BOLD TRADING

emhTrade

The Electricity Authority
via email

16 December 2022

Driving Efficient Solutions to Promote Consumer Interests Through Winter 2023

To whom it may concern,

Bold Trading is an investment advisory firm that specialises in trading in power markets. In addition to being active in New Zealand's hedge market for 5 years, Bold Trading has recently been appointed by the Authority as a Commercial Market Maker. The founders of Bold Trading have many years' experience in power markets, both in trading futures and transmission rights, as well as providing OTC client solutions.

emhTrade also provides investment management services, specialising in New Zealand electricity, and has been an active participant in the hedge market for over a decade.

After the successful award of the Commercial Market Making Agreement, Bold Trading sought to expand its presence on the ground in NZ, culminating in the acquisition of a 50% stake in emhTrade in November 2022. The two firms look forward to playing an even more active role in the New Zealand market including through market making and participation in the market for Futures, FTRs and other risk management products and services.

Thank you for the opportunity to provide input into how best to manage potential generation shortfalls during the coming winter. In response, we provide the following joint submission.

Overview

Fundamentally, the issue that the Authority is concerned about can be boiled down to the 'unit commitment problem'. In our view, as highlighted in the consultation, this definition includes commitment decisions of both generators and consumers.

As has been outlined in MDAG's recent paper[1] the unit commitment problem will be exacerbated by higher renewable penetration (that is intermittent) and the retirement of thermal plant. Given this trajectory, ***we support taking urgent but enduring steps to ensure that unit commitment decisions can and will be made in a way that is efficient and that will lead to reliability in the long-term***.

The two underlying causes can be summarised as:

- Poor Information
- Poor Incentives

Whilst decisions can be improved with better information, it must be recognised that unit commitment decisions will always be made under some degree of uncertainty (given that they are made in regards to the future). Therefore, the greatest long-term value will be derived if the Authority focuses its resources on improving incentives.

We note that even under conditions of uncertain information (demand, wind etc), with appropriate risk transfer mechanisms, it is still possible to create certainty in regards to financial outcomes. Such outcomes create strong incentives.

[1] 2022-06-12 Price discovery in a renewables-based electricity system. https://www.ea.govt.nz/assets/dms-assets/31/MDAG-options-paper-final-2.pdf

In addition to our responses to specific questions, our view is that the following core principles should be applied when defining potential solutions:

1. Maintain the integrity of the Gross Pool if at all possible. External or parallel payments will further erode the incentives on parties to contract, further exacerbating the unit commitment problem in the long-term.
2. Similarly, it is imperative that the System Operator (or any other party) is not able to 'clip the right tail' of the spot price distribution at their discretion[2]. This drastically reduces the incentives of contract purchasers, which results in a lack of unit commitment in the long-term.
3. Scarcity Pricing needs to be invoked around clear, predictable rules that lead to reliable outcomes that reflect scarcity or shortfall. This does not appear to be the case currently. The Authority notes that "In 2021 there were 2.25 hours of energy or reserve shortfall, and in 2022 there were 6 hours". However, in 2022 prices have only exceeded $2000 for 2 hours and have at no time exceeded $5000, a far cry from the $10,000/MWh that the Code defines as a Scarcity Price[3]. Resolving this issue with urgency would dramatically shift incentives.
4. Interventions that are designed to resolve the unit commitment problem may have implications for forward market liquidity and the cost of provision of that liquidity. For example, if there is increased uncertainty or discretion in how much reserve must be procured may lead to difficulty in price discovery for periods beyond the unit commitment horizon (eg months and quarters).

Q1. Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?

Yes, and to make this issue worse, Scarcity Pricing does not appear to be setting the price when there are reserve shortfalls. The fact that the SPD inputs during shortfall situations still appear to have subjectivity and therefore uncertainty is adding to the difficulty in making operational decisions (on both the supply and demand side).

Q2. Do you agree that the factors in paragraphs 4.10 to 4.63 create information challenges or misaligned incentives, and that these make it hard to achieve optimal commitment actions? If not, what is your view and why?

We agree that risk and loss aversion lead to incentives that may not lead to optimal outcomes.

We also agree that discretion in SO and regulator decisions that directly impact reliability at the expense of cost are problematic. We suspect this is the root cause of the lack of Scarcity Price signals despite an increase in the occurrence of reserve shortfall events.

SO discretion and subjectivity should be removed to the extent possible (especially where this discretion has a direct but opaque impact on cost).

[2] This discretion can occur through reduction in reserve margin or procuring of standby generation, or through constraining plant on.

[3] And also, in a number of cases of reserve shortfall, less than 3x the highest reserve offer price.

We don't agree that uncertainty per-se leads to inefficient *incentives*. The key question around incentives is whether the incentive to transfer risk is strong enough to overcome the cost of doing so.

