Generator Nodal Pricing – a review of theory and practical application

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Executive summary

This report by Frontier Economics for the AEMC reviews the theory and practice of generator nodal pricing (GNP). In line with the Terms of Reference, this report provides:

(a) A factual description of GNP and the associated risk management framework(s) and how it differs from the current NEM pricing regime;

(b) A factual description of the issues associated with GNP relative to the current NEM pricing regime, in respect of dispatch efficiency, competition, market power and trading and risk management;

(c) A fact-based review of the practical experience of GNP in those markets that have adopted it; and

(d) In light of the above, a review of the issues that would (or could) need to be addressed in considering a transition to a GNP approach in the NEM.

In addition, Frontier believes it is worthwhile to consider the implications of GNP for investment, as well as the experiences of full nodal pricing (FNP) markets. Both GNP and FNP are examples of locational marginal pricing (LMP).

As requested, Frontier has sought to use the descriptive framework developed through separate work commissioned by the AEMC.

GNP AND RISK MANAGEMENT FRAMEWORKS

GNP has important implications for dispatch, settlement and risk management.

GNP dispatch implications

GNP fundamentally involves localised dispatch and spot market settlement of all generation participants. That is, whether or not a particular generator is dispatched and the price it receives for electricity is determined according to local market and network conditions. GNP was designed to simultaneously achieve two economic objectives – dispatch efficiency and cost-reflective nodal prices. In a system with no constraints or losses, the lowest-cost dispatch is achieved by dispatching the cheapest plant first and progressively dispatching more expensive plant further up the cost "merit order". As a result, nodal prices would be identical throughout the system. However, where network constraints arise, particularly in a network with "loops", nodal prices can vary. Each binding constraint has a "shadow price", which is equal to the reduction in the total cost of dispatch that would occur if that constraint were marginally relieved. The shadow price of a constraint multiplied by the volume of power flow when the constraint binds equals the economic rental attributable to that constraint. This rental forms the basis for the creation of financial hedging instruments.

GNP settlement implications

While GNP involves the dispatch and settlement of *generators* according to conditions at their local node, loads in GNP markets may be dispatched *but not* *settled* according to their local nodal prices. Loads under GNP could either pay the price at a specific node or a load-weighted average regional price. Either way, GNP implies that (at least some) dispatchable loads may be mis-priced in the same way as generators can be mis-priced in a regional market. However, this problem may not be material since (i) most loads are relatively unresponsive to price in the short term and (ii) most loads are non-dispatchable.

GNP risk management implications

Participants in a GNP market are subject to "basis risk", being the risk that the price of electricity at which their derivative contracts are settled may not correlate closely with the price at which their own production or consumption is settled. In order to assist participants in hedging basis risks, most markets with GNP provide for participants to receive or acquire basis risk management instruments, based on the economic rent produced by network constraints when they bind. These instruments are broadly described as "financial transmission rights" or "FTRs". FTRs are instruments that provide their holders with a stream of revenue derived from the differences in nodal prices that occur when transmission limits bind.

FTRs can be defined as "point-to-point" rights or "flowgate" rights. Flowgate FTRs are constraint-by-constraint hedges that give their holder the right to collect payments based on the shadow price associated with a particular transmission constraint (flowgate) while point-to-point FTRs provide a hedge between named injection and withdrawal nodes. The Constraint-Based Residues (CBRs) concept represents a form of flowgate FTR. FTRs can be categorised as either obligations or options. FTR obligations imply that FTR holders possess an obligation to pay when the price differential is negative as well as a right to compensation when the price differential is positive.

A key issue arising in FTR formulation is revenue adequacy. This means that the net revenue collected through the settlement process from the entire set of nodal prices should at least be equal to the payments to the holders of FTRs in the same period. A set of point-to-point FTRs will be revenue-adequate when the implied power flows from the FTRs are "simultaneously feasible".

Another crucial issue involving FTRs is the means of allocating them to participants. This could involve an auction/tender process or an administrative allocation method. The CMR Draft Report highlighted some of the difficulties involved in determining an appropriate allocation of FTRs. One key issue is ensuring the allocation does not create or enhance market power.

Finally, although FTRs can be provided to investors as a reward for merchant-driven expansion of the transmission grid, this is not a prerequisite to their use as risk management instruments across the existing network.

NODAL MARKETS COMPARED TO THE NEM

GNP markets diverge in a number of important respects from the current NEM design.

Dispatch process and outcomes

Dispatch in a GNP market operates in a similar way to dispatch in the NEM, the key difference being that fully nodal markets tend to employ a "full network model" (FNM). A FNM is generally considered to accurately, and in significant detail; represent the underlying physical power system elements of a given network. The current NEMDE should, in principle, be capable of producing similar pricing and dispatch outcomes to those expected under a FNM. However, a FNM would assist with the implementation of GNP as well as potentially offering advantages in the management of system security and network asset utilisation.

The most important difference between GNP markets and the NEM concerns the number of settlement prices. The NEM currently has six regional reference prices (RRPs) within six regions (soon to be 5), whereas tens or hundreds of pricing nodes may be required to implement GNP. Congestion in a regional market such as the NEM may thus lead to 'mis-pricing', being a divergence between the RRP (at which participants are settled) and the local nodal prices (upon which participants are dispatched). This does not arise in a GNP market (at least for generators) where there is complete alignment between the prices used as the basis for settlement and the prices emanating from dispatch.

Mis-pricing in the NEM can give rise to dispatch risk, in that participants are not dispatched to a level consistent with the quantity bid or offered below the RRP. Dispatch risk, in turn, can incentivise "disorderly" bidding by generators. This can harm dispatch efficiency. By contrast, price-taking generators in a GNP market do not have these incentives. However, if the assumption of price-taking is relaxed, the positive dispatch efficiency implications of GNP may no longer hold: As highlighted in the AEMC's Snowy regional boundary decisions, dispatch efficiency in a nodal market is an empirical question.

Basis risk management

In the NEM, generators are settled at their local RRP. This means they face no basis risk in respect of contracts struck within their own region. The NEM design also utilises inter-regional settlement residue (IRSR) units and Settlement Residue Auctions (SRAs) to facilitate participants' management of basis risk across regions. These instruments tend to be non-firm. However, because generators in GNP markets are settled at their local nodal prices, they require explicit basis risk management instruments for *all* contracts not referenced to their own local node. Associated with these rights are issues such as initial formulation, allocation and ongoing management. As highlighted in the CMR Directions Paper, inadequate basis risk management instruments may have potentially harmful implications for contract trading, retail prices and dynamic efficiency in the longer term.

Locational decisions

On the whole, the regional pricing structure in the NEM has led to generation investment in those regions that experienced the highest prices. A more granular pricing structure, such as GNP, would provide even more refined locational signals to investors in new generation. By the same token, it is clear that investors do not make locational decisions solely or even principally on the basis of wholesale spot prices. The extent to which GNP might actually influence locational decisions in practice is, like its impact on dispatch efficiency, a matter that cannot be determined analytically.

INTERNATIONAL REVIEW OF NODAL MARKETS

This report reviews a number of real-world markets that utilise GNP or FNP. Although this review focuses on GNP, FNP markets are worth examining since; the differences are largely a matter of degree and the PJM market, which pioneered FTRs, is a FNP market. Overall, the review examines:

- FNP markets (PJM, New Zealand);
- GNP markets (New York, New England, Singapore);
- A hybrid design (Midwest); and
- Markets transitioning to some form of locational marginal pricing (LMP) (Texas and California).

Some general observations that can be drawn from a review of these markets is:

- All GNP markets settle load on the basis of a load-weighted average nodal price across the relevant load zone;
- FTRs are not universally available, but where they are:
  - Incumbent participants receive a free allocation of rights in recognition of their contribution to the cost of transmission services;
  - The allocation/auction process tends to be complex and involved for market operators and participants alike;
  - FTRs have tended to provide relatively firm hedges for price separation;
- Locational price divergences have not been determinative in locational investment decisions;
- LMP energy markets in the northeast United States are often accompanied by markets for ancillary services and capacity markets – the latter have recently been introducing a more locational element;
- Markets transitioning from zonal to nodal settlement have done so to overcome many of the same issues that arise in the NEM – namely management of intra-zonal congestion and the difficulty in zonal boundary variation; and
- Implementation of LMP markets tends to be time-consuming and expensive.

ISSUES TO BE ADDRESSED IN GNP IMPLEMENTATION

In any transition to GNP, a number of issues need to resolved or otherwise addressed. These issues are discussed below.

Form of load pricing

The first decision to be made is the manner in which load is settled. All existing GNP markets appear to use load-weighted prices to settle all load in the relevant zone/region, rather than the prevailing LMP at the main load centre in the zone (akin to the RRN). Applying a load-weighted approach in the NEM would be likely to marginally change the energy prices currently paid by load, but it is difficult to predict in advance whether consumers' energy prices would go up or down in any given region. A point to note is that to the extent consumers pay more or less for energy in the wholesale market, this may be offset by decreases or increases, respectively, in prescribed transmission prices caused by a fall in intra-regional settlements residues presently arising from the non-pricing of intra-regional congestion. Another issue to consider is that load zones in GNP markets have tended to be relatively small. This suggests that if GNP were to be adopted in the NEM, there would be no clear precedents for load zones anywhere near as large and diverse as the existing regions.

Risk management instruments

The NEM's regional structure currently uses a 'quasi-flowgates' type approach to basis risk management instruments. The implementation of a fully 'unbundled' flowgates approach in a GNP market through, say, CBRs, could rapidly become unwieldy given the sheer number of constraints for which congestion rental rights may need to be developed and allocated. A system of point-to-point (or, more appropriately under GNP, point-to-hub and hub-to-hub) 'bundled' FTRs would therefore appear to be the most logical approach to implementing a risk management regime under GNP. Such an approach will likely satisfy generators' demands for simple and intuitive hedging instruments for use to (and between) local regional and inter-regional load hubs.

As is clear from the United States experience, the determination of the appropriate configuration and volume of FTRs is a difficult issue. Power system checking is an important feature of the northeast allocation mechanisms. Further, annual and monthly multi-round auctions may be necessary to decide which FTRs ought to be allocated and in what volume. All of this suggests a far larger role for the market and system operator in the handling of congestion rentals, and a far more involved process for participants in risk management strategies and auction processes than has been the case to date in the NEM. On the other hand, FTRs may provide firmer hedging instruments than the NEM's existing IRSR units, which may encourage derivative trading.

The allocation of FTRs in the NEM would be a vexed issue. Unlike the northeast United States markets, generators in the NEM do not pay substantial transmission charges. It is these payments in the northeast markets that form the basis for the entitlement of many businesses to a "free" allocation of FTRs (or ARRs in PJM). Applying this approach in the NEM suggests that generators need not automatically receive any FTRs (or ARRs) as part of an initial allocation process. On the other hand, generators in the NEM presently hold an implicit right to be settled at the RRP. This suggests that while generators may not contribute to recovering the costs of the transmission system, there may be a case for some degree of "free" FTR allocation to existing parties if it is considered good regulatory practice to avoid wealth transfers when introducing GNP. One lesson from the PJM experience is that it may be worth imposing a requirement for generators receiving an initial allocation of FTRs to put them up for auction in exchange for the corresponding auction proceeds, so as to avoid creating potential barriers to entry in the market as a result of new entrants being unable to access such hedging instruments.

Full network model

The NEM does not currently employ a FNM. It would be possible to introduce GNP without a FNM, but a FNM is likely to greatly simplify the energy and FTR settlement process under GNP. A FNM may also offer other advantages in terms of system security management and transmission asset efficiency. A means of representing transmission losses in dispatch would also need to be determined.

Caveats to US experience

To the extent that the experience of nodal markets in the United States informs any policy decisions in Australia regarding GNP, it is worth bearing in mind the other important differences between these markets and the NEM. These are chiefly:

- The use of market power mitigation measures; and
- The presence of capacity markets.

Market power mitigation measures

The large role of market power mitigation measures in the northeast United States markets should not be forgotten when drawing inferences about the competitive performance of these markets. The northeast markets typically employ offer-capping mechanisms in situations where generators are deemed to enjoy local market power. The point to be emphasised is that the northeast markets do not provide an assurance that generator market power would not be an issue if GNP were introduced in the NEM in the absence of such intrusive regulatory measures.

Role of capacity markets

The other key point of difference with the northeast US markets is the capping of energy prices and the role of installed capacity markets. Under this model, energy markets are intended to only remunerate generators for their variable costs and a portion of their fixed costs. Ensuring adequate net revenue to meet the remainder of total costs is left to participant capacity obligations and related market arrangements. It should be noted that experience in the longest-lived LMP market (PJM) is consistent with the notion that the locational signals from the energy market are not in themselves determinative of generation investment patterns.

By contrast, the NEM is an energy-only market in which investors in new plant (or demand-side response) are expected to make their locational and investment decisions based on wholesale spot prices (and contracts referenced to those prices).

The relatively low energy market price caps in the United States markets reduce the potential payoff – and hence incentives – for generators with transient market power to exercise that power.

1 Background

1.1 MOTIVATION FOR THIS REPORT

This report, reviewing the theory and practice of generator nodal pricing (GNP), has been prepared by Frontier Economics (Frontier) for the Australian Energy Market Commission (AEMC or Commission).

Frontier understands that the AEMC commissioned this report in light of views expressed by some stakeholders that consideration ought to be given to GNP either as part of the AEMC's Congestion Management Review (CMR) or in the context of the AEMC's market development functions. The AEMC has indicated that it sees this report as providing supplementary reference material to inform future debate surrounding the design and structure of the National Electricity Market (NEM) rather than as a core part of the CMR.

1.2 SCOPE OF THIS REPORT

Through the terms of reference (ToR) for this review, the AEMC requested Frontier to prepare a report providing:

(a) A factual description of what GNP (including the associated risk management framework(s)) is (or could be construed to be) and how it differs from the current NEM pricing regime;

(b) A factual description of the issues associated with GNP relative to the current NEM pricing regime, in respect of:

- Dispatch efficiency;
- Competition and market power issues in the short and long term;
- Trading and risk management;

(c) A fact-based review of practical experience of the issues in (b) in other markets which have adopted a GNP approach; and

(d) In light of the above, a review of the issues that would (or could) need to be addressed in considering a transition to a GNP approach in the NEM.

In addition, Frontier believes it is worthwhile to consider both:

- Experience in full nodal pricing (FNP) markets, given their relevance to understanding GNP markets and the substantial history of the PJM full nodal market, in particular. As discussed later in this report, the difference between GNP and FNP is largely a matter of degree and both can be regarded as a form of locational marginal pricing (LMP); and
- The implications of GNP for investment in generation and other energy infrastructure.

The ToR for this review also noted that the AEMC had already commissioned work in the context of the CMR to establish a common descriptive framework and terminology for considering different pricing options. This common descriptive framework and terminology was to be used in the present review to the extent the consultant considered it practical and appropriate to do so.

1.3 FRAMEWORK FOR THE REVIEW

As noted above, the descriptive framework and terminology for this review seeks to draw from work recently undertaken for the AEMC to the extent considered appropriate.

However, a broader normative framework is still necessary to assist in the identification of issues that would or could need to be addressed in considering a potential transition to GNP in the NEM. For this purpose, Frontier will be guided by the NEM objective, in that the issues that are highlighted are those arising from a consideration of the implications of GNP for:

- Various dimensions of efficiency (productive, allocative and dynamic) – comprising the effect of GNP on economic surpluses arising in the NEM in both the short and long term;
- Good regulatory practice – referring to the means by which policy-makers and regulators seek to ensure that the market design and regulatory framework achieves its intended ends; and
- Positive reform direction – the importance of maintaining continuous and incremental improvement in the development of the NEM.

1.4 STRUCTURE OF THE REPORT

This report is comprised of the following sections:

- Description of GNP and associated risk management frameworks (section 2);
- Implications of GNP compared to the NEM in relation to:
  - Dispatch efficiency;
  - Competition and market power; and
  - Trading and risk management (section 3);
- Review of practical experience of other nodal markets (section 4);
- Issues that could or would need to be addressed in implementing GNP in the NEM (section 5).

2 GNP and associated risk management frameworks

2.1 PURPOSE OF GNP

GNP fundamentally involves localised dispatch and spot market settlement of all generation participants. That is, whether or not a particular generator is dispatched (selected to run or not run as the case may be) and the price it receives for electricity is determined according to local market and network conditions.

The motivation for such localised dispatch and settlement was to simultaneously achieve two economic objectives:[1]

- Dispatch Efficiency: Minimise the cost of generating electricity to meet demand or "load" by dispatching the least-cost set of available generators possible given various power system constraints – referred to as least-cost security-constrained dispatch; and
- Cost-reflective nodal prices: Produce the instantaneous price of electricity at every bus or "node" in the system that reflects the instantaneous short-run marginal cost (SRMC) of serving one incremental unit of load at that location. This price is referred to as the nodal price for that location.

In a system with no binding network limits (constraints) and no network losses, the lowest-cost dispatch would be achieved by dispatching the cheapest plant first and progressively dispatching more expensive plant further up the cost "merit order", wherever those plant were located. As a result, the price of electricity (as reflected in nodal prices) would be identical throughout the system and each generator, no matter where it was located, would be dispatched up to the point where its own marginal cost was equal to the common system-wide marginal cost.[2]

However, network constraints restrict the flow of power from low-cost generators to loads, necessitating higher-cost generators to be dispatched out-of-merit. Therefore, binding constraints always lead to nodal price variations.[3]

In power systems containing network "loops" (where two or more electrical paths are available between any two nodes), nodal prices throughout can diverge in the presence of even one binding constraint due to the physics of electricity flows in such networks. This is because electricity flows according to Kirchhoff's Law, which dictates that power flow along a given path must be inversely

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[1] Synapse Energy Economics Inc., *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, prepared for: American Public Power Association, February 2005, p.1.

[2] Biggar, D., *Congestion Management Issues: A Response to the AEMC*, 12 April 2006, p.5.

proportional to that path's impedance.[4] Least-cost dispatch may then produce a range of counter-intuitive dispatch and nodal price outcomes. To illustrate, consider the 3-node example in Figure 1 below, where for simplicity we assume a lossless network, lines of equal length and a flow limit of ≤100 megawatt (MW) between nodes 1 and 2:

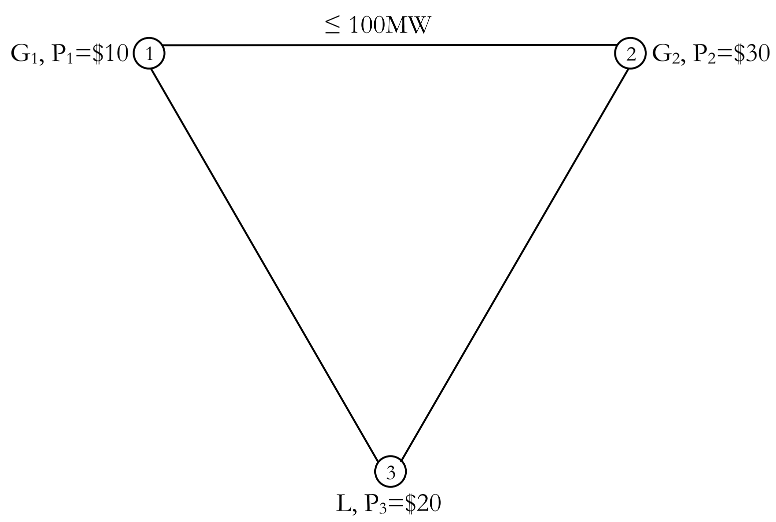

Figure 1: Three-node loop

Consider the situation where a load (L) at node 3 has a demand of 350MW of which generators 1 and 2 (G_1 and G_2 respectively) are competing to meet. Assume that G_1 has a cost of $10/MWh and G_2 has a cost of $30/MWh.

