Northpower

Electricity Authority Consultation: Driving efficient solutions to promote consumer interests through winter 2023

16 December 2022

Overview

Northpower welcomes the opportunity to provide feedback on the Electricity Authority's consultation on driving efficient solutions to promote consumer interests through winter 2023.

In its summary, the Authority describes that "since mid-2021 the system operator has reported there has been a substantial increase in the frequency of trading periods when the available supply is tight (or insufficient) compared to projected electricity demand and normal reserve requirements. This is despite installed capacity keeping up with peak demand, which has been growing after a decade of relatively flat demand."

We are disappointed but not surprised that this has occurred, as it was widely discussed during the development of the TPM. While the purpose of the TPM is not to match generation supply and demand, nonetheless the RCPD price signal provided a price signal to distributors to manage their loads, which assisted with the matching of supply and demand. The removal of this price signal resulted in Northpower (and we understand many other distributors) ceasing to control load for the purposes of managing demand on the grid, and we currently only control load where we have a constraint on our network (during planned or unplanned maintenance). We stated in previous submissions that we thought Transpower had under-estimated the impact of load control by distributors, and this has been borne out through numerous grid emergency notices through 2022.

<u>Northpower submission on TPM:</u>

Transitional Congestion Charge

Transpower has completed analysis that shows removing the RCPD price signal could result in up to 300MW[1] of additional peak load. We are concerned as to the accuracy of this analysis, and particularly the potential for increased grid instability, resulting in more instances of the black-outs experienced on 9 August 2021.

To put Transpower's forecast in context, Northpower and Top Energy's demand response / controllable load on an average winter's night is shown below. The table shows that Northland load would increase by ~10% if we stopped responding to the RCPD price signal.

Demand response	
Northpower	**Top Energy**
• ~31MW of controllable load, with ~20MW of load controlled at any one time. Peak load (net of DG and load control) of 185MW.	• 18MW of controllable load with ~ 7MW controlled at any one time. On 9 August 2021 Anytime Maximum Demand of 16MW peak during the emergency event. • In addition, 14MW of Diesel generation available for network purpose to manage load

The ~27MW increase represents nearly 10% of the total increase that Transpower has allowed for, yet we only represent 3.7% of the grid's peak load. While we might have a high level of mass market ripple control compared to some networks, we also have a high level of large industrials embedded in our networks, which we do not control the load of. Extrapolating this result, peak load could increase by 10% or ~700MW on the grid.

The above table is pre-closure of the Marsden refinery, as such our ability to ability to control load has now increased from 10% to 20% of our peak load, due to the removal of a significant non-controllable load.

We consider the issue is simple. The TPM has removed the price signal which incentivised distributors to manage their total load, which assisted to match supply of and demand for generation. Distributors are not participants on the spot market, so they now have no price signal to load control. The first signal distributors now get to control load is a grid emergency notice.

This gap needs to be solved, in order to bring the distributor's significant DER capability (20% of peak load in Northpower's case) back into the market before winter 2023.

Summary

We summarise our views on the options outlined in the consultation paper. Our comments are framed from a distributor perspective and reflect the practicalities of our role in supporting peak management through our load control capability. Further detail is provided below.

Clarify availability and use of discretionary demand control	We do not consider there is ambiguity on right to use load control. Will not solve the issue. The issue is lack of a price signal to use network load control.
Introduce a new integrated ancillary service	Generally supportive, but note some limitations and complexities.
Selectively increase existing ancillary service cover	Not support.
Procure additional resource outside of the spot market	We support this approach. This would be the most practical and simple option to introduce within the required timeframe.

E - Clarify availability and use of discretionary demand control

We do not believe there is uncertainty around who has the right to use load control. The Default Distributor Agreement sets out the process around who has rights to load control. Most distributors, including Northpower, offer discounted pricing in exchange for being able to control load. If a customer does not wish to offer their load for control, the ripple controller can be removed, and lines charges change (increase) accordingly. Therefore if the customer has a higher value use for the ability to control their load, they are free to choose.

Where we do have a concern is that Transpower are effectively able to use our DER capability by issuing a request to us to reduce load, or a grid emergency notice, at no cost to Transpower. The ability to manage load has a commercial value, and costs EDBs in the form of discounts offered to consumers in exchange for load control, and the cost to procure, install, and maintain ripple devices and ripple plant. If Transpower wishes to use this capability, it is appropriate that we are compensated for this. We believe that Transpower should be required to procure this service, and that it should only be provided for free in an emergency situation.