Steps should be taken to ensure participants have mechanisms to efficiently transfer risk, specifically that risk which arises from uncertainty across the unit commitment horizon (both on the supply and demand side). These mechanisms do not currently exist.

There are two key impediments to short-term risk transfer:

- Weakened incentives to contract due to a lack of, or at least a lack of certainty of, Scarcity Pricing rules setting prices in shortfall events.
- High transaction costs and limited liquidity pools caused by the need for buyers and sellers to bilaterally manage credit risk.

Q3. Do you agree that it is prudent to examine options to address information and incentive gaps identified above? If not, what is your view and why?

Yes, provided that changes made with urgency create enduring long-term benefit (rather than just solving immediate problems).

Q4. Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?

The Authority must also consider the likely economic cost of any option (rather than just the risk of unintended consequences) and show net benefit. It is not enough to simply choose options that can be implemented with the greatest haste.

Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?

The Authority should, with urgency, ensure Scarcity Pricing rules are fit for purpose and working as intended (i.e. Participants can be certain that prices formed as a result of the rules are reflective of energy or reserve shortfall in shortfall situations). This currently doesn't appear to be the case.

Contrary to the Authority, we hold a strong view that an hours (or days) ahead market can provide a low-cost, rapid to implement and easily reversible solution that will provide not only information, but financial certainty and therefore robust incentives for unit commitment.

The Authority should support the nascent hours-ahead market, noting that this market does not *require* any Code changes to provide both better information and better incentives (through certainty of financial outcomes), although as noted below, transaction costs could be reduced with minor Code changes.

Such support could be provided through:

- Drafting and/or publication of a standardised short form contract that leverages the existing HSA arrangements in the Code.
- Raising awareness of the activities of those providing brokering services in this market, for example by promoting the liquidity windows.

- Minor changes to the HSA arrangements in the Code to ensure that all participants can utilise and rely on a standard level of credit support for short-term (hours-ahead) contracts via the Clearing Manager[4]. In doing so this would drastically reduce the transaction costs associated with short-term contracts by centralising the credit approval process.

We disagree with the assessment that an hours ahead market carries any risk of unintended harm, is difficult to modify or remove, or that it couldn't be implemented within months (if not weeks). The Authority appears to have constrained this option to be in regards to physical market arrangements when, in actual fact, financial contracts provide the same incentives and certainty for participants making unit commitment decisions.

Q6. Do you think it would be beneficial to publish the residual offer information used by the system operator when calculating Grid Warning and Emergency Notices? If not, what is your view and why?

Yes, if this could be done through WITS at reasonable cost.

Q7. Do you think it would be beneficial to provide sensitivity case spot price forecasts in forward schedules, as well as central forecasts? If not, what is your view and why?

This is likely to be beneficial, however we suspect most participants that have meaningful unit commitment decisions to make are already making their own price sensitivity forecasts.

Q8. Do you agree that cross-industry work on improving the quality of intermittent generation forecasts is unlikely to be available for Winter 2023? If not, what is your view and why?

We agree, but note that if and when intermittent generators have incentives to improve their forecasts, they will. The regulator should focus on the incentive to improve, rather than the process by which improvements are made.

Q9. Do you agree that the system operator should procure an external wind forecast and ask participants to review their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?

We agree, although the cost of this should be borne by those intermittent generators whose offers are the least accurate, or the System Operator.

Q10. Do you agree that the availability and use of 'discretionary' demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why?

This should not be a priority. The accuracy of such information will be questionable while there is no incentive on any party to ensure quality of forecasting.

Q11. Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?

---

[4] The existing requirement on the Clearing Manager to cancel an HSA if a party to it is in default creates a strong incentive not to use them. A counterparty to a defaulting participant will find themselves at the back of the credit queue with no security held in the event that an HSA is cancelled. This is considerably worse than would be the case if there were no HSA and credit was managed bilaterally through Credit Support Arrangements.

We disagree.

In principle, a standby-reserve ancillary service could be desirable, and if costs were allocated appropriately, would create the necessary incentives for intermittent generation forecasts to improve. However:

- We think the time-frame to implement this in a way that is robust for the long-term makes it infeasible for the purpose of resolving issues in winter 2023.
- If it is introduced, costs should be allocated to those parties that submit bids and offers at the unit commitment time horizon (hours - days) that do not reflect their ultimate consumption and generation.
- This allocation is challenging as standby reserve must be procured based on the *uncertainty*[5] of those bids and offers which is difficult to measure at the time they are submitted.
- The SO must objectively measure and publish the uncertainty in forecasts in order to decide the necessary volume of standby reserve to procure. This process must be certain, transparent and published well in advance.
- There are many approaches to integrating such an ancillary service into the energy and reserve co-optimisation (eg inter-temporal SPD, lengthening of gate closures), each complex in their own right. It would likely be detrimental to consumers to select an option based on its implementation timeframe rather than its long-term net-benefit potential.