Due to Kirchhoff's Law, for power flowing between nodes 1 and 3, ⅔ of that power will follow the 'direct' path 1→3 while ⅓ will follow the 'indirect' path 1→2→3 (since the path 1→2→3 has double the impedance of the path 1→3, half as much power will flow on that path).

In the absence of network constraints, it would be efficient for G_1 to meet the full demand of L and hence set the marginal price at all 3 nodes at $10/MWh. However, due to the 100MW constraint between nodes 1 and 2 in combination with the operation of Kirchhoff's Law, this is not feasible. Under such conditions, G_2 must contribute to supply in order to satisfy the demand at L. For a 1 MW increase in supply at node 2, the 'relieving' effect of counter-flows along the congested line 1→2 implies an equivalent 1 MW increase in supply at node 1 is now possible. This relieving effect is a consequence of Kirchhoff's Law and arises since only *net flow* across a line is relevant (flows of equal magnitude in opposite directions 'cancel' each other out). Thus in the above example, G_2

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[4] Electricity Commission, *Appendix 5: Constraint Pricing and the Spring Washer Effects*, p.2, accessed from http://www.electricitycommission.govt.nz/archives/advisorygroups/wmag/2005/18Aug05/constraint-pricing-app5.pdf on 25 February, 2008.

producing 25MW (of which 1/3 or 8⅓ MW flows across 2→1) allows G_1 to produce an additional 25MW, since 8⅓ MW of capacity is now available along 1→2. Thus in *net* terms, the flow across 1→2 is 100MW but in *gross* terms, 108⅓ MW is flowing from 1→2 while 8⅓ MW is flowing from 2→1.

Since an increment of load at L requires a combination of generation from both G_1 and G_2, the nodal price at L must reflect the costs of both plant. In this case, the price at node 3 is an equally weighted average[5] of prices at nodes 1 and 2 – ie $20/MWh. This example demonstrates how a single binding constraint within a looped network can lead to nodal price divergences throughout the network.

As noted by Gregan and Read, each binding constraint has a price (also known as its "shadow price"), which is equal to the reduction in the total cost of dispatch that would occur if that constraint were marginally relieved.[6] The shadow price of a constraint multiplied by the MW volume of power flow when the constraint binds equals the economic rental attributable to that constraint. This rental forms the basis for the creation of financial hedging instruments, as discussed in section 2.3 below.

In modern electricity markets, it is participant bids and offers – rather than engineering or accounting estimates of costs – that are used as inputs in the determination of both dispatch and spot price outcomes. Consequently, in GNP markets, generators are typically dispatched when their offer prices are below their local nodal price of electricity.[7] As well as being dispatched on the basis of their offers, all generators in such markets are settled on the basis of their local nodal price. Therefore, all generators at a particular node receive the same price in the wholesale spot market for the electricity they generate. This represents one of the key differences between GNP and the NEM (see chapter 3 below).

In a highly competitive GNP market, generators' offers should reflect their individual SRMCs of generating more electricity. To the extent they do not, the positive dispatch efficiency implications of GNP may be compromised, as discussed below.

2.2 DISPATCH IMPLICATIONS

As noted above, generators in bid-based, security-constrained nodal markets are typically dispatched (effectively[8]) if and when their offers lie below their local

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5 A 1MW increase in generation by G_2 provides a 'relieving effect' across constraint 1→2 and allows an equivalent 1MW increase in generation by G_1. Thus in the presence of a binding constraint across 1→2, a marginal unit of power at L requires an equal contribution from G_1 and G_2 (i.e 0.5MW from each). For this reason the nodal price at node 3 is an equally-weighted average of prices at nodes 1 and 2.

6 Gregan, T. and E.G. Read, *Congestion Pricing Options for the Australian National Electricity Market:: Overview, Prepared for the Australian Energy Market Commission*, February 2008, p.4.

7 Ibid, p.5.

8 The dispatch algorithm in such markets does not explicitly make this comparison when determining the dispatch outcome. However, this is the effective result of the dispatch process.

nodal price. Where generators are pure price-takers (ie they cannot exercise even transient market power) dispatch on this basis is consistent with the minimisation of resource costs in meeting demand because generators are offering to supply electricity at a price below or equal to the value of electricity at that location (as indicated by the local nodal price). It should be emphasised that in such markets, generators do not hold a "right" to be physically dispatched that is independent of the dispatch process itself.

The alignment between the basis upon which generators are dispatched and the price upon which they are settled in a GNP market implies that they do not face the risk that they are:

- dispatched but settled at a price below their offer price; or
- not dispatched even though the price they would have received would have exceeded their offer price.

By contrast, as explained in the AEMC's CMR Directions Paper[9] and discussed further in the following chapter, "dispatch risk" can arise in the regionally-priced NEM as indicated by divergences between a generator's (notional) nodal price and the regional reference price (RRP) upon which it is settled.

2.3 SETTLEMENT IMPLICATIONS

As noted above, GNP involves the dispatch and settlement of *generators* according to conditions at their local node. This has significant implications for the financial risks experienced by generators in such a market compared to a regional market such as the NEM, as discussed in the next section. However, loads in GNP markets may be dispatched *but not settled* according to their local nodal prices. As noted in the AEMC Directions Paper, if GNP were implemented in the NEM, loads could either pay:

- The RRP, being the price at the existing regional reference nodes (RRNs); or
- A load-weighted average of load nodal prices within the relevant region.[10]

As discussed in chapter 4 below, the load-weighted approach has been adopted in several of the northeast United States markets, as well as the Singapore market.

In either case, GNP implies that (at least some) dispatchable loads may be mis-priced in the same way as generators can be mis-priced in a regional market (see below). However, this problem may not be material since (i) most loads in the NEM are non-dispatchable and (ii) even most dispatchable loads are relatively unresponsive to price in the short term.

By contrast, under FNP, load participants are also settled on the basis of their local nodal price. This is the key difference between GNP and FNP markets.

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[9] AEMC, *Congestion Management Review: Directions Paper*, March 2007, p.11.

[10] Ibid., p.67.

2.4 RISK MANAGEMENT IMPLICATIONS

While GNP effectively eliminates what the Commission has referred to as dispatch risk for generators, it does subject participants to "basis risk". This is the risk that the price of electricity at which a participant's derivative contracts are settled may not correlate closely with the price at which their own production (or consumption) is settled. For example, generators may enter into derivative contracts (such as swaps or caps) referenced to prices at nodes (such as those at load centres) some distance away. Under GNP, they would be required to make "difference payments" based on the difference between the spot price at the reference node for the derivative contract and the contract strike price, even if they actually earn a lower (or higher) price for their output than that prevailing at the contract reference node.

In order to assist participants in hedging their contract basis risks, most markets with GNP provide for participants to receive or acquire basis risk management instruments based on the economic rentals produced by network constraints when they bind. While these instruments are given different names in different real-world markets, they can be broadly described as a form of "financial transmission right" or "FTR". FTRs are instruments that provide their holders with a stream of revenue derived from the differences in nodal prices that occur when transmission limits bind.[11] Such rights to revenues can be used either:

- for speculative purposes – if a participant takes the view that the relevant nodal price differences will be relatively large and cause the outturn value of the instrument to exceed its price or alienable value; and/or
- for hedging purposes – to offset losses (or gains) incurred due to differences between participants' local nodal prices and the prices at which their contracts are settled, thereby smoothing participants' financial positions.

For example, consider a two-node network (with nodes A and B) where a 1 MW generator located at node A that has entered into a 1 MW swap contract (strike price $20/MWh) settled against the price at node B. Assume that if transmission limit X binds, the nodal price at B rises above the nodal price at A, which is the price at which the generator is settled for its output. Further, assume that the price at B rises to $30/MWh when X binds while the price at A remains $20/MWh. This would mean that the generator would need to make difference payments of $10 per hour on its contract referenced to node B, while only earning $20 per hour on its output. If the generator has costs of $15/MWh, the net result would be that the generator would make a loss of $5 per hour ($20 spot market revenue less $10 difference payments less $15 costs).

In order to hedge against the consequences of the X constraint limit binding, the generator may seek to acquire a 1MW AB FTR. This FTR would provide the generator with a stream of revenue equal to part of the economic rental produced by the constraint when it binds. In this case, assuming the flow across X reaches its limit, the $10 difference payment that the generator will need to make on the

[11] See, for example, Hogan, W.W., *Financial Transmission Right Formulations*, March 31, 2002, p.3 and p.26.

swap contract will be offset by a $10 receipt from its 1MW FTR. Thus, the generator will ultimately receive net revenues of $20 per hour ($20 through the spot market and $10 from the FTR less the $10 difference payment) and make a profit of $5 per hour ($20 less $15 costs). Of course, this ignores whether and how much the generator pays for the FTR. If the generator paid $2 for the FTR, then it would still make a net profit of $3 for that hour. If the generator paid more than $5, it would make a net loss for the hour. The hedging value of the FTR is that, to the extent it is "firm", it protects the holder from any divergence in the relevant nodal prices and hence allows participants to enter derivative contracts settled at other nodes with confidence. FTRs may be less than fully firm in practice, as discussed in chapter 4 below.

2.4.1 FTR design and allocation

Given the importance of FTRs to the successful functioning of GNP (and FNP) markets, it is worth briefly highlighting some of the relevant issues that have been raised in the theoretical literature. Discussion of the practical experience with FTR regimes in different markets is contained in chapter 4, which describes international experience with nodal markets more generally.

Formulation of FTRs

At the highest level, FTRs can be defined as "point-to-point" rights or "flowgate" rights. Simply put, flowgate FTRs are constraint-by-constraint hedges that give their holder the right to collect payments based on the shadow price associated with a particular transmission constraint (flowgate) while point-to-point FTRs provide a hedge between a named injection (or "source") node and a named withdrawal (or "sink") node. As noted by Gregan and Read, the Constraint-Based Residues (CBRs) concept developed by Darryl Biggar represents a form of flowgate FTR because it involves allocating rights to the rentals produced by individual constraints.[12] The CMR Draft Report also explained that CBRs represent a form of "unbundled" transmission rights, in which the economic rental arising from each constraint is dealt with individually.

In his survey of FTR markets, Kristiansen explained that the proponents of flowgate rights claim that point-to-point rights do not provide effective hedging instruments because the point-to-point FTR markets may not work efficiently in practice. The idea behind flowgate rights was that since electricity flows simultaneously along many parallel paths, it was natural to associate FTR payments with actual electricity flows.[13] The key assumptions behind a flowgate approach include a power system with few flowgates or constraints, known capacity limits at the constraints and known power distribution factors that decompose a transaction into flows over the flowgates. However, such assumptions may not be borne out in practice. For example, the CBR proposal

12 Gregan and Read (2008), p.30.

13 Kristiansen, T., "Markets for Financial Transmission Rights", *Energy Studies Review*, Vol.13, No.1 2004, pp.25-74, p.29.

could become complicated for participants to engage with if rights over many hundreds of constraints (flowgates) were made available.

While noting the advantages of flowgate FTRs, in terms of ease of decomposition and secondary trading for each constraint, Bill Hogan, a supporter of point-to-point rights, contended:

> In order to construct… a hedge with the [point-to-point] FTR obligation between two locations, it is only necessary to specify the volume and the two locations. In order to construct an equivalent hedge with [flowgate] FTR obligation, in principle it would be necessary to identify the required [flowgate] FTR obligation amount on each of the potentially hundreds of thousands of affected constraints. To the extent that some or all of the constraints are neglected, the [flowgate] FTR provides an incomplete hedge.[14]

FTRs are often categorised as either "obligations" or "options". Standard FTRs have been described as 'obligations' rather than 'options' because they involve an obligation for holders to pay when the price differential is negative as well as a right to compensation when it is positive.[15] Negative price differentials may arise in "meshed" networks (networks involving loops), as is apparent from Figure 1 above and is discussed further below. FTR options allow participants to avoid making payments where the value of the FTR is negative. According to Hogan, point-to-point options present complications that do not arise for obligations.[16] These complications arise from the need for revenue adequacy for FTRs, which is discussed below.

Chapter 4 discusses the practical experience of point-to-point FTRs in northeast United States power markets that employ some form of LMP.

In this context, it is worth highlighting that the need for and role of FTR-type instruments is slightly different under GNP than under FNP. This is because under FNP, generator and load counterparties that are both located at the same node do not face any basis risk – they are both dispatched and settled on the basis of their local nodal price. However, under GNP, it may be the case that even a generator and a load located at the same node face basis risk from a derivative contract struck with each other at that node.

This means that point-to-point FTRs under GNP would need to be defined between a given source node and the appropriate withdrawal node or hub, depending on how load was to be settled. This could be either:

- the same withdrawal node (such as the current RRNs) – if all loads in a region or zone were settled at the marginal cost of electricity at that node; or
- the same withdrawal "hub" – if load is settled at a weighted-average price.

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[14] Hogan, W.W., *Financial Transmission Rights Formulations*, Centre for Business and Government, Harvard University, March 31, 2002 (Hogan (2002)), p.45.

[15] Hogan, W.W., *Transmission Market Design*, from "Electricity Deregulation: Where to From Here? Conference at Bush Presidential Conference Center, Texas A&M University", April 4, 2003 (Hogan (2003)), p.6. Se also below under Revenue Adequacy.

[16] Hogan (2002), p.32.

Finally, Gregan and Read point out that it may be possible to offer flowgate FTRs (such as CBRs) in the context of GNP, but that point-to-point instruments are much more widespread.[17]

Revenue adequacy

A key issue arising in FTR formulation is revenue adequacy. This means that the net revenue collected through the settlement process from the entire set of settlement prices should at least be equal to the payments to the holders of FTRs in the same period.[18] It can be shown that, under FNP, a set of point-to-point FTRs will be revenue-adequate when the implied power flows from the FTRs are "simultaneously feasible".[19] This finding extends to GNP provided load is settled on the basis of a load-weighted average price.[20], thus implying a net revenue surplus. If load is settled on the basis of a price at a particular node (such as the RRN), this result is less certain - in such cases both net revenue surpluses and deficits are feasible.

Assuming that FTRs in a meshed network are defined as obligations rather than options, it is possible that network conditions can result in such instruments having negative value. To illustrate, reconsider the three-node loop example from Figure 1, where a binding network constraint caused a nodal price divergence. We can observe that power flows from G_2 to L (or node $2 \rightarrow 3$) represent a counter-price flow. Given that the value of an FTR is derived from the difference between the prices at the sink and source nodes, a $2 \rightarrow 3$ FTR will have negative value (and hence a negative price in the market) since $(P_3 - P_2) < 0$.

In such cases, some means of ensuring that participants accept the obligations implied by these FTRs would be necessary to ensure overall revenue adequacy. One approach is to sell these rights at a negative price (ie pay participants to accept them), either through a tender or negotiated outcome. Gregan and Read discuss some of these options and the issues surrounding them, such as the funding of compensatory payments to the acquirers of rights with negative values.[21]

The previous section alluded to the additional complications arising from point-to-point FTR options, as compared to FTR obligations. Hogan suggested that these difficulties stem from the fact that whereas the revenue adequacy of FTR obligations can be ascertained by checking whether the set of power flows

17 Gregan and Read (2008), p.31.

18 Hogan (2002), p.3; Kristiansen (2004), p.31.

19 Hogan (2003), p.6; Kristiansen (2004), p.31.

20 Further, under a GNP system with load-weighted average pricing, positive loss and congestion rents will accrue due to a positive price differential, on average, between (i) generator nodal prices and (ii) the load-weighted average price. See: EGR Consulting, *Network Congestion and Wholesale Electricity Pricing in the Australian National Electricity Market: An analytical framework for describing options,* prepared for: AEMC, Appendix B, 2007 for a detailed discussion.

21 Gregan and Read (2008), p.24.

implied by the FTRs are simultaneously feasible,[22] the revenue adequacy of FTR options cannot. This is because the dispatch process does not include options:

> [I]n the real dispatch, everything is an obligation. Hence the auction model for options does not follow directly from the formulation for economic dispatch.[23]

Hogan went on to say that:

> Without knowing all the other flows on the system, it is not possible in general to know if any particular transaction will be feasible. Hence, to guarantee feasibility it is necessary to consider all possible combinations of the exercise of options. For example, if too few of the other options are exercised, there may be insufficient counterflow to support a particular transaction; or if all the options are exercised, some other constraint might be limiting. This ambiguity does not arise with obligations, which by definition are always exercised.[24]

Nevertheless, FTR options have been introduced in PJM (see section 4.1.3 below).

FTR allocation criteria

Another crucial issue involving FTRs is the means of allocating them to participants. This could involve:

- an auction/tender/negotiation mechanism to determine how much participants pay or receive to acquire or accept particular FTRs or sets of FTRs;
- an administrative allocation based on a particular policy position, such as a view of (implicit) historical transmission rights (as in the LATIN Group proposal to the CMR[25]); or
- some combination of the above.

In its CMR Draft Report, the Commission highlighted some of the difficulties involved in determining an appropriate allocation of FTRs. The Commission commented on the LATIN Group's proposal to allocate Constraint Support Contracts (CSCs, a type of FTR) to existing NEM generators on the basis of a representative dispatch scenario, as well as on the option of allocating via an auction process.[26] Chapter 4 below describes how a number of FNP markets have resolved allocation issues in practice.

Two related issues arise in the allocation of FTRs:

- The first is to ensure that the allocation of FTRs does not create or enhance market power. Much has been written on this topic, but there appears to be a

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22 Hogan (2002), pp.28-29.

23 Hogan (2002), p.32.

24 Hogan (2002), p.32.

25 This was discussed in the AEMC's CMR Draft Report, pp.93-94.

26 AEMC, *Congestion Management Review: Draft Report*, September 2007, pp. 93-94.

consensus that the behaviour of generators in an FTR market needs to be carefully observed and potentially regulated.[27]

- The second issue is whether investment in transmission networks can be left to private investors who receive FTRs in exchange for providing additional transmission capacity. Many commentators have claimed that relying on FTRs to encourage investment in the network by private investors will lead to sub-optimal network development.[28] Even Hogan, the originator of this concept, accepts that complete reliance on market incentives for transmission investment is subject to a number of theoretical caveats as well as being practically unrealistic.[29] He suggested that merchant transmission investment will only be efficient where there is no market power and when investments are not excessively 'lumpy' (in the sense that relatively large transmission investments can reduce nodal price differentials and therefore undermine the value of the FTRs made available by the investment).[30] Kristiansen surmised that:

> The main consensus in the FTR literature is the need for co-existence of central planning and merchant investment for the long-term FTR approach to work and create incentives for transmission expansion.[31]

From a practical perspective, very little merchant or unregulated transmission investment has occurred in nodal markets. In the NEM context, we do not consider the use of FTRs as a reward for merchant-driven expansion of the transmission grid as a prerequisite to their more general use as risk management instruments across the existing network. Investment in the grid could continue to be the subject of economic regulation.

