NewPower energy

17 June 2025

Submissions
Electricity Authority
P O Box 10041
Wellington

Via email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper— Promoting Reliable Electricity Supply: Frequency-related Code Amendment Proposals

NewPower Energy Services Ltd (NewPower) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) consultation on the proposed frequency related code amendments.

NewPower, the holding company for Infratec NZ Limited (Infratec) and NewPower Energy Limited (NEL), are subsidiaries of WEL Networks Limited, New Zealand's sixth largest distributor. Infratec, an Engineering, Procurement and Construction (EPC) company, is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned Rotohiko, NZ's first utility scale 35 MWh battery energy storage system (BESS) facility at Huntly, connected to WEL Networks' distribution assets. By way of context for this submission, NEL is the owner, operator and trader of generation assets including the Rotohiko BESS, which operates within both Network and Grid compliance modes, and so can offer a range of network, transmission, and energy market services within NZEM's wholesale market dispatch compliance rules. This BESS is already contracted to the System Operator as an ancillary service agent for instantaneous reserves.

Infratec has also constructed and commissioned approximately 118 MW of utility-scale solar farms connected to distribution networks across New Zealand for both NEL and customers, with an additional 80 MW currently under construction.

Key points in our submission

In summary:

1. In NewPower's prior submission to the Authority's frequency consultation in August 2024, NewPower's preference was for the frequency issues to be solved by market solutions (Option 3, i.e. procuring more frequency keeping volume). NewPower's preference has not changed.

   The justification behind this preference was for frequency management costs to be transparent and to expand the frequency response market to incentivise BESS to participate in this market and encourage more BESS investment.

2. The Authority states that the proposed changes will reduce frequency keeping and reserves costs. While this may be true, the proposed changes will impose more costs onto generators. These generators will need to recover these costs through other market products like energy and reserves (likely pushing the price of these products up to compensate). This in essence is shifting costs to consumers from one category to another, with less transparency of actual frequency management costs.

   From NewPower's perspective we have estimated the new +/- 0.1 Hz deadband will increase frequency management cost of its Rotohiko BESS by ~5,000%[1] from the current maximum deadband (+/- 0.2 Hz). This cost is based on warranted energy throughput being used for frequency keeping and meaning less energy throughput available for energy arbitrage each day. NewPower is against the +/- 0.1 Hz deadband change.

3. NewPower welcomes the Authority's discussion in the paper regarding the treatment of BESS and other generation technologies with regards to the new frequency code changes.

   NewPower notes that although there is discussion of the treatment of BESS and other generation technologies, there is no clarity in the proposed code changes around this. This gives investors in BESS and other generation technologies no certainty on frequency management related costs and will reduce investor confidence.

   NewPower is very supportive of the Authority's idea of BESS "*asset owner performance obligations should apply to energy storage systems when they are idle (i.e., neither charging nor discharging)*". This will avoid the unintended consequence of BESS potentially disconnecting from the power system for periods to avoid high frequency management costs (when the costs are forecast to outweigh any revenue). NewPower suggests this idea is included in the proposed code changes.

   NewPower believes the Authority should modify the code changes to address and finalise how BESS will be treated. The market already has two BESS generators operational and another under construction (total of 435 MWh), so NewPower believes it should be addressed now.

[1] Based on current levels of frequency variability. It could be argued that frequency variability will reduce with the proposed changes, but there will be more intermittent generation coming online which will cause more variability. Therefore, the current level of variability is considered a fair analysis until the actual effects can be seen.

NewPower notes that it has provided figures for the cost of lost revenue due to frequency management for BESS to the Authority's Common Quality Technical Working Group at its request (provided on 27th March 2025). The cost of lost revenue for BESS was shown to be significant. This is another reason why the code changes should address how BESS is specifically treated now.

4. NewPower questions how intermittent generators will be able to comply with clause 8.17 (contributions by injections to overall frequency management)?

