Generator Nodal Pricing:

Review of a report by Frontier Economics

Prepared for

The Australian Electricity Market Commission

by

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Executive Summary

1. The Australian Electricity Market Commission (AEMC) has requested EGR Consulting to review a paper on Generator Nodal Pricing (GNP) prepared for the AEMC by Frontier Economics. An interim draft review was discussed with the AEMC, and with Frontier, who then revised their report. Our review was than adapted, and re-structured, to match the final Frontier paper.

2. Overall, we consider this to be a well written report, and a useful contribution to the debate on congestion management options for the NEM. The paper provides a useful and accessible summary of experience in US markets, in particular, and the interpretation of the evidence is reasonably balanced and accurate.

3. As always, though, improvement is possible and we suggest that further work could eventually be done on developing more specific conclusions of direct relevance to the NEM, using the terminology developed in the recent AEMC framework paper(s).

4. As requested by the AEMC, we have supplied our own commentary on some of these issues, based on our own experience of the markets concerned. This is not intended as a criticism of Frontier's work, or a refutation of their interpretations, but merely as a complementary opinion. Our comments, which sometimes reinforce and sometimes contrast with Frontier's, have been grouped into five sections, as follows.

5. First, we provide a brief overview, giving our perspective on what a GNP market might look like, and how it relates to other proposals under recent discussion, using the terminology of the framework paper.

6. Second, we reinforce the cautions expressed by Frontier with respect to the difficulty of drawing any firm conclusions from studies which attempt to determine a causal relationship between observed market spot price differentials and transmission or generation investment.

7. Third, we suggest some cautions with respect to accepting the conclusions from US analysts, in particular, about what might be considered unacceptable expressions of market power, given the very different design of the NEM. But we do agree that localised market power could sometimes be a problem under a GNP. As Frontier notes, this might be controlled by financial contracts analogous to the Constraint Rental Contract (CRCs) discussed Gregan and Read in the context of regimes based on constraint pricing.

8. Next, we provide our own informal commentary on lessons to be drawn from the New Zealand market experience, broadly suggesting that, while the number of trading hubs/regions which New Zealand participants might find desirable may be significantly less than the number of nodes in the current nodal market, it is probably significantly more than the three suggested by Frontier's sources. Extrapolating that experience to Australia might suggest 25-50 hubs. But we also observe that it is very difficult to change the market design and/or structure once participants have operated under one structure for long enough to have established commercial positions based on the status quo.

9. Finally, we note that many might see the most telling observation from the US data as being that Texas and California, the two markets which started out with a regional structure similar to the NEM, are now on track to convert to a nodal model. Thus we suggest that, if more work were to be done on US markets, it could usefully be focussed on asking why these markets are evolving from a NEM-like structure toward Full Nodal Pricing, and why such evolution is not also appropriate in Australia.

Contents

Generator Nodal Pricing:

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1. Introduction

The Australian Electricity Market Commission (AEMC) have provided a copy of a paper on Generator Nodal Pricing (GNP) prepared for the AEMC by Frontier Economics[1], and have requested EGR Consulting to review that paper. We understand that the AEMC commissioned Frontier Economics to conduct a review and prepare a report on GNP covering:

(a) A factual description of what generator nodal pricing (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 generator nodal pricing relative to the current NEM pricing regime, in respect of:

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

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

(d) In light of (a), (b) and (c), a review of the issues that would (or could) need to be addressed in considering a transition to a generator nodal pricing approach in the NEM.

That report was expected to take account of:

1 *Generator Nodal Pricing: a review of theory and practical application.* Report by Frontier Economics to the AEMC, 8 February 2008

- *Submissions from stakeholders to the AEMC's consultation documents published under the CMR;* and, to the extent practical and appropriate

- *Reports available on the AEMC's website intended to establish a common framework and terminology for considering different pricing options.*

The AEMC requested a peer review of the Frontier paper with a view to improving the credibility of the report as supplementary reference material for the Congestion Management Review. Specifically, the RFP states that:

- *The consultant's peer review is to consider the accuracy and balance of the report's content and the completeness of the report in addressing the provided review scope.*

- *The peer reviewer is also invited to provide comments on specific areas of the report where further expansion or clarification may add value.*

- *The consultant will need to review the Request for Proposal for the GNP review and the GNP report.*

- *The consultant's report will set out the findings.*

- *The consultant report or a summary of the report may accompany the GNP report when the AEMC publishes the latter.*

- *The AEMC will provide the consultant with the scope of the GNP review and the GNP report.*

After further discussion, with the AEMC an iterative approach was adopted, in which:

- The reviewer prepared an interim review indicating areas in which the Frontier report might be corrected, adapted, or expanded to improve accuracy, clarity or balance;

- Frontier then responded by adapting their report to the extent that they thought appropriate, and also provided comments on the areas in which they preferred not to revise their report; and

- The review was then adjusted to reflect those changes, so as to produce a report intended for publication of both the review and the revised paper.

It may be relevant to note that we have no strong view as to whether GNP, or FNP (Full Nodal Pricing), should ever be adopted in the NEM.[2] As noted earlier, we have been closely involved with the development of both FNP and GNP markets, but have also been closely involved, from time to time, with development of the zonal NEM market. We recognise that each type of market has both advantages and disadvantages. Thus our focus is not be on arguing a case for, or against, adoption of GNP in the NEM, but on ensuring that a balanced view is provided, and reasonable inferences drawn, particularly with respect to the implications for the NEM

Specifically, the remainder of this interim report is divided into two parts:

- First, a high level "evaluation" of the Frontier report, focussing on whether or not it fulfils the stated objectives;

- Second, a brief summary of our own complementary perspective with respect to the lessons which might usefully be drawn for the NEM from experience in the markets discussed. This starts with a brief overview of how the GNP proposal fits in with other congestion management proposals recently considered, then moves on to make more specific comments about some points raised by Frontier.

