is, 100% of the time) the price was at or below $9,167/MWh, the highest price recorded during the year. For 90% of the price periods the price was at or below $35.63/MWh. The lowest price during the year was a little under $8/MWh.

Figure 2: Price distribution curve

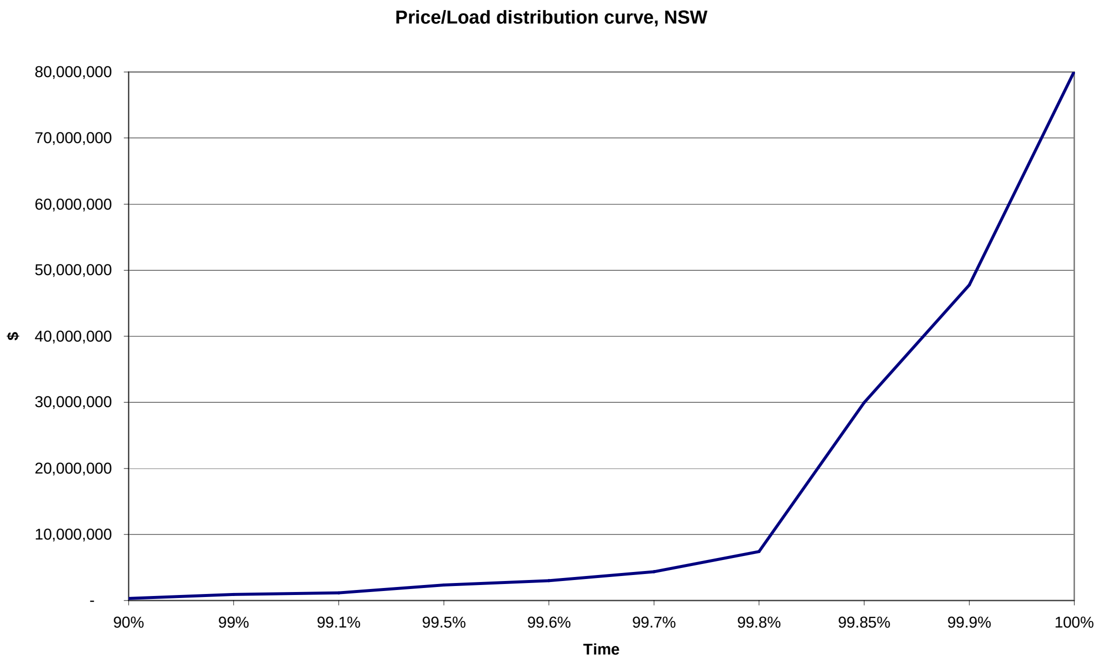
Demand is also variable within the NEM. In particular, demand during periods of prolonged hot weather can be substantially higher due to high air-conditioning load. This is particularly marked in the Southern States, where air-conditioning load can increase substantially if the temperature is higher than usual. It is less marked in Queensland, where summer temperatures generally result in high air-conditioning load. Figure 3 shows the demand on the same day of the week but a week apart in the NSW region. This illustrates the impact of temperature fluctuation on demand.

Figure 3: Variation in demand



In most but not all cases, high price periods are also periods of high demand. As a result, the overall revenues (for generators) and costs (for retailers) in the spot market are more skewed than the spot prices. As a result, the price duration curve for price times load is more skewed than a simple price duration curve. This is shown in Figure 4.

Figure 4: Price/load distribution curve



3.2 Inter-regional price volatility

Inter-regional price differences create an additional risk for parties buying or selling contracts, if those parties are in different regions. This level of locational risk to unhedged participants is greater than in some other markets, such as the UK, and less than markets – such as New Zealand – which have adopted nodal pricing.

An example is a generator selling a swap contract in another region. This generator faces a risk if the price in that region is above the price in the generator's region. It will then be obliged to make payments against the high price in the region in which it is selling, while receiving lower prices in the region in which it is producing. Given the skewed distribution of electricity prices, that risk can be considerable.

Price separation between regions is volatile. When transmission between the regions is unconstrained, there is a relatively small difference (usually around 1% of regional prices) attributable to loss factors.

Prices in each region can rise as high as $10,000/MWh. When prices are high in one region, they are often (but not always) also high in other regions. As a result, price separation between regions can vary between from zero or very low levels up to nearly $10,000/MWh. Regional prices often move together, with high prices in several regions at the same time. However, on occasion they separate. As a result inter-regional price differences are highly volatile. This is borne out by the data in Table 1 below which shows the mean and standard deviation of the price differences between the selected regions for 2005. This shows standard deviations that are between 20 and 300 times larger their respective means.

Table 1: Mean and standard deviation of price separation across regions

	NSW_p-QLD_p	NSW_p-VIC_p	VIC_p-SA_p	$SNOWY_p$-NSW_p	$SNOWY_p$-VIC_p
Mean $/MWh	8.1	4.8	-6.2	-5.3	-0.5
Standard Deviation $/MWh	172.1	264.0	123.6	178.3	156.1

Figure 5 below shows the distribution of the price separation between New South Wales and Queensland over a year, for those periods when the New South Wales price was equal to or above the Queensland price (and so power flows will have been from Queensland to New South Wales). The price separation over the year averaged $8.1/MWh. However, for a small number of periods the price separation was very much higher, reaching a peak of $8809/MWh.

As a result, the graph shows a few short-lived spikes. Although these are short-lived, they are very material to the risks of inter-regional trading. For example, a 100 MW swap contract which had no hedge against price separation would face a loss of $13.5M during the top 48 periods – which equates to 24 hours.