Chapter 4 below discusses the types of FTRs that have been implemented in a number of real-world electricity markets, including evidence of the practical experience regarding the efficacy and efficiency of these instruments.

2.5 ANCILLARY SERVICES

Although this paper is not directed at the pricing of ancillary services, it is important to note that a number of ancillary services are complements or substitutes in their provision by generators. For example, energy and regulation are complements, since a generator must provide some energy to provide regulation, (but need not provide regulation in order to provide energy). However, energy and regulation are also substitutes, since the provision of regulation requires a generator to deviate from its optimal energy output. Similar

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[27] Kristiansen (2004), pp.33-34.

[28] See, for example, Joskow, P. and Tirole, J. (2005). "Merchant Transmission Investment", *The Journal of Industrial Organisation*, Vol. 53(2), pp. 233-264.

[29] Hogan, W.W., "Market-Based Transmission Investments and Competitive Electricity Markets", Centre for Business and Government, Harvard University, August 1999, p.21, as cited in Hogan (2003), p.16.

[30] Hogan (2003), p.16.

[31] Kristiansen (2004), p.35.

issues arise with regulation and operating reserves. When these multiple services are offered in the same power market, the complementarities and substitutabilities must be fully recognised to achieve productive efficiency.[32] For example, it may be the case that tailored financial instruments could be used to incentivise the efficient provision of services such as generator 'gatekeeper' (interconnector support) services or non-energy services. Having said that, GNP is not a prerequisite for the use of these mechanisms to achieve those efficiencies.

[32] O'Neill, R., U.Helman, B.F.Hobbs and R.Baldick, "Independent System Operators in the USA: History, Lessons Learned, and Prospects", Chapter 14 in Sioshansi, F.P. and W.Pfaffenberger (eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, pp.494-495.

3 Nodal markets compared to the NEM

GNP (and FNP) markets diverge in a number of important respects from the current NEM design. A number of the key differences between the NEM and a fully nodal market were noted in the papers prepared for the CMR. These and other pertinent observations are discussed below.

3.1 DISPATCH PROCESS AND OUTCOMES

3.1.1 Dispatch engine

As explained in the CMR Issues Paper, the central dispatch process in the NEM seeks to minimise the cost of supplying power to meet demand at each RRN, based on the bids and offers presented by market participants. Network thermal and stability limits are represented in constraint equations within the NEM dispatch engine (NEMDE). NEMDE solves an optimisation problem to yield the least-cost set of participant bids and offers to serve load, subject to these constraints.[33]

As noted in the previous chapter, generation dispatch in a GNP market operates in a similar way to dispatch in the NEM. The key difference is that nodal markets tend to employ a "full network model" (FNM), whereas in the NEM, the physical limitations of the transmission network are expressed indirectly using generic constraint forms that are "oriented" to the relevant RRN.[34] In this context, it is worth briefly exploring the potential role and implications of adopting a FNM.

Full Network Model

A FNM reflects a significant degree of network representation by incorporating a highly detailed representation of the underlying physical power system into the network model. A FNM could, for example, represent every network element (connection point, substation, transformer, etc) in the system. It follows that a FNM oriented in this way is capable of generating locational prices for each such point on the system.

In its 2004 Consultation Draft for the Ministerial Council on Energy (MCE), consultants CRA suggested that pricing and dispatch outcomes produced by NEMDE should theoretically be equivalent (at least for energy terms) to those under a FNM, assuming the same physical network representation.[35] The chief advantage of implementing a FNM in a regional market would be a potential improvement in NEMMCO's ability to maintain system security.[36] Gregan and Read also suggest that regardless of any changes to market design, it would be

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[33] AEMC, *Congestion Management Review: Issues Paper*, March 2003, pp. 11-12.

[34] Gregan and Read (2008), p.5.

[35] CRA, *NEM: Transmission Region Boundary Structure (Draft Report)*, September 2004, p.21.

[36] CRA, *NEM: Transmission Region Boundary Structure (Draft Report)*, September 2004, p.21.

desirable to replace NEMDE with a FNM.[37] Some commentators have further contended that the implementation of a FNM in a regional market may promote efficiency, given that transmission assets could be run 'closer to their limits'[38]. The extent to which this is the case depends on both the current accuracy of system constraint estimates under NEMDE and the level of conservatism built-in to existing constraint and loss equations.

In the context of the implementation of GNP, while pseudo-nodal prices[39] can be derived from NEMDE using the existing constraint and loss equations, NEMDE is not designed to automatically generate locational prices for each node. Therefore, a FNM reflecting at least the first set of attributes noted above is likely to facilitate the operation of GNP. Such a model could also be used to formulate and settle FTRs[40]. Whether it is worth implementing a FNM that provides a more accurate approximation of power system conditions is a matter than can be considered separately from GNP.

3.1.2 Nodes for pricing and settlement

The key difference between GNP and the NEM is the number of nodes that are explicitly priced for the purpose of settling participants' wholesale market transactions. The NEM currently has six RRNs within six regions (soon to be 5): Queensland, New South Wales, Snowy, Victoria, Tasmania and South Australia. While Frontier has not undertaken an independent review of the likely number of nodes under GNP, the Draft Stage 1 Report of the National Electricity Code Administrator (NECA) for its Review of the Integration of the Energy Market and Network Services (REIMNS) suggested that over 340 nodes would be required to implement FNP.[41] NEMMCO may be able to provide more up to date advice on this figure.

Depending on how load was settled under GNP (see section 2.3), the number of nodes required to implement GNP may be less than for FNP. Specifically, settling load on the basis of a load-weighted nodal average price within a region would require the same number of nodes to be explicitly priced as under FNP. The difference would be that only the load-weighted average of those prices would be used for load settlement purposes. By contrast, settling load on the basis of a particular nodal price (eg the current RRP) would only require that load node to be priced in addition to all generator nodes in the region.

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37 Gregan and Read (2008), p.31.

38 IES, *Regional Boundaries and Nodal Pricing: An Analysis of the Potential Impact of Nodal Pricing and Market Efficiency*, December 2004, p.25.

39 Gregan and Read (2008), p.5.

40 Gregan and Read (2008), p.31.

41 NECA, *The Scope for Integrating the Energy Market and Network Services, Volume 1 Draft Report*, Table 5, p.25.

3.1.3 Mis-pricing and dispatch risk

The CMR Directions Paper[42] and the Draft Report[43] explained that an implication of congestion in a regional market such as the NEM is that it may lead to a divergence between the RRP (at which participants are settled) and the local or pseudo nodal prices (upon which participants are dispatched). This situation, referred to as "mis-pricing", does not arise in a fully nodal market where there is complete alignment between the set of nodal prices used as the basis for settlement and the set of nodal prices emanating from the dispatch process.

Mis-pricing in the NEM can give rise to dispatch risk, in that participants are not dispatched to a level consistent with the quantity bid or offered relative to the RRP. Dispatch risk, in turn, can give rise to detrimental incentives for market participants. In particular, it can incentivise "disorderly" bidding by generators, even where generators are price-takers[44]:

- constrained-off generators have an incentive to offer capacity at below their SRMC in order to be dispatched and receive the (higher) RRP; and
- constrained-on generators have an incentive to offer capacity at very high prices or not at all in order to avoid being dispatched where the RRP is below their SRMC.

By contrast, generators acting as price-takers do not have incentive to behave in this manner in a GNP market, due to the complete alignment between dispatch and settlement prices. Specifically, if a generator bids below its SRMC and is dispatched, it will receive its local nodal price, which may also be below its SRMC. Alternatively, if a generator bids at a very high price, it may not be dispatched even if the price it would receive may be well in excess of its SRMC.[45] For such participants, bidding at SRMC is ordinarily a dominant strategy.

3.1.4 Market power and dispatch efficiency

Assuming price-taking generator bidding behaviour, GNP should yield lower economic costs of dispatch than a market in which generators are routinely mis-priced in the presence of congestion. As noted in the CMR Draft Report[46], mis-pricing leading to disorderly bidding can result in higher-cost plant displacing lower-cost plant in the dispatch merit-order. This means that the costs of serving

[42] AEMC, *Congestion Management Review, Directions Paper*, March 2007, pp.11-13.

[43] AEMC, *Congestion Management Review, Draft Report*, March 2007, pp.48-50.

[44] "Price-taking" refers to a generator's inability to affect the price it receives at settlement by offering more or less of its capacity or offering its capacity at different prices. In this report, generators who are not price-takers and who are under-contacted will be described as having a degree of "market power", even if this power is only transient. Over-contracted generators will have the opposite incentive, i.e. to drive prices down.

[45] Note that this paragraph assumes price-taking generator bidding behaviour. If generators are able to exercise transient market power, it may be in their interests to withhold some output and/or offer some capacity in excess of SRMC.

[46] AEMC, *Congestion Management Review, Draft Report*, March 2007, p.55.

load are higher than they would be if the generators had not been mis-priced. Hence, the NEM may not promote dispatch efficiency to the same extent as a market in which at least generators are settled nodally.

However, if the assumption of price-taking is relaxed, the positive dispatch efficiency implications of GNP may no longer hold. This is because if some (or all) generators offer capacity at prices *above* their SRMC, the displacement of higher-bidding generators by lower-bidding generators may not result in genuinely least-cost dispatch. In fact, more granular pricing arrangements may even *encourage* generators to exercise market power. Generators may be incentivised to refrain from offering all of their output at their SRMC in order to prevent constraints from binding that could otherwise yield lower local settlement prices. This may take the form of offering a fraction of their output at marginal cost and bidding the remainder as unavailable, offering all of their output at a price above marginal cost, or some combination of these.

By way of example, in the consultation process for the Snowy regional boundary options, Snowy Hydro commented on its incentives to exercise market power. Snowy Hydro submitted that more localised pricing of its Murray and Tumut plant would encourage it to withhold output to leave "headroom" on lines to its north and south.[47] This could reduce the economic efficiency of dispatch compared to a situation where Murray and Tumut were mis-priced by being settled at the Victorian and NSW RRPs, respectively. In response, the Commission noted that whether a more refined pricing structure was likely to improve or worsen dispatch efficiency was not a matter that could be resolved analytically – it could only be tested with the aid of simulations that allowed for interdependent bidding behaviour to be modelled.[48]

At the same time, the CMR Directions Paper made the observation that a more refined regional structure (or GNP for that matter) would limit the impact of a generator's exercise of market power to a smaller area than if the generator were included in a larger region or zone.[49] This would particularly be the case where the generator was located electrically close to the RRN such that it could have a great influence on the determination of the RRP. By contrast, a generator located electrically far from the RRN may instead simply be constrained-on if it seeks to exercise market power. Either way, the difficulty remains of making sound *a priori* judgments about the impact of nodal pricing on dispatch efficiency outside of a price-taking environment.

3.2 BASIS RISK MANAGEMENT

The Commission's papers also explained the concept of financial basis risk. Due to the present regional settlement arrangements in the NEM, participants

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[47] Snowy Hydro Ltd, *Submission to consultation: Management of negative settlement residues in the Snowy Region*, 10 February 2006, p.5.

[48] AEMC, *Draft Rule Determination, Draft National Electricity Amendment (Abolition of Snowy Region) Rule 2007*, 19 January 2007, p.32 and p.37.

[49] AEMC Directions Paper, p.49, citing Harvey and Hogan (2000).

currently avoid basis risk in respect of derivatives trading within their own region.[50] However, basis risk can arise in the NEM to the extent that participants enter derivative contracts that are referenced to other regions' RRNs. The NEM design utilises inter-regional settlement residue (IRSR) units and Settlement Residue Auctions (SRAs) to facilitate participants' management of basis risk. However, as noted in Gregan and Read[51], as well as in the CMR Draft Report[52], such instruments do not provide *firm* hedges for inter-regional price risk.

By contrast, as noted above, generators in a GNP market have a wider potential exposure to basis risk, determined by the extent to which they enter contracts that are settled against prices at other nodes. Given that such generators are likely to seek explicit point-to-hub and hub-to-hub risk management instruments to hedge their positions, it is likely that GNP markets will require far more numerous and more comprehensive basis risk management instruments than currently exist in the NEM. Associated with these explicit rights are issues regarding initial formulation, allocation and ongoing management.

As highlighted in the Directions Paper, inadequate basis risk management instruments may have potentially harmful implications for contract trading, retail prices and dynamic efficiency in the longer term:[53]

> Ultimately, if the available basis risk management options are inadequate, participants could respond by simply choosing not to contract across regional boundaries, or more broadly, across locations that are effectively settled at different prices. This could have a range of negative implications for the promotion of the NEM Objective. For example, competition for financial derivative products across the NEM could be reduced. Retailers tend to rely heavily on such products to hedge their spot market exposures and typically have highly inelastic demand for them, so less competitive contract offerings could increase wholesale contract premiums. This could eventually flow through to higher retail prices, particularly in net importing regions. Higher retail prices could, in turn, lead to lower consumption by loads compared to a situation in which basis risk was lower.
>
> In the longer term, high basis risk may result in less retailer entry, less retail competition and again, higher retail prices. At the same time, contract prices could be depressed in generation-rich (net exporting) regions, possibly leading some generators to go unhedged. These factors may also discourage generators from locating in areas where fuel costs are low, simply to avoid the risk of price separation. In the long run, the distortion in the prices or availability of contracts could have long term implications for generator location and investment decisions, and therefore, for the long-term dynamic efficiency of the market.

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50 In the terminology of Gregan and Read (2008), regional settlement implies that market participants currently receive congestion revenue rights (CRRs) based on the Implicit Dispatch Matching Allocation (IDMA).

51 Gregan and Read (2008), pp.9-10.

52 AEMC, *Congestion Management Review, Draft Report*, March 2007, pp.101-103.

53 AEMC, *Congestion Management Review: Directions Paper*, March 2007, p.17.

Consequently, to the extent congestion is associated with increased basis risk, and this risk cannot be managed through hedging instruments or other mechanisms, economic welfare may be less than it would be otherwise.

3.3 LOCATIONAL DECISIONS

While a review of the implications of GNP on participants' locational investment decisions was not explicitly part of the ToR, we consider it worthwhile to make some observations on this important matter. This is because investors' locational decisions will have implications for economic efficiency and prices in the long run. Economic efficiency in the context of electricity markets is concerned with the minimisation of the costs of supplying load and there is no reason, in principle, why this assessment ought to be restricted to short-term considerations. The ToR acknowledges the importance of long-term considerations in requiring that competition and market power issues need to be considered in this context.

On the whole, the regional pricing structure in the NEM has led to generation investment in those regions that have experienced the highest prices – namely, South Australia and Queensland. Victoria has also experienced investment in peaking plant as a result of the region's increasingly "peaky" load profile.

A more granular pricing structure, such as GNP, would provide even more refined locational signals to investors in new generation. Other things being equal, one would expect electricity investors to make more locationally efficient decisions when faced with these more refined signals. By the same token, it is clear that investors do not make locational decisions solely or even principally on the basis of wholesale spot prices. Indeed, the Commission itself highlighted the importance of other locational factors in its Draft Report on the CMR, such as availability of fuel and water sources, environmental restrictions, carbon risk and portfolio risk.[54] A recent report by Synapse Energy Economics for the American Public Power Association in the context of the northeast United Stated nodal markets highlighted similar factors, citing the availability of suitable sites, the availability and cost of land, access to fuel and transmission lines, requirements for cooling water and local opposition.[55]

Therefore, while highly localised prices may influence locational decisions on the margin, whether and to what extent this translates to altered locational decisions in practice is – like the dispatch efficiency implications of GNP – a matter that cannot be determined analytically. It may be possible to model the impact of GNP on locational decisions, but any such modelling would need to take account of these other important decision variables.

Evidence on the role of nodal prices in generation investment in overseas markets is discussed below in chapter 4.

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[54] AEMC, *Congestion Management Review, Draft Report*, March 2007, pp.76-77.

[55] Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.9.

3.4 ANCILLARY SERVICES

As touched on in section 2.5, there are important complementarities and substitutabilities between energy and some ancillary services such as regulation and reserves. The NEM presently has real-time markets for frequency control ancillary services (FCAS) where FCAS requirements are determined and settlement occurs on a NEM-wide basis. At the same time, NEMDE co-optimises energy and FCAS dispatch to ensure overall least-cost outcomes.

As stated by NEMMCO in its 1999 Ancillary Services Review, the technology required to co-optimise both active and reactive power in a nodal pricing system was at that time not available[56]. In its recently released review of FCAS, NEMMCO repeated this observation, suggesting that the feasibility of co-optimised active and reactive power within a nodal pricing framework was still in question.[57] However, introducing nodal pricing for active power in conjunction with the current contract-based approach to network support and control services may address this problem.

Finally, as discussed in Gregan and Read, it may be possible to allocate types of tailored financial instruments, such as constraint support contracts (CSCs), in ways to promote efficient provision of certain types of ancillary services, such as NCAS.[58] Similarly, such instruments could be used to provide 'gatekeeper' generators with incentives to support interconnector capability.

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[56] NEMMCO, *Ancillary Service Review – Recommendations: Final Report*, October 1999, p.17

[57] NEMMCO, *FCAS Review: Final Report*, July 2007

[58] Gregan and Read (2008), pp.32-33.

4 Review of practical experience of other markets

This chapter reviews published evidence on the practical experience of markets with GNP or FNP. Despite the fact that the primary focus of this paper is the theory and practice of GNP, it is worthwhile to consider experience in FNP markets for a number of reasons.

First, in most cases, the difference between GNP and FNP markets is a matter of degree rather than their fundamental nature. As noted in section 1.2, both are forms of locational marginal pricing (LMP). In particular, all the real-world GNP markets examined in this chapter settle load against load-weighted nodal average prices across one, or several, load 'zones' within the market. This requires nodal prices for all load centres to be calculated, even though they are only indirectly used for settlement purposes. Such load zones also tend to be much smaller than the regions in the current NEM, further attenuating the differences between GNP and FNP compared to the NEM. The Midwest market actually allows participants some input as to whether loads will be settled on the basis of a nodal or zonal price.

Second, the FNP market of PJM provides an important case study because it pioneered the implementation of FTRs. For these reasons, it is the first international market discussed in this section. Other northeast United States markets, such as New York and New England, share many similarities with PJM but commenced later and are thus best discussed against the background of the PJM model.

It is also worth noting that LMP was set out as a key element of the United States Federal Energy Regulatory Commission's (FERC's) standard market design (SMD) proposal in 2002. While this proposal was withdrawn in 2005[59] following "a firestorm of opposition" in the wake of the Californian power crisis,[60] it has influenced recent market reforms in the United States – as discussed below, several US markets that have historically utilised zonal markets for settlement are moving to some form of nodal pricing.

We have also briefly described the experience of the New Zealand FNP market given (i) its status as the first FNP market and (ii) its geographical proximity.