Whilst the detail in the consultation paper is scant, it appears that the SO would be given discretion (increasing uncertainty, and potentially increasing reliability and cost to an inefficient level). It seems this would effectively act as a *demand multiplier* in SPD. If this was signalled and certain at the unit commitment horizon, ceteris paribus, we would expect more unit commitment.

However, this would not be due to the fact that outcomes were certain, but rather because the risk of uneconomic dispatch would be so low as to make the commitment decision low risk.

We note that to move the price distribution by this magnitude would require a dramatic increase in expected prices over the entire unit commitment horizon, including in situations where there would have, in hindsight, been no shortfall.

Q12. Do you agree that selectively increasing ancillary service cover should be considered as an interim option for Winter 2023? If not, what is your view and why?

We disagree.

Given the Authority has stated that the primary drivers of the problem are poor information and poor incentives, we are concerned that this is being put forward as an option. Any subjectivity in when these selective increases will take place will increase risk and potentially reduce liquidity in the contracts markets.

Rather than trying to artificially move the entire distribution[6] to the right when there is risk of shortfall, a more efficient outcome will be achieved if:

- Scarcity Pricing reliably sets prices in shortfalls that reflect the cost of that shortfall (creating an incentive for net-purchasers to contract); and

[5] This uncertainty is separate and distinct from the actual error that is observed on any given occasion that reserves are procured.
[6] Over the unit commitment horizon

- There is an efficient means for participants to transfer that risk, such that participants with the flexibility to do so will make unit commitment decisions (on the supply and demand side).

An urgent review of the Scarcity Pricing mechanisms will achieve the former, whilst a centrally cleared, financially settled hours ahead market would achieve the latter.

Q13. If increased cover from an existing ancillary service at times is pursued further as an option for Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?

We do not support this option. In any case, it should only be pursued if the cost can be recovered effectively from either the SO when they act overly conservatively, or from participants whose bids and offers create uncertainty.

Q14 Do you agree the option of requiring retailers to make compensation payments to customers affected by forced power cuts should not be explored for Winter 2023? If not, what is your view and why?

We agree.

Q15 Do you agree that reviewing the default pricing in the Code to apply in energy and reserve shortfalls should not be explored for Winter 2023? If not, what is your view and why?

We strongly disagree that this should be deferred.

Rather, <u>ensuring these prices are reliably reflecting the underlying system conditions is, in our view, the lowest cost and most quickly implementable option proposed</u>. It is also the most likely to lead to the correct incentives for efficient unit commitment decisions (provided risk transfer conduits exist).

Q16 Do you agree that an hours-ahead market should not be explored for possible adoption for Winter 2023? If not, what is your view and why?

We disagree.

Whilst it is true that an integrated two-stage settlement process would be complex and unachievable by 2023, the majority of the benefits derived from such a process would arise from a financially settled short-term (day-ahead and hours-ahead) market.

Most, if not all, of the requirements for such a market are in place today.

As the Authority notes, participants' exposure to financial contracts (or the lack there-of) can dramatically change their incentives. We are surprised that the Authority has completely overlooked a financial hours ahead market as an option.

The most effective mechanism to create the correct incentives for unit commitment is an hours ahead market. This can be achieved within months, if not weeks if the Authority:

- Ensures the Scarcity Pricing provisions in the Code lead to prices that reliably and predictably reflect scarcity when scarcity exists (in energy or reserve).

- Ensures that the existing HSA arrangements can be utilised in such a way as to provide vanilla credit arrangements between all physical market participants (dramatically lowering transaction costs).

- Supports and promotes liquidity in such a market.

Q17 Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter 2023? If not, what is your view and why?

We agree. In order to ensure that in the long-term the correct incentives are in place for efficient unit commitment decisions, it is imperative that the integrity of the gross pool be maintained.

Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?

Yes, although we note that these options will have limited value given they only impact information, rather than incentives.

Q19 Do you agree that options F and G should be assessed further to determine if they are likely to have net benefits? If not, why not?

Only option F, and only with due care in the design and cost allocation. This is very unlikely to be feasible in the short-term.

Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?

We disagree.

Option I should be pursued with urgency. This review should focus on the mechanism as much as the dollar value of prices. It is clear that the Scarcity Pricing mechanisms in the Code have not led to prices that have accurately reflected scarcity. This has reduced the incentive to contract, which has led to lower levels of contracting, which has, in turn, reduced the unit commitment incentive.

A version of option J that relies on financial contracts should be pursued.

We agree that options C, H and K should not be pursued (for winter 2023)

Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?

As noted above, a minor change to the HSA provisions could dramatically lower the transaction cost of short-term contracts and should be pursued.

Once again, thank you for the opportunity to participate in this consultation. We would be happy to discuss further at your convenience.

Regards,

Stu Innes
CEO & Co-founder
emhTrade

L. Hamill

Luke Hamill
CIO & Founder
Bold Trading