[2] For the record, in his role as Senior Consultant for CRA, Dr Read has previously expressed the view that FNP or GNP are probably not appropriate for the NEM, at the present time, but that they could reasonably be considered at some future date.

2. Evaluation

This is a well written report, and a useful contribution to the debate on congestion management options for the NEM. The topic is large and the coverage necessarily selective. But the paper provides a useful and accessible summary of experience in US markets, in particular, while the interpretation of the evidence is reasonably balanced and accurate. At the outset, then, we should say that there is very little in the Frontier report with which we would strongly take issue, and no major deficiency in the report, relative to the stated objectives. As always, though, further development is possible and opinions may be balanced against differing perspectives. Specifically we suggest that more attention could usefully be devoted to the following areas, on which we provide our own comments in Section 4 below:

1. Making more use of the terminology and framework developed in "framework paper"[3] underlying the Gregan and Read paper referenced by Frontier, so as to facilitate comparison between the GNP proposal and the CP-based proposals discussed there.[4]

2. Focussing the extensive material provided with respect to US FNP/GNP markets more closely on issues of direct relevance to congestion management in the NEM, and on drawing out those lessons more explicitly, as they might apply in the NEM regulatory context.

3. Deriving lessons for the NEM (both positive and negative) from the New Zealand experience with FNP partly because, in several respects, it is more like the NEM than US FNP markets.

4. Deriving lessons for the NEM from the experience of those US markets (California and Texas) which started out with a regional structure like the NEM, but apparently now consider it more prudent to develop towards FNP designs.

Frontier have already modified some aspects of their report in light of issues we have raised, including those listed above. Rather than recommend further modification of the report to deal more fully with these aspects, our intent here is merely to suggest areas in which more work might be usefully done, in future, and to provide indicative comments of our own on some points, so as to broaden and balance the perspective provided by Frontier, as requested by the AEMC.

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3 *Network Congestion and Wholesale Electricity Pricing in the Australian National Electricity Market: An analytical framework for describing options* EGR Consulting report to the AEMC, November 2007

4 We understand that this report was not made available to Frontier until after their review was largely complete.

3. Lessons for the NEM

3.1. Overview

As already noted, there is really nothing in the Frontier report with which we would strongly take issue. The views expressed seem reasonable inferences from the evidence presented. On the other hand, we have been specifically requested to provide balancing perspectives, where appropriate, based on our own somewhat different experience of GNP/FNP markets, and of the NEM. Thus, in expressing an alternative viewpoint, we are not suggesting that the viewpoint expressed by Frontier is wrong, or should be changed, but merely that it might also be useful to make a balancing perspective available to participants. In some cases we are merely reinforcing views already expressed by Frontier. [5]

Before doing so, though, it may be worth summarising our understanding of how a GNP market proposal would relate to other congestion management proposals discussed in recent times.

Basically, in the notation of the framework paper, GNP corresponds to a limiting case of Congestion Pricing (CP) in which:

- All constraints are "managed"; and
- All generation and interconnector flow terms are "exposed' in all constraints in which they are involved.
- Loads are still fully "protected", in the sense that they sense that they are not involved in the congestion pricing regime, or equivalently receive implicit Constraint Rental rights (CRRs) to their local Regional Reference Node (RRN) or Hub; and
- TNSPs and ancillary service providers are (probably) also "protected", in the sense that they are not involved in the congestion pricing regime. [6]

Thus this proposal lies at one extreme of a spectrum of CP-based options. We do not see any real technical difficulty in converting the current NEM structure into a GNP based market. All that would happen, for loads, is that the Regional Reference Price would be set by load-weighted averaging, rather than from a Regional Reference Node price. But generators would face prices which are

5 In some cases, similar points are made several times. In general we focus on the first such instance.

6 The potential involvement of such parties is compatible with the FNP proposal, but not a major focus of this report.

already implicit in the NEMDE solution, and could be produced using that software.

Thus, while it could be desirable to introduce a Full Network Model (FNM) in conjunction with a change to GNP, that change would not be necessary. Conversely, it may well be desirable, irrespective of any discussion of GNP.

The intra-regional situation faced by generation would be different, though. We do not see any likely demand for a generalised FTR regime under this GNP based proposal, because loads will have no interest in entering into transactions at their nodal prices. Under GNP, generators would be seeking to obtain hedging with respect to a regional load hub price (possibly via a regional generation hub price, as discussed in Appendix B of the framework paper), and then between Regional Reference Prices (as at present).

Thus the inter-regional trading situation might not be very different from that at present, and the hedging issues pertaining to "trans-regional" constraints (ie constraints on inter-regional flows which are not Pure Interconnector Limits (PILs) could be dealt with using some variant on the CP based CBR or CSP/CSC regimes, as discussed in Chapter 6 of the framework paper.

There has been debate in the literature as to whether it is better to use point-to-point FTRs, or constraint based "Flow Gate Rights (FGRs)" even in FNP markets. In some cases FGRs, or CRRs[7], may be more natural hedging instruments than FTRs and, under certainty, the complexity of the two regimes seems similar. Under uncertainty, though, the FTR concept seems significantly simpler because the number of potential FGR/CRRs increases to match the number of all possible future binding constraints, whereas the number of potential FTRs does not.

The CP-based approach discussed in the framework paper is more general, though, in that it allows selective application of congestion pricing. As we move across the spectrum from a zonal market to a nodal market, most of the "generic" constraints in NEMDE become explicit flow limits in a Full Nodal Model (FNM)[8]. If the current NEMDE representation is correct, these explicit constraints would have exactly the same shadow prices and RHS values as those implicit in NEMDE at present. Thus the volume, price and number of potential CRRs could be exactly the same, irrespective of how many nodes there were in the market representation.

