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Submissions
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SUBMISSION ON SPOT MARKET REVIEW

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Options to improve retail competition – Findings of the spot market review" discussion paper (the **paper**) released by the Electricity Authority (Authority) in February 2015.

2 We commend the Authority for organising the well-attended forum with the two expert advisors. We acknowledge perhaps the key point made by the two advisors: that these sorts of markets are complex and the interactions between the various moving parts are many and often subtle. Achieving the right balance is not easy.

3 Our submission is in two parts:

- General comments on the paper, and
- (Brief) responses to the specific questions in the paper (as an appendix).

General comments

4 We are generally supportive of the overall conclusions of the paper that there is no compelling reason to make any fundamental changes to New Zealand's spot market design (para 1.2). We also endorse further work in the two proposed areas of real-time pricing and an hours-ahead market, although we expect there to be significant conceptual and practical barriers to overcome.

Real time pricing

5 Real-time pricing will, we expect, require more rapid resolution of various technical issues involved in achieving a pricing solution. Those resolutions should we believe tend to favour simplicity over perceived accuracy. (We touch on this theme further below.) They should also in our view err where it is reasonable on the side of the purchaser / consumer. For example where a price could be set at the highest cleared generation offer as opposed to the (higher) cost of non-supply in a shortage

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situation, the lower of the two should be chosen.[1] This is because setting the administered energy price at VoLL means consumers pay VoLL twice: once for the energy that is delivered, and again for the energy that is not.

6 In one sense real time pricing is just minimising the amount of time you have to wait to find out whether you've lost your shirt. More important we believe is considering the point at which prices lose their economic content due to any response to them no longer being possible? We don't know when this is, but we suspect it is prior to real time. And given that any gap creates inevitable differences between what was expected and what actually happened, how are they dealt with?

Ahead markets

7 Perhaps the most significant issue with an hours-ahead market is the interaction with longer range forward markets. We recall that in 1996 there was, for a short period, a day-ahead market. However this market foundered once ECNZ announced that the reference price for its hedge contracts would be the final price and not the day-ahead price, thereby creating a basis risk for any day-ahead purchases. That potential problem does not seem to have gone away with the passage of time.

8 On other matters considered in the paper, and while we respect the quality of the expert reports that have been commissioned, we are not yet convinced that there is no scope to improve (simplify), or at least further investigate improvements to current arrangements. We also believe other areas are worthy of investigation. Together, these are as follows:

- Zonal pricing,
- Dealing with exceptionally high prices (including infeasibilities),
- Optimisation over longer periods, and
- The nature of demand-side response.

9 Before we discuss these specific examples, we must first acknowledge that the wholesale electricity market is somewhat unlike other markets. Of particular relevance to this submission is that the wholesale electricity 'market' prices are discovered in a different way: the prices are the result of the application of a linear programme. This might give them a precision that is somewhat spurious and a credibility that they do not deserve. Put another way, the mathematical purity of the approach does not automatically mean the resulting prices are strong on economic content when we think in terms of choice, opportunity cost and willingness to pay.

10 We acknowledge that there are many different types of markets, and all have rules of various sorts. However we submit that the wholesale market is particularly unusual in that, while sellers can never receive less than their offers, buyers can in fact end up paying more, much more, than they were prepared to. The quid pro quo is that consumers can buy as much as they want, and this certainly has value to them, but

[1] We acknowledge that price setting is more complicated than depicted here.

we are not aware of any formal analysis that establishes whether this balance point between the interests of buyers and sellers is currently in the right place. And were the balance point to be moved, we do not believe that the market ceases to be less of a one just because of that, and there is not, in our view, any overall *inevitable* efficiency loss.

11 The linear programme also has technical features, such as infeasibilities, which confirm a strong element of artificiality in the resulting prices. Not only do the initial 'prices' that signal an infeasibility have the potential to alarm the uninitiated, but the way they are resolved involves the application of business rules which are to some extent arbitrary.

12 We note a specific element of current market design is scarcity pricing, which is well described in the paper. Here administrative rules override the price level (setting a cap and a floor) and also include a duration limit for how long such modified prices can apply. These arrangements have (in part) been credited with improving management of hydro storage in recent years. Whether or not they have, they confirm that unmodified wholesale market prices are not seen as efficient in all cases, and that is all the more reason to believe that this may not be true in other cases as well.

