Orion

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Submissions
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SUBMISSION ON REAL-TIME PRICING PROPOSAL

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Real-time pricing proposal" consultation paper (the **paper**) released by the Electricity Authority (Authority) in August 2017.

2 In summary:

- We support the proposal, in broad principle.
- The possible interaction with existing and possible new demand side response needs further consideration.
- It is unclear to us exactly when prices are to be produced under the proposal: whether they are a little ahead of a period or a little after the start of a period. In either case there is a question of whether the prices are actionable in the way that the paper conceives.
- We believe that the benefits may be overstated.
- We question whether a "scarcity" price, at the levels proposed, is appropriate in all or even most circumstances.
- We are concerned that some forms of demand side response may lead to inefficient outcomes, and, in the extreme, to unstable outcomes which could be worse than no response at all.
- There are important links to other Authority projects that need to be more fully considered.
- We believe that for a change of this magnitude a further round of consultation is desirable before the Authority makes a final decision.

3 The remainder of our submission is in three parts:

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- High-level comments on how system management might evolve in the context of increased deployment of distributed energy resources,

- Comments on some aspects of the paper, and

- Responses to the questions in the paper as Appendix 2.

High-level comments

4 New and emerging technologies create new risks and opportunities for the wholesale electricity market and the power system more generally. There is a significant risk that the development of real time pricing in isolation of understanding the high level risks, challenges and opportunities associated with a new future will lead to sub-optimal outcomes and/or reputational damage for the industry. The risk of market and power system instability and the proposal around scarcity pricing and load curtailment (or threat of) are particularly concerning in this regard.

5 In our view the broader high-level problem definition should consider:

- How will the market and power system need to change as customers with 'conforming/predictable' demand and energy profiles transition to customers with choice around when they consume, store or export energy?

- How do we address uncertainty – what is the transition roadmap and how will risks be managed?

- How does the future change the power system risk profile – more uncertainty leading to greater risk of failure - asymmetry – striving for efficiency (small gain) at the risk of failure (huge loss)

- With enhanced demand side management capability how will we forecast medium term system security during peak demand?

- How will the market and power system make best use of supply and demand side resources both existing and new?

- How do we ensure that demand side response to the wholesale market does not overload the distribution network (from either load or export)?

- How do we ensure that demand side resources are allocated to the highest value proposition at the right time - wholesale market or delivery?

6 Exploring these problem definition questions and issues will help to provide clarity around next steps and the actions that industry participants need to take. There is potential for a rapid pace of change in technology and customer expectations associated with that. The electricity industry needs to move quickly but value should be placed on a low risk approach. There is much to be gained in the short term from implementing steps that achieve co-ordination and transparency of information and capability. In many cases, market capability can be overlaid later when back office system and functionality

development catches up with customer expectations. A diagrammatic depiction of this is included as Appendix 1.

7 In terms of the real time pricing proposal, we observe the following:

- The potential for load and price oscillations and hence power system instability.
- Wholesale prices not reflecting competition created by demand side response.
- A lack of transparency around DSM capability and hence problematic system security planning – short and medium term.
- Peak winter wholesale prices dominating demand side response at the expense of driving power system delivery costs which are not reflected in real time.

8 A lower risk approach would consider:

- Transparency around demand side response capability – the same or similar to supply side
- Co-ordination of supply and demand side resources across the day, not just the next few minutes
- What needs to be done to ensure that the load forecast remains a reasonable prediction of base load
- How demand side response impacts on the distribution system can be efficiently managed

9 We expand on some of these points below.

Comments on aspects of the paper

10 As we see it there are three key ideas in the paper:

- Spot prices should be more actionable and more efficient
- Final prices should be based on the dispatch schedule
- Where emergency load shedding is implied by the dispatch schedule then administrative "scarcity" prices should apply.

Prices should be more actionable and more efficient

11 These are desirable attributes. However, we believe there is a trade-off between them that is not acknowledged in the paper. The closer to real time we get the smaller the set of available actions, even if the efficiency of any particular action increases. In the limit, the time frame is zero and no actions, efficient or otherwise, are possible. It is consumers, directly or indirectly, that respond to prices so their ability to respond and in what time frame needs to be top of mind when considering the trade-off.