7 Internationally, FGRs have primarily been discussed in a nodal market context. The CRR concept is very similar, but developed to match the NEM zonal market structure.

8 There will generally be other constraints, typically security limits, which do not reduce to this form, and may still be represented as generic constraints in a FNP model. These will also impact on nodal prices, and inter-nodal price differences, and hence on hedging requirements and FTR values. But see discussion below with respect to non-NEO effects.

The only reason why the CSP/CSC (and potentially CBR) proposals might involve fewer hedging instruments is because they allow us to ignore constraints which do not bind too often, or too seriously, as a matter of policy. As the number of “managed” constraints builds up, though, the point is likely to be reached where an FTR–type mechanism will be more suitable than a CRR/FGR approach.

Thus we do not disagree with Frontier’s suggestion that a hub-based FTR regime would most likely be the appropriate mechanism to adopt in a GNP market. It seems to us arbitrary, though, whether node-to-hub or hub-to-hub rights are called “FTRs” or “Bundled CRRs”. In the limit the two are almost identical, if all constraints are “managed” under a CP-based regime, and all generation “exposed”, using the terminology of the framework paper.

There is one other point of difference, though. Unlike in FNP markets, a significant issue in the NEM is that just generating/ consuming power in a particular location could be deemed to be an “ancillary service”. Hence all the discussion about “gatekeepers” and “interconnector support”, in the CRA work for NEMMCO, and then for the MCE. The need for such “ancillary services” would effectively disappear in a FNP market. The need for generators to supply such services, explicitly, would disappear in a perfectly competitive GNP market, too. And Frontier rightly notes that FTRs could be used to secure the provision of these “services” in situations in which potential “suppliers” have significant local market power.

But, as Chapter 7 of the framework paper points out, even in an FNP market, a CSP/CSC type regime could still be appropriate to deal with what that paper calls “non-NEO”[9] effects of generator injection. That is, it could be used to provide incentives to generators who “supply”, for example, reactive power or unit inertia in ways and locations that reduce congestion. These factors should not be reflected in nodal prices, because they are unit specific, and not just location dependent. Thus they can not be addressed using FTRs, which relate only to nodal price differences.

[9] Ie not “Network Energy Only”

3.2. Difficulty of implementing/operating GNP markets

Frontier makes a number of points about the difficulties which may be experienced in implementing a GNP market, and about the difficulties which might be experienced by participants operating within such a market. We do not particularly disagree with the points made by Frontier, but offer an alternative perspective on a few of them, based on a history of involvement with both types of market.

Implementation of LMP markets tends to be time-consuming and expensive. (p4)

> This is true for any electricity market, of any form, in our experience. But no evidence is presented to suggest that LMP markets are markedly more expensive to implement than any other market form. The establishment and development costs of the NEM have not been insignificant, particularly when the time and costs incurred by market participants are accounted for.[10] What is true, though, and highly relevant here, is that implementation of any significant change to a market tends to be time-consuming and expensive.
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> Thus even though development of GNP market may seem conceptually straightforward, we concur with Frontier that any transition from the current NEM to GNP is not likely to be straightforward. We might also suggest that the unwillingness to incur ongoing development costs in the New Zealand market has not been entirely positive. Thus, although failing to implement FTR market to complement the FNP spot market has saved costs, many would say that it has inhibited competition, particularly at a regional level. It seems unlikely that NEM participants, who currently enjoy a form of implicit hedging via IDMA would consider it acceptable to lose that protection in such a way. Thus the cost of implementing some form of (hub-based) FTR regime should probably be considered as a concomitant cost of introducing GNP into the NEM.

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[10] If anything, our informal impression, based on involvement with both markets is that the implementation and ongoing development costs of the zonal NEM market have been higher than for the New Zealand FNP market. Since implementation in 2006 there have been only very minor changes to the New Zealand spot market design, market-clearing formulation, constraint formulations, or dispatch engine, for example. Although recent expenditure on IT systems has ben significant, it is debatable how much of that is was speciofically required by the FNP market design.

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 (p17)

This is correct, but it should be recognised that loads facing a Regional Reference Price, however formed, will want to trade at that price, rather than at a local GNP price. Thus the basis risk is all faced by the generator, which will need to somehow acquire a node to hub transmission right to cover it. In this regard it is worth noting that giving loads access to a Regional Reference Price implicitly (via IMDA) grants them CRRs to the Regional Reference Node, and that may significantly impact on the volume and firmness of hedging available to generators, as discussed in the framework paper.

But we also note that local generator/load discrepancy issue highlighted by Frontier does create consistency issues for vertically integrated entities, particular co-gen plant, for example. There is no truly consistent "fix" for this. So, even though the volumes involved may not be large, this was probably the greatest conceptual difficulty in implementing the Singapore GNP market, for example.

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. (p29)

We understand that the point being made here is that, while GNP would allow prices to generators in the NEM to fully reflect the unpredictability and transience of constraints, it could lead to a degree of load-price averaging in the NEM that is not found in existing GNP markets.

Thus it has been suggested that, while this would not create any technical difficulties, it could lead to a degree of incongruity between generator pricing and load pricing not found elsewhere: Presumably, GNP would only be adopted if one expected material but unpredictable levels, locations and timings of congestion. After all, if few constraints ever bound except at State borders, there would be little call for GNP. In this context, Frontier suggests that large (State-wide) load zones could involve averaging much more diverse load prices than in the US GNP markets (such as New York and New England).