   Clause 8.17 reads: "*Each generator (while synchronised) and the HVDC owner must at all times ensure that its assets, other than any generating units within an excluded generating station, make the* ***maximum possible injection*** *contribution to maintain frequency within the normal band (and to restore frequency to the normal band).*"

   In clause 8.17 does "maximum possible injection" for an intermittent generator mean maximum export power or the maximum the intermittent generator can do given the available weather conditions? This is important to clarify as if "maximum possible injection" for an intermittent generator means maximum export power, then all intermittent generators must have BESS installed to satisfy this requirement, which would be highly uneconomic just for the purposes of frequency management. NewPower believes the Authority should address this in its code changes.

   NewPower would also like to raise to the Authority's attention on how co-located intermittent generation and BESS would be treated under these code changes. It is highly likely that these types of hybrid generators will exist soon. If a co-located BESS has an export limit less than 10 MW, but the solar has an export limit more than 10 MW how will this be treated?

5. The Authority states in the consultation paper at 5.14 that "*Intermittent generators are considered to meet the clause 8.19 requirement to maintain pre-event output by continuing to generate at their available capacity, provided their output is in line with their forecast output*". The current code and changes do not seem to cover this.

   NewPower notes that clause 8.19 is not explicitly for controlling frequency inside the normal band, whereas clause 8.17 is.

   NewPower suggests that the Authority explicitly states in the code changes how compliance of clause 8.19 for intermittent generators will work.

   The statement "output is in line with their forecast" does not align with the clause 8.19 wording "ensuring that each of its generating units can and does, at a minimum, sustain pre-event output". There is no guarantee that the intermittent generator can sustain pre-event output due to changing weather conditions.

6. NewPower believes that the definition of maximum export power should be modified to state "*(b) the power export limit* ***which applies to at least a full trading period*** *imposed by an active power export control device* ***under normal system conditions***". This would allow BESS to not have onerous requirements when its maximum power export limit for a trading period is less than 10 MW, but its reserve capability is over 10 MW (i.e. maximum of 15 minutes for reserve response).

This is to incentivise BESS to still provide larger quantities of reserves, rather than minimising reserves to avoid frequency management costs. NewPower has also suggested some further changes to the definition of maximum export power in the answer to Q1.6.

7. NewPower would like to encourage the Authority to investigate grid forming Inverter Based Resources (IBR) and its role in maintaining system strength / inertia. Having grid forming inverters will increase the amount of IBR that can run at any given time while keeping the power system stable.

8. In the past the Authority has provided robust net benefit calculations for code changes, however we note the Authority has not provided a net benefit calculation for these proposed code changes. NewPower believes the Authority should conduct this analysis for all three options proposed before deciding on the final code changes.

NewPower welcomes discussion with the Authority on any points in our submission that the Authority would like further clarification or information for.

Yours Sincerely,

[redacted]

David Barnett
CEO
NewPower Energy Services Ltd

Appendix 1: NewPower's response to the consultation questions

Questions	Comments
Q1.1 Do you support the Authority's proposal to amend the Code to require smaller generating stations to comply with frequency-related asset owner performance obligations?	No, NewPower's preference was and still is Option 3 (procuring more frequency keeping managing the increasing frequency fluctuations). The proposal increases costs for generators which will likely be transferred into other market products and the true costs for managing frequency will not be transparent. The proposed code changes are generation technology agnostic. NewPower believes the Authority should address the challenges / higher costs that some generation technology (BESS and intermittent generators) will bear with these changes. NewPower notes that the Authority has included discussion in the consultation on how these different generation technologies may be treated, but there is no clarity in the proposed code challenges that follow on from this. This may cause the confidence of BESS and intermittent generation investors to reduce and may stall or delay investment in generation. The costs for small generators to prove compliance with AOPOs are considerable. The costs of carrying out full protection studies are considerable. With regards to the cost of AOPO compliance for smaller generation NewPower suggests *modifying clause 8.25A to something like following: " 8.25A (3) Whether a generator is complying with subclause (2) must be determined using power system analysis that uses— (a) study cases provided by the relevant grid owner; and (b) relevant system assumptions provided by the system operator. Or if the generator has a maximum export power less than 30 MW, compliance can be based on generator OEM documentation and assessed during system events".* We support a simpler compliance framework for smaller generation i.e. show compliance after an event has occurred. NewPower does support grandfathering existing excluded generators above 10 MW will avoid immediate costs of compliance if Options 1 & Option 2 are implemented.

