Driving efficient solutions to promote consumer interests through winter 2023

Contact Energy Submission

16 December 2022

Introduction and Summary

1. Thank you for the opportunity to provide our views on the consultation paper on driving efficient solutions to promote consumer interests through winter 2023.
2. We are glad that the Electricity Authority (the Authority) is considering this important issue. The industry is facing some genuine risks over winter 2023 and it is important that there is a robust solution to this risk.
3. We have contributed to and fully support the submission from the CEO Forum. Further to that submission we'd also like to raise:
    a. the importance of protecting New Zealanders from outages;
    b. why using slow-start thermal to address winter peaks is very challenging;
    c. the need to communicate shortfall information in a way that retains confidence in the market;
    d. support for options proposed by the Authority to improve information to market participants;
    e. support for a short-term winter peak ancillary service like that proposed by the CEO Forum; and
    f. a recommendation for the Authority to step up work on ways to support the growth of the demand response market as a key part of the longer-term solution.
4. We have also provided responses to the consultation questions as an attachment.

It is important to protect New Zealanders from outages

5. Power outages can have a very significant impact on New Zealanders. Much of our economic activity screeches to a halt, produce may be wasted, people may go cold, and some life-saving equipment may no longer function.
6. As noted by the CEO Forum, we are at a key point in the decarbonisation journey where there is greater need to build confidence in the market to support wide-spread electrification. If there are shortages consumer confidence in the market could be materially harmed, which may slow uptake of a range of technologies from EVs to moving industrial process off fossil fuels.
7. While the Authority may be correct that there is an economically efficient level of 'shortage' we place a very high standard on ensuring that the lights stay on. We consider this to be a key part of our role as a provider of such a critical service.

We also agree with the concerns raised in the CEO Forum submission about the accuracy of the security standards applied by the Authority.

8. Curiously, we are seeing that there is greater risk to security of supply in high demand period in years where hydro lakes are the fullest. This somewhat unintuitive result occurs because in years where the hydro lakes are full, slow start and expensive thermal plant are comparatively inefficient to run for extended periods due to the high cost of fuel and carbon credits. That means these plant are often shut down as was the case through late winter 2022. In dryer years these plants operate throughout winter and can be cycled up and down at shorter notice, as well as using the available hydro well to cover peaks. We note that the EA's market security standards were not developed with this scenario in mind. This has the potential to be exacerbated if thermal plants close in coming years.

Using slow start thermal to address winter peaks is very challenging

9. Slow start thermal generation has previously been a reliable source of power for winter peaks as it typically ran for most of winter. However, the economics of operating thermal plants is increasingly challenging due to increased renewable generation, rising fuel and carbon costs, and aging plant. This means slow-start thermal plant are turned off earlier or more often than previously as the market signals suggest limited need for its generation in the days and weeks ahead. In the past thermal generators often continued plant operation through short term economic loss events so that the plant was available later as market conditions changed. With elevated input costs this is no longer economically viable.
10. The key challenge is then to have a robust market signal for returning slow-start thermal plants to service, particularly as it relates to very short duration "peaks". Further to the matters raised by the Authority, there are a number of other factors relevant to this decision.
    a. We face operational limits on the number of starts we can place on a plant such as the Taranaki Combined Cycle (TCC) which fits into this category. Increasing this number brings forward maintenance requirements, imposing a real cost.
    b. There is uncertainty around the size of the 'start-up costs'. For some plant the lead in time can be as long as three days. While some capacity can be offered into the market during this time, we have no way to accurately predict the prices leading up to the shortage event due to uncertainty around wind capacity, demand, actions of other participants, etc. We can also face significant losses pre and post event with input costs used to bring the plant on and off.

c. Under competition it can be difficult to recover the full start-up costs. For example, if expected prices were sufficient to start up TCC, then it is likely that the Huntly Rankines would also face a similar incentive. If both started up, but there was not sufficient demand for the capacity of both plants, then they would compete each other down to marginal cost. We have to take this risk into account when considering whether to incur start-up costs.

d. The remaining life of a plant can complicate the calculation of expected returns. For example, a plant with only a few years of life remaining may not have a reasonable expectation of experiencing a shortage period of sufficient severity to cover start-up costs. Taking the stylised scenario at page 13 of the consultation paper, a 5% chance of sufficiently high prices means that only 1 in 20 potential scarcity events would result in high enough prices. Since Transpower has begun issuing Consumer Advisory Notices in May 2019, there have been on average just over 6 notices per year. That means for a plant with an expected remaining life of less than three years, there may be less than 20 potential scarcity events, and therefore no expectation that there would be an event with sufficiently high prices to cover start-up costs.

e. There continues to be material uncertainty about demand, level of wind generation and the role of interruptible load (for instance ripple control) in the event meaning significant uncertainty about the potential for sufficient prices to justify the start, several days out from the event.