We do not disagree, but note that this could be taken as an argument supporting a case that there is so much congestion in the NEM that more regions are needed, perhaps quite a few more, in order to properly capture the economics of the situation, and produce reasonable dispatch/pricing alignment. Or it could be taken as an argument for GNP, but with a more refined regional structure being applied to loads at the same time. Or it could be taken as an argument for something similar, but implemented using a CP-based approach.

To us, it seems quite plausible that any or all of these conclusions might apply in the NEM, at some future date. We would note, though, that it seems unlikely, at the present time, if we accept the AEMC's recent conclusion that there is no need for explicit congestion management measures in the NEM.

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. However, the Synapse report did not refer to any evidence confirming such perceptions. (p36)

Frontier's caveat seems appropriate here. In theory Synapse is quite wrong, in that FNP is supposed to be based on a detailed and objective system representation, plus transmission offers, and nothing else. Arguably this is a much more robust and transparent process than the process by which plant may be constrained on/off in a zonal market.[11] It is true, though, that FNP/GNP can sometime produce 'surprising' prices, and this can be a serious issue for some participants. In our experience, the "subjective" element mainly relates to System Opeartor (SO) actions, eg to de-rate or re-configure transmission system components, in such a way as to impact on nodal prices.

Some may see this as an argument not to have FNP/GNP. Others would argue that this is one of the strongest reasons to adopt FNP/GNP. SO decisions will have the same physical, and hence economic, impact, irrespective of the market regime. Thus it may be argued that the key advantage of FNP/GNP in this circumstance is that it brings home to all concerned what those commercial/economic implications actually are, and creates pressure for improvement.

[11] Or the process by which generic constraints may be selected and formulated in the NEM.

3.3. Investment impact of FNP/GNP

Frontier rightly states, in several places, that the evidence presented with respect to correlations between investment patterns and nodal prices does not prove the case for FNP/GNP. And they rightly advise caution with respect to accepting the opposite conclusion, that nodal price differentials make no difference. But we would like to reinforce that caution by suggesting several reasons why studies based solely on such observations do not, and probably can not, prove the case, either way.

To some extent, while not suggesting that Frontier falls into this category, we suggest that authors who look for actual observed nodal spot prices to "explain" investment are looking for something which should not be expected to exist. More specifically, we offer the following observations with respect to some of the comments made in this report.

(Hogan) *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 (p20)*

> We do not disagree with this, or with the conclusion that some degree of regulation is required. But note that the issue here is not so much that the commercially driven model is theoretically flawed if there are scale economies in investment, but that it must rely on contracts which are so firm over such a long term, that they become unworkable in the socio-political context of Western democracies.
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> Unfortunately, this reality has often been obscured by the tendency for FNP advocates to simplify their message by claiming that "nodal spot prices" give the correct incentives for transmission investment. It is not, "nodal spot prices" that give the correct incentives for transmission investment, but (in theory), the difference between nodal spot price projections, with and without the investment. And that difference must be captured by contracts, agreed before investment, not by charging spot prices, before investment.
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> The discrepancy involved here is quite large, with optimal spot price differentials only covering 10-30% of optimal investment cost, according to studies in New Zealand and Chile. Hence our earlier comment that authors who look for actual observed nodal spot prices to "explain" investment are looking for something which should not be expected to exist. But, conversely, the fact that they do not find it does not invalidate the theory, when correctly understood.

At the risk of stepping out of line with some proponents of FTR markets, we might also comment that adding relatively short term FTRs (eg of 1, or even 5 years duration) to the market design does not materially alter the situation.[12] Such instruments may be useful for risk management within an annual budget cycle, but we find it hard to imagine that investors will commit to paying for either generation or transmission assets on the basis of "guarantees" provided by such short term instruments. That would be like building a power station on leased land, with an annual tenancy/rent review.[13]

Hence our stress on the importance of long term transmission capacity rights, of some form, in various contexts. And hence, in part, our caution with respect to the efficacy or efficiency of regimes which propose to re-allocate FTRs, or CRRs on the basis of future behaviour. It should be recognised that the US experience shows that an LMP/FTR market can be initiated without necessarily creating long term FTRs. But the discussion of FTR allocation issues, and of the ARR regime on p33 of the Frontier report underlines the importance of long term property right allocation.[14] We would only add that this is not just a matter of "fairness" or of protecting incumbent positions, but of economic efficiency, since the (non-)allocation rules affect both behavioural and entry incentives, as discussed in Paras 386-393 in Section 6.3.2 of the framework paper.

As noted in the GNP report, the issue of whether the allocation of FTRs to investors in transmission networks would lead to appropriate levels of transmission investment does not need to be resolved for FTRs to provide a suitable means of managing basis risk in a GNP market. Nor is there any expectation, or requirement, that introducing a GNP regime in the NEM would fundamentally alter the status quo, under which transmission investment is primarily undertaken as a regulated, rather than market, activity. But, we also note that the fact that some authors find that short term FTR prices do not "explain" investment does not invalidate the theory, when correctly understood.

In terms of locational variation, there were only nine instances of binding transmission constraints in Singapore in 2006 (p63)

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[12] In our view, similar comments apply to relatively short term capacity market arrangements, whether regional or otherwise, and this view is reinforced by Frontier's discussion of the PJM capacity market in Section 4.1.4.

[13] See, for example, Frontier's discussion of the New York market on p49.

[14] PJM's 2003 ARR regime discussed on p33 is conceptually very similar to that proposed by Read [2002] in: *Financial Transmission Rights for New Zealand: Issues and Alternatives.* Released by the Ministry of Economic Development, May 2002. Available in PDF format at http://www.med.govt.nz/ers/electric/ftr/index.html.