Figure 5: Price distribution curve for inter-regional price separation for NSW-Qld

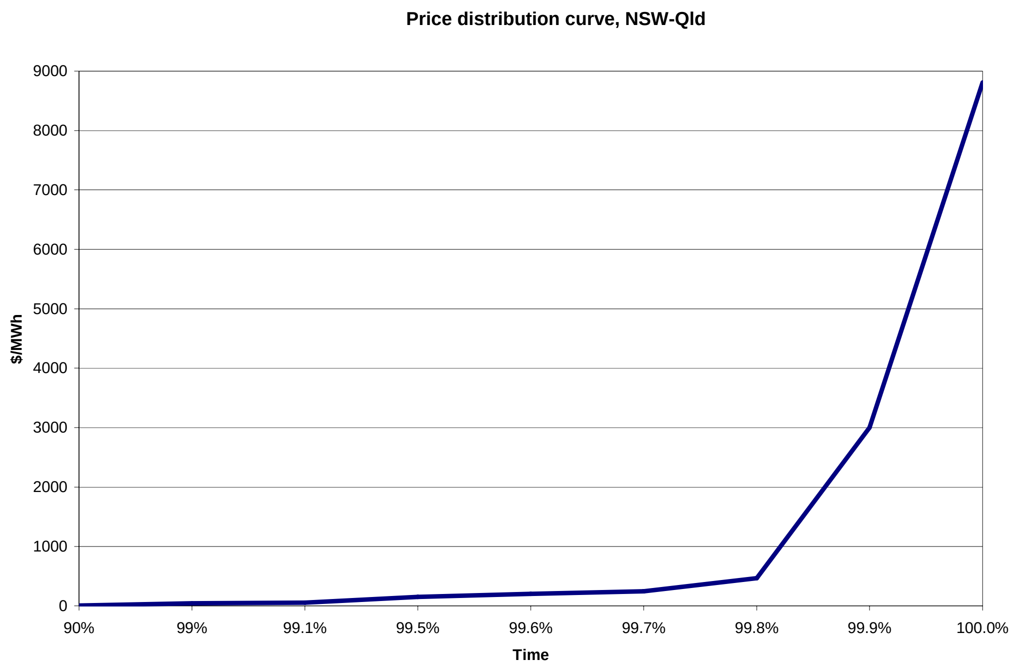
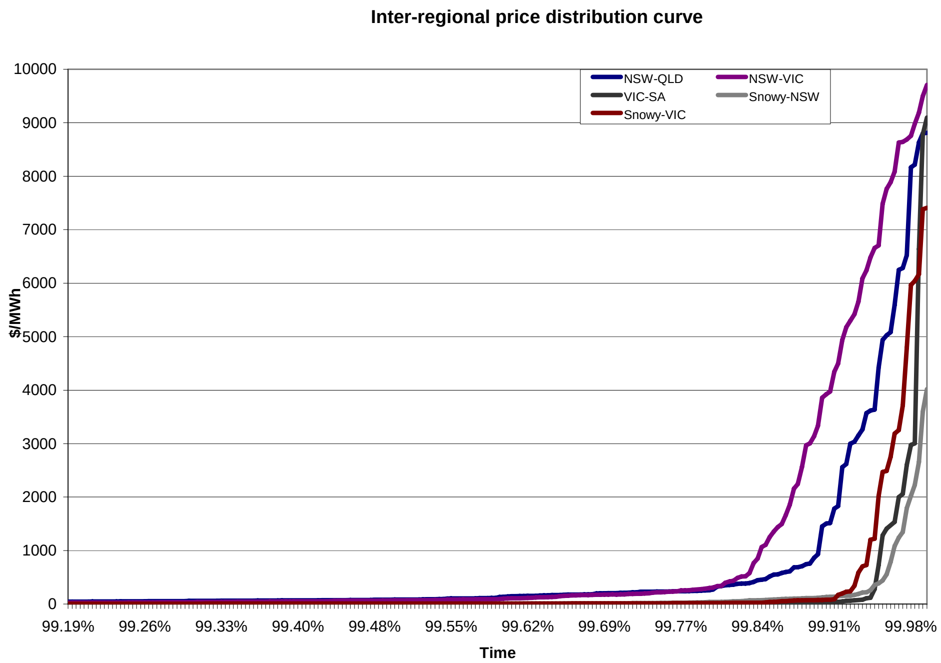


Figure 6 below widens the analysis to show the price duration curve of price differences on the selected boundaries.

Figure 6: Price distribution curve for inter-regional price separation across various boundaries



Like Figure 5 this shows on the y-axis the difference in prices between regions. The X-axis shows the percentage of time in 2005 that price differences were equal to or below that level. The curves illustrate that in the case of Snowy-NSW, VIC-SA and Snowy-VIC there were significant price differences for only 0.08% of the year, while for NSW-Qld and NSW-VIC, price differences were only significant for around 0.5% of the year. An examination of the underlying data suggests that these instances of significant price difference were sporadic.

As this data illustrates, the NEM as a whole is very volatile. Price separation between regions has an even greater level of volatility. Market participants need to reduce these risks to manageable levels, and do so through the contract market. The next section describes the operations of the contract market.

4 Contract market

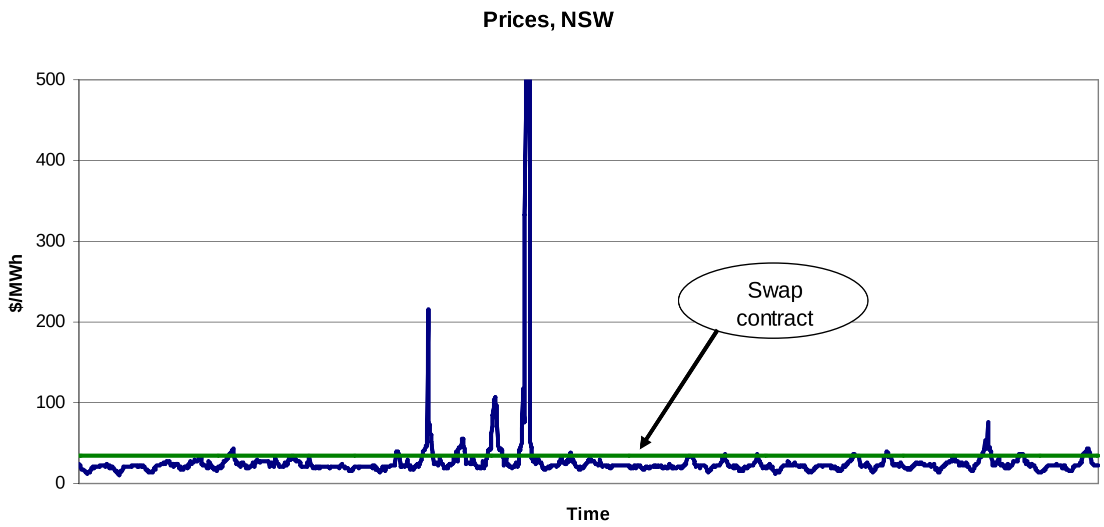
4.1 The contract market

As discussed in Section 3, the spot market has a high level of volatility and so of risk. To a large extent these risks are inverse between sellers (i.e. generators) and buyers (almost entirely retailers) in the wholesale market.