[59] O'Neill, R., U.Helman, B.F.Hobbs and R.Baldick, "Independent System Operators in the USA: History, Lessons Learned, and Prospects", Chapter 14 in Sioshansi, F.P. and W.Pfaffenberger (eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.479-528, p.487.

[60] Joskow, P.L., *Transmission Policy in the United States*, AEI-Brookings Joint Center for Regulatory Studies, October 2004, pp.24-26.

4.1 PJM

4.1.1 Background

The PJM (Pennsylvania-New Jersey-Maryland) electricity market commenced on 1 April 1998. It has evolved and expanded geographically over time and now serves 51 million people across 13 States and the District of Colombia. It contains over 450 participants, an average installed capacity of over 160 GW and peak load of 145 GW (in 2006). The market also includes more than 3000 "busses" (as at 2005) for which locational prices are calculated.

PJM is comprised of a number of separate markets: a Day-Ahead Energy Market, a Real-Time (balancing) Market, an FTR market and separate markets for capacity and different ancillary services (such as regulation and synchronized reserve).[61]

Full details of all of these markets (including the documents referenced in this chapter) are available at: www.pjm.com. This paper only highlights some of the key relevant features of the market.

4.1.2 Energy Markets

As noted above, PJM incorporates two energy markets – a Day-Ahead Energy and a Real-Time (balancing) Market.[62]

The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand-side bids and scheduled bilateral transactions. The Real-Time Market is a spot balancing market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions and are published on the PJM website.

The Day-Ahead Market enables participants such as Load-Serving Entities (LSEs, similar to retailers) and generators to purchase and sell energy at binding day-ahead LMPs by submitting hourly demand or bidding schedules, respectively. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion costs based on the congestion prices (see below) between the transaction injection and withdrawal points. All purchases and sales in the Day-Ahead Market are settled at the day-ahead prices. Finally, FTRs are settled on the basis of the congestion component of day-ahead LMPs.

The Real-Time Market enables those generators and dispatchable loads that were not selected in the day-ahead scheduling process to bid for use. They may rebid between 4pm and 6pm of the day prior to the relevant trading day, but if they do not, their original bids from the Day-Ahead Market remain in effect. Real-time LMPs are used to settle LSEs for demand that exceeds their day-ahead scheduled

61 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, pp.5-6, 10.

62 See PJM, *Manual 11: Scheduling Operations, Section 2: Overview of the PJM Two-Settlement System*, Revision: 32, Effective Date: September 28, 2007, pp.17-18.

quantities and generators are paid the real-time LMPs for output that exceeds day-ahead scheduled quantities.

Market power rules

The PJM energy markets also incorporate a number of rules designed to curb the exercise of market power. One of these is a FERC-mandated $1,000/MWh offer cap.[63] In addition, there are a number of specific 'market power mitigation' rules to prevent the exercise of local market power, particularly when constraints bind. These rules involve direct capping of generators' offers based on cost-based schedules.[64] The test for determining whether a generator had local market power was changed in 2006, with the introduction of the "three pivotal supplier" test. This measure replaced the offer capping of *all* units required to alleviate a constraint to situations where the local market structure was deemed uncompetitive and where specific owners were considered as having structural market power.[65]

Nodal pricing

PJM's LMPs reflect the sum of:

- System Energy Price – this represents the cost of energy, ignoring constraints and losses, and is uniform across all nodes in the market;
- Congestion Price – this represents the cost of congestion in the presence of binding constraints; and
- Loss Price – this represents the cost of marginal losses by location (since June 2007 – prior to that, LMPs in PJM did not reflect the costs of losses).[66]

Therefore, LMPs reflect the full marginal cost of serving an increment of load at each bus. Despite the large number of LMPs that are calculated, PJM uses "hubs" for commercial trading purposes. These hubs are a cross-section of representative buses and their prices are less volatile than for a single node because each hub price is a weighted-average of nodal prices within a given area. The Western hub is the most actively traded location.[67] Section 4.1.6 below discusses the markets performance based on actual PJM price outcomes.

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[63] This cap applies throughout the United States.

[64] PJM, *Manual 11: Scheduling Operations, Section 2: Overview of the PJM Two-Settlement System*, Revision: 32, Effective Date: September 28, 2007, pp.24-25.

[65] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, pp.6-7. Details of the three pivotal supplier test are contained in the *Amended and Restated Operating Agreement of PJM Interconnection LLC*, section 6.4.1 (e)-(f) and are discussed in Appendix J of the 2006 State of the Market Report, pp.411-416.

[66] PJM, *Locational Marginal Pricing, PJM Member Training Development*, presentation, 8 January 2008, pp.7-10.

[67] PJM, *Locational Marginal Pricing, PJM Member Training Development*, presentation, 8 January 2008, p.51.

4.1.3 Risk management – Financial Transmission Rights (FTRs)

Formulation

FTRs in PJM are point-to-point instruments, defined according to their point of receipt (power injection point) and point of delivery (power withdrawal point). They are available for any location for which PJM posts a Day-Ahead Congestion Price. Generally speaking, this may be from and to any:

- Single bus;
- Hub;
- Zone;
- Aggregate;
- Interface bus.[68]

For each hour constraints are binding, the holder of an FTR receives a payment of up to the difference between the sink (point of withdrawal) and source (point of injection) congestion price in the Day-Ahead Market multiplied by the amount of power specified in the FTR. This payment may be either positive (to the holder) or negative (from the holder) depending on which price is higher. The difference in LMPs multiplied by the FTR MW amount is referred to as the FTR "target allocation". Depending on the amount of FTR revenues collected, FTR holders with positively valued FTRs may receive payments between zero and their target allocations. FTR holders with negatively valued FTRs must pay their charges based on their target allocations. Where FTR holders do receive their target allocation, the associated FTRs are referred to as "fully funded".[69] (See below for the performance of FTRs as hedging instruments.)

FTRs in PJM may be obligations or options. An FTR obligation provides a credit (positive or negative), equal to the product of the FTR MW amount and the congestion price difference between the withdrawal and entry points that occurs in the Day-Ahead Market. FTR options, which were introduced in June 2003, only provide positive credits.[70]

Both FTR obligations and options are available for 24-hour (ie effective at all times), on-peak and off-peak periods. Presently, FTRs have terms from one month to one year,[71] although FERC has also granted approval for PJM to

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[68] PJM, *Manual 6: Financial Transmission Rights, Section 1: Financial Transmission Rights Overview*, Revision 10, Effective Date: 1 June 2007, p.9. One caveat is that for the annual FTR auctions (only), FTRs nominating individual load buses are not available (but hubs, aggregates, etc are still valid).

[69] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.308.

[70] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.308; PJM, *FTR Market Frequently Asked Questions*, updated February 1, 2005, p.6.

[71] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.40.

implement longer-term FTRs.[72] We understand that PJM's Long-Term FTR Working Group is currently developing 3-year FTRs and even longer-term ARRs (see below).[73]

The total supply of FTRs is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible (see section 2.4.1 above).[74] PJM conducts simultaneous feasibility tests using a Direct Current (DC) power flow model to ensure simultaneous feasibility and hence revenue adequacy of the requested set of FTRs. Such tests are run for yearly, monthly, and weekly analysis periods, when network resource changes are submitted, as well as during the determination of the winning quotes for the annual FTR auction and the monthly FTR auctions.[75]

Related to FTRs in PJM are Auction Revenue Rights (ARRs). ARRs are rights allocated to firm transmission customers that entitle the holder to receive a share of the revenues from the annual FTR auction. As with FTRs, all ARRs must be simultaneously feasible to ensure they can be supported by the system. [76] To date, ARRs have been allocated annually. However, the PJM Long-Term FTR Working Group has been developing proposals for 10-year ARRs to be allocated to existing and new LSE.[77]

Allocation

FTRs were introduced at the commencement of the market on 1 April 1998. They were initially allocated to incumbent participants who paid regulated transmission charges, in order to enable those parties to hedge the congestion costs associated with serving their native load obligations in the advent of the new LMP-based market. These parties were able to sell their rights but were not obliged to do so. Due to the competitive advantage this gave to incumbents, the rules were changed in June 2001 so that PJM treated all requests for FTRs identically. The revised process allocated FTRs to customers paying regulated transmission charges based on annual peak load share rather than on historic

72 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.311.

73 PJM Issues Tracking: *MRC005: Long-Term FTRs*, viewed at 1 February 2008, http://www.pjm.com/committees/mrc/issue-tracking/mrc005/mrc005.html

74 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, pp.308-309.

75 PJM, *Manual 6: Financial Transmission Rights, Section 1: Financial Transmission Rights Overview*, Revision 10, Effective Date: 1 June 2007, p.48.

76 PJM, *Manual 6: Financial Transmission Rights, Section 1: Financial Transmission Rights Overview*, Revision 10, Effective Date: 1 June 2007, p.48; PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.326 and p.335.

77 PJM Issues Tracking: *MRC005: Long-Term FTRs*, viewed at 1 February 2008, http://www.pjm.com/committees/mrc/issue-tracking/mrc005/mrc005.html.

priority. However, the link between entitlement to FTRs and generation resources owned by the relevant LSE remained intact, deterring competition.[78]

Starting in June 2003, the allocation process was changed again to require that all FTRs were put up for auction in an annual and monthly auction processes administered by PJM. In exchange, transmission customers, as the payers of regulated transmission charges, would receive ARRs, which would entitle them to the auction proceeds of "their" FTRs. These parties could also choose to buy back those FTRs via the auctions through a process called "self-scheduling".[79] It is now the case that when a new control zone is added to PJM, participants are eligible to receive an allocation of FTRs for two years, after which they can only receive ARRs, which they can choose to self-schedule into FTRs if they wish.[80]

There are currently three mechanisms through which FTRs can be obtained:

- Annual FTR Auction – all types of FTRs (obligations, options, 24-hour, peak and off-peak) that are consistent with the total transmission capability for the next planning period are offered at the annual auction and open to all market participants. The annual auction takes place over four rounds, each of which allows for FTRs purchased in earlier rounds to be offered for sale in later rounds. Holders of ARRs who wish to acquire FTRs are guaranteed to receive their requested FTRs;[81]
- Monthly Balance of Planning Period FTR Auctions –these auctions make available the residual FTR capability on the transmission system after the Annual FTR Auction and allow market participants to offer for sale any FTRs they currently hold. Market participants can bid for or offer: (1) monthly FTRs for any of the next three months remaining in the planning period, or (2) quarterly FTRs for any of the quarters remaining in the planning period. FTRs bought or sold in these auctions can be obligations or options and for 24-hour, on-peak or off-peak periods;[82]
- Secondary market – this is a bilateral trading system that facilitates the trading of existing FTRs between market participants through an internet

[78] Kristiansen (2004), pp.42-43.

[79] Joskow, P.L., *Transmission Policy in the United States*, AEI-Brookings Joint Center for Regulatory Studies, October 2004, pp.28-32, especially pp.29-30.

[80] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.311 and p.327; PJM, *FTR Market Frequently Asked Questions*, updated February 1, 2005, p.1.

[81] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, pp.309-310.

[82] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.310.

application.[83] Participants are also free to trade FTRs amongst themselves without PJM involvement.[84]

4.1.4 Capacity Market

Although it has limited direct relevance to the use of FNP in PJM, or the role of FTRs, it is worth briefly outlining the PJM capacity arrangements. These arrangements are designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. Therefore, new generation investment in PJM is not intended to be driven solely or even principally by pricing signals emanating from the FNP energy market.

The previous Capacity Market arrangements were replaced by the new Reliability Pricing Model (RPM) in June 2007. Under the RPM, it is mandatory for LSEs to participate in either the RPM or else elect to apply Fixed Resource Requirements (ie self-supply). Under the RPM, each LSE serving load within PJM must pay a locational reliability charge based on their specified capacity obligation.[85] The RPM is intended to address a number of concerns about the previous Capacity Market, including:

- Lack of locational element to capacity pricing incentives – the RPM provides locational capacity prices combined with market power mitigation rules;
- Capacity price volatility due to a vertical demand curve for capacity – the RPM provides a more graduated demand curve for capacity to reduce price volatility;
- Short-term commitment of capacity resources – the RPM incorporates a longer-term procurement auction.[86]

In this sense, the design capacity arrangements could be regarded as moving closer to the design of the PJM energy markets.

4.1.5 Ancillary services markets

PJM currently provides several ancillary services through market-based mechanisms: regulation, energy imbalance and synchronized (formerly 'spinning') reserve.[87] Energy imbalance is provided through the Real-Time Market while the Regulation and Synchronized Reserve Markets are cleared simultaneously and co-optimised with the Energy Market to minimise the overall cost of supply.[88] Other

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[83] PJM, *Manual 6: Financial Transmission Rights, Section 1: Financial Transmission Rights Overview*, Revision 10, Effective Date: 1 June 2007, p.10.

[84] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, p.311.

[85] PJM, *Manual 18: PJM Capacity Market*, Revision: 0, Effective Date: 1 June 2007, pp.4-6.

[86] See Sener, A.C. and S. Kimball, "Reviewing Progress in PJM's Capacity Market Structure via the New Reliability Pricing Model", *Electricity Journal*, December 2007, Vol.20, Issue 10, pp.40-53, p.41; PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.30.

[87] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.30.

[88] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.31.

ancillary services, such as reactive power, are provided through member requirements and scheduling and remunerated on a regulated cost basis.[89]

4.1.6 Market performance

Energy markets

While we are not aware of specific analysis of the dispatch efficiency implications of FNP in PJM, the Synapse Energy Economics report cited above did make a number of observations about the implementation of FNP in PJM. Synapse noted that in a number of respects, locational prices in PJM arose from an imprecise application of optimisation theory. This imprecision was derived from several differences between theory and application:[90]

- Reliance on bid-based dispatch rather than actual generator costs – allowing scope for the exercise of market power;
- Use of "state estimators" to approximate power system conditions such as voltages, power flows and generation and load levels, which may incorporate errors in system representation that would flow through to dispatch and pricing outcomes;
- Other factors such as generation ramp-rates and minimum run times, variability of transmission line limitations and operator discretion in dispatch decisions.

Synapse appropriately noted that it was not clear whether such imprecision was any better or worse than the imprecision that accompanies pricing in non-LMP markets – after all, system operators in all systems have to deal with many of these issues. Synapse's key point was that the reality of FNP meant that the resultant price signals can be subjective and unreliable, and may be perceived to be arbitrary and subject to change.[91] However, the Synapse report did not refer to any evidence confirming such perceptions.

With respect to price outcomes, the average hourly LMP across PJM as a whole rose from $21.72 in calendar year 1998 to a peak of $58.08/MWh in 2005 before falling to $49.27/MWh in 2006.[92] The highest prices have recently tended to occur in the summer months and during early evenings. Synapse reported that market prices in PJM for the 5-year period post-inception were lower (on average) than those expected under the regulated system pre-1999 restructuring.[93]

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[89] PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.30.

[90] Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.16.

[91] Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.16.

[92] PJM, *Locational Marginal Pricing, PJM Member Training Development*, presentation, 8 January 2008, pp.57-59.

[93] Synapse Energy Economics Inc, *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs*, prepared for: PJM Interconnection, L.L.C., June 2004, p. 32.

In general, prices in PJM are higher in eastern zones than in western zones. This is primarily the result of congestion at three key points: the Bedington-Black Oak Interface, the Kammer and Wylie Ridge Transformers and the 5004/5005 Interface.[94]

The costs of congestion (measured as the difference in LMP-based dispatch costs between the actual system and an unconstrained system) in PJM have risen dramatically in recent years, but have remained a fairly constant proportion of PJM turnover. Congestion costs rose from $453 million in 2002 to $2,092 million in 2005 before falling to $1,603 million in 2006, all the while remaining between 7 to 10% of PJM billings.[95] The Bedington-Black Oak Interface, mentioned above, was the largest single contributor to the costs of congestion in 2005 and 2006, accounting for 31% of total congestion costs in 2006 ($492 million). The top four constraints together accounted for nearly half total PJM congestion costs in 2006.[96]

Moving beyond the role of FNP, there has been significant debate about the benefits of PJM more generally compared with the previous arrangements. Some have criticised the implementation of PJM and similar markets on the basis of higher costs and prices (in part due to the exercise of market power), lack of investment in transmission infrastructure and failing retail competition.[97] Others have responded with studies showing prices in PJM are lower than would be otherwise.[98] It is not intended in this report to tackle these broader questions on the success or otherwise of large-scale reform programs.

Market power

As noted above, PJM incorporates extensive rules directed at mitigating the exercise of market power in its various markets. In the year immediately following market restructuring, some commentators suggested that competition in the PJM had been adversely affected[99]. However, the PJM Market Monitoring Unit (MMU) was satisfied that energy markets have operated competitively since 1999.[100] The MMU also concluded that all market outcomes in 2006 were competitive, except for the regulation market, which could not be determined to

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94 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 7 – Congestion*, March 8, 2007, p.274. See also Appendix A for a map of PJM control zones.

95 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.36.

96 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, pp.39-40.

97 See, for example, Blumsack, S.A., J.Apt and L.B. Lave, "Lessons from the Failure of US Electricity Restructuring", *Electricity Journal*, March 2006, Vol.19, Issue 2, pp.15-32; Moody D.C., "Ten years of experience with deregulating US power markets", *Utilities Policy* 12 (2004) pp.127-137.

98 See, for example, Krapels. E.N. and P. Flemming of Energy Security Analysis, Inc, *Impacts of the PJM RTO Expansion, A Report Prepared for PJM*, November 2005.

99 Mansur, E. (2007). Upstream Competition and Vertical Integration in Electricity Markets, *Journal of Law and Economics*, 50(1), pp125-156.

100 PJM Market Monitoring Unit, *State of the Market Reports (2000-2006).*

be either competitive or non-competitive.[101] In the energy market, the MMU found that LMPs exhibited low mark-ups over marginal costs by marginal plant, despite moderate to high levels of supplier concentration.[102]

That said, the MMU found "serious" market *structure* issues in the Capacity Market and went so far to say that "Market power is endemic to the existing structure of the PJM Capacity Market", but at the same time found no *exercise* of market power in that market.[103] This strong language may have been partly motivated by PJM's desire to promote the new RPM capacity market alluded to above.

Risk management instruments – FTRs and ARRs

The most recent PJM State of the Market Report for 2006 noted that the FTR market is competitive.[104] Kristiansen had previously noted that FTR buying bids, volume and revenue had increased up to 2002 as congestion increased. He observed that the FTR bid volume typically exceeded the offer volume by 10 times in 2002.[105] This trend has continued, with only 10.5% of demand being met at the annual FTR auction and only 6% of demand being met during the monthly FTR auctions from June to December 2006 (inclusive).[106]

PJM also reported that while the ownership concentration of FTR obligations was relatively low, it was high for FTR options.[107]

The prices of auctioned FTRs have been relatively low: weighted-average prices for "buy-bid"[108] FTR obligations and options in the 2006 annual auction were $1.12/MWh and $0.29/MWh, respectively. 24-hour buy-bid FTRs attracted a higher price ($1.95/MWh) than both peak and off-peak FTRs (both $0.78/MWh). Prices were even lower in the subsequent monthly auctions.[109]

Importantly, PJM also reported the revenue adequacy or "firmness" of FTRs. Revenue adequacy refers to the extent to which FTRs hedge congestion costs on the specific paths for which FTRs are held, and is reported as a percentage of the FTR target allocations (see section 4.1.3 above). On this criterion, FTRs were paid at 91% of target allocation in 2005-06 and at 100% for the first seven

101 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.6.