12 All actions take time to implement, but some take longer than others, and so become less and less possible as we approach real time. The proposal limits the time available to the time between one set of dispatch prices being published, and the next. It is not clear on what basis this approach has been chosen as opposed to, for example, setting final prices based on information available 10 or 30 minutes before any particular period. It may be that implicitly the proposal seeks to minimise constrained on payments?

13 As we understand the proposal, forecast prices are still to be published and we see some risk that the present uncertainty around the relationship between forecast and final prices will simply shift to a different comparison. If forecast prices are supposed to be the, or at least a, reliable source of information for decision-makers, and if forecast prices are the most actionable prices but won't closely signal actual prices, there may be little overall improvement.

Prices should reflect dispatch

14 That prices should reflect dispatch is certainly reasonable on the face of it, and will probably result in reasonable outcomes most of the time. We note that final prices do currently reflect actual dispatch even if it takes a while to work out exactly what that was.

15 However, we note that there will still be variances between the dispatch schedule, and what actually happens in real time, and how the system operator (SO) responds to these over time will be critical.

16 The dispatch process is inherently short term, which it must be to manage the system in real time. However, that does not mean that actions in one dispatch period do not impact on actions and available resources in later periods. We see some risk that the proposal makes dispatch even more myopic than it currently is, and perhaps even blind to circumstances and opportunities. We also see some risk of instability if and when there is material un-bid demand response that is not knowable by the SO as this could create material, and greater than present, divergence between what was expected when prices are set and what actually happens.

17 As we submitted in relation to demand forecasting,[1] consideration should be given to whether the optimisation period needs to be changed. We think that a day is a more appropriate period for optimisation, particularly with respect to existing and possibly increasing use of storage to manage demand in real time.

18 At the Wellington workshop on 24 August a suggestion was made that price could become a variable in the demand forecast. While that sounds reasonable, we expect there are a few significant issues to work through if it is to be implemented. It does, however, highlight the potential wider issue of how the SO will factor un-bid demand response into its forecasts.

19 More generally the relationship between the demand forecast that drives dispatch, and the demand forecast that drives forecast prices needs to be well understood.

[1] Orion New Zealand Ltd, Submission on spot market review, 5 May 2015, p8 and 9.

20 Reassuringly though, the paper sees dispatch as pragmatic (para 3.30). We believe this principle could have wider application when thinking about how prices are set, and this is discussed further in the next section.

The price in scarcity situations

21 As we understand the proposal, where there are insufficient offered or bid resources (including transmission resources) available to the SO to meet forecast demand, then administratively set "scarcity" prices should apply. The price is effectively taken from a look-up table based on the proportion of forecast demand that cannot be met. The table in the paper has three steps with prices varying between a floor at $10,000 per MWh and a cap of $20,000 per MWh. We presume that the administrative high price is communicated to the world at the same time as the SO calls on distributors to curtail demand?

22 The 2011 work that is said to support the proposed prices links the floor price to the need to encourage, or not discourage, investors in last resort plant.[2] Given the passage of time it seems reasonable to ask whether that investment has occurred? The paper provides no information.

23 We also note that $10,000 per MWh is a very big number, and one that will likely be a good deal higher than the next highest-priced resource available. We are not sure that the normal concepts of supply and demand curves, and the way equilibrium might be found from their interaction, are robust to such large steps. The paper mentions that more certain prices might encourage investment in batteries, and that is probably true, but if and when there is a lot of battery storage on the system, the way the batteries' control system reacts to prices that are potentially changing between very high and very low in real time, needs to be considered.

24 More generally though, and referring back to the point about pragmatic dispatch, we can safely say that there are usually material resources available that would reduce demand at prices (or costs) much lower than those in the table. It might be argued that these should be reflected in demand bids, but there are costs involved in coordinating all of that, particularly for rare occurrences. On the Orion network there is typically around 50MW of storage heating load that is, for reasonably extended periods of time, available at near zero cost.[3] If prices are supposed to reflect dispatch, and dispatch can be pragmatic, then why can't price setting be pragmatic?

25 This isn't just theoretical. In the examples given in the spreadsheet (published along with the consultation paper) that relate to branch constraints on Islington circuits on 25 November 2015 and 16 February 2017, in both cases these seem to have been managed by Orion responding with a modest amount of storage heating being turned off for a short period. We can be reasonably sure that this response was at near zero cost.[4] The proposal risks

[2] Electricity Authority, Scarcity pricing – Overview, 27 October 2011.