As a result, these parties can enter contracts which reduce the risks faced by both parties. An example is a swap contract. A generator and a retailer can agree a fixed price for a defined volume of electricity over a period. This is a derivative contract. That is, it does not entail either the generator physically supplying the electricity or the retailer (or its customers) consuming it. Rather, both agree to make payments, with reference to the spot market price, which have the effect of firming up the price for a defined volume of electricity.

This is illustrated in Figure 7 below, with reference to the monthly prices for NSW shown above. When the spot price is above the strike price for the swap, the generator pays the retailer. When the spot price is below the strike price, the retailer pays the generator. As a result, both effectively end up paying (or receiving) the agreed strike price in the contract, regardless of the level of spot prices. As this is achieved through payment for the difference between the contract and spot prices, a contract of this form was known as a 'contract for differences' in the England and Wales pool.

Figure 7: Swap contract



Virtually all contracts with respect to electricity sold through the NEM are derivative contracts. That is, they are financial contracts (in this case, a contract for differences from the spot price) rather than contracts to physically supply. The form of these contracts varies. Common forms include:

- *Swap contract:* an agreed strike price for a fixed (or sometimes variable) volume of electricity achieved through payment of the difference between the spot price and the strike price

- *Cap agreement:* an option for a defined quantity of electricity at a defined maximum price. When the spot price exceeds the strike price, the seller is obliged to pay the difference. Caps are available at a variety of strike prices. A $300/MWh strike price is the most commonly traded form of cap

- *Floor agreement:* similar to a cap, but with the seller compensating the buyer if the spot price is below the strike price, effectively setting a floor on the price faced by the buyer of the contract

- *Collar contract:* both a floor and a cap are set by the contract. The parties face an exposure to spot price in between the floor and the cap, but place limits on the risk borne by both parties

- *Swaption:* a right to enter into a swap contract, with a defined volume and strike price, at a future date. The right may be to buy ('call') or sell ('put') the swap. A contract of this form places a limit on the risk faced by a party (such as a financial intermediary) who wishes to take a position in the market, but does not have an underlying physical hedge.

- *Asian option*: an Asian option is similar to a cap, but applies to the average price over a defined period, rather than the price in each trading interval.

- *Flexible volume*: Non-standard contracts can be negotiated which provide some flexibility in the demand covered by the contract. This can be triggered by maximum demand for the retailer, or by maximum demand in the region (which assists the generator in real-time monitoring and management of its contract position). Contracts of this kind may particularly support retail entry, as small retailers have fewer options for managing demand risk.

The characteristics of the contract market are set out in recent publications, including the survey of contract market liquidity undertaken by PricewaterhouseCoopers for the NGF and ERA, and the annual AFMA survey. We have drawn on these sources while undertaking this work. We have not undertaken any new research into the characteristics of the contract market, but have consulted a number of market participants on the possible impact of a change to locational pricing in the spot market on contract market liquidity.

The contract market substantially reduces risk for market participants. However, there are a number of risks which are only partially addressed by the contract market.

Demand risk: as described above, demand is very variable. Most retailers seek a high level of contract cover. However, they face a problem in ensuring adequate contract cover for infrequent periods of very high demand, while not incurring excessive contracting costs.

This is partly addressed through using a mix of standard contracting instruments (such as swaps and caps) to ensure adequate cover is provided at reasonable cost. Flexible contracts, as discussed above, are typically procured through bilateral OTC trade. There is no standard contract of this nature which is traded on the SFE, and the product is not normally offered by brokers as it may require bilateral negotiation between the two parties.

Finally, retailers may be exposed to some spot risk if demand rises well above levels foreseen when preparing their contracting strategy.

Volume risk: generators can protect their contract position during periods of high prices through generating and selling into the spot market. Generators face a risk if this 'physical hedge' is not possible. They may then be exposed to the cost of purchasing from the spot market at very high prices to meet their contract obligations.

This risk arises if the generator is unable to get dispatched during periods of high prices. This can arise due to physical unavailability of the plant. A common response is to adopt a conservative contracting position, for example to maintain one unit which is uncontracted, and is available to provide a physical hedge in the even of failure at other units.

Generators are also exposed to risk that they may not be dispatched due to transmission congestion.

Basis risk: basis risk arises when the two contracting parties face different prices. As described above, prices are uniform within a region, other than an adjustment for fixed marginal loss factors. These fixed factors are predictable, and so create little risk.

Parties who contract between regions in the NEM face the risk that prices separate between the two regions. This price separation can be significant. The next section describes the instruments used to hedge inter-regional price risk in the NEM.

The hedge against inter-regional price separation is based on the settlement surpluses that arise when power flows from low-price to high-price regions. This hedge is also exposed to risk from the level of transmission transfer capability during periods of high price separation.

Credit risk: credit risk arises from the possible failure of a counter-party to meet its contractual obligations. Credit risk is affected by the approach to margin calls and mark to market arrangements under different forms of OTC and SFE trades. We have not analysed how this might be affected by a change to locational pricing.

Credit risk poses a significant problem for parties trading in the NEM. A standard solution is to diversify credit risk, by contracting with several parties. It is likely that a significant increase in locational pricing would lead to smaller numbers, and reduce the ability to diversify credit risk.