102 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.11.

103 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, pp.29-30.

104 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.6.

105 Kristiansen (2004), p.46.

106 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.41; PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, pp.312-313.

107 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.41.

108 Those FTRs with a positive price.

109 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.41.

months of 2006-07.[110] To the extent payments to FTR holders cannot be fully funded, they are reduced proportionately – in other words, the value of the FTRs is not underwritten by the independent system operator (ISO) or by network customers.

Investment and retirement decisions

Generation

The 2006 State of the Market report emphasised the importance of attracting efficient new plant entry as a litmus test for the success of the market arrangements:

> The ultimate test of a competitive market design is whether it provides incentives to invest that are acted upon by market participants, based on incentives endogenous to the competitive market design and not in reliance on the potential or actual exercise of market power. The net revenue performance of the Balancing [ie Real-time] Energy Market over the last eight years and the Day-Ahead Energy Market over the last seven years illustrates that additional market modifications are necessary if PJM is to pass that test. A combination of the RPM design and enhancements of scarcity pricing are two such modifications.[111]

PJM noted that net revenues to generators have generally been below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types since market start. This shortfall was attributed to the application of reliability standards, meaning that scarcity conditions in the energy market occur with low frequency. The introduction of the new RPM capacity arrangements was intended to provide more sustained and localised signals for new generation investment,[112] as well as to enable transmission and demand-side responses to compete with generation to provide capacity resources.[113]

The Synapse report cited above found that there was "no clearly discernible causal link" between recent generation investments in PJM and the presence of LMP.[114] Synapse reviewed actual and proposed generation investments, as well as plant retirements, between 1999 and 2006 and compared these to the LMP indications of where new generation was most needed in the system. Synapse did this by grouping the zones that had been part of PJM for a reasonable amount of time into tiers reflecting relative 2005 average price levels. Although the identity of zones within the tiers was somewhat contingent on the year selected (2004 yielded significantly different absolute prices and a slightly different tier allocation

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110 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.42; PJM Market Monitoring Unit, *2006 State of the Market Report, Volume II: Detailed Analysis, Section 8 – Financial Transmission and Auction Revenue Rights*, March 8, 2007, pp.323-324.

111 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.20.

112 PJM Market Monitoring Unit, *2006 State of the Market Report, Volume I: Introduction*, March 8, 2007, p.19.

113 PJM, *2006 Annual Report*, p.16.

114 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.xiii.

than 2005), there was a general trend of higher prices in the east than the west (by about $5/MWh during peak times and $2/MWh at off-peak times),[115] consistent with recent outcomes published by PJM (see above). Despite this, new generation investment was approximately evenly divided between the western and eastern regions of PJM. Synapse stated:

> There is no evidence in these data that higher prices attract more generation investment; to the contrary, most of the new megawatts have been concentrated in the lowest-priced two tiers. A more reasonable interpretation of the data is that projects have been concentrated in areas where there is abundant access to fuel, land and labor are available, and local opposition is not prohibitive.[116]

Synapse did note some limitations to their analysis, including that the lumpiness of generation meant that a single project could dominate the overall investment picture for a given year and that much of the new investment was planned, constructed and commissioned prior to the recent increase in average prices. However, Synapse suggested that the former problem was inherent to all generation investment in an LMP market and that the latter fact indicated that investors did not foresee the subsequent dramatic increase in prices that did occur.[117]

A further key limitation of the Synapse analysis is that it did not actively seek to compare LMP investment outcomes with a counter-factual of a non-LMP approach other than by asserting that the results may have been no different. This is always the difficulty with uncontrolled empirical studies. However, at the least, the report shows that actual investment outcomes are consistent with the notion that matters other than prices do affect locational decisions.

Synapse also considered the location of recently-proposed new generators in the PJM "queue" that were either being constructed or were under active consideration. It found that two-thirds of generation in both these categories was located in the lower-priced western or southern parts of PJM.[118] In Synapse's view, it was this lack of locational investment response that led to the advent of the RPM, which (as noted above) effectively implements a locational capacity market. However, Synapse had prepared a separate study for the Pennsylvania Office of Consumer Advocate that estimated the transfers from consumers to owners of base load generation as a result of this scheme would be over $5 billion per annum,[119] based on peak load projections for 2012. We have not

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115 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, pp.20-21.

116 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.25.

117 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, pp.25-26.

118 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, pp.30-31.

119 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, pp.31-32. Report cited as: Hausman, E. et al, *RPM 2006: Windfall Profits for Existing Base Load Units in PJM – An Update of Two Case Studies*, Prepared for Pennsylvania Office of Consumer Advocate, February 2006.

reviewed this report, although a recent paper by Sener and Kimball agrees that the new arrangements may provide windfalls to existing baseload generators.[120] That said, early indications are that the RPM is providing reasonable price signals for investors, even if it is too soon to tell whether it will provide appropriate levels and certainty of remuneration.

As well as examining new generation investment, Synapse considered the volume and location of existing plant retirements. It found that the vast majority of plant retirements in recent years occurred in the highest-priced regions of PJM, dominated by over 440 MW of retirements in the eastern PSEG zone.[121] An analysis of the overall net cumulative change in capacity (investment less retirements) by price tier from 1999 to 2006 showed that the highest tier had a very small increase in capacity up to 2002, but almost no net increase since then.[122]

That said, the same observations we made above in relation to the lack of a counter-factual would also apply to Synapse's analysis of proposed new capacity and plant retirements.

Transmission

In 2004, Paul Joskow noted that PJM had been reluctant to commission new transmission investment beyond what was required to meet generator connection or 'reliability' requirements. He also noted that the expectation that 'economic' investments would be made on a merchant basis had not come to fruition at that time.[123]

Subsequently, PJM has increased its focus on investments beyond generator connection and reliability requirements, as evidenced by the first regional transmission plan.[124] As part of the plan, PJM authorised the development of $1.3 billion in upgrades to maintain grid reliability until 2011, which is expected to reduce congestion costs by $200-300 million per annum. In addition, a 240 mile 500 kV line was approved from southwest Pennsylvania to northern Virginia. PJM has also directed additional studies and evaluation of ten significant grid investment proposals worth $10 billion for the period up to 2021, many of which seek to serve the relatively congested eastern half of the market.

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120 Sener, A.C. and S. Kimball, "Reviewing Progress in PJM's Capacity Market Structure via the New Reliability Pricing Model", *Electricity Journal*, December 2007, Vol.20, Issue 10, pp.40-53, p.50 and pp.52-53.

121 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.28.

122 Synapse Energy Economics Inc, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers*, Prepared for American Public Power Association, February 5, 2006, p.30.

123 Joskow, P.L., *Transmission Policy in the United States*, AEI-Brookings Joint Center for Regulatory Studies, October 2004, pp.28-32, especially pp.36-37.

124 PJM, *2006 Annual Report*, p.15.

4.1.7 Lessons for the NEM debate

Several important caveats apply is using the PJM experience to inform future policy formulation in the NEM. First, PJM is a FNP rather than GNP market. Second, PJM has both organised capacity markets and specific market power mitigation measures in place, neither of which are being considered in the current debate surrounding the appropriate approach to congestion management in the NEM. As noted in section 5.5 below, these differences mean that it is not possible to draw inferences about the likely exercise (or non-exercise) of transient market power in the NEM under GNP based on experience in PJM and similar markets.

Nevertheless, several key lessons can be drawn from the PJM experience. First, evidence presented by Synapse suggests that factors other than LMP signals in the energy market affect locational investment decisions. Again, as noted in section 5.5, this should perhaps not be surprising given the important role of the capacity market in PJM in stimulating investment and the fact that until recently, the capacity market has not offered locational pricing signals. Second, merchant-driven transmission investment, based on LMP differences, has not been substantial to date. This suggests that ongoing regulation of transmission investment is likely to be unavoidable, even in a FNP market.

4.2 NEW YORK

4.2.1 Background

The current New York market commenced in November 1999. The New York Control Area (NYCA), which comprises New York State, is administered by the NYISO, a not-for-profit organisation. All electricity that passes through the NYCA grid must be scheduled through the NYISO market. The NYISO facilitates and administers markets for installed capacity, energy, ancillary services and Transmission Congestion Contracts (TCCs, similar to PJM's FTRs). Full details of all of these markets (including the official documents referenced below) are available at: www.nyiso.com. This paper only highlights some of the key relevant features of the market.

4.2.2 Energy Markets

Similar to PJM, the NYISO energy market consists of a Day-Ahead Market and a Real-Time Market. Generators and parties to bilateral agreements may submit offers in both markets but loads may only submit bids in the Day-Ahead Market.

In both the Day-Ahead Market and the Real-Time Market, locational-based marginal prices (LBMPs, similar to LMPs) are produced in respect of each hour of the relevant day. LBMPs are published for a representative bus and data on the marginal cost of losses and congestion are published for each generator bus, zone (of which there are 11) and hub. Generators selling into the energy market are paid their LBMP, while loads buying in the markets are charged a zonal price based on a load-weighted average of LBMPs in their zone.[125] Congestion can lead to a divergence between zonal prices, the prices at generation buses and between the NYCA and the neighbouring control areas – Ontario, PJM, New England and Quebec – for which hourly boundary prices are also calculated.[126] Thus, the New York market reflects GNP plus zonal pricing for loads.

Parties to a bilateral contract may elect to bid a transaction as a firm point-to-point transaction, in which case they agree to pay congestion charges to secure delivery of the requested energy. Alternatively, they can enter a non-firm point-to-point transaction in which case they indicate a willingness to accept the scheduled delivery of power only if there is no congestion.[127]

In general, day-ahead and real-time LBMPs should not systematically diverge due to the ability of participants to arbitrage. However, real-time and supplemental commitment of plant to maintain reliability of supply (as distinct from being a response to price signals) can lead to a reduction in real-time prices compared with day-ahead prices at the expense of higher uplift costs.[128] Alternatively, forced outages can lead to higher real-time prices than day-ahead prices.

Market power rules

The NYISO energy markets also incorporate a number of rules designed to curb the exercise of market power. One of these is a FERC-mandated $1,000/MWh offer cap. Further, as in PJM, market power mitigation rules apply in an effort to prevent the exercise of local market power. The NYISO applies a conduct-impact test that can result in 'mitigation' of (ie direct adjustment to) participants' bid parameters if the bid exceeds certain thresholds and if the bid would have a significant effect on the energy price. As in PJM, the approach to mitigation has been refined, in New York's case, since May 2004. Prior to that, mitigation was implemented in New York City to adjust unit offers right down to variable operating costs whenever the market software detected material congestion between Indian Point and New York City. The new approach applies the same framework used elsewhere in the State.[129] The latest Monthly Report (from November 2007) shows that the proportion of hours in which market mitigation was effected in the New York City load zone decreased from about 15-20% in 2006 to less than 5% in 2007, most likely due to new generation investment in the City zone.[130]

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125 See NYISO, *Market Participants User's Guide, Guide 1*, March 2007, p.3-17; Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.24.

126 See for example, NYISO, *Monthly Report November 2007*. Zone names are set out on p.4-AG.

127 NYISO, *Market Participants User's Guide, Guide 1*, March 2007, p.2-3.

128 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.xi-xiv

129 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.49-53.

130 NYISO, *Monthly Report November 2007*, p.4-AD.

4.2.3 Risk management – Transmission Congestion Contracts (TCCs)

Formulation

The NYISO offers TCCs to assist participants in hedging the basis risk resulting from congestion. A TCC represents the right to collect, but the obligation to pay, the Day-Ahead Market congestion rents associated with 1 MW of transmission between a specified point of injection and a specified point of withdrawal (zone, substation or generator bus).[131] Given the eleven congestion zones, the four neighbouring control areas and hundreds of other buses for which NYISO calculates LBMPs, Siddiqui estimated that there were approximately 120,000 potential permutations of points of injection and withdrawal,[132] although this diversity is mitigated by the default "unbundling" of TCCs (see below).

The Day-Ahead Market congestion rents are determined by the difference in the congestion component of the Day-Ahead Market LBMPs at the points of injection and withdrawal for each hour of the effective period. Payments to holders of TCCs are funded through congestion rents collected in the Day-Ahead Market when the congestion components of LBMPs differ between locations.[133] To the extent that actual congestion rents are insufficient to fully-fund TCCs (ie to ensure TCCs are fully financially firm), the shortfall is charged to transmission owners and passed through to final customers through service charges – thus, non-firmness is "socialised".[134] Such shortfalls may arise where transmission outages occur that were not modelled in the TCC auction. Transmission customers are also required to fund, through an uplift, shortfalls in congestion revenues arising due to actual flows in real-time exceeding the flows modelled in the Day-Ahead Market.[135]

The number and type of TCCs that the NYISO can award to market participants is restricted by the physical configuration of the transmission system. The NYISO uses security-constrained power flows that correspond to the set of TCCs and grandfathered rights (see below) that have been awarded to ensure that the allocated TCCs do not violate any security constraints.[136] However, since there are many feasible combinations of injections and withdrawals that do not violate any security constraints, there are many feasible sets of TCCs and grandfathered rights. The NYISO uses an auction process to determine which set of TCCs the NYISO will award.[137]

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131 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.2-1.

132 Siddiqui, A., E. Bartholomew, C. Marnay and S. Oren, *Efficiency of the New York Independent System Operator Market for Transmission Congestion Contracts*, Managerial Finance, Volume 31, Number 6, 2005, pp.1-45 (Siddiqui et al), p.6.

133 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.2-1.

134 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.66-67.

135 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.68-70.

136 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.3-1.

137 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.2-1.

Another feature of TCCs is that NYISO automatically "unbundles" TCCs awarded through an auction unless the holder notifies NYISO otherwise. Unbundling addresses the diversity of TCCs that can emerge by separating a 'bundled' TCC into standard components, each of which are a single TCC. As part of this process, the NYISO reference bus is treated as either a point of injection or withdrawal. Thus, the standard components of a TCC are:

- Point of injection to the Zone containing that point;
- Point of injection Zone to the Zone containing the point of withdrawal; and
- Point of withdrawal Zone to the point of withdrawal.

These standard components are less diverse than the original TCCs, and are intended to improve the tradability and liquidity of the TCC market.[138]

Allocation

Prior to the implementation of the New York market, a number of TCCs and grandfathered rights were assigned to recipients of services under the then-existing transmission agreements. These rights had the duration of the original rights and could be bought and sold equivalently with new TCCs created by the NYISO in multi-part auctions.[139]

The NYISO conducts two types of auctions for TCCs:[140]

- Capability Period Auctions; and
- Reconfiguration Auctions.

Capability Period Auctions occur six-monthly and take place in two stages, with multiple rounds in each stage. Participants who successfully acquired TCCs in one round can resell them in subsequent rounds or the second stage. The NYISO is required to consult with participants to determine the "class" or duration of TCCs that are auctioned and seeks to achieve consensus regarding the products offered for sale.[141] In the past, Siddiqui notes that the TCCs available in initial auctions have varied from 6 months to 5 years.[142]

Reconfiguration Auctions occur monthly and allow the initial TCC holders to sell TCCs for the following month through a single-round auction.

For each round of an auction, the NYISO runs a security-constrained power flow to determine the simultaneous feasibility of the TCCs to be awarded. As part of this, the power flow model treats all grandfathered rights and TCCs that have not been offered for sale in the auction as given injections and withdrawals.[143] In the auction, participants specify the maximum amount they are

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138 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, pp.3-14-3-16.

139 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.2-1.

140 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, pp.3-1-3-2.

141 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.3-3.

142 Siddiqui et al (2005), p.7.

143 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.3-1, p.3-3, pp.3-17-3-18.

willing to pay for TCCs and sellers specify the minimum amounts they are willing to accept for the TCCs offered for sale. The objective of the auction is to maximise the bid minus offer value of the TCCs awarded, subject to the constraint that the set of all outstanding TCCs and grandfathered rights must correspond to a simultaneously feasible security-constrained power flow in each time period.[144]

Participants are also free to trade TCCs in the secondary market on agreed terms and conditions. The secondary market allows greater flexibility for participants to tailor TCCs to suit individual transactions or exposures. The secondary market is not regulated by the NYISO and operates bilaterally.[145]

4.2.4 Capacity Market

The Capacity Market is designed to ensure that sufficient capacity is available to reliably meet New York's electricity demands. This market provides signals that supplement those provided by the NYISO's energy and operating reserves markets.[146]

The New York Installed Capacity (ICAP) market is based on the obligation placed on LSEs to procure ICAP to meet minimum requirements. The requirements are determined by each LSE by forecasting the contribution to its transmission district peak load, plus an additional amount to cover the Installed Reserve Margin.[147]

Since 2001, the amount of capacity that each supplying resource is qualified to provide to the NYCA is determined by an Unforced Capacity (UCAP) methodology rather than Installed Capacity. UCAP is a measure of resource availability adjusted to reflect forced outages.[148] The New York Reliability Council recommended certain installed capacity margins for the NYISO in order to achieve the one-day-in-ten-years outage standard. Since these recommendations are stipulated in the terms of ICAP, the NYISO uses a control area-wide forced outage rate to convert this recommendation into UCAP terms. LSEs can meet their capacity obligations by self-scheduling, bilateral purchasing or through one of the NYISO's forward procurement auctions. Any remaining obligations are settled against the NYISO's monthly spot auction where clearing prices are determined by a capacity demand curve. Currently, the capacity auctions have three distinct locations within New York: New York City, Long Island and Rest-of-State.[149] The capacity auction clearing prices in New York City and Long Island are generally much higher than those in the Rest-of-State.

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144 NYISO, *Manual 3 – Transmission Congestion Contracts Manual*, May 31 2007, p.3-1.

145 Siddiqui et al (2005), pp.7-8.

146 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.xvi-xvii.

147 See: http://www.nyiso.com/public/products/icap/index.jsp

148 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.105-106.

149 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.xvi.

It should also be noted that much of the capacity in New York City is subject to market power mitigation measures, consisting largely of caps on the revenues that the generators' owners can earn from the capacity market and a requirement to offer the capacity into the market at a price no higher than the cap.[150]

4.2.5 Ancillary Services Market

The NYISO operates day-ahead and real-time markets for operating reserves and regulation. In addition to satisfying the operating reserve requirements in real time and setting prices for those services, these markets play an important role in the shortage pricing that occurs in the energy market. When there is a shortage of reserve requirements, the economic value of the reserve sets the reserve price and is reflected as part of the energy price. Similarly, because the ancillary services markets are co-optimised with the energy markets, the clearing prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.[151]

4.2.6 Market performance

Energy markets

Adjusting for a dramatic surge in the price of fuel in 2000, energy prices in the year after market inception averaged close to 1999 levels.[152] This first year also saw frequent price corrections by the NYISO due mainly to pricing inputs and market data being either incorrect or incomplete.[153] More recently, average Day-Ahead Energy Market prices in 2006 decreased by 20 to 30% in most parts of New York. This was primarily due to lower natural gas prices, which fell by more than 25% over the same period.[154] Lower load levels in 2006 also made a contribution to lower prices, but played a smaller role than falling fuel prices.[155]

Average prices in the eastern region of New York were $22/MWh higher than in the western New York region ($77/MWh compared with $55/MWh). This was in part due to about 1000 MW of new generation being commissioned in New York City in 2006, which helped to reduce both prices and constraints into the city.[156] The primary transmission constraints in New York occur at four locations: the central-east interface that separates eastern and western New York; the transmission paths between the Capital region and the Hudson Valley; the transmission interfaces into New York City; and the interfaces into Long

150 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.109.