[3] This amount is generally available during the day. A similar additional amount could be available at various times during the night when the significant quantity of night rate storage heating is on.

[4] Other low cost response that could be called upon for local constraint issues is switching of load between GXPs. We note in passing that purchasers do not know in real time what GXP their customers are fed from.

replacing a simple solution that works well with a more complex solution that works less well.

26 Beyond storage heating there is further relatively low cost (compared to $10,000 per MWh) response available. For example we have commercial arrangements in place with around 9MW of diesel generation that is prepared to run for $500 per MWh. There is a further 40MW of diesel generation connected to the network that, in principle, could be procured to run at much less than $10,000 per MWh.

27 Of course "scarcity" times might coincide with times when these sorts of resources are heavily occupied fulfilling their primary function of supporting our load management, but it will always pay to find out first.

28 To us this suggests that, if a look-up table approach is to be used in scarcity situations, it should include tranches of the much lower cost resource that is both available and that will in many cases actually be the resource called upon. This would align much better with the concept that prices should reflect dispatch.

29 More philosophically, if we are at the point of curtailing demand then, at least to some extent, the supply side of the industry – generators, the SO, the grid owner, distributors, third party aggregators and retailers – has collectively failed to meet consumers' reasonable expectations. Before we turn supply off to some of those consumers, and charge a hefty price for the demand of those that are not turned off, we need to be able to look them in the eye and say we had explored all other available options and had no choice. In our view the proposal as it stands does not do that.

30 To develop an analogy used at the Wellington workshop, the proposal is as if you decide to go to a restaurant based on the menu on the website, but find once you get there that the menu keeps changing even while you are deciding what to order, and then, having finally ordered the fish for the main, being told that only an entrée-sized portion is available and that you'll have to pay at the price the restaurant thinks you would have been prepared to pay for it had you not eaten for a week.

31 Interestingly, and if we understood the discussion at the Wellington workshop correctly, this approach would not apply in sustained shortage situations such as those arising in dry years when rolling outages are occurring. It is unclear to us why the proposed approach to what are now infeasibilities, if it is a good one, should not also apply in such situations. In fact aren't these the most important situations? It also raises the question of what prices are to apply in sustained shortage situations when there are rolling outages. We would judge that an understanding of that is critical to parties thinking about investment in last resort generation or equivalent approaches.

The price at other times

32 We have fewer concerns about real-time price setting at other – non scarcity – times as this will generally be reflecting non-administrative bids and offers.

33 However, the concerns about the extreme short term nature of dispatch and how this interacts with the longer term (in this case primarily the rest of the day) forecast remain.

34 As well as the difficulties for the SO knowing quite what the demand it is looking at is made up of, there is the greater difficulty of knowing what will happen to that demand over subsequent periods. The quality of the SOs demand forecasting will be critical to success, and this will be more so the greater is the demand response. Much of the estimated benefits of the proposal arise from increased demand response, and we tend to agree this is more likely if the price is more certain. What is not clear is that this is actually a benefit when the impact on dispatch over time is taken into account.

Interaction with distributor load management during some periods

35 Distributor load management inevitably influences the wholesale energy market at certain times, since it changes demand – decreases it or increases it – compared with what it would otherwise have been. This affects dispatch and the proposal in a number of ways:

- As already noted, load management is a potentially low cost source of demand response.
- Load management may use resources, or make unavailable resources, that other parties may have bid or offered.
- Load management may offset the effects of other resources. For example we are normally controlling to a load limit based on real time demand observations. If other demand response is occurring at the same time the system will automatically shed or restore load to keep aggregate load at the limit.
- It will be important for the SO's forecast to accommodate this response.

36 As the number of parties participating in the market increases, be it directly or via third-parties such as load aggregators, there will be increasing interaction between the various parties and the associated resources. We believe coordination of these interactions will become more and more important as the number increases.

Other Authority projects – demand forecasting,

37 We believe the real-time pricing proposal interacts with the Authority's demand forecasting proposal in some very important ways:

- The relationship between short term demand forecasts (say for the next 48 trading periods) and dispatch forecasts needs to be understood.
- Improvements to forecasting (all forms) need to consider how existing and possible new demand response will be factored in.