4.2 Inter-regional hedging

As described above, within a region prices at different transmission nodes only vary with respect to fixed loss factors. Prices between regions vary with respect to dynamic loss factors. Prices also vary between regions when transmission lines constrain, so that different generators are setting the system marginal price in different regions. This can lead to very significant price differences between regions.

Market participants can respond to the risk of inter-regional price separation in several ways. They can avoid inter-regional price risk by contracting within the region, or regions, within which they have a generation or retail load. We understand that some generation companies currently adopt this strategy, and only contract within their region. However, if this approach was universally adopted it would lead to an increasing 'regionalisation' of the NEM, and reduced competition.

Market participants can also avoid inter-regional price risk by developing a balanced portfolio. This would need to be balanced both in overall generation and load, and in the region in which generation and load is located. The risks are particularly high during a few short-lived high price periods. As a result, an internal hedge could partly be pursued simply by developing peaking capacity. This provides a physical hedge against the greatest risks from inter-regional price separation.

A number of participants in the NEM appear to have adopted elements of this strategy. Three main companies have substantial vertical integration between generation and retail. In some cases this integration is limited to peaking plant, to cap wholesale price risks. And there appears to be an interest by market participants in developing generation capacity to match regional loads as these loads grow.

However, the focus on inter-regional balance appears to be much less than in some other markets, which have a higher level of locational price risk. For example, as discussed below, New Zealand has seen 'customer swaps' between gentailers to avoid inter-regional price risk.

The two approaches described above are means of avoiding or reducing imbalance between generation and load. A further possible strategy is to contract in a way which results in locational price risk, and to manage that risk through:

- purchasing SRAs, which give rights to the settlement residues that accrue when power flows from low-price to high-price regions, and so provide a partial hedge against price separation, or

- taking a long/short position in one regional contract market, and a short/long position in another regional market.

The settlement residue auctions are described below.

4.2.1 Settlement Residue Auctions

When prices separate between regions, this results in inter-regional settlement residues (IRSRs). The IRSRs are determined by the price difference between regions, and the power flows between regions when prices differ. The IRSRs are generally positive, as power flows are usually from the low-priced regions to high-priced regions.

The IRSRs are made available to market participants through a settlement residue auction (SRA). Participants in the auction can bid for units of the settlement residue on an interconnector in one direction or link bids across multiple interconnectors.

There are four auctions every year. An auction opens for bids following the publication of the number of units being offered ten business days prior to the opening of the auction date and closes for bids at 2pm on the day of the auction.

The units are allocated to the market participants on the basis of the bid prices (commencing with the highest bid) until all units have been allocated. The auction clearing price is set at the price of the lowest bid that was allocated a unit and is paid by all successful participants for the units they acquire at the auction.

Successful participants in the SRA swap a fixed amount of money (auction bid) for a variable amount of money (the actual settlement residue). This variable amount is related to the price separation between regions. The IRSRs therefore assist with hedging against price separation between regions.

The SRAs are not a perfect hedge against price separation, as the IRSRs are dependent on power flows from low-price to high-price regions. Two factors may reduce the effectiveness of SRAs as a hedge against inter-regional price separation:

- NEMMCO has no means of funding negative settlement residues. Until recently it has therefore intervened to prevent negative settlement residues when they emerge[2]. As a result, the settlement residues have been smaller than they would be otherwise, and their effectiveness as a hedge against price separation is also reduced, and

- Transmission capability is sometimes low at times of high price separation[3]. Again, this will mean that the settlement residues will be lower than would have been the case if transmission capability had been higher.

The total settlement residues over that period are slightly under $1 billion, in money-of-the-day prices. A little over 40% of the total is due to settlement residues between Snowy and New South Wales. This rises to nearly 60% for residues from this link and from Queensland to New South Wales. As a result, flows into New South Wales have been the dominant source of settlement residues in the NEM.

Residues between New South Wales and other regions have been very minor. Residues from Victoria to South Australia have been material (but residues between South Australia and Victoria less so), and residues between Snowy and Victoria have also been significant. Total auction proceeds to date are around 60% of the value of the actual settlement residues. This does not necessarily indicate a mis-pricing. The settlement residues are highly volatile, in a similar way to spot market prices but with greater volatility. For much of the time price differences are low and settlement residues are minor. The majority of the residues are accrued in a short period, when lines are constrained and prices diverge sharply. In addition to the level and frequency of price separation, the availability of transmission during price separations is also uncertain. The recent analysis in the ERIG report showed significant variation in the volume of electricity flows during periods of high price separation between regions.

The auction proceeds are therefore very uncertain on an ex-ante basis. This uncertain future cash flow is being exchanged for a certain cash payment.

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2 Under a Rule change recently approved by the AEMC, NEMMCO will adopt an alternative approach when negative settlement residues arise for northward power flows across the Snowy Region, by netting off the positive residue between Snowy and NSW from any negative residue between Victoria and Snowy.

3 Pages 174-175 of the Energy Reform Implementation Group discussion papers, November 2006 includes data on inter-regional flows at times of high price separation.

However, while it is unsurprising that the actual proceeds differ from the cash flows, it is of interest that the relationship of the proceeds to actual settlement residues varies by link. This is illustrated in Table 2. For each link, the table shows total proceeds divided by the actual revenues received, over the period from January 2001 to June 2006.

Table 2: Relationship of ex-ante auction proceeds to ex-post residues

Link	Proceeds/Residues
SN-VIC	173%
VIC-SA	92%
Rev NSW-QLD	76%
SA-VIC	72%
VIC-SN	47%
SN-NSW	36%
QLD-NSW	35%
NSW-SN	33%
Total	**61%**

This may suggest that market participants may have greater difficulty pricing some settlement residues. As noted above, the Snowy-NSW settlement residues account for around 40% of the total settlement residues to date. However, the proceeds from auctioning these residues have been particularly low (along with two other links, which have lower residues).

