Major Electricity Users' Group

Promoting a robust electricity market

1 March 2024

Sarah Gillies
Chief Executive
Electricity Authority
PO Box 10041
WELLINGTON 6143

Sent via email: OperationsConsult@ea.govt.nz

Dear Sarah

Potential solutions for peak electricity capacity issues

1. This is a submission from the Major Electricity Users' Group (MEUG) on the Electricity Authority's (Authority) consultation paper "*Potential solutions for peak electricity capacity issues*"[1] published for consultation on 12 January 2024.

2. MEUG members have been consulted on the approach to this submission. Members may lodge separate submissions. This submission does not contain any confidential information and can be published on the Authority's website unaltered.

Summary of MEUG's comments

3. MEUG welcomes the Authority's investigation into potential solutions to address peak capacity issues with the New Zealand electricity system. This is an area of increased focus within the sector, through analysis such as MDAG's final report and as we head into winter 2024. MEUG does not support the introduction of an Integrated Standby Ancillary Service or out-of-market solutions to manage residual security of supply risks. The Authority outlines several disadvantages of these options and the cost impact it would have on consumers, with uncertain benefits and an increase in complexity.

4. MEUG recommends that the Authority place greater attention on measures to "flatten the demand curve" through demand management mechanisms and optimising the use of battery storage, therefore making the most of existing infrastructure and system capacity (generation, transmission, and distribution). We believe that the Authority needs to focus on:

    a. Greater incentives and possibly intervention to bring more Time of Use tariffs to the market. Urgent attention should also be given to the development of transmission congestion pricing to drive down peak energy use, following the negative impacts on peak demand from the removal of the Regional Coincident Peak Demand (RCPD) charge under the prior TPM.

[1] https://www.ea.govt.nz/documents/4385/Consultation_paper_-potential_solutions_for_peak_electricity_capacity_issues.pdf

b. Improvements to the Demand Dispatch process enabled under Real Time Pricing, to encourage greater participation by industrial and commercial consumers, reflecting the operational conditions facing businesses and the value of this resource to the system.

c. Investigation of a day ahead market to signal and greater incentivise the use of firming generation, demand response or battery storage.

5. We expand on each of these points below and how they can assist with peak electricity capacity issues in the short to medium term. We recommend that the Authority consider a cross-submission period for this consultation paper or consider assigning this issue to its new advisory group for analysis,[2] as there are several issues that warrant further consideration.

Capacity issue well canvassed but greater focus needed on demand side response and flattening the demand profile

6. The Authority's consultation paper canvasses in detail the issues that New Zealand's electricity system is facing, as we transition towards greater renewable generation to support increased electrification of our economy, to meet our net zero obligations. The consultation paper sets out the factors that have led to a focus on winter peak capacity and why it expects these issues and coordination challenges to continue into winter 2024 and 2025. MEUG agrees that this is a pressing issue which has been the subject of much sector discussion, through reports such as the Market Development Advisory Group's (MDAG) final report,[3] and Transpower's Winter 2024 Outlook paper.[4]

7. We welcome the discussion of the numerous workstreams that are underway in the short- to medium-term to address the peak capacity issues, alongside wider improvements to the electricity market. However, we believe that the paper does not give enough weight to addressing the key underlying issue – how to smooth demand over a 24-hour period to ensure that we optimise use of the installed generation, transmission, and distribution infrastructure – while still enabling consumers to meet their energy needs.

8. Greater focus needs to be given to reducing the peaks (as highlighted in Figure 1 below),[5] which is where capacity is under pressure. These peaks have increased in recent years with the consultation paper noting that "*Six of the top 10 record demand peaks occurred this winter [2023], with five of these occurring in August*".[6] This has also led to an increasing number of Consumer Advice Notices (CANs) highlighting low residual situations in the last 12 months.