The Authority has flagged an option under which distributors could offer demand management services to retailers. We have made this suggestion through our pricing consultations, and received no interest. We believe that the main impediment is that the ripple controllers installed on most networks respond to a ripple signal sent at a certain frequency, and therefore cannot differentiate between customers of different retailers. While it would be inefficient to switch ripple devices every time a consumer changes retailer, there are options to upgrade the devices so that they can be controlled individually via cellular connection. This would require considerable investment and certainty of recovery through a market mechanism.

Alternatively, onboard controllers in smart meters could also be used in the same way, via cellular connection. Using the onboard smart meter controller would require new protocols between retailers and EDBs, because it would potentially open up the load control to retailers to control as well as distributors. If the load is not available to drop when a distributor calls on it (because they retailer has already called on it) distributors are unlikely to continue to offer discounted lines charges for this load.

We would also like to reiterate the challenges in forecasting the availability of load which can be dropped. As distributors are not able to access data from smart meters, we cannot view load in real time. Therefore the only way we can calculate the load available to be dropped, is by completing a ‘drop load test’. This is where you send the ripple signal to drop load, and measure how much the total load on the network drops as a result. Load changes by season, day of the week, and time of the day, but a drop load test can only be carried out a few times due to the impact on consumers, therefore the drop load tests are used to estimate the balance of the year. Distributors sometimes use conservative estimates as a result, but this can lead to over-corrections when a greater quantity of load than forecast is dropped.

F - Introduce a new integrated ancillary service

We support the introduction of a new ancillary service. As we foreshadowed during development of the TPM, as distributors are not subject to the spot market, removal of the RCPD price signal from the TPM has removed the incentive for distributors to manage load to assist with matching supply and demand. Reinstating a price signal through a new ancillary service will assist to resolve the issue and return distributor’s DER capability to the market.

We do not have any specific feedback on how an ancillary service should work, except that it should fairly compensate distributors for their DER capability and the costs they incur, and that the Authority needs to be cognisant of the technical limitations of accurately forecasting resource availability and the risk of over-responding as a result.

We also note that an ancillary market is not a perfect solution. Under the TPM, the distributor’s requirement to manage load and the System Operator’s needs to match supply and demand would sometimes coincide. As such, we could control to both manage our network, and to assist the grid operator, at the same time. We could do this because the TPM charge was based on the *total* load.

However an ancillary service would likely be based upon how much load you could *drop* when called upon. This means that you can't meet both network requirements and grid requirements at the same time – if you controlled load to meet a network requirement, you would need to reduce the amount you made available to the ancillary service. In short, an ancillary service would be more complex and technical to deliver, and therefore expensive compared to the broad but effective RCPD price signal. A price signal does not need to be perfectly cost reflective, to be effective.

G - Selectively increase existing ancillary service cover

We are not clear on how increasing ancillary service cover would help to resolve the issue. Increasing ancillary service cover would attract more ripple control into the interruptible load market, which would only be triggered in the event of an under-frequency event. The goal is to reduce load before the under-frequency event is triggered, rather than increase the capability to respond to an under-frequency event.

As a distributor, we have historically *reduced* our offers made into the interruptible load market in winter, in order to make the load control available to meet network requirements and respond to the RCPD price signal.

K - Procure additional resource outside of the spot market

We support this approach, which would effectively see distributors compensated for making load available to drop when required by the System Operator. Retailers (and in turn consumers) are in turn compensated through lower lines charges, for example on our network controlled rates are between 0-1c/kWh in most cases.

We support this as a more simple approach than creating a new ancillary service market, that could be implemented quickly for winter 2023. As the marginal cost to control load is low, it is unlikely that a complex and perfectly cost reflective price signal through an ancillary market would be required to induce distributors to control load. A simple off-market arrangement could incentivise distributors to reintroduce their DER capability, as they did under the RCPD.

The Authority is concerned that resource providers might reduce supply into the spot market, increasing the need for the (more generous) separate payment mechanism. We suggest a potential solution is limiting the separate payment mechanism to providers who are not participants in the spot market, such as distributors. This will bring distributors into the fold whereas presently they are not subject to any market, and at the same time will avoid double signalling.

If you have any queries regarding this submission please contact Shane Ruxton (shane.ruxton@northpower.com)