A note on process

38 On 31 August the Authority published the following market commentary:

MORE ACCURATE PRICING CAN UNLOCK TECHNOLOGY POTENTIAL

It's important to improve the certainty and reliability of spot price information to enable the growth of new technology, such as batteries and electric vehicles, and business models.

For example, batteries can help to meet demand in peak periods, but need reliable spot price information to ensure they contribute energy at the most valuable times. It's likely that consumers will be less inclined to invest in and use batteries if they can't get reliable spot price information to help them make those decisions.

Currently, spot market prices are finalised two or more days after 'real-time'—after generators have supplied electricity to the market and consumers have used the electricity. However, if prices were finalised in real-time, participants and consumers would receive more price certainty and could make better decisions about their electricity use.

On 1 August we published a consultation paper on our real-time pricing proposal. If progressed, our proposal will be a major development for New Zealand's electricity market, and is the result of a detailed programme of work over many years.

Our proposal would enable smarter decisions which are likely to save consumers money and reduce the overall investment that New Zealand needs to make in the power system. Prices would be more actionable and more efficient, and the process would be simpler and easier to understand.

"More actionable" means consumers and participants can trust and respond to the prices they see in real-time. More efficient means consumers and participants would be much less likely to regret their decisions, and prices reflect the cost of resources actually used to run the power system at the time.

Submissions on our consultation close at 5 pm on Tuesday, 26 September 2017.

39 This commentary appears to prejudge matters currently subject to consultation. In our view this is not appropriate as it is at odds with good consultation principles, for example as set out in the Authority's guidelines for distributors consulting on pricing changes:[5]

The [consulting party] must approach the matter with an open mind, and must be prepared to change or even start a process afresh.

and

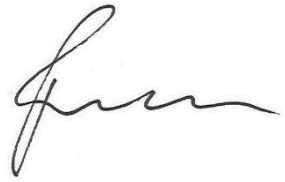
Good practice includes: no pre-determination of any particular outcome, including being open to the possibility that, through the consultation process, any or all of the … change proposals may be abandoned or modified in response to feedback received.

[5] Electricity Authority, Guidelines for consulting on distributor tariff structure changes, 2 July 2012, p3.

Concluding remarks

40 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

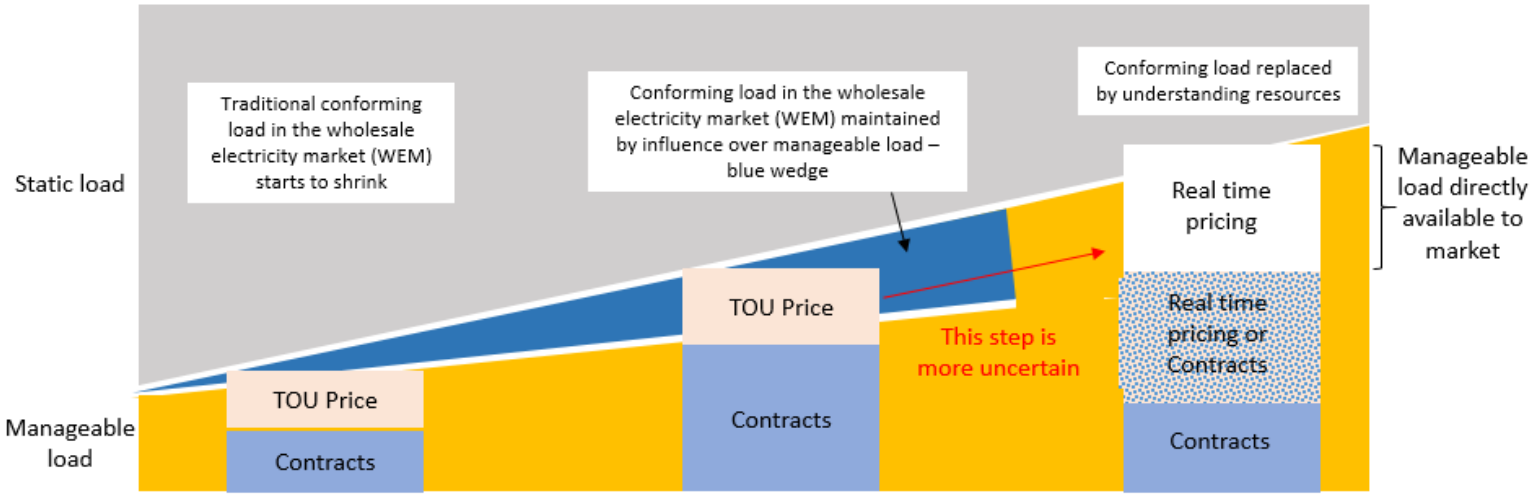


Rob Jamieson
Chief Executive

Appendix 1:

Possible evolution of system management

(with a focus on the residential customer context)



Customer behaviour	Influenced by Retailer time of use pricing such as night and day Distribution contracts with Retailer/ customer for hot water management	Influenced by Retailer time of use pricing such as night and day Contracts for hot water, EV and battery storage management services becoming increasingly common	Influenced mainly by real time pricing signals Aggregator contracts for transmission and/or other market services may also influence customer behaviour
Market attributes	Emergence of transmission contracts Manageable load behaviour not material enough to affect the WEM Wholesale real time pricing emerging Aggregators starting to emerge	Aggregators offer transmission alternatives Contracts substitute for the complexity of a full dispatchable market model down to the household level Wholesale electricity market remains stable by a role to create load conformity/profiling	The use of large scale generation, the grid, networks and customer resources is optimised almost entirely by the real time market Power system stability is maintained by using infinitely variable price to coordinate resources at individual premises

Appendix 2: Responses to specific questions

Submitter: Orion New Zealand

Number	Question	Response
Q1.	Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	Yes we agree with the broad principle. However, we believe a number of approaches align with the broad principle. More generally though, actionable prices must encompass the time it takes to carry out the actions. If the nub of the problem is actually that forecast prices are an unreliable indicator of final prices, then producing final prices more quickly simply brings forward the disappointment.
Q2.	Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	Yes. As an aside, the paper would have been clearer if the examples in Figures 3, 4 and 5 had not all been five minute intervals, since there is no difference between time weighted and arithmetic averages in such cases.
Q3.	Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.	Yes.
Q4.	Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	No. These are not necessarily generation shortages, but situations where, even with all available offered and bid resources dispatched and including transmission resources, forecast demand cannot be met. If such an approach is to be used the table of default values should at least reflect the actual resources available to the system, many of which are usually available at much lower cost than the values proposed in the paper. We do not believe the paper gives adequate attention to the potential impact pre-defined, and high, scarcity prices could have on generator offer behaviour in situations where generators are pivotal. In some scenarios a generator may be able to reduce quantities offered at relatively low prices knowing that the total quantity offered is insufficient and that therefore they will receive a price much higher than their offer price. At the very least this suggest the safe harbour provisions in the Code should be reviewed as part of this project.

Q5.	Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.	Partially, and subject to our response to question 4. We note however that, if it actually happens, demand curtailment is a very blunt instrument which results in total loss of supply to a group of consumers who will not necessarily experience impacts in line with the very averaged concept that is VoLL. It is conceivable that dispatch of higher cost offers or bids may have been better in hindsight.
Q6.	Do you agree the SO does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?	Yes, at least at this stage. We are not sure emergency load shedding is the right term. We suspect many and perhaps most situations will be able to be handled with much lower impact actions by distributors. In fact, and as noted at the Wellington workshop, this typically happens now. We think it is more important that the SO does not make changes to the pragmatic approach to real time dispatch.
Q7.	What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning.	No comment.
Q8.	Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning.	We believe the rationale for the cumulative price limit was to ameliorate cumulative financial effects during sustained high priced periods. We do not see why this rationale is no longer relevant just because the way final prices are produced is different?
Q9.	Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning.	Yes. More generally we believe the approach of relaxing constraints can have wider application. For example a reduction in modelled security level might reduce the need for load shedding, and we are reasonably sure that if you asked the customers that are shed if they would have preferred just running the risk of being shed, the answer would have been “Yes!”.
Q10.	Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning.	No comment.