This is correct, although reference to the 2006 NEMS market report suggests that the nine "instances " refers to nine days on which congestion occurred, sometimes for only one or two periods but apparently over an extended period in other cases. Clearly, congestion prices are not a major feature of the Singapore market. But consideration of this situation raises another caveat about the interpretation of this kind of observation.

As Frontier notes elsewhere, a generator that has 'localised market power', and understands their local network topology, will always try to just avoid forcing the system into constraint, because doing so would force their local injection price down, to their detriment. Thus, given the small number of generators involved in Singapore, and the even smaller number affected by any particular constraint, it is perhaps surprising that congestion prices are ever observed at all.

Although this kind of 'second order' response by generators who choose to not congest the system may affect the allocation of rents (although that depends on the FTR/CRR allocation), it is not necessarily sub-optimal, from a national cost benefit perspective.[15] But the point is that it is the threat of price differentials which provides the incentive for the behaviour. So, once more, a lack of observed price differentials does not necessarily mean that the dispatch is unconstrained, and nor does it mean that the GNP regime is redundant, or deficient.

… it is clear that investors do not make locational decisions solely or even principally on the basis of wholesale spot prices (p4)

Locational price divergences have not been determinative in locational investment decisions…. (but) *capacity markets .. are introducing a more locational element (p4)*

It should be noted that experience in the longest-lived LMP market – PJM – has not demonstrated that investment responds to locational signals from the energy market. (p6)

(and similar comment elsewhere, eg on p24 in Section 3.1.4)

The point is fairly made. Power stations can not be built where there are no resources, but price signals of any kind will make some difference, other

[15] The effect does not apply in a perfectly competitive market, and can be shown to be optimal for the case of a single user of a spur line, except inasmuch as that user feels it necessary to leave 'headroom" so as to ensure the constraint does not bind. For local oligopoly cases, though, it implies an inappropriately large incentive for larger users to back off, because they have the most to lose when the constraint binds.

things being equal. It seems unlikely that NEM investors take no notice whatsoever of regional price differences, or more exactly regional price projections, under the status quo. But (as noted above) the impact of FNP/GNP signals on locational investment decisions can not really be assessed without considering their interaction with signals derived from locational capacity markets and/or from transmission cost recovery charges. One also needs to consider locational contractual commitments and/or load-sharing obligations, and projections of prices with and without investment, over plant life-times.[16]

The implication is, though, that we can accept Frontier's conclusion,[17] that the evidence presented does not show any strong correlation between nodal spot prices and locational invest activity, without necessarily inferring that locational spot prices, or spot price projections, do not matter at all. As Frontier acknowledges, there are many other factors which affect this decision, and which could not be accounted for in a report of this nature.[18] Thus we would simply say the evidence presented is inconclusive, either way.

Common sense suggests, though, that the order of the impact will be proportional to the locational variability in (hypothetical projected) spot price signals, relative to the locational variability in other signals, such as transmission cost recovery and resource costs. We certainly would not suggest that this mechanism can be shown to be working perfectly in any electricity market of which we are aware, but it is a moot point whether electricity markets are any less optimal than other markets, in this respect.

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….. Synapse suggested that (this) problem was inherent to all generation investment in an LMP market (p40)

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[16] Thus a participant with a commitment to serving loads in a particular region may well invest in generation so as to relieve anticipated congestion, and so prevent adverse locational spot prices developing. And, in a rational market, we could reasonably expect that large generation investments will not be built in situations where their presence will create congestion that significantly depresses local prices. Thus the nodal market may be working perfectly, as a locational signalling device, even when no significant locational price differentials actually appear in the market. But this also depends very much on the way in which transmission costs are recovered, and particularly whether participants creating congestion have to pay to relieve that congestion.

[17] Or perhaps the conclusion in Frontier's sources.

[18] And do not appear to have been considered by Frontier's sources.

Again, Frontier caveats some of the Synapse work appropriately. If the issue here is lumpiness of generation investment, this is an issue impacting on the economics of rival investments irrespective of LMP, or indeed of any market at all. But it is worth noting that Frontier goes on to say that:

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. (p40)

We note that, if market prices are capped, then so are nodal prices, and hence locational price differences. Theoretically, though, locational prices, and hence price differences, need to be free to rise right up to the "value of lost load" in order to give appropriate incentives for markets in transmission capacity, or locational generation, to work properly. If energy prices can not rise that high, a locational capacity market has to be developed in which capacity prices can be set directly.

3.4. Market power under FNP/GNP

Frontier correctly notes the concerns expressed, in several contexts, about locational market power in FNP/GNP markets. We would argue that FNP does not create locational market power, but it changes the way in which it might be exercised, with results that may be more or less damaging than the behaviour observed under the NEM status quo, which also be seen a an expression of market power. Frontier does not really opine, either way, on whether the conclusions about market power in the literature are necessarily applicable to the NEM. But we would urge caution with respect to simply accepting conclusions from US analysts, in particular, about what might, or might not, be considered acceptable in this area.

As Frontier points out, most US market are structured differently from the NEM, and one must consider the overall situation, including energy and capacity markets, before making any comparisons. One needs to adopt a balanced perspective on these issues, across all NEM activities. But we also note that US analysts may make different assumptions about realistic, and even desirable, goals for regulation in electricity markets, than have been adopted to date in Australia.

More specifically, we offer the following observations with respect to some of the comments made in this report.