It is possible that this difficulty in pricing the link reflects the ability of Snowy Hydro to affect prices and so settlement residues. If so, this would suggest that a significant increase in locational pricing would also lead to increased difficulty in pricing settlement residues. However, we have not attempted either quantitative analysis, or consultation with market participants, to determine how far this may be an explanatory factor. An alternative explanation would simply be that the relationship of proceeds to actual residues is inevitably uncertain, and too much significant cannot be attached to any specific relationship between the two.

As this section illustrates, the contract market plays a critical role in reducing risk and enabling competition and trade in the NEM. The current large regions allow these benefits to be pooled across a large number of participants, although at the cost of some loss of pricing efficiency. The next section considers what impact a change in the level of locational pricing in the NEM might have on the contract market.

5 Impact of locational pricing on the contract market

5.1 Changes to locational pricing

Preceding sections have described the substantial risk in the NEM, and the way in which the contract market is used to reduce risk. This paper advances the thesis that a marked change in locational pricing would lead to an increase in transaction costs in the contract market, and a reduction in its efficiency. In order to discuss that, we have considered the possible form of a step change in locational pricing.

One mechanism for such a change would be the introduction of new pricing regions or zones. For example, the analysis by Darryl Biggar discusses the extent of generator mis-pricing in the NEM. The paper concludes that around 70 pricing zones would be required to eliminate all mis-pricing in the NEM. This would be one possible change to the regional framework of the NEM.

To be clear, we are not suggesting that either Darryl Biggar or the AEMC have advocated such a change. Biggar's paper explicitly states some degree of mis-pricing in the NEM can be tolerated on an on-going basis. However, the analysis does indicate the scale of change that would be required to ensure pricing regions are well aligned with existing congestion in the transmission network. This assists with consideration of how to weigh up an objective of cost-reflective pricing in the spot market against other objectives.

A further means of introducing locational pricing would be through an interim, discretionary measure, in response to congestion which might be short-lived. This was for example advocated in CRA's paper on the Transmission Region Boundary Structure.

This section starts by considering the impact of a change in the locational structure of the market on hedging requirements. It then considers the likely impact on financial market efficiency, and spreads in the contract market. Finally, we consider what impacts this might have in the physical market, through altered investment and/or operation decisions.

5.2 Impact on inter-regional hedging

A step change increase in the level of locational risk in the NEM would result in:

- A much greater change in the level of inter-regional hedges required to maintain a constant risk position
- A reduction in liquidity in contract markets, and
- Increased complexity in pricing inter-regional risk, and an increase in the information asymmetry between market participants.

These different components are inter-related. They are described in turn below.

5.2.1 Increased hedging volumes

The NEM currently has six regions. As illustrated in Figure 8 this creates the possibility of 30 inter-regional price differences. A region cannot differ in price with itself, but can differ with all other regions. This slightly over-states the actual inter-regional price risk (since there is effectively no load in the Snowy Region).

Figure 8: Possible inter-regional price differences in the NEM

	SA	VIC	NSW	QLD	Snowy	TAS
SA						
VIC						
NSW						
QLD						
Snowy						
TAS						

SRAs provide a way to hedge inter-regional price risk. Other ways to hedge inter-regional price risk through derivatives would be by buying or selling contracts in one region and selling or buying a matching amount in another region. This hedges the uncertainty of the difference in the spot prices at the two Regional Reference Nodes.

If the number of regions was increased to 30 there could be up to 30*30-30 = 870 inter-regional price differences that have to be separately priced and hedged. SRAs – which are defined in terms of price differences and flows between adjacent regions – would be poorly adapted at providing inter-regional hedging in such a multi-regional market. This is because SRAs only hedge between adjacent regions. If a 30 region network was radial a participant would need to buy 29 different SRAs to hedge prices between the region at either end.

If the NEM was priced nodally with around 280 generation nodes (defined by connection points) and around 400 demand nodes, there would potentially be 680 prices and 680*680 – 680 = 461,720 nodal prices differences in each half-hourly settlement period. Of course many of these prices would only differ for transmission losses for most settlement periods. However, at times of significant transmission constraints there could be very large differences in prices between some nodes.

Clearly a greater number of regions leads to a greater number of inter-regional prices. The history of transmission constraints in the NEM suggests that there are only a few enduring transmission constraints. Significant constraints generally arise sporadically around the system. With a spot price that can reach as high as $10,000MWh, low probability events can nevertheless result in significant price separation. This is illustrated in the price duration curves in Figure 4 and Figure 5.

Simply pointing to the increasing number of potential price separations from a greater number of priced regions does not fully convey the resulting complexity in the contract market, of increasing the number of priced regions. In particular, for any single market participant, inter-regional imbalances are unlikely to be constant over the course of a day. This is because the aggregate demand of the market participant's customers in one region will typically vary during the day. In this case, the participant's exposure to the risk of uncertain inter-regional price differences will vary across the day. Such a participant could therefore wish to swap or buy/sell forward, different amounts for peak hours and off-peak hours.

In addition to diurnal demand variation, there are often also significant seasonal or weekday versus weekend variations. This means that participants need to obtain different types and quantities of derivatives so that they are able to hedge their specific production/consumption profiles. To achieve a reasonable degree of hedging it may therefore be necessary to acquire numerous different derivative products.

Market participants who have generation at more than one node and who supply customers at more than one node could therefore need to enter into very many more contracts to hedge their locational basis risk than under the existing six region model. In the New York ISO for example, where nodal prices are calculated, there are 120,000 different financial transmission rights (or Transmission Cost Contracts as they are called) which entitle the holder to the difference in the nodal price between the sink and the source.

5.2.2 Reduced liquidity

The introduction of a large number of regions would greatly increase the possible number of significant price separations that participants would be exposed to, and hence the number of products required to hedge inter-regional price risk. This could be expected to result in a loss of liquidity in the trade of such products.

The demand for hedges at particular nodes might have relatively few participants. Many regions may have only one dominant retailer. There might be only one or no generator located in a region, and a lower number of generators seeking to hedge across the region.