13 Another consideration is the boundary between pricing decisions that affect the final energy price, and those that affect elements such as constrained on and off payments. Inherent in this distinction is some reasoning that there are some things that should affect final prices and some that should not, without violating the principle that generators that generate should be paid their offer price. This in turn is a decision about the way that costs should appropriately be recovered, and in particular how much they should be socialised – charged to all participants at all locations as opposed to specific participants at specific locations.[2]

14 One way to think more generally about the way the market might be improved is to consider what sort of arrangements we might see were the market to be based on bilateral contracts rather than a set of rules. We believe it is at least conceivable that we might see *contractual* mechanisms to manage things like unit commitment, short term scarcity, infeasibilities, high spring washers and sustained high prices that shared risk somewhat differently to the current arrangements.

15 Some light might also be shed by thinking about how arrangements would work in a hypothetical central / single operator system. For example, might they optimise dispatch over a longer period?

16 Finally we consider that it is important to distinguish between spot pricing for dispatch, and the medium to long term signals that arise from the wholesale market. In our view the latter are the more important from an economic perspective given the lumpy and to some extent sunk cost nature of generation investments. By contrast, many different short term scenarios will be consistent with broadly similar longer term

[2] There may be similar considerations with wider ancillary services.

outcomes.[3] Indeed there are probably a near infinite number of offer price sets that would lead to exactly the same physical dispatch.

Zonal pricing

17 We fully acknowledge the expert advisors' concerns, based on issues that have arisen in overseas markets, about the risks of moving away from nodal pricing in New Zealand, and we tend to agree that a fundamental point is who is managing constraints, although we would add that the tools available to actually manage constraints are also relevant. We also agree that change itself can be risky and costly even if conceptually desirable, and turning a nodal approach into a zonal one is a good example.

18 Nevertheless, new entrant and small retailers consistently report that dealing with the number of pricing nodes is costly, so we consider that zonal pricing may merit further investigation. In that vein, we think that zonal pricing – for load - that acknowledges the following features of the current arrangements might pose few if any of the risks stated in the paper:

- Many nodes are spur nodes, meaning there is unlikely to be anything other than a small price difference reflecting different losses. Even if there were to be constraints on a spur line, it is unclear how this would be managed other than by relieving the modelled constraint for solving purposes. As a first cut this suggests that pricing at "interconnection" nodes only would be a low risk simplification.

- A significant number of nodes are at the same physical location but just at different voltages. The price difference between such nodes is usually trivial, and in any case is not something that reflects a meaningful choice made by consumers. (We note in this regard the statement in para 7.9 of the paper that "diluting the locational price signal causes participants to make less efficient decisions." We submit that this is something of an overstatement with respect to many and perhaps most nodal price differences: there are no material or meaningful decisions that can be made.)

- Consumers can at various points in time be connected to different nodes on the same network, and most will have no idea this can happen, or has happened. We note that the reconciliation process acknowledges this by the use of balancing areas, and if we can't really say where consumption was physically sourced from, it seems inconsistent to price as if we do?

- Orion and a number of other distributors have been acquiring spur assets from Transpower over recent years.[4] In doing so the number of nodal pricing points has reduced considerably, but we do not believe the market is any less

[3] And some might reflect transient market power.

[4] For example Orion has acquired the Papanui, Springston, Addington and Middleton GXPs in their entirety, and acquired the Bromley 11kV assets. The number of nodal pricing points from Orion's acquisitions alone has reduced by seven out of sixteen. By shifting the distribution / transmission boundary, these acquisitions reduce the loss and constraint excess, and increase distribution network losses. In Orion's case at least, the former effect has not been commented on, while our modelling of the latter effect indicates that it is not material.

efficient as a result, and as far as we are aware, no one has claimed any efficiency loss. We are not aware of any party making different "decisions" at all, let alone less efficient ones.

- The Authority's own consideration of FTR nodes and hubs has, correctly in our view, stopped well short of increasing the number to around 250. This is an implicit acknowledgment that the probability of anything other than loss-based price differences between a node and its logical FTR node is near zero.

- Retailers and consumers rather vote with their feet in this space: retail offerings are often standard across all GXPs in, say, a distribution network area, indicating that any wholesale cost differences are trivial.

19 We have not given much thought to the detailed design of a zonal pricing approach, but the discussion above suggests that all nodes within a balancing area could be priced the same?

20 In any case, this submission is not the place for detailed design. Rather, we simply suggest that the Authority think again about ways that the number of pricing nodes might be reduced in ways that do not unduly compromise market operations.

High prices

21 The uncapped nature of New Zealand's spot market has been commented on many times. In particular the way infeasibilities are handled with the absence of any cap occasionally leads to prices that are alarming but, absent an understanding of the exact calculation of them, not necessarily misleading. As a minimum we suggest that infeasibilities in any price schedule be dealt with consistently and if possible before prices are published. If they must be published then they should either be flagged - rather than presented as an actual price - or replaced with some best estimate of what the price could reasonably be.