9. MEUG contests that a large proportion of this increase in peak demand can be linked to the removal of the Regional Coincidental Peak Demand (RCPD) signal under the old Transmission Pricing Methodology (TPM). We refer to the Authority's 2022 report that found that:

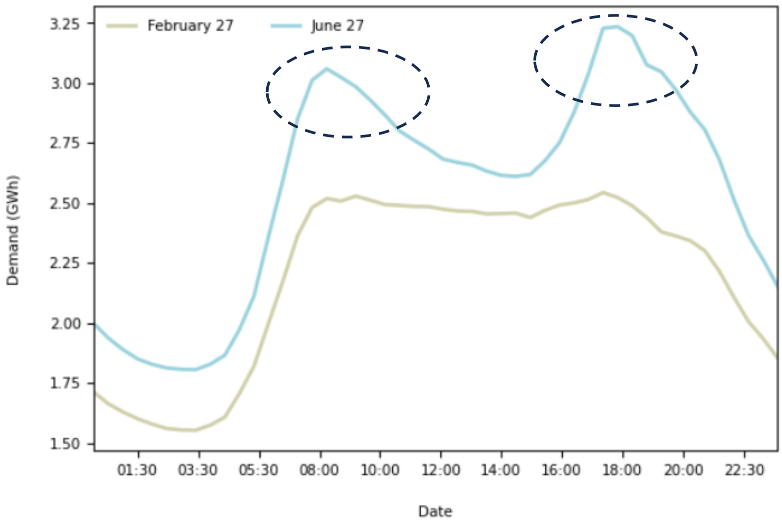
> *"Peak consumption (the highest 300 total consumption trading periods) has been growing by between 10-20MW (or 0.4%) per year over the last nine years. However, the increase in peak consumption in 2022 was higher than this underlying growth would suggest and not accounted for by colder weather, given 2022 was a relatively warm year.*

---

[2] *The Electricity Authority Advisory Group – Decision paper*, Electricity Authority, 27 January 2024, https://www.ea.govt.nz/documents/4653/Decision_paper_on_Advisory_Groups.pdf
[3] For example, paragraph 8.13, MDAG final report, 11 December 2023, www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf
[4] Section on supplying energy demand through 2024, *Winter 2024 Outlook,* Transpower, 31 January 2024, https://static.transpower.co.nz/public/bulk-upload/documents/Winter_2024_Outlook.pdf?VersionId=DPFASMT6ciqNPngxy5oXP4ZEuH.RrFEJ
[5] We note that the peak loads illustrated in Figure 1 are between 3.0 and 3.25 GWh for a half-hour or 6.0 to 6.5 GW. These peaks are low compared to both winter peaks and installed capacity.
[6] Paragraph 11, Appendix A of the consultation paper.

We found evidence that some large industrials have changed their electricity consumption over peak periods—they previously decreased or shifted consumption in peak periods to reduce their RCPD charge—but did not appear to do this in 2022. We estimate that removing the RCPD charge increased daily peak consumption by around 150MW during the top 300 consumption periods in 2022."[7]

Figure 1: Daily demand on 27 February 2023 and 27 June 2023[8]



10. As the new TPM was implemented, it was stated that the spot price signal would be sufficient to maintain and drive demand response. However, this has yet to happen at a scale to make a discernible difference to demand profiles. We consider that the wholesale spot price only has relevance in the immediate sense (as paragraph 3.34 of the consultation paper states), and the increases in demand following the removal of the RCPD suggest customers are insensitive to high wholesale periods for short periods. We also note that many large customers are no longer participating directly in the wholesale market for their electricity needs due to the increased volatility (switching to contracting arrangements such as CfDs or PPAs), dampening exposure to daily spot prices.

11. The consultation paper outlines a small number of demand response agreements and arrangements (two of which relate to MEUG members) where positive progress is being made[9], as well as the current incentives that are in place for demand response. However, progress is still slow, and it is unclear what extent of demand response the Authority considers is needed or optimal to support the electricity system through the energy transition.