It therefore seems certain that a large increase in the level of locational pricing would lead to a reduction in liquidity. We note that the recent NGF survey of contract market liquidity was generally positive on levels of liquidity and a trend of increasing liquidity. However, it also found a lack of liquidity in some regions even with the current structure, stating: *"..the overwhelming majority of respondents (13 of 17) viewed South Australia as having insufficient liquidity[4]"*. Respondents indicated that they therefore regarded the regional market as very risky, due to the difficulties of adjusting a short position.

The survey also stated *"It is generally accepted that an increase in the number of price nodes would likely reduce the level of liquidity in the market."*

This experience is borne out in other markets. For example the British market has always had a very deep contract market – more than 90% of electricity sold through the previous England and Wales Pool was contracted - and this has risen further following NETA so that the spot market (the "Balancing Market") now accounts for only 2-3% of traded electricity. In New Zealand by contrast as noted below, market participants have integrated vertically and geographically in order to hedge their exposure to locational and spot market risks.

5.2.3 Increased complexity in pricing risk

An increase in the number of regions, and a reduction in liquidity, are likely to make it considerably harder for participants to price risk.

Large, liquid and competitive markets reveal prices through the competitive process. Buyers can check the prices that they are being offered (at least for standard products) by several

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[4] PwC, Independent Survey of Contract Market Liquidity in the NEM. We are not aware if the survey also considered contract market liquidity in Tasmania, which could be expected to be even more illiquid.

different sellers. Buyers can be confident that if liquidity is sufficient, their purchase decisions will not change market prices after they are executed.

These characteristics appear to apply at least for the larger regional contract markets at present. Products are becoming more standardised, there is an increasing number of participants, and volumes as large as 50 MW for both caps and swaps do not appear to significantly affect subsequent prices[5].

Smaller and less liquid markets create greater problems in pricing. A buyer can no longer be confident that the prices being offered are reasonable. As a result, more analysis may be needed in order to determine a reasonable price for different hedging products. Several factors may reduce the ability of parties to undertake this analysis:

First, there will be a lack of historical data for the parties concerned to analyse as a basis for pricing different hedging products. This would be a problem with the introduction of new regions. While there will be many years of data on nodal prices and power flows, there will be no history of inter-regional prices or of contracts related to those prices.

Academic literature on financial transmission rights suggest that the absence of this data is a significant issue affecting the efficiency of transmission hedge markets. This is raised for example in a review of the New York Transmission Congestion Contract auctions[6], which summarises well the position of some critics on the impact of locational marginal pricing (LMP) on price discovery:

> *"One of the biggest weaknesses of LMP markets, according to critics, is that locational forward price discovery is typically weak. Under the LMP design, the NYISO, which holds full information on the state of the transmission system, primarily focuses on creating efficient hourly spot prices. Even in these LMP markets, however, the majority of trade is in (bilateral) forward markets, which are traded on expectations of future locational spot prices. Market participants must be able to form reasonable expectations of future locational prices if forward market liquidity is to be maintained and the allocative efficiency of forward prices is to be preserved. LMP, say critics, fails this important test."*

The absence of historical data might also be a particular problem with the use of transitional measures for congestion pricing of short-lived constraints, as recommended in CRAI's report.[7]

Second in electricity markets that have adopted constrained dispatch and pricing models – such as the NEM Dispatch Engine (NEMDE) – it is not possible to calculate nodal prices by simply stacking supply offers against demand bids in order to calculate clearing prices. Instead NEMDE calculates nodal prices within each NEM region based on the marginal cost to serve an extra unit of demand at defined reference nodes.

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5 Op cit., page 24

6 See Adamson, S and Englander S, 2005. "Efficiency of New York Transmission Congestion Contract Auctions", proceedings of the 38th Hawaii International Conference on System Sciences; Siddiqui, A., Bartholomew, E., Marnay, C., and Oren, S. 2003, "On the efficiency of the NYISO Market for TCCs, Energy Analysis Department, UCLA; Patino, E., Morel, B.. 2006. "An option theory method to value Electricity Financial Transmission Rights, Carnegie Mellon Electricity Industry Centre Working Paper CEIC-06-03.

7 CRAI, Transmission Region Boundary Structure, September 2004.

In the absence of constraints, it is possible to predict nodal prices on the basis of offers and demand at the reference node. However, when transmission constraints bind, nodal prices can deviate from generation offers by a significant margin, and can even be negative. This can result from constraints deep within the network that may be electrically and/or geographically remote from the node that is being priced. For example, it was noted that in the Pennsylvania-New Jersey-Maryland (PJM) market (where the same constrained dispatch algebra applies in the calculation of nodal prices) one congested transmission line produces 2000 different nodal prices.[8]

This is an unavoidable outcome of a price based on a constrained dispatch algorithm. This will for example affect pricing at Murray (following changes to the pricing arrangements) and would affect pricing at many more nodes if a larger number of regions was introduced.

The inability to predict possible nodal prices at times of constraints – or even to meaningfully attach probabilities to the possible range of their values - makes the pricing of locational risk particularly difficult.

Third, individual participants may be able to influence the level and extent of price separation between nodes. It is widely recognised that Snowy Hydro has an ability to withhold and increase prices at Tumut. Smelters and other major consumers may have an ability to influence nodal prices by their demand behaviour.

These factors suggest that a large increase in locational pricing would lead to a substantial increase in the complexity of assessing inter-regional price risk, and in agreeing a reasonable price for instruments (such as SRAs) which assist in managing the risk. The PwC survey appeared to support this finding, stating:

"Some respondents believed that any additional level of complexity brought about by increasing the number of nodes would be too much for the market to manage. It was quoted that the amount of information and prices currently in play is already complex and time consuming to assimilate with participants often concentrating on select regions and products that best fit with their strategies."[9]

[8] Patino, E., Morel, B.. 2006. "An option theory method to value Electricity Financial Transmission Rights, Carnegie Mellon Electricity Industry Centre Working Paper CEIC-06-03.