11. We are happy to meet with Authority staff to run through the economics, and practicalities of these risks in more detail if desired.

Communicating shortfall information should take account of the impact on confidence in the market

12. Currently the way that the market is alerted to a potential shortfall event is via a Consumer Advisory Notice (CAN), and later a Grid Emergency Notice (GEN). Since the outage on August 9 2021 these notices have attracted significant media interest, and questions about the ability to keep the lights on.[1]

[1] https://www.newshub.co.nz/home/new-zealand/2022/10/transpower-issues-warning-notice-calling-for-more-electricity-generation.html; and https://www.nzherald.co.nz/nz/nationwide-power-worries-transpower-issues-warning-as-winter-big-chill-kicks-in-threat-now-under-control/LTVY6JOP73HO6TFUD4BCMN4MM4/

13. This is beginning to unfairly damage confidence in the market. These notices are an important signal to turn on remaining capacity, and help the market function, but are instead used to incite fear and raise public concern about the ability of the market to deliver.
14. We recommend adjusting the language of these notices, and potentially only communicating with registered participants in the market. Public notices should be reserved for situations where there is a high likelihood of impact on consumers, not for intra-market communications.
15. We also would hope that the EA would take a leadership role in responding to and communicating on these events, particularly given the position on the "What is the ideal level of reliability?" taken in 3.5 to 3.8 of the Consultation Paper.

Better information will support the efficient operation of the market

16. We support the urgent implementation of options A, B, D and E, and for these to be retained long-term. We also support the adoption of option C, but note that it is unlikely to be fully implemented for winter 2023.
17. However, these options are unlikely to be sufficient to cover the risks for winter 2023. As noted above, even with perfect information it is often inefficient to turn on slow start thermal. Other mechanisms need to be considered to ensure the risk of a consumer impact is minimised.
18. Option E to clarify the availability and use of discretionary demand control is particularly important. The current uncertainty around distributor discretionary demand impacts on incentives for other market participants to meet winter peaks.
19. At its core, we don't think distributors have the right incentives to offer this load. Clarifying and strengthening their incentives will make their actions more predictable. Ultimately this may require some form of payment from retailers to distributors to compensate for using this capacity.
20. To operate effectively market participants must have clarity on whether the discretionary demand is entered into the wholesale energy market, or into the reserves market and if so at what point and in known quantities.
21. This lack of clarity affects decisions about offering additional supply, and providing demand response From a demand response perspective, we must decide whether to offer the flexible load into the wholesale energy market, or into the reserves market. The expected return in the reserves market therefore represents the opportunity cost of offering into the energy market. If we do not have confidence in energy market price forecasts and the impact of distributor ripple control, we would be hesitant to remove reserves market offers in order to obtain wholesale market value which may not materialise.

22. We raise a few other technical details in our response to question 10 attached.

In the short term a winter peak product is likely necessary

23. To provide the level of security that consumers desire, and protect confidence in the market the information focussed options are likely insufficient for winter 2023. Some form of winter peak product is likely necessary, such as that proposed by the CEO Forum.

24. In developing this product there are a few key features it must have:

    a. It must be supply and demand side agnostic. Demand side solutions may be better placed to quickly ramp up for Winter 2023. In doing so it should ensure that, payments can be directly made to flexibility product participants, rather than having to negotiate for compensation from the energy retailer.

    b. Market participation requirements will need to be developed as soon as possible, and ideally the offer and dispatch process would be as similar as possible to existing reserve markets.

    c. The mechanism should be time limited, with a 1 year term appropriate, so as not to create a long term unintended consequence to the market – i.e. we should trial and see flaws in the product. As below, we consider that wide-spread adoption of demand response (particularly for commercial and industrial customers) is the best long-term solution.