Q1.2 Do you consider the 'legacy clause' provisions in the Code amendment proposal should apply to a generating station for a finite period of time (e.g. 10 years)? Please explain your answer.	No, the cost of retrofitting a generator in 10 years' time to comply is still likely to be uneconomic. This is the same justification for the legacy clause in the first place.
Q1.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.	Yes. The existence of a threshold (whether 30 MW or 10 MW) above which additional obligations and costs are faced will cause developers of small generation stations to change their behaviour to avoid costs where they can (e.g. build generation stations up to a maximum output of 9.9 MW). The changes still maintain the onus of frequency management upon generators. There are currently significant loads that cause frequency variability and there will be new large loads like data centres which cause frequency variability (especially with the large uptake of AI). NewPower suggests that the Authority investigates how loads can manage frequency variability especially with smarter controllable loads becoming more prevalent. This would share the frequency management burden across generators and loads.
Q1.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.	No, NewPower does not believe Option 1 & 2 is preferrable to Option 3. The reason for this is the unintended consequences stated by NewPower in both sections (unintended consequences highlight in the answers to Q2.3 as well). Option 3 is the only option that provide full transparent costs for frequency management.
Q1.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?	No, the analysis is too limited and doesn't factor in the costs and long-term effects of the unintended consequences pointed out by NewPower in this submission. The Authority has not considered the costs of smaller generators demonstrating compliance properly. Which will include additional grid/network studies at additional cost and time to complete. These studies are generally completed in the development stage of projects, so this will increase the cost to develop generation projects.
Q1.6 Do you have any comments on the drafting of the proposed amendment?	The maximum export definition refers to **generating plant** yet the AOPOs refers to the maximum export of a **generation station**. NewPower suggests that these definitions are aligned or linked.

	For avoidance of doubt, there should be clarity around how the maximum export power for generation stations with multiple generation plant should be calculated. It is not simply the summation of all nameplate ratings as there can be material losses between the generating plant and the point of connection. We would also like to highlight that the "nameplate" rating of intermittent generation is subjective. We suggest the following changes to the definition of "maximum export power" to cover the issues raised above and the edge case where generators have short term overloads greater than 10 MW (but standard output is less than 10 MW) to allow these generators to provide short term grid stability assistance to the grid without having to bear the costs of frequency management: *"maximum export power means, in respect of a generating plant, the lesser of— (a)* ***the design maximum power that can be exported at the point of connection****; or (b) the power export limit* ***which applies to at least a full trading period*** *imposed by an active power export control device* ***under normal system conditions****."* NewPower notes that a generation runback scheme also imposes active power export limits on generation stations. So has added wording above to state "under normal system conditions". NewPower suggests that clause is changed to include all intermittent generation (not just wind): *"8.25D Application Clauses 8.25A and 8.25B do not apply— (a) to a wind generating station when it operates at less than 5% of rated MW;". We* suggest this clause should apply to intermittent generation in general. NewPower also recommends the Authority checks what percentage limit is checked against other intermittent technologies (i.e. other inverter-based technology).
Q2.1 Do you consider there to be any type of generation technology that cannot, and never will be able to, comply with a dead band of ±0.1Hz? Please explain your answer.	Intermittent generators will not be able to comply with the +/- 0.1 Hz frequency deadband (if the definition of **maximum possible injection** in clause 8.17 is the **maximum export power**). As there is no guarantee the weather conditions will enable them to respond to a frequency deviation outside of +/- 0.1 Hz of 50 Hz.