151 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.xv.

152 Capital Economics, *2000 New York Market Advisor Annual Report on the New York Electric Markets*, April 2000, p.iii.

153 FERC, *Investigation of Bulk Power Markets: Northeast Region*, November 2000, p.29.

154 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.vii and pp.1-2.

155 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.vii.

156 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.vii and pp.1-2.

Island.[157] The constraints into and within New York City meant that average prices were 14% higher in the City than in the eastern upstate region. Eastern upstate prices were 23% higher than west region prices, although much of this difference can be attributed to transmission losses.[158]

Total congestion costs (based on LBMP differences) decreased by more than $200 million in 2006 to $770 million as compared with $990 million in 2005. This was largely due to lower gas prices and the 1000 MW of extra capacity commissioned in New York City.[159]

Market power

Apart from some "teething" problems in 2000 (consisting mainly of isolated cases of non-competitive bidding) the NYISO has operated competitively since inception, with no systematic evidence of market power abuse.[160] The latest State of the Market Report comments that the New York energy and ancillary services markets generally performed well in 2006, with no evidence of significant market power abuse or manipulation by participants.[161] Consultants, Potomac Economics, examined 30 hours in 2006 when shortages occurred, sending real-time prices up close to $1,000/MWh. They did not find evidence of any significant withholding of generating resources. Rather, the shortages generally resulted from periods of very high demand during hot summer weather or during thunderstorms, when transmission capability was reduced. They found that in certain constrained areas, mostly in New York City, some suppliers had local market power. However, in these cases the ability of suppliers to exercise power was limited by the market power mitigation measures in the energy and capacity markets, as described above.[162]

Risk management instruments – TCCs

The 2006 State of the Market report found that congestion revenues generated in the Day-Ahead Market were substantially lower than payments to TCC holders until 2004, leading to the socialisation of the shortfall across transmission customers. This shortfall occurred because the transmission capability assumed in the TCC auctions generally exceeded the capability modelled in the Day-Ahead Market. Whilst this was corrected in 2004, shortages re-emerged in 2006 as a result of transmission and generation outages that were either forced or were not planned until after the seasonal TCC auctions.[163]

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157 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.x.

158 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.x.

159 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.x.

160 Capital Economics, *2000 New York Market Advisor Annual Report on the New York Electric Markets*, April 2000, p.iii.

161 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.iii and pp.43-53.

162 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.v.

163 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.67-68.

The State of the Market report also found that west-to-east TCCs were generally under-valued, while TCCs with withdrawal points in New York City were generally over-valued. According to the authors of the report, Potomac Economics, this was probably because participants did not expect congestion to decrease as sharply as it did when new generation entered the market in 2006.[164]

The only empirical analysis of TCCs in the New York market of which we are aware was undertaken by Siddiqui et al using data from 2000 and 2001. Care must be taken when interpreting this work because the paper was focussed on a relatively short time period, relatively soon after the restructuring of the New York market. Nevertheless, it is worth noting that Siddiqui et al found that participants in New York typically 'over-pay' for TCCs.[165]

The conclusion states:

> In order to examine the performance of a system employing the [point-to-point] approach, we empirically analyse the NYISO TCC market, using publicly available data from 2000 and 2001 on TCC prices paid and congestion rents collected by market participants. We find that by some simple measures the market performs well. For example, buyers of TCCs predict congestion correctly most of the time. However, the TCC market appears to be a weaker hedge for complex transactions, i.e., those involving larger exposures roughly of greater than $1/MWh or across multiple congestion interfaces. Particularly, we obtain a robust result that prices and revenues are consistently biased in one direction, with TCC buyers paying prices for expensive TCCs far in excess of what this model predicts. Furthermore, cumulative analysis of the entire two-year data set indicates no evidence of market participants learning how to use the instrument more efficiently over time.[166]

The authors came to the conclusion on multiple transmission interfaces by developing a geographical indicator (GI) for each TCC by determining the zones in which the point of injection (PoI) and point of withdrawal (PoW) for the TCC were located. The GI represented the number of zonal interfaces between the pair of points. The authors also developed a predictive power index (PPI) by calculating the absolute difference between the net congestion rental for a TCC and the price paid for the TCC. The higher the PPI, the less accurate the ability of the buyer of a TCC between a given PoI and PoW to predict the value of congestion. They found that the PPI increased (often superlinearly) with the GI. They thus concluded that the market for TCCs is not efficient across multiple congestion interfaces.[167]

The authors discussed some reasons for why TCC trading across multiple interfaces might not be efficient:

> The NYISO TCC market's PTP system is based on forward trading of thousands of different POI/POW permutations. Therefore, trading is thinner and

[164] Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.xi.

[165] Siddiqui et al (2005), pp.20 and 27.

[166] Siddiqui et al (2005), p.27.

[167] Siddiqui et al (2005), p.26.

> opportunities for efficient price discovery weak. Further, TCCs are defined in a rigid way, i.e., a fixed capacity over a fixed period, with high transactions costs involved in disaggregating them in the secondary market. This makes TCC trading more difficult for market participants. Alternatively, in more compact markets, risk management is more straightforward because the forward positions required to hedge against a given spot market exposure are immediate. Moreover, because TCC prices are based on an artificial congestion pattern verified as feasible but not necessarily likely at the time of the auction, actual congestion patterns will differ leaving TCCs mispriced. Since actual PTP transfer capability depends on the actual power flows, or at least those seen in day-ahead trading, secondary trading of TCCs is limited, resulting in illiquidity. This attribute makes it difficult to hedge using PTP instruments such as NYISO TCCs without ex ante knowledge of transmission congestion. Such obfuscation is the likely cause of the poor performance of NYISO TCC markets… [168]

In short, there appear to have been three key reasons why participants ended up over-paying for TCCs across multiple zones or for larger price exposures:

- High transactions costs arising from:
  - The lack of liquidity for many longer-distance PoI/PoW combinations – making efficient price discovery more difficult;
  - Disaggregating down TCCs sold in the auctions for the secondary market; and
- The execution risk associated with actual electricity flows and congestion varying from those expected in the TCC auctions upon which TCC prices are determined.

The finding in Siddiqui et al suggests that long distance basis risk management through the use of TCCs may be very difficult or expensive. However, it is not clear if the financial risks and costs of 'long distance' trading are mainly due to the need to trade across 'multiple congestion interfaces' or due to the long-distance nature of the transactions. The riskiness of an inter-zonal contract position may be derived from the physical and financial firmness of the relevant interconnectors, not the number of interconnectors across zones *per se*. However, it is not clear if TCCs would have been more useful if the number of interfaces between a given pair of points (nodes) were reduced. In other words, the inefficiency of TCCs for hedging contracts over long distances may have more to do with the capacity of the relevant transmission links between two points, and generator bidding and output patterns, than the sheer number of zonal interfaces between the two points.

Either way, these findings can be contrasted with IRSR units in the NEM, which have generally been auctioned at prices below their outturn values.[169]

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[168] Siddiqui et al (2005), pp.26-27.

[169] See AEMC, *Congestion Management Review Directions Paper*, 12 March 2007, pp.24-25.

Investment decisions

Significant generation investment has occurred in recent years in the NYCA. Between January 2002 and June 2003, 316MW of capacity was added, while in the Central Zone (located in the central-west of New York State) approximately 1,600 MW of new capacity was installed in 2004 and 2005 reflecting the commissioning of the Athens and Bethlehem plants.[170] Further, as noted above, approximately 1,000 MW of new capacity was installed in the New York City area in 2006, about half of this in January and the other half in May.[171]

Potomac Economics undertook an analysis of the long-term economic signals produced by the NYISO markets as part of the 2006 State of the Market Report. This involved analysing the combined net revenues from the energy, ancillary services and capacity markets that would have been received by various types of plant at six different locations.[172] The analysis showed that although net revenues in 2006 could support new plant in certain locations, there was considerable uncertainty about the revenue that would be earned over the life of the investment. For example, the 1000 MW investment in the Astoria East load pocket of New York City in 2006 caused net revenues to fall by 31%.

A recent reliability needs assessment revealed that new capacity was required in the lower Hudson Valley but had not been forthcoming to date because this area was classified as part of the "rest of state" installed capacity zone and thus did not receive its own capacity price signal.[173]

The State of the Market Report also noted that the new Neptune Line was scheduled to come into service in 2007, which would increase import capability into Long Island from New Jersey by 660 MW.[174]

On the basis of this limited information, it is difficult to determine whether the use of LMPs for generation settlement in New York materially influenced investment timing and location.

4.2.7 Lessons for the NEM debate

As was the case with PJM, the presence of both capacity markets and explicit market power mitigation measures must be noted as important caveats when drawing on the NYISO's reform experience for the NEM. However, putting these to one side, New York's experience in congestion risk management (in particular the importance of accurate and reliable transmission capability modelling for the purposes of FTR auctioning), is also likely to be of value in considering the practicability of implementing risk management instruments in a GNP NEM. Finally, given the large geographic size of the NEM, New York's

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170 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.16 and 64.

171 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.109.

172 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, pp.10-14.

173 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.14.

174 Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.14.

early experience with long distance basis-risk management is of particular interest. The tendency for participants to overpay for such long-distance hedging instruments may have implications for risk management in a GNP NEM.

4.3 NEW ENGLAND

4.3.1 Background

The current New England electricity market began operation in March 2003. It now covers the States of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.[175] Similar to the situation in PJM and New York, the New England ISO (ISO-NE) now operates a number of markets:

- Day-Ahead and Real-Time energy markets;
- Financial Transmission Rights (FTRs);
- Ancillary services markets including forward and real-time operating reserves markets and a regulation market; and
- Installed capacity market.

Similar to New York, New England can be described as a GNP market, as load is settled on the basis of one of eight zonal LMPs, which are each an average of LMPs within the zone.[176]

4.3.2 Energy markets

Both the Day-Ahead and Real-Time energy markets produce LMPs for settlement purposes – approximately 1,000 prices are produced every 5 minutes, including a New England hub price, which is an average of 32 nodal prices.[177] As in New York, load is settled on the basis of a zonal price that is an average of the nodal prices within that zone. Also in line with other north-eastern United States markets, the Day-Ahead Market serves as a 'financial' market to hedge against real-time 'physical' market price volatility by settling against day-ahead prices. The objective of the Real-Time Market is to ensure there is sufficient capacity available to meet real-time demand, reserve requirements and regulation requirements (both the latter being ancillary services – see below).[178]

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175 See: http://www.ferc.gov/market-oversight/mkt-electric/new-england.asp

176 *Transmission Planning Informational Workshop*, September 19, 2005, presentation by Stephen J. Rourke, Director, Reliability & Operations Services, p.6.

177 *Transmission Planning Informational Workshop*, September 19, 2005, presentation by Stephen J. Rourke, Director, Reliability & Operations Services, p.5; Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.23.

178 *Transmission Planning Informational Workshop*, September 19, 2005, presentation by Stephen J. Rourke, Director, Reliability & Operations Services, p.26.

4.3.3 Risk management – Financial Transmission Rights (FTRs)

Similar to other northeast United States markets, the New England market design incorporates FTRs to hedge congestion cost differentials in the Day-Ahead Market. In 2006, ISO-NE auctioned FTRs with one month and one-year terms. Approximately half of transmission capability is released for the annual auction of one-year FTRs and the other half is made available for the monthly one-month FTR auctions.[179] Similar to PJM and unlike the case in New York, if the ISO does not collect enough congestion revenue to pay FTR holders the entire entitlement over the year, FTRs payments are discounted on a pro-rata basis.[180]

4.3.4 Ancillary services markets

As noted above, ISO-NE operates markets for operating reserves and regulation. Forward and real-time operating reserves markets are intended to ensure that sufficient resources and available to produce electricity when a generator outage or other system contingency occurs. The market for regulation aims to ensure an ability to instruct specially equipped generators to increase or decrease output on a moment-by-moment basis to keep supply and demand in balance.[181] Several changes were made to the reserve markets in late 2006, including the addition of a locational requirement for both the forward and real-time markets, with the real-time locational reserve market co-optimised with energy in the real-time market.[182] The regulation market remains non-co-optimised with the energy markets.[183]

4.3.5 Capacity market

ISO-NE is implementing substantial changes to its installed capacity market, moving to a forward capacity market (FCM) with locational requirements that would cause capacity to be procured three years forward. This forward procurement is intended to facilitate the entry of new generation, which generally requires at least three years to complete the regulatory and construction processes to enter the market. The first FCM auction is scheduled for February 2008.[184]

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[179] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.36.

[180] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.38.

[181] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.1.

[182] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.15-16.

[183] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.15.

[184] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.4.

4.3.6 Market performance

Energy markets

New England electricity prices fell significantly in 2006 from 2005 levels, with the New England day-ahead hub price falling from $78.54/MWh to $60.94/MWh.[185] This was partly due to lower natural gas prices and partly due to lower electricity demand in 2006. Prices were highest in the key Connecticut load zone compared with generation-rich areas such as the Maine zone. While overall congestion in the New England energy market was low, the Norwalk-Stamford "load pocket" within the Connecticut zone did experience significant congestion from 2005 onwards, leading to the highest and most volatile day-ahead energy prices in the market. On average, the day-ahead average price in Norwalk-Stamford was $22/MWh higher than in the surrounding areas of Southwest Connecticut (which is also within the Connecticut load zone).[186]

The New England energy markets experienced other concerns in 2006. The physical interchange of power between the New England and New York markets was poorly coordinated: on August 1 and 2, New England exported significant quantities of power south to New York even though (i) the New England price was as much as $800/MWh higher during much of this period and (ii) ISO-NE made emergency purchases from the NYISO. The New England Market Monitoring consultant states:

> Had the interchange between the markets been optimised, it is likely that New England would not have experienced a shortage in at least five of the eight hours.[187]

Another issue was the use of fast-start and supplemental units to supply load in real time for reliability reasons. As noted in the discussion of the New York market, this can have the effect of depressing real-time prices and increasing uplift costs to participants. Such costs are difficult for participants to hedge against. Further, because LMPs are set by generator offers – which are expected to reflect incremental operating costs – fast-start resources may be committed by the real-time market software even when real-time prices do not cover generators' start-up costs.[188] Additionally, where fast-start or supplemental units are required to satisfy security or reliability requirements, they are not eligible to set prices. The ultimate effect of these measures is to create incentives for generator 'gaming' and to mute price signals for new generation investment and demand response.[189]

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[185] Federal Energy Regulatory Commission, *New England Electric Market*, January 2008.

[186] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.6.

[187] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.8.

[188] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.8-9.

[189] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.5, pp.9-11 and p.71.

Market power

Since inception in 2003, New England's wholesale electricity market has reportedly performed competitively on the whole, with only isolated cases of non-competitive bidding in the Boston area in 2004.[190] According to ISO-NE's Market Monitoring Unit consultants, the New England market performed competitively in 2006.[191] Potomac Economics recognised the scope for increased exercise of market power in an LMP market and found that the largest suppliers in a number of key load zones were 'pivotal' (ie the energy and operating reserves requirements could not be met without that supplier).[192] However, much of the capacity of these plants was covered by reliability agreements or was subject to supplemental dispatch, both of which mitigated the ability of these suppliers to exercise their power. The consultants noted that competitive concerns were likely to increase in the future as reliability agreements expired and supplemental commitments decline. They recommended that ISO-NE continue to closely monitor structural and behavioural market power indicators, especially in constrained areas.[193]

Risk management – FTRs

The 2006 State of the Market report noted that New England has experienced relatively little congestion in historically-constrained areas since implementing the standard market design in 2003.[194] A large share of price separation between load zones has been due to transmission losses rather than constraints. However, as noted above, flows into the Norwalk-Stamford sub-area within the Connecticut load zone were heavily congested, leading to substantially higher prices in that sub-area than elsewhere in the zone and market.[195]

Overall, congestion revenues in both 2005 and 2006 were higher than FTR payments, although this was not the case for several months late in 2006. While this would ordinarily lead to a reduction in payments to FTR holders such that payments did not exceed revenues, surpluses in other months of 2006 were sufficient to ensure this did not need to occur.[196] Therefore, FTRs could operate as a reasonable hedge against congestion costs for both of these years.

Further, congestion costs in the Day-Ahead and Real-Time Markets in 2006 were generally consistent with FTR prices, suggesting that participants valued FTRs reasonably accurately in the FTR auctions.[197] FTRs auctioned in the monthly auctions were more accurately valued than FTRs in the annual auction, as one

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[190] Potomac Economics, *2004 Assessment of the Electricity Markets in New England, June 2005,* p.ii.

[191] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.2.

[192] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.20-21.

[193] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.21-22.

[194] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.5-6.

[195] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.5-6.

[196] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.39.

[197] Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, pp.41-43.

would expect given the need for longer term predictions regarding congestion costs to be made in the annual auction. The key exception to the accuracy of participants' predictions was for FTRs from the Connecticut sub-area into the congested Norwalk-Stamford sub-area – here the monthly FTR market did not fully anticipate the high levels of congestion into Norwalk-Stamford. However, Potomac Economics did not find any general structural or methodological impediments to efficient FTR pricing.[198]

Investment

Since market inception in 1999, New England's transmission system has been experiencing increasing congestion.[199] Between January 2002 and June 2003 (during which time the current market structure was adopted) 4,159MW of additional generation capacity came onto the system.[200] During 2004 the regional reserve margin increased, indicating short-run oversupply. This was triggered by a fall in peak demand due to cooler temperatures and a slight increase in supply due to new generation capacity (see above).[201] In 2006, the Bethal-Norwalk 345KV transmission line came into operation under a two-phase plan designed to increase reliability and import capacity for Southwest Connecticut.[202]

4.3.7 Lessons for the NEM debate

Acknowledging the capacity market and market mitigation features of the New England market, a potentially important lesson is the treatment of concentrated pockets of load within certain load zones. Market behaviour and outcomes in these locations have been managed to date through reliability agreements. However, it could be instructive to observe outcomes going forward to see if participants can and do respond to price signals in these areas or whether intervention of some kind continues.

4.4 MIDWEST ISO

In light of the extensive discussion of other, more established United States LMP markets, this section provides only a brief description of the Midwest market.

The Midwest market commenced on 1 April 2005 and is operated by the Midwest ISO (MISO).[203] The market commenced with LMPs determined by cost-based offers and initially did not incorporate markets for ancillary services.[204]

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198 Potomac Economics, *2006 Assessment of the Electricity Markets in New England*, June 2007, p.43.