Much has been written on this topic, but there appears to be a consensus that the behaviour of generators in an FTR market needs to be carefully observed and potentially regulated (p19-20)

> This is a fair summary of the literature, not only on FTR markets, but on electricity markets generally. But, at the risk of stepping out of line with the literature, we might suggest that this perception rests at least partly on two reinforcing factors:
>
> - The incentives for academics to publish interesting papers on the technically challenging topic of market power analysis; and
> - The history of electricity as a regulated sector in the US.
>
> Many US authors would seem to regard virtually any deviation from SRMC as "abuse of market power". Analytically, we can accept the logic underlying that view, and voice similar concerns with respect to the potential impact of out-of-merit dispatch, etc. But, leaving aside the issue as to whether SRMC is always well defined in the real world, it should be recognised that few, if any, of these authors expect the same standard to be applied to other sectors with similar cost structures. One simply does not see similar papers arguing for SRMC pricing in the accommodation or transport sectors, for example.

Without going into the pros and cons of the apparently inconsistent paradigms being pursued by regulatory authorities dealing with different sectors in the US, it is critical to note that the 'energy only' market designs adopted in this part of the world (including Australia, New Zealand, and Singapore at least) are intended to treat electricity more like a normal commodity. Thus it is not only accepted, but intended, that market participants will recover part of their capacity costs by forcing prices above SRMC, at times, just as accommodation and transport providers do, on a routine basis. Technically, this may be described as "exploiting market power", but that is not the same thing as "abuse of market power".

Witness, for example, the quotation on p39 from the PJM Market Monitoring Unit, *2006 State of the Market Report*:

> *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.* (emphasis added)

Frontier seem to quote this with approval, and we completely agree with the underlying theoretical point. A perfectly competitive market should produce an optimal "economic" level of generation investment if there are no scale economies in generation, investors are not risk averse, and prices can always rise high enough to choke off demand without any threat of regulatory intervention, And, provided we extend the definition of SRMC to include the marginal cost of choking off demand, such a perfect market would be characterised by "SRMC" pricing at all times. Thus it is easy to agree with the sentiment here,

Real markets do not exhibit such conditions, though, and real governments, regulators, and industry technical committees may find the "optimal economic investment level" disturbingly low. Thus theoretical statements of this kind should be treated with caution in the real world.[19] In the PJM context, it may be interpreted to refer to an ideal situation in which a perfectly competitive capacity market produces an optimal investment pattern, given which a perfectly competitive spot market then produces SRMC pricing, up to some cap. In an ideal "energy only" market design, though, prices must clearly exceed SRMC (as conventionally defined) in cases where supply is short. And, realistically, once other factors are accounted for, they may reasonably be expected to exceed SRMC at other times, too.

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[19] And they would surely be thought strange in any other industry. Technically, the whole art and science of 'revenue management" in the airline industry, for example, is all about *reliance on the potential or actual exercise of market power*. Seat prices are routinely pushed well above SRMC in order to cover capacity/overhead costs, even in an industry which can reasonably be regarded as "workably competitive", at least in the US.

Our point, here, is not to argue the case for either market design philosophy, and Frontier does not do that either. Nor is it to say that GNP or FTR markets need not be regulated. In fact we do think it likely that localised market could be an issue in some specific situations, under GNP, just as it could for the CP-based regimes discussed by Gregan and Read. That is a major part of the reason why CRA proposed that "Constraint Support Contracts" (CSCs) were likely to be required, in conjunction with congestion pricing, and that these might need to be negotiated into place, rather than simply auctioned. This same concern motivates the discussion of Constraint Rental Contracts (CRCs) in the Gregan and Read paper.

On the other hand, though, we suggest that the degree of concern expressed with respect to some of these issues, in the US market context, should not necessarily imply that the same degree of concern would be appropriate in the context of the NEM market design. We also suggest that the degree of competition expected in any market has to be proportionately less, in a smaller market. These comments apply at least equally to the discussion of market power generally, as in Section 3.1.4, for example, and with respect to PJM.

But this discussion raises another point, which is noted in the paper, but not expanded upon. One reason why these markets take a relatively strict approach to "market power" in the energy market is that they also have capacity markets, which provide an alternative means for participants to cover their capital requirements. In this context, offer caps, for example, may be seen as an essentially neutral aspect of the market design, merely effecting a separation between energy and capacity markets. The real issue, in such markets, is whether market power can be exploited, and perhaps abused, in the capacity market. But that issue does not seem to attract so much attention, at least in this paper.

In this regard we consider it telling that, despite all the concern about market power, particularly in capacity markets, where it is apparently "endemic"[20] we read on p39 that:

> *PJM noted that net revenues to generators have generally been below the level 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.*

In other words the participants had not been able to exercise enough market power to even bring prices up to sustainable levels, let alone "abuse' their position to extract super-normal profits.

Finally, we note that the specific concerns often expressed with respect to FTR markets largely relate to potentially negative impacts on consumers. But that

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[20] Para 2 p38.

is not relevant under GNP, because consumers are guaranteed access to their Regional Reference Price. Specifically, concern is often expressed that generators will buy up FTRs which allow them to control access to consumers in some location, and then drive their prices up. But the "FTRs" which would allow them to do this are, in fact, the "CRRs" implicitly allocated to the loads, under GNP. In this sense, GNP acts like the proposal advocated by Read [2002], to allocate long term capacity rights to loads, prior to the (proposed) opening of an FTR market in New Zealand.

…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 (p64)

Our comment here arguably relates only to terminology. We understand that Frontier considers that a high level of vesting contract cover is not an "explicit" market power mitigation tool, unlike a rule that directly prevents generators from bidding in certain unwanted ways, such as the offer-capping rules in the northeast US markets. This is a fair comment, if the focus is on the degree of intervention in market processes likely to be required on an ongoing basis, and the cost implications of such intervention.