Q11.	Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning.	Also see our response to question 12. A bottom up forecast of load does not of itself provide sufficient information, as in most cases more generation will need to be dispatched to meet any given demand due to losses. It is unclear from the paper how forecast demand gets translated to required supply. Perhaps more importantly, if there is a significant increase in demand response will this potentially make more nodes non-conforming, and what are the implications of that?
Q12.	Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning.	If demand data is needed then the source should be the best available. It is less clear what the demand data is for. It appears it forms the basis of a short term forecast, but how this forecast is produced and how it relates to the longer term (say day ahead) forecast that underpin forecast prices is unclear. Also how will the longer term forecast adapt to actions taken in real time? The essence of the problem here is that any and all response will be reflected in changes in metered quantities. The SO is going to need to know the components of the demand it is looking at in order to manage dispatch for the next period. Suppose for example that the SO sees a demand of 5,800MW, and uses this to forecast demand of 6,000MW for the next dispatch period. Also suppose that there are only dispatchable offers and bids for 5,900MW, so the SO sets the real time price to (say) $10,000 per MWh since it expects to have to instruct EDBs to curtail load. Now suppose that price and curtailment signals reach the real world and demand turns out to be 5,800MW. What does the SO do with this number for the next dispatch period, as it now includes an unknown combination of unbid demand response and curtailment. Does the SO interpret this load as meaning curtailment is no longer required - meaning that the scarcity price no longer applies - or that the curtailment must stay in place and therefore so to must the scarcity price? The wider question here is how does the SO deal with unforecast demand response, and changes in it, that occur throughout out the day? We note that, by definition, metered demand can never in real time exceed the resources available to meet it, but metered demand may always reflect responses that are, at least to some extent, unknowable.

Q13.	What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning.	We have no strong views. We do note, however that the prospect of and concerns about yo-yo dispatch may become more of an issue when and if increased unbid demand response occurs given the potential impact this will have on the SO's forecasts.
Q14.	Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning.	We are not sure that compliance has any meaning in the context of dispatch-lite. How would anyone ever know that a dispatch "notification" had not been acted on? It certainly won't be known in real time. As a consequence it appears conceivable that a dispatch light demand response bid could set the price even though that demand response never actually happens. While this looks like an opportunity for the demand side to manage prices down, it otherwise appears undesirable. On the other hand it may still be superior to the consequences of unbid demand response.
Q15.	Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning.	No comment.
Q16.	Do you agree with using the last bid or offer received in a trading period when calculating constrained on and off payments? If not, please explain your reasoning.	No comment.
Q17.	Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning.	Yes.
Q18.	Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter).	A bit of both: automated as much as possible, but with manual intervention for unusual exceptions.
Q19.	If we retain a manual claim process for pricing errors under RTP, who should perform that role: – the SO? – the Authority? – the pricing manager, as their only function? – some other party? Please explain your reasoning, including regarding any possible conflict of interest.	We believe the SO is best placed, perhaps with the Authority in an approval capacity.

Q20.	Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning.	Yes.
Q21.	Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning.	As we understand it, forecast schedules cover significantly more trading periodsthan real time scheduling, so it is unclear how far into the future this alignment will occur. Of more interest is how ongoing divergences between forecast and dispatch schedules are to be managed.
Q22.	Do you agree with the proposed use of dispatch schedules to apportion loss and constraint excess for financial transmission rights each month (if that is required)? If not, please explain your reasoning.	No comment.
Q23.	Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning.	No comment.
Q24.	Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.	No comment.
Q25.	Do you agree with the cost benefit assessment? In particular: – what (if any) other sources of benefit should be included in the assessment? – what is your view on key assumptions, such as the level of improved demand response enabled by RTP? – what (if any) other sources of costs should be included in the assessment? Please explain your reasoning.	We are uncertain that any increased demand side response will necessarily be more efficient. If it makes load inherently more difficult to forecast, and inherently less stable in real time, it may decrease efficiency.
Q26.	Do you agree with our assessment of alternative RTP designs? If not, why not	As noted above, actions take time, and the proposal seems to us to have shortened the available time to as little as it can possibly be without it being zero. We consider that the paper has not adequately shown that this is superior to Option A, or some variant of Option A. Para 4.25 of the paper points to Option A being an “ahead-market”, which is true, but so is the proposal, it’s just less ahead and for a (probably) shorter period. The same para also notes that “a lot can change in 30 minutes”, which is certainly true,

		but a lot can change in, say, 5 minutes as well. Whether “a lot” is more or less under the proposal than it is now remains to be seen.