199 FERC, *Investigation of Bulk Power Markets: Northeast Region*, November 2000, p.I-35.

200 The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, 2005, p.62.

201 FERC, *2004 State of the Markets Report, June 2005,* p.83.

202 FERC, Electric Power Markets – ISO-NE, accessed from: http://www.ferc.gov/market-oversight/mkt-electric/new-england.asp#mkt on 22 February, 2008.

203 Midwest ISO, *Market Year in Review*, April 2006, p.1.

204 Midwest ISO, *Market Year in Review*, April 2006, pp.1-2.

The Midwest market is a hybrid between GNP and FNP. LMPs are calculated for a number of nodes, but only some of these priced nodes are used for commercial settlement purposes. Load can be settled on the basis of one nodal price or on the basis of an aggregation of nodal prices for the relevant zone. The choice of the form of load settlement lies with the relevant LSE for that area.[205]

The Midwest market incorporates FTRs, which are available through annual and monthly allocations and auctions.[206] As in other northeast United States markets, FTRs entitle their holders to a stream of payments (or oblige them to pay a stream of charges) based on transmission congestion costs in the Day-Ahead Market. The FTR Manual allows for both point-to-point FTRs and flowgate FTRs, as well as allowing for both FTR obligations and options (as in PJM). However, the market commenced by offering only FTR point-to-point obligations and it does not appear that other types of rights are yet available.[207] Point-to-point FTRs are available from and to generation and load nodes, load zones, hubs, interfaces and fixed aggregates, subject to a simultaneous feasibility test conducted by the MISO.[208]

Energy prices in 2005 (post-market restructuring) were on average higher in the Midwest region than in previous years. However, these increases were attributed to higher than expected demand coupled with rising input costs rather than to poor market design or implementation issues.[209] Midwest ISO's reform process has reportedly been relatively uneventful to date and following a smooth introduction in 2005, the market has continued to operate competitively.[210] Net revenue analysis for the 2005-2006 period shows that even the highest price regions in the Midwest have not generated sufficient returns to provide incentives for new generation.[211] Comparison between the Midwest's reform experiences and those expected under the NEM should be tempered by the caveat that MISO operates an explicit capacity market to mange reserve capacity.

4.5 UNITED STATES ZONAL MARKETS IN TRANSITION

It is worth making some brief observations on other United States markets that do not currently utilise nodal pricing, but are intending to introduce it in some form in the near future. The two key markets of interest are:

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205 Midwest ISO, *Market Concepts Study Guide, Version 3.0*, updated December 2005, pp.15-17.

206 Midwest ISO, *Financial Transmission Rights, FTR Market Participant User's Manual, Version 3.2*, June 29, 2006, p.2 and p.5.

207 See Midwest ISO, *Financial Transmission Rights, FTR Market Participant User's Manual, Version 3.2*, June 29, 2006, p.4. This is the current version of the manual available on the MISO website, so one could infer that as at January 2008, point-to-point FTR options and flowgate FTRs are not yet available. However, we have not confirmed this directly with the MISO.

208 Midwest ISO, *Financial Transmission Rights, FTR Market Participant User's Manual, Version 3.2*, June 29, 2006, p.5.

209 Potomac Economics, *2005 State of the Market Report: The Midwest ISO*, July 2006, p.iii.

210 Potomac Economics, *State of the Market Report: The Midwest ISO (2005-2006).*

211 *Ibid.*

- California (managed by the California ISO); and
- Texas (managed by ERCOT).

4.5.1 California

The current California market applies a 'simple zonal' network model to perform zonal congestion management. The zonal model incorporates radial modelling of transmission capacity constraints within the context of a radial flowgate model that manages congestion only as interfaces between congestion zones. If intra-zonal congestion appears likely, the California ISO (CAISO) is required to constrain-on or -off particular plant, as in the NEM. However, unlike the NEM, plant that are constrained-on or -off do receive some form of compensation.[212] On a day-ahead basis, CAISO may require certain plant to offer their capacity in the real-time market in return for certain minimum payments under the rules or contracts. If this is not sufficient to overcome congestion, CAISO can constrain-on or -off plant out-of-merit order in real-time. Constrained-on plant are paid the higher of their bid price or the zonal market clearing price but cannot set the real-time price. Constrained-off generators are charged the lower of local reference prices and the zonal price. Out-of-sequence bids are also subject to local power mitigation rules through a 'conduct' test.[213]

California can presently be described as having a 'weak' energy-only market. It lacks formal capacity markets, but market participants face certain capacity obligations to manage reserves. CAISO is currently considering the introduction of a centrally organised capacity market as part of their Resource Adequacy Initiative.[214]

In response to the growing complexities of intra-zonal congestion management, the CAISO is intending to commission its "market redesign and technology upgrade" (MRTU) in early 2008. The implementation of MRTU (formerly 'MD02') was sequenced around 4 phases over a 5-year period. Phase 1A and 1B focused on market power mitigation measures and real-time economic dispatch; Phase 2 introduced integrated day-ahead markets while Phase 3 rolled out the full network model and LMP designs.[215] The MRTU program utilises LMP in conjunction with the implementation of a full network model in order to help alleviate transmission congestion as well as to provide stronger locational incentives for investment in generation and transmission networks. The MRTU

212 CAISO Department of Market Monitoring, *Annual Report on Market Issues and Performance*, April 2007, pp.6.1-6.2.

213 CAISO Department of Market Monitoring, *Annual Report on Market Issues and Performance*, April 2007, p.6.2.

214 CAISO, *Resource Adequacy Initiative*, accessed from: http://www.caiso.com/docs/2004/10/04/2004100410354511659.html on 134 February, 2008.

215 CAISO, *The ABC's of MD02*, accessed from: http://www.caiso.com/docs/09003a6080/16/59/09003a60801659b5.pdf on 13 February, 2008.

model thus not only accounts for loops and similar complexities, but also facilitates more comprehensive congestion management.[216]

A recently announced delay, which pushed MRTU's culminating 'Go Live' launch back two months, was blamed on system stability and performance concerns.[217] At this stage the revised launch date is 1 April, 2008.

4.5.2 Texas

The Texas electricity market, operated by the Electric Reliability Council of Texas or ERCOT[218], has been widely regarded as a success, partly due to its avoidance of the problems experienced by California and, in particular, because of its competitive retail market.[219]

The ERCOT market has an energy-only design and currently applies a zonal approach to congestion management, with five zones now in place. The number of zones has not been static, commencing with three[220] and with the fifth created in 2005. Congestion between zones is managed through a balancing market, whereby if zonal price separation occurs production is increased in the higher-priced zone and reduced in the lower-priced zone, much like the NEM.[221] Participants can hedge against zonal price divergence by acquiring Transmission Congestion Rights. Congestion within each zone is managed through the redispatch of individual generators, with generators receiving compensation through specific payments – these payments are effectively compensation for being constrained-on or –off. The cost of these payments is recovered from market participants through a zonal uplift charge.[222]

When ERCOT was originally established, Adib and Zarnikau noted that it was expected that, *inter alia*:

- 'Local' (intra-zonal) congestion would be random and infrequent;
- Zonal prices would be sufficient for siting new investment;
- Adjusting the number of zones would be systematic and timely;

216 CAISO, *New PTO Network Model for MRTU Design Implementation, White Paper*, 25 Aug. 2006.

217 CAISO, *MRTU Homestretch (7 February, 2008),* accessed from: http://www.caiso.com/MRTUHomestretch/MRTUHomestretch_200802.html on 13 February, 2008.

218 Potomac Economics, *2006 State of the Market Report for the ERCOT Wholesale Electricity Markets*, ERCOT Independent Market Monitor, August 2007, p.xxvi.

219 Adib, P. and J.Zarnikau, "Texas: The Most Robust Competitive Market in North America", Chapter 11 in Sioshansi, F.P. and W.Pfaffenberger (eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.383-417 (Adib and Zarnikau (2006)), pp.383-384.

220 See Zarnikau, J., "A review of efforts to restructure Texas' electricity market", *Energy Policy* 33 (2005), pp.15-25, p.18 and Adib and Zarnikau (2006), pp.394-395.

221 Zarnikau, J., "A review of efforts to restructure Texas' electricity market", *Energy Policy* 33 (2005), pp.15-25, p.18. See also ERCOT, *ERCOT Protocols, Section 7: Congestion Management*, December 1, 2007.

222 Adib and Zarnikau (2006), pp.394-395.

- Market decisions would have a small effect on reliability.[223]

However, Adib and Zarnikau noted the concerns of ERCOT's Wholesale Market Oversight (WMO) group that these assumptions have not been borne out in practice. [224] Local congestion has been systematic and frequent, resulting in opportunities for generator gaming of constraints and leading to high uplift costs. It has also become apparent that the creation of new load zones is problematic and creates commercial uncertainty.

As a consequence of these problems, ERCOT now intends to implement LMP by late 2008. ERCOT's nodal market redesign process involves 4 'tracks'. Track 1 and 2 initiated operator and participant system procurement and development processes. Track 3 is focused on market training while Track 4 involves system testing and finally nodal market implementation.[225] It was recently reported that the costs of nodal market implementation have increased from $249 million to $311 million.[226]

Generally speaking, the challenges faced by ERCOT during their market restructuring process have concerned operational, commercial and mitigation functions. Of particular importance has been "the need to provide operational procedures and methodologies that are consistent with competitive markets".[227] Having gained valuable insight from the numerous challenges faced by other LMP markets to date, ERCOT is continuing to refine their market design.

4.5.3 Lesson for the NEM debate

Both the Texas and Californian markets are based around the use of zones to manage key points of congestion. However, both are moving to nodal designs. At least in the case of Texas, the driver for change appears to be the difficulty of managing increasing occurrences of local intra-zonal congestion and the difficulty of changing zonal boundaries in a timely and predictable manner. To some extent, the NEM has experienced similar issues. However, it is also clear that transitioning to nodal markets involves high costs. Therefore, any change to the NEM's market design requires a consideration of both the advantages and disadvantages of any such change.

223 Adib and Zarnikau (2006), pp.399-400.

224 Adib and Zarnikau (2006), p.400. See also Zarnikau, J., "A review of efforts to restructure Texas' electricity market", *Energy Policy* 33 (2005), pp.15-25, p.21. The State of the Market Report also commented on generator gaming incentives: Potomac Economics, *2006 State of the Market Report for the ERCOT Wholesale Electricity Markets*, ERCOT Independent Market Monitor, August 2007, p.xx.

225 Texas Nodal Team, *Transition Plan Outline*, accessed from: http://nodal. ercot.com/docs/tntarc/tp /index.html on 13 February, 2008, p4.

226 "ERCOT: Grid change price rose $62 million", DallasNews.com, 11:18pm CST on Wednesday, January 16, 2008.

227 Gavin, J., Flores, I. and Yu, J. (2005). Texas Market Redesign: Refining Congestion Management and Market Mitigation, *Power Engineering Society General Meeting (IEEE),* prepared by ERCOT.

4.6 SINGAPORE

4.6.1 Background

The National Electricity Market of Singapore (NEMS) commenced trading on 1 January, 2003. The NEMS is an energy-only, GNP market comprising 39 injection and 380 withdrawal points. Installed capacity in 2007 was 10,414MW with a peak demand of 5,624MW, giving the NEMS a very large reserve margin of 85.2%.[228] The standard NEMS VoLL is $S5,000/MWh (roughly AUD $3,865/MWh), however this figure can 'float' according to the underlying factor(s) which contribute to a demand-supply imbalance.[229]

4.6.2 Energy Markets

The NEMS wholesale market comprises:[230]

- a real-time market for the security-constrained co-optimised dispatch and pricing of energy, regulation and reserve ancillary services; and
- a "procurement market" in which the market operator, the Energy Market Company (EMC) contracts for other ancillary services such as reliability must-run services, reactive support, voltage control, black start capability and fast-start capability.

The real-time market operates on a half-hourly basis and yields nodal prices for generation settlement. These nodal prices reflect the impact of transmission losses and constraints on dispatch, although both are relatively small in the Singapore system: instances of significant transmission constraints are rare and typical losses are about 1-2% due to the small geographic spread of the system and use of underground cables in the transmission network.[231]

In the NEMS, loads pay the Uniform Singapore Energy Price (USEP), which is a demand-weighted average of the nodal prices at all off-take (load) nodes, while generators receive their MEP (Market Energy Price), which is their nodal price. The result is that the total amount paid by all consumers under the USEP is the same as the total amount that would be paid if all consumers paid their nodal price for the electricity they consumed.[232] Notwithstanding the use of nodal prices to settle generation, there are a few areas where the NEMS diverges from the design of the northeast United States markets and more closely approximates the Australian NEM. These include:

- Absence of a day-ahead energy market;

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228 Energy Market Authority, *2007 Statement of Opportunities for the Electricity Industry*, 2007.

229 See Energy Market Company, *RCP paper No. EMC/RCP/23/2005/CP10, Review of Constraint Violation Penalty Factor, Decision*, 18 November 2005, p.3.

230 Energy Market Authority, *Introduction to the Singapore New Electricity Market – January 2006*, p.2-2.

231 Energy Market Authority, *Introduction to the Singapore New Electricity Market – January 2006*, pp.9-4-9-6; Energy Market Company, *NEMS Market Report 2006*, p.27.

232 Energy Market Authority, *Introduction to the Singapore New Electricity Market – January 2006*, p.9-5.

- Absence of FTRs – the Market Rules make provision for FTRs but they are not yet in existence (see below); and
- Application of a (relatively high) VoLL to cap market prices in place of much lower price caps and explicit market mitigation measures in the United States. The maximum price paid to generators in the NEMS is 0.9 x VoLL.[233]

The market operations process is also broadly similar to the Australian NEM.

4.6.3 Risk Management

There is presently no allocation of FTRs in the NEMS. However, Chapter 7, Section 2.4 of the Market Rules describes the settlement of FTRs in the event that an allocation is made in the future. Interestingly, the Rules do not address the structure of FTRs, but do set out the basis of allocation if one is made – each generator would receive FTRs from its node to the Singapore hub, with the quantity based on its historical production during constrained periods. The (expected) negative impact on market performance due to a lack of risk-management instruments is effectively mitigated by the lack of transmission constraints in the system.

To further reduce potential basis risk faced by generators when settling vesting contracts, in 2003 NEMS replaced USEP (a weighted-average off-take price) with a weighted-average MEP (injection price) as the standard vesting contract reference price.[234]

4.6.4 Ancillary Services Market

Through its primary market operations, the EMC co-optimises the dispatch of energy, reserve and regulation products while operating a separate "procurement" market for other ancillary services, such as reactive support and voltage control services, black-start capabilities, fast-start services and reliability must-run services.[235] For the period 1 January, 2007 to 31 March, 2008, total expenditure on contracted ancillary services was $S9,736,723 representing approximately 69MW of contracted power.[236]

4.6.5 Market performance

Prices and congestion

Apart from a dip in the USEP in 2004 to $S82.35/MWh, wholesale electricity prices in Singapore have steadily increased since market restructuring in 2003.[237]

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233 Energy Market Authority, *Introduction to the Singapore New Electricity Market – January 2006*, pp.9-5-9-6.

234 Energy Market Company, *2003 NEMS Wholesale Electricity Market Report*, 2003, p.10.

235 Energy Market Authority, *Introduction to the Singapore New Electricity Market,* January 2006, p.2-2; Energy Market Company, *Ancillary Services* accessed from: http://www.emcsg.com/n6465,35.html on the 26 February, 2008.

236 Ibid.

237 Energy Market Company, *NEMS Wholesale Electricity Market Report (2003-2006).*

These price increases have been in line with rising fuel oil prices but have increased at roughly half the rate of the associated input costs.[238] The average USEP for 2006 was $S132.42/MWh, up 20% from $S109.90/MWh in 2005. The volatility of prices also increased in 2006.[239] This rise in the level and volatility of prices was due to a combination of factors: higher oil prices (to which natural gas prices – a major fuel for Singapore's generators – are pegged), record demand and lower spare generation capacity.[240]

In terms of locational variation, there were only nine instances of binding transmission constraints in Singapore in 2006 and one incident of significant load shedding. Across Singapore, the lowest average locational price in 2006 was $S131.78/MWh in the west and the highest was $S132.99/MWh in the northeast.

Market power

With:

- a reserve margin (registered generation capacity in excess of peak demand as a percentage of peak demand) of 88% in 2006; and
- a high level of vesting contract coverage of 65% of demand,

the exercise of market power was not noticeable in the NEMS. The Market Surveillance and Compliance Panel did investigate allegations of market manipulation in late 2005, but found no evidence that the market was unfair or inefficient at that time.[241]

Investment Decisions

Due in part to an already present large excess of capacity, NEMS has seen little investment in generation assets since inception in 2003.[242] Using forecasted increases in demand and striving to maintain a minimum reserve margin of 30%, generation investment in the NEMS is expected to increase by 1,755MW over the next 4 years.[243]

4.6.6 Lessons for the NEM debate

Several important caveats apply to the Singaporean reform experience. These primarily include the small (geographic) market size, the extensive use of underground cables, the high reserve margin, the relatively congestion-free grid and the significant levels of vesting and bilateral contract coverage.

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[238] Energy Market Company, *2006 NEMS Wholesale Electricity Market Report*, 2006, p.5.

[239] Energy Market Company, *NEMS Market Report 2006*, pp.24-25.

[240] Energy Market Company, *NEMS Market Report 2006*, p.5, p.15, p.21 and p.23.

[241] Energy Market Company, *NEMS Market Report 2006*, p.15.

[242] Chang, Y. (2007). The New Electricity Market of Singapore: Regulatory Framework, Market Power and Competition, *Energy Policy*, 35(1), pp.403-412.

[243] Energy Market Authority, *2007 Statement of Opportunities for the Electricity Industry*, 2007, p.26.

Subject to the above caveats, several lessons can also be drawn. First, Singapore's energy-only, GNP market structure is the most similar in design to how the NEM would appear with GNP. To this end, market design issues and transitional steps taken during the NEMS reform process may be of particular interest. Second, the experience in Singapore shows that explicit market power mitigation measures are not essential to ensuring a competitive wholesale energy market where other conditions are favourable.

4.7 NEW ZEALAND

4.7.1 Energy Market

The New Zealand wholesale electricity market is governed by Part G (Trading Arrangements) of the Electricity Governance Rules. These Rules provide for the bidding and dispatch of plant, ancillary services provision and network operation. The system operator (Transpower, also the network operator) publishes indicative real-time prices on a 5-minute basis.[244]

The New Zealand electricity market incorporates FNP, with approximately 250 separate nodal prices posted across a grid with about 480 entry and exit points. Notwithstanding a fundamentally different market structure, there are a number of similarities between the New Zealand market and the NEM that are not found in markets elsewhere. Both are energy-only markets with generally non-intrusive approaches to the exercise of transient market power. For example, unlike the northeast United States markets, New Zealand has no price cap on generator offers or a cap on the market price.[245] Both also employ energy and reserve co-optimisation and a similar market dispatch engine.