    d. It must ensure that pricing signals remain sufficient to signal the need for new generation and / or for existing plants to stay in the market to provide sufficiency of supply in the mid to long term

    e. It should be designed to enable participants to come in and out of availability, similar to the energy or IR market, as desired. This would assist in creating a greater response and more cost-effective product. An example would be Ripple Control or slow start thermal plant which may be necessary to be utilised for other reasons at certain points but at other may be able to participate in the winter peak product.

    f. It must recognise the role that the plant at the “top of the offer stack” still plays in providing security, as, at least on initial assessment, it would appear that this plant may be run substantively less. This could have the unintended consequence of making the plant less or even uneconomic, and the associated risks of government intervention undermining commercial investments.

       We believe this could be addressed with a constrained-on mechanism (to enable participation in energy and FIR markets) or by some other form of payment in conjunction with the winter peak product. If this risk is not addressed we are concerned that supply-based response may only shift from the energy market to the winter peak product which is not the intention.

25. We note that many of the mechanisms established as part of the Transpower Demand Response programme are still in-tact and could potentially provide fast access to 100-150MW of demand response (although it is unclear how much of this amount publicly stated by Transpower includes ripple control hot water which participated in the programme). The Authority should consider whether this capacity can be utilised in whatever scheme it develops.

26. We also recommend that the Authority takes advantage of the expertise of the industry, including our staff at Simply Energy. Simply is one of the largest demand response providers in New Zealand and can help ensure that whatever programme is established is compatible with demand side participation. Some of the features that will need to be considered include: the relationship to existing reserve markets, notice period ahead of being dispatched as standby reserve, how many trading periods will the reserve apply to, and how the standby reserve be paid (both when on standby, and when dispatched).

Encouraging Demand Side Participation is Key to Managing Winter Peaks in the Longer Term

27. To address winter peaks in the longer term we recommend that the Authority immediately starts a work programme to facilitate greater demand response to peak events. The focus of this programme should be to improve clarity on how and when demand response can address market peaks, and ensure that barriers to demand response participation in the market are removed, while maintaining market signals for generation investments. In summary:
    a. The move to Real Time Pricing enables greater clarity and incentive for demand side participants to reduce load in high priced period
    b. Encouraging this, temporarily through a winter peak product and later through demand response priced by offers and participating in the energy market, should be the long term goal
    c. Removing barriers and encouraging more bilateral contracts between market participants – customers, distributors, retailers and generators, should also be encouraged.

Attachment: Response to Consultation Questions

Question	Comment
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, we agree it has become more challenging. Further to the points raised by the Authority we also note that: • There are operational limits on the number of starts for slow-start thermal plant • There is uncertainty regarding the start-up costs • Competition can affect the ability to recover sunk start-up costs • Remaining plant life can complicate a risk-based approach to recovering start-up costs. These points are further expanded on at para 10 of our submission above.
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?	
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 we support better information and incentives to help resolve the commitment issue.
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?	Yes
Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	We broadly agree with the set of options proposed by the Authority for Winter 2023. As part of a longer-term solution we recommend that the Authority immediately begin a work programme to support a greater level of demand response into the market. For example, the Authority should consider a mechanism like the Wholesale Demand Response Mechanism (DRM) introduced Australia in 2021. This may help overcome the challenges identified, including having both generation and load offered and co-optimised in the spot market only. The DRM also has the advantage of enabling and facilitating retailer-agnostic flexible load into the spot market in all trading periods, rather than just 'standby reserve' as explored in Option F (Introduce a new integrated ancillary service) of the consultation paper.
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.
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?	Yes.
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 that better forecasts for intermittent generation are unlikely for winter 2023. However, we support this work beginning immediately so that better forecasts are available as soon as possible.
Q9. Do you agree that the system operator should procure an external wind forecast and ask participants to review	Yes.