12. MEUG considers that much greater work needs to be done to remove barriers and incentivise demand response from a broader range of consumers, from industrial and commercial consumers through to individual households. We have long advocated for demand-side participants to be able to receive a form of payment that reflects the full benefits of the service provided and reflects the costs to the participant (i.e., lost production). This could be equivalent to the spot market electricity price for the volume participants have bid into the price stack at

---

[7] Page 2, *The impact of the RCPD charge removal on peak demand*, Electricity Authority, 21 March 2023, https://www.ea.govt.nz/documents/2338/The_impact_of_the_RCPD_charge_removal_on_peak.pdf
[8] The changing nature of electricity demand in Aotearoa, Electricity Authority, 25 July 2023, https://www.ea.govt.nz/news/eye-on-electricity/the-changing-nature-of-electricity-demand-in-aotearoa/
[9] See paragraphs 3.3 to 3.12 of the consultation paper.

the final settlement price by the System Operator (i.e., the same as a generator). We believe that this would allow clearer price discovery in the electricity market.[10]

13. MEUG disagrees with the Authority's reasoning why it believes that paying consumers not to consume risks distorting the incentive away from the productive and efficient use of electricity and may lead to over-compensation or the concept of "double dipping". We believe the following statement from the consultation paper no longer holds true in all cases:

> *"Generators use resources and incur costs to produce a megawatt. Consumers save their resources for another use when they do not use a megawatt."* [11]

14. As we transition to greater levels of renewable electricity generation (solar, wind, geothermal steam), there is no fuel that generators need to purchase. Generators must only be funded for capital and maintenance costs for the generation infrastructure. In contrast, for an industrial or commercial customer, there may be alternative fuel that needs to be paid for (i.e. from switching from electricity to biomass) and there is an opportunity cost associated with the impact on production – for example, the delay in bringing equipment back online and the impact this may have on scheduled customer orders. MEUG also consider that the Authority's reasoning needs to progress beyond a binary first-pricing argument and be tested by thinking about development of models that could manage the risk of overcompensation (the flipside of high payments to generators when capacity is short).

Do not support use of complex ancillary measures

15. The consultation paper dedicates considerable discussion to Integrated Standby Ancillary Service or out-of-market solutions to manage residual security of supply risks. MEUG does not support these measures because:

   - They do not address the underlying issue of smoothing the demand profile, therefore not making optimal use of resources in the system.
   - The measures increase costs to consumers, without a corresponding security of supply benefit.
   - They would take considerable time to design and implement, not providing support for either winter 2024 or winter 2025.
   - They distort investment signals for generators and could lead to withholding of resources to seek greater compensation from the ancillary market or out of market arrangement. These types of measure could have the same negative consequences on the market as was experienced with the reserve generation plant at Whirinaki.
   - The measures would add complexity to an already complex sector, where very few participants, particularly those on the demand-side, are resourced at levels to actively participate in the spot market.
   - The Authority itself notes that "*even signalling a long-term solution for an integrated standby ancillary service could discourage demand-response innovation in the near-term*."[12]

16. MEUG encourages the Authority to halt investigation into such options, until efforts have been exhausted to increase and optimise the use of demand side response and battery energy storage systems (BESS).

---

[10] As outlined in MEUG's cross-submission on *Dispatch notification enhancement and clarifications*, 13 October 2023, http://www.meug.co.nz/node/1324

[11] Footnote 35, consultation paper.

[12] Paragraph 7.43 of the consultation paper.

Focus must be on optimising demand side response and battery storage

17. MEUG considers that there are several improvements that can be made in the short-term that will bring greater demand response to the market and increase use of battery energy storage systems, smoothing out the peaks of New Zealand's demand profile. Given our members interests and role as consumers, we focus on recommendations to optimise the role demand response in the New Zealand market.

Greater use of TOU tariffs and focus on transmission congestion

18. MEUG would encourage the Authority to put greater focus on incentivising greater deployment of distribution level TOU tariffs and ensuring that these signals flow through to retail TOU offerings to the mass market. Progress is being made in this space across EDBs and we note that this part of the Authority's distribution pricing reform programme. However, greater benefits could be achieved if this work was accelerated, and the market look to progress on from (some of) the relatively simple TOU tariffs currently in use (off-peak, shoulder, peak). We encourage the Authority to look at the full range of regulatory tools it has available to ensure that TOU tariffs are brought to market.