However, with respect to the number of nodes priced in New Zealand, Geoff Bertram of the Victoria University of Wellington argued that:

> Much of this detail seems redundant to effective functioning of the market, and on balance has probably impacted negatively on market efficiency.[246]

Bertram commented, in 2005, that there were only two important transmission bottlenecks in New Zealand: the inter-island HVDC link and the central North Island. Thus, the three key nodes in the system are Benmore (at the southern end of the HVDC link, Haywards (and the northern end of the HVDC link) and Otahuhu (in Auckland, north of the central North Island bottleneck). Bertram said that the prices at these three nodes tend to move quite closely together, except when one of the key constraints binds. He went on to say that price divergences at the other nodes are generally insignificant.[247] NZIER's 2007 report

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244 NZIER, *The markets for electricity in New Zealand, Report to the Electricity Commission*, February 2007, pp.5-6 and p.15.

245 NZIER, *The markets for electricity in New Zealand, Report to the Electricity Commission*, February 2007, p.29.

246 Bertram, G., "Restructuring the New Zealand Electricity Sector 1984-2005", Chapter 7 in Sioshansi, F.P. and W.Pfaffenberger (eds), *Electricity Market Reform, An International Perspective*, Elsevier (2006), pp.203-234 (Bertram (2006)), p.215.

247 Bertram (2006), pp.215-216.

for the Electricity Commission (the industry regulator), confirmed that the correlation between these key nodal prices remained strong.[248]

The Electricity Commission has since approved the development of two significant transmission projects to assist in the reliability of supply to Auckland: the Whakamaru to Pakuranga 220 kV line (upgradeable to 400 kV) at a cost of $NZ824 million and the upgrade of the Otahuhu Substation at a cost of $NZ99 million.[249]

The Electricity Commission published an Issues Paper on its Market Design Review in early 2007. This highlighted a range of wholesale market issues that had been of concern to participants, including basis risk due to locational price differences.[250]

4.7.2 Risk management

Financial Transmission Rights (FTRs) were initially intended to be part of the New Zealand FNP market structure. There was a flurry of work in 2001-02, including a draft supplementary Government Policy Statement on FTRs.[251] This GPS provided that FTRs should be introduced to assist in the management of locational price risk resulting from transmission losses and constraints. Without much progress having taken place, this work was suspended – the FTR work was subsumed in the October 2006 GPS on Electricity Governance.[252] This GPS obliged the Electricity Commission to oversee the development of FTRs and address a range of issues surrounding them. To date, the Electricity Commission has formed the Hedge Market Development Steering Group, which has developed papers on options for transmission hedge instruments.[253] The working group's preferred package includes a proposal to allocate loss and constraint rentals on a locational basis.[254] The next steps include publication of a more specific issues and options paper in the first quarter of 2008, to be followed by a full consultation paper.

4.7.3 Market Performance

Since market deregulation and the introduction of nodal pricing in 1996, the New Zealand market has experienced several periods of significant price volatility.

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248 NZIER, *The markets for electricity in New Zealand, Report to the Electricity Commission*, February 2007, Figure 8, p.37. Note that the first chart of Figure 9 on p.38 showing substantial differences in selected nodal prices appears to be in error.

249 See Electricity Commission, *Annual Report 2006/07*, pp.13-14; Electricity Commission, "Electricity Commission approves NI grid upgrade", *Media Release*, 5 July 2007.

250 Electricity Commission, *Issues Paper – Survey of Market Performance, Market Design Review*, paras 235-238, pp.3-34-3-44.

251 Draft dated 6 September 2002

252 See para 78.

253 For example, Electricity Commission, *Hedge Market Development – Issues and Options: Overview Paper*, 18 July 2006.

254 See: http://www.electricitycommission.govt.nz/opdev/wholesale/Hedge

These periods corresponded to two prolonged dry periods in 2001 and 2003 and were significant given New Zealand's relative dependence on hydro generation. Adjusting for these spikes reveals that wholesale electricity prices have been fairly consistent over the last 7 years.[255] According to CRA, despite New Zealand's unique characteristics, wholesale and retail energy markets have been 'workably competitive' since nodal market inception.[256]

In an effort to manage basis risk in the absence of formal congestion-hedging instruments, participants in the New Zealand market have relied on regionalisation (supplying only customers in a close geographic proximity to generation facilities), vertical integration and an industry-developed hedging market (EnergyHedge). EnergyHedge has experienced only mild success to date with low trading volumes due to an apparent lack of demand.[257]

Two main consequences of the lack of adequate congestion-hedging instruments are apparent in New Zealand's energy market. These are:

- restricted consumer choice due to 'regionalisation', giving rise to a form of 'locational discrimination';[258] and
- reduced investment incentives, since the (likely) higher costs associated with either incurring or attempting to avoid basis risk through other means adds to an investments required hurdle rate.[259]

Nevertheless, according to NZIER, roughly 6,000MW of private generation investment has been proposed by various market participants in recent years, of which 25% (or 1,500MW) appears on face value to be economically feasible.[260]

4.7.4 Lessons for the NEM debate

Perhaps the most salient lesson from New Zealand's experience relates to the point raised by Geoff Bertram (see section 4.7.1). Given that there are (or were) only 2 major congestion bottlenecks in New Zealand's transmission system, the question arises as to whether 245 discrete nodes are necessary. On the one hand, if material congestion consistently appears only in certain areas, it may be appropriate to adopt a market design incorporating much fewer nodes (or regions). On the other hand, if congestion is material but unpredictable, it may be worth considering the pricing of a full complement of nodes.

255 NZIER, The Markets for Electricity in New Zealand, prepared for the Electricity Commission, February 2007, p.36.

256 CRA, Competition and Investment Incentives in New Zealand's Electricity Markets, prepared for : Meridian Energy, February 2005, p.1.

257 Electricity Networks Association, *Submission: Hedge Market Development (Issues and Options),* October 2006, p.1.

258 Transpower, *Financial Transmission Rights and Rentals*, March 2002, p.1.

259 CRA, *Competition and Investment Incentives in New Zealand's Electricity Markets, prepared for Meridian Energy*, February 2005, p.43.

260 *Ibid.*, p30.

5 Issues to be addressed in considering GNP implementation in the NEM

This final chapter considers the issues that would need to be given particular consideration in contemplating a move to GNP in the NEM, based on the theory and practice discussed above. The key issues to consider are:

- The form of settlement pricing for load;
- The formulation and allocation of financial risk management instruments;
- The need or utility of employing a full network model and the treatment of losses;
- The implications for ancillary services markets; and
- The caveats surrounding the transferability of the United States experience of nodal markets.

In relation to a number of these issues, transitional arrangements may be necessary to assist the implementation of a GNP market. While the nature and duration of transitional arrangements are largely a function of compromises struck between participants and policy-makers in the relevant market, the above discussion of the markets moving from zonal to nodal pricing in the previous chapter (California and Texas) may provide some guidance in this area. Most notably, these experiences suggest that implementation of LMP markets tends to be time-consuming and costly. Whether policy-makers in California and Texas fully anticipated the extent of these costs in deciding to move to nodal markets is unclear. However, we are not aware of any suggestions that such moves are now regarded by those policy-makers as regrettable or misconceived.

5.1 FORM OF LOAD PRICING

As noted in section 2.3, an important issue to address in implementing GNP in the NEM is the basis upon which load should be settled. All GNP markets examined in this report use the load-weighted average of load or off-take LMPs to settle all load in the relevant zone/region, rather than the prevailing LMP at the main load centre in the zone (akin to the RRP). This means that there should be no net positive or negative congestion rentals or settlements residue arising purely as a result of the mis-pricing of load at settlement.

Applying a load-weighted approach in the NEM would be likely to marginally change the energy prices paid by load at the moment; to the extent that RRNs are currently located at or near major load centres whereas actual load is scattered more widely, regional load-weighted nodal average prices would differ from current RRPs. However, it is difficult to predict in advance whether consumers' prices would go up or down in any given region – this is an empirical question that depends on the location of the RRN relative to the location(s) of the loads in the region. A further point to note is that to the extent consumers pay more or less for energy in the wholesale market, this may be offset by decreases or increases, respectively, in prescribed transmission prices caused by changes in the value of intra-regional settlement residues. As different TNSPs may currently allocate these intra-regional settlement residues differently, it is extremely difficult to predict whether a given consumer at a given location would be better or worse off in terms of their delivered energy cost (taking account of changes in both their energy price and transmission charge).

We would also note that GNP has been implemented for different reasons in different markets. In Singapore, the rationale appears to be based on social or political grounds. However, in New York, it may be an interim step to FNP; NYISO consultants, Potomac Economics, suggested that the current zonal approach inhibits participation by the demand-side of the market.[261]

Another issue to consider is that load zones in GNP markets have tended to be relatively small:

- New York has eleven load zones in an area 60 per cent the size of Victoria
- New England has eight load zones in an area 75 per cent the size of Victoria; and
- Singapore's entire city-state is one market in an area less than 1 per cent the size of Victoria.

This suggests that if GNP were to be adopted in the NEM, there would be no clear precedents for load zones anywhere near as large and diverse as the existing regions.

5.2 RISK MANAGEMENT INSTRUMENTS

The key issue in applying GNP to the NEM would almost certainly be the formulation and allocation of transmission congestion rights.

5.2.1 Formulation

While there was originally a debate about physical versus financial transmission rights in the literature, practically speaking, this debate has been resolved in favour of financial rights. Financial rights would also align well with the existing open access regime applying to the NEM.

Due to the present regional settlement arrangements, the NEM only offers inter-regional basis risk management instruments, which are not firm. The implementation of GNP would require the formulation of new risk instruments to enable generators to hedge their exposures to local (as well as inter-regional) load hubs. Such instruments would logically comprise some form of 'bundled' point-to-hub and hub-to-hub FTRs. As noted in the CMR Draft Report, the wide application of an 'unbundled' rights approach such as CBRs could rapidly become unwieldy given the sheer number of constraints for which congestion rental rights may need to be developed and allocated.

[261] Potomac Economics, *2006 State of the Market Report New York ISO*, July 2007, p.26.

As noted in the discussion of the northeast United States markets, the determination of the appropriate configuration and volume of FTRs is a difficult issue. For FTRs to be revenue-adequate, they need to represent power flows that are simultaneously feasible. Power system checking is thus an important feature of the northeast allocation mechanisms. At the same time, while many FTR configurations may be simultaneously feasible and revenue adequate,[262] the system operator will not know which configuration maximises trading benefits. Hence, the northeast markets tend to utilise annual and monthly multi-round auctions to allow the strength of participants' revealed preferences to decide which FTRs ought to be allocated and in what volume. Power system checking occurs within each round of each of these auctions.

Therefore, regardless of the initial allocation of FTRs (or even whether or not there is one), it would appear to be necessary to conduct multi-round auctions to maximise the value of the potentially available congestion rentals in the NEM. It is also likely to be both necessary and useful to conduct periodic auctions to enable participants to trade FTRs (as in the northeast markets) closer to the time period to which they apply. Each stage would require a power flow analysis to be undertaken to evaluate the simultaneous feasibility of power flows and hence the revenue adequacy of the FTRs. All of this suggests a far larger role for (most probably) the market and system operator in the handling of congestion rentals, and a far more involved process for participants in risk management strategies and auction processes than has been the case to date in the NEM. Adib and Zarnikau note that nodal markets may demand additional resources of smaller market players to understand a more complex market and additional capital to hedge transmission risks.[263]

Offsetting some of these additional complexities is the potentially greater firmness of FTRs compared with the NEM's existing IRSR instruments. While participants in the NEM currently face no basis risk when entering derivative contracts in their own region, they do encounter basis risk when contracting at other RRNs. As discussed in the CMR Draft Report, existing IRSR units provide a relatively poor hedge for inter-regional contractual exposures because of uncertainty over the flow capability on directional interconnectors at times of inter-regional price separation.[264] Some of the causes of this uncertainty would be overcome with FTRs in a GNP market, in part because all relevant constraints would be explicitly priced.

5.2.2 Allocation

Putting to one side the question of formulation, the allocation of FTRs in the NEM as part of the implementation of GNP would be likely to be a vexed issue.

Unlike the case in the northeast United States markets, generators in the NEM do not pay substantial transmission charges – they pay only for their shallow

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262 At least subject to the physical performance of the network.

263 Adib and Zarnikau (2006), footnote 36, p.400.

264 CMR Draft Report, p. 102.

connection costs. It is these payments in the northeast markets that form the basis for the entitlement of many businesses to a "free" allocation of FTRs (or ARRs in PJM). Applying this approach in the NEM would suggest that generators need not automatically receive any FTRs (or ARRs) as part of an initial allocation process.

On the other hand, the Singapore market Rules refer to an allocation methodology that is intended to be used if a decision is made to allocate FTRs in that market. That methodology provides FTRs to existing generators based on historical dispatch patterns at times of peak system loading, even though generators in Singapore (like in Australia) do not pay substantial transmission charges.

As noted by Gregan and Read, generators in the NEM presently hold an implicit right to be settled at the RRN, thereby being "protected" from congestion price risk within that region.[265] This implicit right would be lost in a move to GNP. This suggests that while generators may not contribute to recovering the costs of the transmission system,[266] there may be a case for some degree of "free" FTR allocation to existing parties if it is considered good regulatory practice to avoid wealth transfers when introducing GNP. How such an allocation could be determined is an open issue, although the LATIN Group proposed a method in their submission to the Commission.

In any case, one lesson from the PJM experience is that it may be worth imposing a requirement for generators receiving an initial allocation of FTRs to put them up for auction in exchange for the corresponding auction proceeds (ie ARRs), so as to avoid creating potential barriers to entry in the market as a result of new entrants being unable to access adequate hedging instruments. It is unclear, however, if this remedies the problem if, as in PJM, ARR holders are guaranteed to receive their requested FTRs.

Finally, as discussed in Gregan and Read, it may be possible to allocate tailored financial instruments in ways to promote efficient provision of certain types of ancillary services, such as NCAS.[267] Similarly, such instruments could be used to provide 'gatekeeper' generators with incentives to support interconnector capability.

5.3 FULL NETWORK MODEL

Several commentators have suggested that a FNM should be adopted in the NEM – at least for dispatch purposes – to both maximise transmission asset efficiency and assist in the management of system security.[268] Read and Gregan

265 Gregan and Read (2008), p.8.

266 Apart from the fact that generators are settled on the basis of marginal rather than average losses, where marginal losses tend to be approximately double average losses.

267 Gregan and Read (2008), pp.32-33.

268 See: CRA, *NEM Transmission Region Boundary Structure (Draft Report)*, September 2004, p.21 and IES, *Regional Boundaries and Nodal Pricing: An Analysis of the Potential Impact of Nodal Pricing and Market Efficiency*, December 2004, p.25.

also suggest that regardless of any changes to market design; it would be desirable to replace NEMDE with a FNM.

In the context of moving to a GNP market, NEMDE could continue to be used for dispatch and settlement purposes. However, a FNM would facilitate both localised pricing as well as FTR formulation and settlement. The key questions would surround the precise form that the FNM ought to take. While a model incorporating a detailed representation of the underlying physical power system (that was able to automatically produce LMPs) would be the top priority, a FNM could also provide a more accurate approximation of power system conditions.

5.3.1 Treatment of losses

The implementation of GNP in the NEM would also raise the question of the appropriate treatment of electricity losses for both dispatch and pricing. Losses can be incorporated on a static or dynamic basis and can either be endogenous or exogenous to the model. The method chosen has implications for the accuracy of the loss approximation within the model and also for the volatility of prices within a nodally priced market.

5.4 ANCILLARY SERVICES

As noted in section 3.4, the introduction of nodal pricing for both active and reactive power may presently be infeasible on technological grounds. However, introducing nodal pricing for active power in conjunction with the current contract-based network support and control ancillary services may overcome this concern. Indeed, the United States LMP markets appear to use this approach (see, for example, section 4.1.5 above on PJM). The United States markets also generally appear able to accommodate co-optimised dispatch of energy and FCAS.

As noted above, some forms of congestion rights could be used to promote efficient provision of certain types of ancillary services.

5.5 CAVEATS TO US EXPERIENCE

To the extent that the experience of nodal markets in the United States informs any policy decision in Australia regarding GNP, it is worth bearing in mind the other important differences between these markets and the NEM. These are:

- The use of market power mitigation measures within energy markets; and
- The presence of capacity markets.

These differences do not imply that these markets cannot inform a debate regarding GNP in the NEM; but they do suggest that all the important features of these markets need to be borne in mind when considering the potential implications of introducing GNP in the NEM.

5.5.1 Market power mitigation measures in energy markets

This report, as well as the AEMC's CMR publications, discusses how nodal pricing may encourage or discourage particular generators to exercise market power. The effect of GNP on a generator's incentives will depend on various matters such as the size, technology and location of the generator, as well as system conditions and strategic interactions with other relevant generators. The net effect of all of these influences cannot generally be determined analytically under the current Rules.

In this context, the large role of market mitigation measures in the northeast United States energy markets should not be forgotten when drawing inferences about the competitive performance of nodal markets. These markets typically employ offer-capping mechanisms in situations where generators are deemed to enjoy local market power. Under these conditions, generators' energy market offers are capped to ensure they reflect incremental operating costs only. This implies that on occasion start-up costs may not be recovered from market LMPs, resulting in incentives for strategic behaviour. This is similar to what is currently observed in the NEM when generators are constrained-on.

The point to be emphasised is that the northeast markets do not provide an assurance that generator market power would not be an issue if GNP were introduced in the NEM in the absence of such intrusive regulatory measures. At the same time, if policy-makers were open to the introduction of specific market power mitigation measures alongside GNP, the northeast markets could provide some guidance as to options that could be considered in the NEM.

On the other hand Singapore is a GNP market that does not have *explicit* market power rules.[269] However, the combined effect of a high reserve plant margin, the relatively constraint-free nature of the grid, the high level of compulsory vesting contract cover and the strong role of Government ownership and indirect influence all may have limited the existence of market power and/or its exercise to date. Therefore Singapore, too, does not provide a clear insight into whether and how market power may be exercised in the NEM should GNP be adopted.

5.5.2 Role of capacity markets

The final key point of difference with the northeast US markets is the role of installed capacity markets and the capping of energy market price offers at $1,000/MWh. These characteristics are linked, as the energy markets are directed towards enabling the recovery of generators' variable operating costs while the recovery of remaining costs is left to LSE capacity obligations and related market arrangements.

In this context, it is perhaps not surprising that experience in the longest-lived LMP market (PJM) has not demonstrated that locational signals from the energy market are determinative of generation investment patterns. One reason for this

[269] It could be argued that the presence of high levels of vesting contracts represent an implicit form of market power mitigation.

is likely to be the fact that the role of LMP in these markets is restricted to the energy market. It will be interesting to see if the new RPM – which is intended to provide locational capacity signals – will change this situation.

By contrast, the NEM is an energy-only market in which investors in new plant (or demand-side response) are expected to make their locational and investment decisions based on wholesale spot prices (and contracts referenced to those prices). One consequence of the NEM design is that the market price cap (VoLL) is set at a much higher level to assist the recovery of both variable *and* fixed costs at times when supply is insufficient to meet demand. Compared to the NEM, the relatively low energy market price caps in the United States markets reduce the potential payoff – and hence incentives – for generators with transient market power to exercise that power. Thus, even without the intrusive market power mitigation measures referred to above, it is likely that the NEM under GNP would experience greater exercise of transient market power than it would if it incorporated a US-style capacity market as part of its design.

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