22 More generally though, we believe the uncapped nature of the spot price may still act as a barrier to entry as it feeds right through to assessment of entrant credit risk by banks given the difficulty of establishing plausible worst cases. We cannot say for sure that it is an *inefficient* barrier to entry, but we submit that further investigation is warranted.

23 We note that price caps can take a variety of forms. For example they can be a particular value in any half hour, a limit on accumulated financial impact over a period (as in Australia) or business rules like "where the highest offer is greater than VoLL, the price will be capped at VoLL." [5]

Optimisation

24 As we understand it, the spot market effectively treats every half hour at every node as a separate market. (It does acknowledge constraints on how quickly generators can move from one state to another.) We are not sure this leads to a better outcome

[5] With possible implications for constrained on payments.

than might result from optimising over a longer period, such as a day. We are not in a position to do this modelling, but after 20 years in the trees it is possible that we have lost sight of the wood. We recommend that the Authority considers doing further analysis in this area.

Demand side response

25 While demand side participants now have the dispatchable demand regime available to them, we believe that there is a broader context that should be considered.

26 As we have previously discussed with the Authority, there are a number of forms of demand response. Of particular interest to Orion, and of particular relevance to this topic, is the use of load management capability to condition demand on the system so that it is both more certain and less variable.

27 One specific example is the load management coordination amongst upper South Island (USI) distributors on peak demand (usually winter) days. This coordination involves the managed sharing of each distributor's load management capability to achieve a combined load that does not exceed a pre-agreed (but alterable) limit, all within the constraint of hot water heating service levels.[6] Most of this response involves the shifting of load within the day so that the total amount of energy delivered is not affected. Over the medium term the response helps ensure that new transmission investment in the USI will only occur when it is cheaper than the demand response alternative. Over the short term it dramatically changes the load profile on the coldest days, with consequent if coincidental effects on the spot market.

28 There are two implications of this:

- First, the USI load manager has the best forecast available of USI demand on the coldest days, yet it is not used in dispatch and pricing.
- Second, while the coordination currently occurs on only a relatively few days each year, there is no reason why coordinated load management cannot deliver a similar result on any day, nor any reason why the same approach cannot be applied across the country.

29 We think the first inevitably leads to inefficient dispatch on at least some days. It appears that the quality of load forecasting in the current market is not seen as particularly important and we do not understand why?

30 The second suggests that New Zealand is missing out on least cost dispatch every day, and least cost dispatch, when all is said and done, is a plain English expression of the spot market objective function. Orion has in the past proposed the concept of a local system operator as the party best placed to efficiently coordinate load management.

[6] Typically of the form "no more than X hours off in any Y hour period".

31 All of this becomes potentially even more relevant if we are headed for a future with very widespread distributed generation and storage.

32 To a large extent our concerns here link back to the period of optimisation. It is hard to imagine that a load that is both flatter and less variable over a day cannot, where the optimisation is daily, be met by a lower cost dispatch than a load that is peakier and more variable.

Other observations

33 There are two particularly interesting graphs in the paper: Figures 3 and 5.

34 Figure 3 is interesting when we consider the economic content of the prices that might result. Is it really the case that an offer price of zero means there is no economic cost associated with production of the relevant MWh? On the other hand, does $5,000 per MWh really represent the incremental resources needed to produce the last tranche of MWh? We do not make these comments to challenge the commercial drivers of the offers in question, but we are not sure that that is the same thing as marginal cost as conceived in the economics of efficiency.

35 On the other hand, if the last 100MW or so of the offer stack does in fact cost $5,000 per MWh in economic terms then we observe that:

- that is well in excess of (about 10 times) the marginal cost of diesel generation and there is around 100MW of such generation connected in New Zealand (there is around 46MW in the Orion network alone),[7] and

- there is probably enough traditional hot water storage heating demand to avoid the need to ever dispatch this last offer tranche.

36 We think the apparent ongoing impediments to the use of lower cost responses merits further investigation.

37 Dr Howard Haas at the forum noted that PJM had carried out a study to determine whether the prices seen in PJM reflect a hypothetical “incremental cost of service”, and concluded that they did. However, we suspect such a study is easier in the context of a market such as PJM where capacity is separately contracted for. In New Zealand’s energy-only market it is probably a lot harder. It may, nevertheless, be worthwhile.