their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?	
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?	Yes Improved predictability and transparency of discretionary demand control will improve both short term generation and demand response offers. This may require better incentives to distributors and clarity on this response may support long term investment signals in further peak capacity plants or similar. The Authority should also consider the timeframes required for unit commitment decisions. These need to be made a day or more ahead. A warning of only a few hours is insufficient may be able to be responded to by some participants but likely will note elicit the full response of all plant as has been assessed in arriving at Winter Energy Margin calculations and so may not resolve the unit commitment issue. If discretionary demand control is entered into the market via the Dispatch Notification system, this should only include 'additional' load control which has been triggered for spot market purposes (though a retailer contract or otherwise), rather than all load control including for regular network management purposes (there will need to be some way to distinguish the two for verification purposes).
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?	Yes We support the proposal from the CEO Forum. This product should be neutral between demand and supply side solutions. The 'standby reserve' product as proposed has the advantage (as we understand it) of enabling a demand response provider to offer load from any retailer into the market (assuming the demand response provider gets paid like FIR and SIR, and can remunerate the participating end consumer directly). We believe this is far more likely to deliver MWs faster than the demand response provider needing to put in place commercial arrangements with the retailer of the end consumer in order to recover some of the value created for the retailer through lower wholesale purchase costs. However we believe it must recognise the role of the highest priced units that remain in the stack and be setup to compensate them either through constrained on mechanisms of other form of compensation. This is to ensure the product does not have any unintended consequences for those plants. Along with considering the ability of the System Operator to implement such a product, the Authority should also consider whether flexible generation, battery or demand response providers can implement the systems required to participate in time for winter 2023 and how they could elect to be in the product as theirs needs changed over the time in question. Market participation requirements will need to be developed as soon as possible, and ideally the offer and dispatch process would be as similar as possible to existing reserves.

	Other considerations include, for example, is the expectation that standby reserve would not also be offered into any other markets, eg the spot market through DNx or Reserves? Will standby reserve receive a dispatch to be 'on standby' (ideally with enough notice period to amend reserve offers prior to gate closure), and then another 'dispatch' to drop load? What trading period(s) will the dispatches apply to – single or multiple? How will the response be verified? How will the standby reserve provider be paid – for available periods and for periods where load is called upon to be dropped? We would be happy to meet and discuss these and other considerations further, to help design a product which maximises the potential to deliver the required outcomes for the System Operator and the prospect of market participants being able to contribute in time for winter 2023.
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?	No. We believe that there needs to be clarity in the lead in to these events on how much reserve is likely to be needed (plus some margin) so that a rational amount is held in that market for the ultimate emergency event should a plant or critical piece of infrastructure trip. Beyond this amount participants should be encouraged to reduce consumption in the lead-in to the peak as the winter peak product proposed by the CEO Forum seeks to achieve. Furthermore, the difference between trying to encourage participation in the reserves market vs via the winter peak product is the speed of availability. In our experience, along with Simply Energy, we find that significant additional load reductions are available with sufficient notice, typically 30 mins to several hours. This load however is not configured or capable of participating in the reserves market due to time considerations (it cannot definitively respond in 6 or 60 secs) and as a result encouraging this capacity into the energy market whilst ensuring sufficient reserves and reserve price signals remain should be the focus
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?	Instantaneous reserve. There are no load participants in the frequency keeping market, and there is more potential for additional resource from a greater range of providers in the instantaneous reserve market.
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?	Yes, we consider the other options are likely to provide a better incentive, and are more likely to address peaks in winter 2023.
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?	Yes, although we support a review of the default prices in the next few years.
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?	Yes, this would likely be too complex to be in place for winter 2023.
Q17 Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored	Yes

further for Winter 2023? If not, what is your view and why?	Although if the alternative is a very real prospect of supply interruption for end consumers, and sufficient other options cannot be implemented in time for winter 2023, this option may be in the best interests of end-consumers in the short term. We understand the Transpower Demand Response program previously built a portfolio of 100-150MW of demand response (predominantly small scale generation, we are unsure how much of the portfolio was ripple control hot water), which was with end consumers on FPVV contracts and would not have generally responded to spot market pricing signals. Presumably the majority of this demand response could be reactivated for winter 2023. The implementation effort would be very low to reutilise the program via Transpower in its role as the System Operator rather than asset owner, and we understand there are multiple demand response providers already able to automate participation in the program. Presumably the Demand Response could be signalled to the market in the same way hot water ripple control load could be signalled through Dispatch Notifications.
Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	Yes
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?	Yes, for both Option F and Option G.
Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	Yes, subject to our comments on above on Option K. We would also like to see work on Option C begin immediately, even if it is not complete in time for winter 2023.
Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	.