19. Attention must also be given to development of transmission congestion pricing to drive down energy use around peak period. As noted above, the removal of the RCPD charge has led to an observable increase on peak demand and impacted the deployment of demand side response. This warrants serious reconsideration of the decision and the underlying assumptions made when approving the new TPM.

20. We advocate for investigation into a transitional price signal that could bridge between the approach under the prior TPM, and direction set under the new TPM. We note that in the Authority's decision on the new TPM:

> *"Transpower is able to propose a Transitional Congestion Charge (TCC) later, via an operational review of the TPM as already provided for by the Code (see cl 61 of the Guidelines and cl 12.85 of the Code). An operational review can occur at any time provided it is more than 12 months after the TPM was last approved."*[13]

21. This review should be explored with urgency.

Improvements to Dispatchable Demand

22. As outlined above, we consider that demand-side participants should be able to receive a form of payment that reflects the full benefits of any demand side response service provided and reflects the costs to the participant. This is an area that needs further debate with all market participants, where the underlying assumptions that deter the Authority from considering this option can be reviewed.

23. We welcomed the inclusion of information on international demand side participation schemes, such as that used in Australia, Singapore, and the United Kingdom. While these schemes have only had limited uptake to date and have been used in markets demonstrably bigger than New Zealand, we disagree that the principles of these schemes could not be of value here or provide useful learnings for designing a New Zealand specific scheme. We would welcome greater discussion with international officials on learnings from these schemes and how they could work with the New Zealand market.

24. There are also improvements that could be made to the dispatchable demand regime that would better reflect the operational conditions of many large industrial and commercial customers. At present, participants in the dispatchable demand market must make decisions about reducing load or shutting down operations based solely on pricing signals in a half hour

[13] Paragraph 10.3, *Transmission Pricing Methodology 2022: Decision paper,* Electricity Authority, https://www.ea.govt.nz/documents/1809/2022-TPM-Decision-paper1358263.1.pdf

trading period. Large industrial processes will often require sufficient notification to enable load reduction and will require a considerable period to return production / operations to full load. Based on discussions with some MEUG members, this can often be in the range of 4 – 6 hours.

25. There is no certainty that the pricing signals driving dispatchable demand deployment will remain sufficiently high over multiple trading periods, to adequately compensate industrial consumers for this loss in production. This is the key issue that is deterring many of MEUG's members from participating in dispatchable demand, particularly if investment in technology and new equipment is required to enable demand side response.

26. We recommend that the Authority do an immediate piece of analysis on a trading model for demand response that offers demand response for blocks of 2 to 4 hours, to provide more demand certainty around the costs and benefits of demand response. This would help to rank the cost of demand response against other alternatives such as BESS or firming generation.

Investigation of a day ahead market

27. MEUG recommends (further) investigation into the benefits of a day ahead market to signal and greater incentivise the use of demand response, battery storage or firming generation. This mechanism could provide financial security to:

- Demand response participants to alter production, utilise alternative fuel supplies and ready equipment for multiple periods of being dispatched off.
- Encourage BESS owners to charge up their infrastructure in the periods prior to being dispatched.
- Slow start thermal plants to warm assets to be ready for dispatch (although noting the expected decrease in these types of plants).

28. We also consider that there may be merit in demand-side response agreements being incorporated into pricing schedules to provide greater visibility.

Next steps

29. MEUG has welcomed the opportunities over recent months to discuss demand-side response with staff from the Authority and what we consider is needed to incentivise greater participation from industrial and commercial customers. We repeat our recommendation that the Authority consider a cross-submission period for this consultation paper or consider assigning this issue to its new advisory group for greater analysis.

30. If you have any questions regarding our submission, please contact MEUG on 027 472 7798 or via email at karen@meug.co.nz.

Yours sincerely

KJ Boyes

Karen Boyes
Major Electricity Users' Group