38 Figure 5 represents a useful breakdown of the risks facing a small retailer. In terms of the Authority’s education role, we trust that this sort of information is shared with potential entrants as it may help to allay concerns such as those about the number of nodes. We make the following observations:

- The modelling is presumably assuming the various products are being used to back off a retail position, but what is the nature of that position?

[7] According to the Authority’s website for ‘liquid fuel’ distributed generation.

- It would be useful to enhance the analysis to compare the 100% risk managed cost with retail market prices. What margin is left?

- If we think about a retailer selling a multi–year contract now, for the next few years, then monthly baseload futures are not available to manage profile risk beyond the first quarter, if that was the idea. We acknowledge they may nevertheless provide useful information about the monthly shape of the forward curve.

- Does this assume the FTR is a perfect hedge? We understand that revenue adequacy requirements mean that not all of the relevant grid capacity is auctioned, and moreover that FTR settlements are scaled in the event that actual grid capacity is less than was 'sold', which is precisely when an FTR is otherwise likely to be most needed. Is the FTR secondary market "liquid" as stated? As an interested observer (and indeed a consumer) that is not a participant, we cannot easily find information on current market prices for FTRs. This is in contrast to readily available information on futures.

39 Another way to interpret Figure 5 is as a broad indication of the relative importance of various elements of the spot price in terms of potential economic signalling. By far the most important component is the underlying cost of grid generation as represented by the prices at say Benmore and Otahuhu. Then there is the much less significant component of downstream losses and constraints, an even smaller component from variations associated with peak demand price sensitivity, and finally there is a small residual. We think this means that in considering changes to the wholesale market the most weight should be given to the most important components, and much less weight should be given to unimportant components.

40 Finally we note possible medium term fundamental changes to the generation mix that could completely turn the wholesale market on its head. Widespread deployment of distributed generation, in particular PV with storage, including storage in the form of electric vehicles, could, over the next decade or so, render grid generation a very marginal proposition. No matter what changes to the current arrangements are investigated or implemented, we need to be mindful of not closing off options.

Concluding remarks

41 Thank you for the opportunity to make this submission. Orion does not consider that any part of this submission is confidential. If you have any questions please contact Bruce Rogers (Pricing Manager), DDI 03 363 9870, email bruce.rogers@oriongroup.co.nz.

Yours sincerely

Bruce Rogers
Pricing Manager

Appendix – Responses to specific questions

Question		Submission
Q1.	Do you agree with the choice of high level spot market design issues we've considered? If not, what other issues should be evaluated and why?	While the title of the paper is "Options to improve retail competition" we saw little in it from the perspective of either entrant retailers or end consumers. To this extent the proposals are unlikely to address the concerns of those that feel the current wholesale market arrangements excessively favour generators and perhaps have a bias towards perceived accuracy over simplicity.
Q2.	Do you agree that the Authority should explore real time pricing options in 2015/16? Please explain your reasoning.	Yes we agree this is worthy of further investigation. However we are unsure whether this helps with some potential problems and may just result in parties being surprised – favourably or unfavourably - sooner.
Q3.	Do you agree that the Authority should not explore zonal pricing in 2015/16? Please explain your reasoning.	No. We believe there are simpler options than those conceived of in the paper that could simplify arrangements for participants, and in particular new entrants. We note that consideration of appropriate zones could draw on the work used to determine additional FTR nodes.
Q4.	Do you agree that the Authority should explore introducing an ahead market (and shorter gate closure) in 2015/16? Please explain your reasoning.	Yes we agree this is worthy of further investigation. That investigation should consider the interaction of the spot market and the further ahead markets such as futures. What those markets and contracts settle against will likely have a significant impact on participation in any spot ahead market.
Q5.	Do you agree that the Authority should not explore 'paid for' demand response programmes in 2015/16? Please explain your reasoning.	In part. As previously indicated to the Authority, in our view demand response is most valuable when it is coordinated, and there is significant risk of paid-for response free-riding on other response. However, more generally in the area of demand response, we believe the paper has not adequately considered the wider role of demand side management in potentially supporting much more accurate

		forecasting of demand, and in shaping that demand to deliver a lower cost dispatch solution over the day. This in turn suggests that optimisation over periods longer than half an hour could lead to superior outcomes for New Zealand.
Q6.	Do you agree that the Authority should not explore mandatory capacity products in 2015/16? Please explain your reasoning.	Yes. We consider that a key success of New Zealand's wholesale market has been the way it has commercialised and de-politicised generation investment (and disinvestment) decision-making. We note that at least some commentators (for example Tony Seba) are forecasting a very significant deployment of PV over the next decade or so, with PV (with storage) becoming the cheapest source. It will be interesting to see how owners of existing generating plant respond to these sorts of developments.