We would comment, though, that vesting contracts can also be viewed as forms of "market power mitigation measure", in the sense that they are introduced, and designed, at least partly to curb market power. It remains to be seen how the Singapore market will perform once the effect of those vesting contracts is diluted, and capacity margins reach levels which are sustainable in a market environment.[21] Thus we would urge caution with respect to the danger of making an unduly positive interpretation of the Singapore market experience, just as much as we would urge caution with respect to the danger of making an unduly negative interpretation of US market experiences.

In our view, though, financial contracts of this type provide a less interventionist, and more desirable, means of curbing market power than the more "explicit" measures employed in some US markets, and referred to by Frontier. In Singapore, the major issue is the national capacity margin, and the vesting contracts referred to are not locational. But the use of CRCs for "active congestion management" discussed by Gregan and Read can provide an analogous mechanism for controlling localised market power in a CP-based market. As Frontier notes, equivalent instruments could be used for the same purpose in a GNP market.

[21] Noting the special transitional situation applying, to date, in Singapore, whereby entry has been occurring on the basis that entrants have been allocated a share of the vesting contracts.

3.5. Lessons from New Zealand

We offer some specific comments on the New Zealand experience with an FNP market. This is partly because, being an energy only market, it is in some respects more similar to the NEM than the US FNP markets. But it is mainly intended to balance some of the inferences which Frontier has quite reasonably drawn from the sources available to it with some observations of our own, based on extensive experience of that market. Overall, our perspective would be that the transmission network situation in New Zealand is a little more complex and dynamic, implying that the nodal market design is perhaps not so far away from providing an optimal level of detail as might be inferred from reading Frontier's report and/or its sources.

More specifically, we offer the following observations with respect to some of the comments made in the Frontier report.

Bertram commented.. that there were only two important transmission bottlenecks in New Zealand:… and that the prices at … three (key) *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. (p64)*

> With due respect to Prof Bertram, if his remarks are being taken to imply that only 3 nodes really matter, that would not reflect our understanding of the consensus of industry opinion. At the outset, though, we should observe that the number of nodes that really matter to loads, can not be greater than the number of major load centres, which is not a very large number in New Zealand, or even in Australia. But the issue for a GNP market is the number of nodes that really matter to generators. That number may be greater, and the key nodes will generally not be the same.[22]
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> Certainly it is true that prices at *three nodes tend to move quite closely together, except when one of the key constraints binds.* In fact that is what should be expected at all nodes, *except when one of the key constraints binds[23]*. But the real issue is what happens when constraints do bind, and how often that happens.
>
> Being a hydro system, it is quite possible that New Zealand could get through a whole year of moderate and balanced inflows without significant, persistent, price separation. In other years, though, price separation may be both significant and persistent, and the direction of flows, and hence of

[22] The three nodes referred to by Bertram in 2005 would have consisted of one generation centre in the South Island, and two load centres in the North Island.

[23] Although marginal losses are high enough to create significant differentials even in that case.

congestion and price differentials, may be basically North-South in one year, but South-North in the next.

At the opposite end of the spectrum, Transpower actually argued in the debate over FTR market introduction, that a full node-to-node FTR regime was most appropriate, because it was difficult to find any consistent groupings of nodes, by price. Our own informal investigations of current industry opinion suggest that participants would now be content with something between 11 and 20 nodes/hubs. But we should also say that this was already the consensus before market start in 1996… that is until debates began over which nodes should be included in each hub/region, and how the system model was to be approximated. As a result, once all transaction costs were considered, nodal pricing was actually deemed to be easier and cheaper, and certainly quicker, to implement.

It might be suggested that New Zealand's experience could shed some light with respect to the appropriate number of nodes to be priced under a GNP re-esign of the NEM. There is an issue here with respect to what these "nodes" are to be used for. So far as we are aware there is still strong support for retention of an FNM in New Zealand, and no great aversion to the calculation of prices at all nodes in that FNM. Thus the focus of industry discussions relates more to the number of trading hubs/regions at which load and/or generation weighted prices might be calculated.

Conservatively, accepting 10 hubs as the minimum on which consensus might now be reached, that might imply 50 hubs for the NEM, if New Zealand is taken to be equivalent, in geographical and power system size, to one NEM region. Or it might imply 25 hubs for the NEM, if New Zealand is taken to be equivalent, in geographical and power system size, to two NEM regions.

But the evidence need not be interpreted in this way. For historical and geographical reasons, the NEM now has five natural regions, whereas New Zealand has two[24]. Thus there is a certain logic for operating a market at that regional level of aggregation. The problem comes when considering the next level of detail below that, because, in New Zealand, it is not obvious where boundaries can be drawn in a way which is both justifiable now, and sustainable over time.

Thus, for example, Bertram's remark may be taken as implying that a third "region" should be created for Auckland, being the largest city and, more or less at the opposite end of the North Island from the Wellington, where the HVDC link to the South Island connects. But if Transpower's current plans

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[24] That is, the two main Islands, each of which forms a separate AC power system, connected by a single HVDC link.

come to fruition, there may then be no significant constraints on power flowing across the HVDC link, or into Auckland, for a decade or so. At the same time, constraints in other parts of the country can be expected to become increasingly important, particularly because major investments in geothermal and wind generation are creating transmission flows in quite unexpected places. It might still be said, then, that there are *only two important transmission bottlenecks in New Zealand*, or more exactly three in the next round of transmission proposals, but they are now expected to be at quite different places from those Bertram was presumably referring to in 2005.

The relevance of all this to the NEM depends on the nature of intra-regional networks, how often constraints bind, the nature of the resultant pricing patterns, and how much impact generation and/or investment might be expected to have, in terms of shifting the likely location of congestion. If congestion is insignificant, no form of congestion management mechanism is likely to be worthwhile.[25]

If congestion is significant, but shifting, then an FNP/GNP approach may prove easier, in the long run, than any form of sub-regionalisation, or constraint pricing, that requires frequent changes to the (explicit or implicit) allocation of congestion right, and all the controversy likely to ensue. Arguably, this is the greatest potential advantage of GNP to the NEM.