[9] Op cit, page 28

6 Experience in other markets

This section examines the approach to locational pricing in the British and New Zealand electricity markets. The design of these markets reflects opposing views on the appropriate pricing and management of locational price risk.

6.1 The British market

The British market design reflects the importance that has been placed upon achieving a liquid and competitive wholesale market. The design reflects the view that such liquidity should not be jeopardised by including transmission congestion in the calculation of wholesale energy prices.

In a consultation paper on proposed changes to the pricing of transmission access, Ofgem, the industry regulator explained its view that[10]

" … *it is not possible to separate completely electricity and transmission prices. However, by separating these prices as much as possible, Ofgem believes that market transparency will be improved, making it easier to identify and deal with any locational market abuse. In addition, Ofgem believes that failure to separate the prices will result in distortions to the wholesale electricity markets, which in turn could lead to reduced levels of liquidity in these markets. The effects of this could include price increases and reduced competition with the subsequent negative implications for consumers' interests … Separating, as far as possible, the price of traded electricity from (transmission) capacity will reduce the level of distortions in the traded electricity price and reduce incentives on participants to exercise local market power.*"

Professor Littlechild suggested further that

"… *we were conscious of a danger that the market could be too thin if there had to be trading at each location rather than in the market as a whole. We were also sceptical about the nodal pricing approach (I had worked on this literature earlier from a mathematical perspective) - seemed to me to involve an element of central planning which we were keen to get away from*".[11]

In place of locational electricity prices, the British arrangement has involved financially-firm access to the transmission grid by generators. Under the previous Electricity Pool in England and Wales, this was achieved by paying generators that were constrained-up in order to resolve constraints (i.e. required to produce more than they were willing to at the System Marginal Price), their actual bid. Generators that were constrained-down were paid their "lost profit" (the difference between the System Marginal Price and their bid) for the amount that they were constrained down. The System Marginal Price therefore reflected the competition amongst all generators without regard to whether not their production would result in transmission constraints.

Since 1995 the National Grid Company (NGC) has been incentivised to manage the cost of constraints, which was recovered from electricity consumers as part of an "uplift" component in the Pool Selling Price. While the cost of constraints increased to above GBP300 million before NGC was incentivised to manage it, it was subsequently reduced to around GBP30million or around 0.5% of the value of electricity in the wholesale market.

The change to the market design under the New Electricity Trading Arrangements (NETA) has retained financially firm transmission access although the mechanism for its implementation differs. Under NETA, generators are able to enter contracts without

[10] Source: Ofgem February 2002, Transmission access and losses under NETA, Revised proposals.

[11] Personal correspondence, 15 November, 2006.

considering whether their resulting contracted positions will result in transmission constraints. NGC is responsible for ensuring that the power system operates within physical limits and therefore will enter the Balancing Market to buy and sell generation and/or demand in order to "buy-out" any transmission constraints that arise.

Under NETA NGC has continued to be incentivised to manage the cost of transmission constraints and this cost has remained at low levels, although it has increased recently following the development of a GB-wide electricity market.

However, although the British approach has sought to exclude transmission from the calculation of market prices it would be misleading to conclude that there has been a reluctance to achieve cost-reflective transmission charges. Transmission network use of system charges contain significant geographic differentials reflecting a long run incremental cost methodology developed by NGC but approved by Ofgem. Similarly, Offer and subsequently Ofgem has sought to introduce more accurate pricing of transmission losses although this has been vehemently opposed by some industry participants, has generally not been supported by the government, and proposals have twice been blocked following judicial review.

In Australia, the debate on dispatch efficiency versus contract market efficiency often portrays these as mutually exclusive: i.e. that nodal pricing would lead to more efficient dispatch but will damage the efficiency of the contract market, or that a more liquid contract market will come at the expense of less efficient dispatch. The analysis in the British market appears focused on meeting both objectives.

In the British arrangement, NGC is incentivised to manage the cost of transmission constraints. To the extent that it responds to this incentive – and there is substantial evidence that this is the case – the resulting dispatch will be the most efficient possible, taking account of the available transmission network. In delivering this dispatch at the times of transmission constraints, it will nevertheless have been necessary for NGC to enter the Balancing Market and to pay some generators to increase production and others to decrease production in order to ensure that the power system remains with its limits. The cost of this action (higher profits for generators that are constrained-up and lost profit for generators that are constrained down) is borne by transmission users through the Balancing Services Use of System charge which is levied based on metered volumes.

This arrangement results in a wealth transfer (rather than a loss of economic efficiency) between transmission users (both generators and consumers) and those generators that are constrained up or down. As noted earlier the value of this has been 0.5% of the value of electricity in the wholesale market. Calculated at a retail level, the value would be less than 0.25% of the value of retail electricity. This could be seen as the (financial rather than economic) cost to be set against the benefit of a liquid contract market.

6.2 The New Zealand market

The New Zealand electricity market commenced operation in October 1996, a little over six years after the Electricity Pool in England and Wales. At the time, the New Zealand electricity market was one of the first fully "nodal" electricity markets with prices calculated half hourly at around 260 nodes based on a constrained optimisation. Prices are calculated by M-Co, on behalf of the Electricity Commission, so that the price at each node reflects the cost (based on generation bids) of meeting one additional unit of demand at that node. Price differences between nodes reflect the cost of losses and the cost of sourcing energy from more expensive sources when transmission constraints bind. As long as the power system remains unconstrained, prices will vary between nodes based only on the marginal value of losses, which can nevertheless be significant at some nodes.

At the time that the electricity market was developed, Transpower (the transmission network service provider and power system operator) offered a transmission hedge product although it subsequently withdrew the product. Transpower subsequently developed a new transmission hedge product in 1998 but this was rejected by some market participants and so Transpower could not fund it. Since that time, the development of financial transmission hedges has the subject of debate but no firm action.

In 2002 the Loss and Constraint Allocation Working Group, a working group co-ordinated by M-Co, developed options for the allocation of residual rentals and proceeds from the auction of FTRs. In 2004 the government issued a Policy Statement inviting the Electricity Commission to give priority to improving hedge market transparency. Most recently, the Hedge Market Development Steering Group co-ordinated by the New Zealand Electricity Commission has completed its preliminary considerations and developed options for possible transmission hedge products.

It appears therefore that in the presence of significant locational basis risk, incumbents have responded by developing geographically balanced retail-generation business structures that ensure that they are able to manage the risk effectively.

The adoption of nodal pricing and the concomitant difficulty in hedging locational basis risk has been identified as providing barriers to entry, and the ability to exercise market power. For example the International Energy Agency concluded that "*The lack of liquid and transparent financial markets to hedge electricity price risk and locational basis risk is a significant barrier to entry that exacerbates market power concerns*".[12]

Similarly the Hedge Market Development Steering Group noted that "*the ability to manage locational-based price risks has also been a recurring concern. It is not just that users have paid very high prices from time to time as a result of transmission constraints, but that the difficulty of hedging these risks has restricted the entry of retailers into areas in which they do not have generation and this has compromised the level of competition in the retail market*".[13]

In the absence of the ability to hedge basis risk through financial hedges, the electricity industry appears to have integrated vertically (generation and retail) and along geographic lines so that participants are geographically balanced.

For example in 2001 Meridian Energy a South Island generator carved out of the Electricity Corporation of New Zealand (ECNZ) in 1999 purchased the South Island electricity customer base of the Natural Gas Corporation. At the same time, Genesis Power, which is predominantly a North Island generator and was also carved out of ECNZ in 1999, bought NGC's North Island electricity customer base. Similarly in 2002 Trust Power and MightyRiver Power swapped customers apparently in order to achieve greater geographic balance between the location of their generation and customers.

In its 2002 report for the New Zealand Electricity Market Rules Committee, Trowbridge-Deloitte reported "*a high correlation between generation output and retail load of vertically integrated companies in both the Upper North Island and the South Island. The correlation is not as strong in the Lower North Island but the region accounted for just 11% of the generation sent out in April 2002*"[14]

[12] International Energy Agency, 2006.
[13] Hedge market development – issues and options, Hedge Market Development Steering Group, Electricity Commission New Zealand, 18 July 2006.
[14] Trowbridge-Deloitte, Assessment of Outcomes achieved by Full Nodal Pricing in NZEM, December 2002.

There our now 5 dominant vertically integrated generator-retailers (Genesis Power, Meridian Energy, Contact Energy, Mighty River Power and Trust Power) that together supply 95% of the customer base. Customer switching has diminished from an annualized peak of 25% p.a. in June 2001 to around 8% by December 2005.[15]

Some commentators suggest that it is not appropriate to attribute the outcomes that have been delivered in New Zealand at the door of nodal prices. Rather, some consider that the problem is that suitable financial hedges including locational basis risk hedges, were not introduced concurrently with the introduction of such nodal prices.

It seems clear that the industry has had difficulty in developing suitable hedge products both to hedge locational basis risk and market price risks. While locational basis risk hedges were offered by Transpower from the start of the market and attempts were made to introduce new products two years after the market started, these did not succeed. Market participants seemed to have responded accordingly with the only significant pure retailer (Transalta) exiting the market in 2001 after suffering significant losses attributable to unhedged sales contracts. The remaining participants have moved quickly to integrate vertically and achieve geographically-balanced generation/retail positions.

While there is apparently still a strong desire in government and the Electricity Commission to have liquid hedge markets, with a high degree of vertical and geographic integration it is not clear that there is now significant demand for such products.

[15] Source: Paul Grey, Metering International, Issue 3, 2006.

7 Conclusions

Our conclusion is that an increase in locational pricing in the spot market, either as a permanent change or as a transitional measure, is likely to result in a greater level of inter-regional price risk, lower liquidity in contract markets, and greater difficulty in pricing the risks.

Conversely, a reduction in locational pricing in the spot market would be likely to increase liquidity in the contract market, possibly at the cost of some reduction in dispatch efficiency. Moreover, any gains through reduced costs will be shared with all market participants located in the region.

Other things being equal, higher transaction costs will make bearing and managing inter-regional price risk less attractive than the alternatives. These alternatives include:

- Contracting locally rather than trading across regions;
- Building more generation so that market participants can hedge their geographically-defined retail positions without needing to contract with others. This is likely to lead to a higher level of generation reserve than would arise if participants considered they were able to hedge their positions by contracting with others;
- Developing a geographically balanced generation and load portfolio by swapping generation and/or customers with other market participants.

High spreads for inter-regional trade may also lead to an increasingly 'regionalised' market, with new investment being undertaken in response to contract market signals within a single region rather than across the NEM as a whole. Similarly new entrants would face a barrier to entry unless they were able to combine access to generation with their contracted demand.

Higher transaction costs will also mean that spreads are higher in the contract market than would otherwise be the case. New investment responds to price signals in the contract market. As a result, one response to the increased transaction costs is likely to be earlier investment than would otherwise be the case, with a consequent loss of dynamic efficiency.

These outcomes are contrary to the intent underlying the creation of the NEM which has been to encourage the development of a nationally competitive electricity market.

We have not attempted to fully quantify the comparative materiality of impacts on efficiency in the spot market with contract market impacts. Similarly, we have not attempted to assess the impact on dynamic efficiency of differing locational signals under different models. However, analysis by the AER of the costs of constraints in the NEM concluded that they have been between $30m and $45m in 2004 and 2005. There is no reason to believe that greater locational pricing will cause this to diminish. Also, the relative insignificance of this cost in proportion to wholesale market sales of around $6bn suggests that there is not a material inefficiency with the existing arrangements.

Total electricity volumes in the NEM are around 200,000 GWh per year, and volumes in the contract market are well above that. Evidence from submissions to ERIG, and from the survey by the NGF, suggests that there is substantial variation in contract spreads. These factors suggest that the benefits from reduced transaction costs in the contract market are material enough to be an important element for consideration by policy makers.