The same may be true if congestion occurs on loop constraints, rather than on simple inter-regional links. Simple bounds divide markets into distinct regions. But loops create "spring washer" price patterns, in which one constraint creates different prices at each node around the loop, and in all locations connected to the loop, with no clear regional boundaries.[26] This kind of pattern may best be dealt with by either an FNP/GNP market design, or a CP-based regime as discussed in the framework paper. We might suggest that one reason why US markets have mainly opted for FNP is that they probably have very much more complex loop flow issues than either New Zealand or Australia.

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[25] If constraints seldom bind, though, this suggests over-capacity which should not be sustainable under a rational economic investment regime. And that suggests an alternative focus of regulatory attention.

[26] This is the case for constraints arising in one major loop around New Zealand's central North Island, for example.

In an effort to manage basis risk in the absence of a formal congestion-hedging instrument, 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.. (p66).

This paragraph is correct, but some further explanation may help. The New Zealand market differs from the Australian market in that there is strong vertical integration between generation and retailing, on a more-or-less national basis. This is one very powerful reason why energy hedging markets have had so little success. They are of little interest to a vertically integrated "gentailer" (ie generator/retailer) who has a reasonably matched portfolio of generation assets and customer obligations.

But there are two different vertical integration strategies here. While it is true that some *participants in the New Zealand market have relied on regionalisation (supplying only customers in a close geographic proximity to generation facilities)*, this is a minority strategy. The majority of "gentailers" also rely heavily on geographical diversification. And this is a major reason why transmission hedging markets have not received much industry support. It really does not matter to a nationally diversified "gentailer" if the market settlement system implies an allocation of "transmission rights" to generation or load at the "wrong locations". Such a "gentailer" is operating at all locations, and it is merely a matter of internal accounting to attribute rents collected for the "wrong locations" to the "right locations", if so desired.[27]

Thus the failure of FTR markets in New Zealand need not necessarily imply that the same would be true in Australia. It should be recognised that the New Zealand market has been dominated by a relatively small number of relatively diversified participants from the start. In this respect the NEM is probably more like US markets, where there are much larger number of participants, who must trade more actively over longer distances, and FTR markets have been quite successful.

Conversely, it may reasonably be said that the failure to establish an FTR markets in New Zealand, from the outset, has forced participants to adopt strategies which means that those which have survived now see little need for one. Thus the evidence may be interpreted as underlining the importance of introducing FTRs, or equivalent instruments, in conjuction with any GNP

[27] Thus locational hedging is arguably not much of an issue for any established gentailer, because all have now adopted either diversified or regional vertical integration, to survive. The major issue in the New Zealand market, is the implication that retail competition becomes limited in certain regions, where lack of FTRs makes it difficult for an independent entrant to compete with either a nationally diversified or regionally integrated incumbent (It is not obvious that the situation is any worse than in, say, the super market business, though.)

> development, even if the need for them does not seem urgent. The need did not seem urgent in New Zealand either, because constraint rents were relatively low in early years. But many now believe that situation should really have been taken as window of opportunity, to introduce an FTR regime while stakes were low. It has not become, and will not become, any easier as time progresses, and participants bed in commercial positions based on the absence of FTRs.

So the most significant lesson from the New Zealand experience may be a negative one: That it is very difficult to change the market design and/or structure once participants have operated under one structure for long enough to have established commercial positions based on the status quo. A similar situation seems to have arisen in the NEM, with regional boundaries, for example, proving significantly more rigid than had originally been hoped. Similarly, the principal difficulty in moving toward any form of explicit congestion pricing seems to arise from perceived conflict around the allocation of congestion rights.

On the other hand, the principal justification for moving to an FNP or GNP framework may be that, once established, the potential for conflict over, for example, regional boundaries, is significantly lessened. It does not disappear, though, as conflicts over potential FTR allocations in New Zealand show.

3.6. Lessons from Texas and California

As noted earlier, we believe that Frontier has drawn reasonable inferences from its sources. Overall, though, we do suggest that experience in FNP/GNP markets might be interpreted somewhat more positively than in this report. But we note that this report does not focus strongly on what others may see as the most telling observation from the US data, namely that Texas and California, the two markets which started out with a regional structure similar to the NEM, are now on track to covert to a FNP model.

We understand that it was not the purpose of the GNP report to comment on whether these experiences mean that a shift to GNP in the NEM is appropriate or not. And, as noted in the Introduction, we are not ourselves strong advocates of FNP or GNP for Australia at this time. But it is worth noting that, in light of the Texas/California experience some would argue that the real questions become:

- What is it about the zonal model which has proved so unsatisfactory in the US?; and
- What is it that makes a zonal market more attractive in Australia than in, say, Texas?

It is not our role, here, to investigate of those questions, but perhaps the answers might include some gains to be made, in the US, from cross border integration between similar market designs. The availability of a pool of expertise trained with respect to the analysis of a particular market form is a significant issue, even if there is no cross-border trade, and it is not an insignificant issue for the NEM either.[28]

Conversely, in Australia, the development of a relatively simple "regionalised" transmission network topology, for both historical and geographical reasons may provide ample justification for maintaining an essentially regional market structure.

Still, if more work were to be done on US markets, at some future date, we would suggest focussing more attention on the reasons behind the evolution of California and Texas from a NEM-like structure toward FNP.

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28 A rather disastrous initial experience with its zonal market design is obviously a major factor in California…. But that need not be taken to imply that all zonal market designs are similarly flawed. The NEM, for example, has been successful to date, and we are not aware of comparable problems with the Texas market.