Q2.2 Do you support the Authority's proposal to amend the Code to specify a permitted maximum dead band of ±0.1Hz, beyond which a generating station must contribute to frequency management and support?	No, not with the proposed change changes as they are. There are too many unintended consequences, and the changes do not address or provide clarity for BESS and intermittent generators. NewPower believes how BESS and intermittent generators are treated needs to be bottomed out and included in the changes.
Q2.3 Do you see any unintended consequences in making such an amendment? Please explain your answer.	As stated in one of our key points, the proposed code changes will incur large lost revenue costs for BESS. This has significant knock-on effects, including potentially delay or slowdown of BESS investment. An unintended consequence is that BESS may choose to disconnect from the system to avoid large frequency management costs and only connect when they intend to charge or discharge (and forecast reserves revenue is less than cost of frequency keeping). This would result in a loss of reserves offers and other grid support from BESS during the time it is disconnected and would decrease security of supply and increase reserves costs. The Authority has discussed a solution to this where BESS "*asset owner performance obligations should apply to energy storage systems when they are idle (i.e., neither charging nor discharging)"*, but this has not been included in the proposed code changes. NewPower believes this needs to be fully addressed in the code changes, as there are BESS already operating in the market. The Authority has stated in its consultation that the proposed code changes will decrease frequency keeping and reserves prices. Increasing net free reserves and reducing frequency keeping / reserves prices will reduce the commercial viability of BESS and other generators. In overseas markets frequency keeping and reserves are key revenue streams for BESS, so reducing the viability of these revenue streams in New Zealand will hinder BESS. BESS will likely look to reduce their frequency droop setting to slow down their frequency response to minimise throughput. This will result in not utilising BESS effectively for frequency management. BESS investor confidence will likely reduce and as an unintended consequence less BESS may be built in New Zealand, which will likely have a negative impact on consumers.

	Another unintended consequence with the proposed code amendment is that with the lack of clarity around how intermittent generators comply with clause 8.17, it may force intermittent generators to install BESS to comply with “maximum possible injection” to maintain within the frequency deadband.
Q2.4 Do you agree the proposed Code amendment is preferable to the other options identified? If you disagree, please explain why and give your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010.	No, NewPower does not believe Option 1 & 2 is preferrable to Option 3. The reason for this is the unintended consequences stated by NewPower. Option 3 is the only option that provide fully transparent costs for frequency management.
Q2.5 Do you agree with the analysis presented in the Regulatory Statement? If not, why not?	No, the analysis is too limited and does not factor in the costs and long-term effects of the unintended consequences pointed out by NewPower in this submission. The Authority has not estimated the total cost to generators (which will likely be passed onto consumers) for this change and compared it to the benefits of the code changes. The Authority should calculate the net benefit of each of the three options to determine which option it should look to finalise. The Authority has not included analysis of the lost revenue costs to BESS due to frequency keeping using up BESS warranted energy throughput limits. NewPower provided the Authority’s Common Quality Technical Working Group with a cost per MWh for BESS frequency keeping which was shown to be significant. This cost has not been factored into the analysis. Although the Authority’s analysis shows that reserves and frequency keeping costs will decrease it has not analysed any unintended consequences of this. For example, this likely will hinder BESS investment due to key revenue streams being reduced, what impact will this have on consumers in the long run?
Q2.6 Do you have any comments on the drafting of the proposed amendment?	See issues below which NewPower believes needs addressing in the proposed code amendment.

	Treatment of BESS and other generation technologies NewPower welcomes the Authority's discussion in the paper regarding the treatment of BESS and other generation technologies with regards to the new frequency code changes. NewPower notes that although there is discussion of the treatment of BESS, there is no clarity in the proposed code changes. This gives investors in BESS no certainty on frequency management related costs and may reduce investor confidence. NewPower is very supportive of the Authority's idea of BESS "*asset owner performance obligations should apply to energy storage systems when they are idle (i.e., neither charging nor discharging)"*. This will avoid the unintended consequence of BESS disconnecting from the power system for periods to avoid frequency management costs (when the costs are forecast to outweigh any revenue). NewPower believes this should be addressed in these code changes as there are already BESS operating in the market. **Treatment of intermittent generators** NewPower questions how intermittent generators will be able to comply with clause 8.17 (contributions by injections to overall frequency management)? Clause 8.17 reads: "*Each generator (while synchronised) and the HVDC owner must at all times ensure that its assets, other than any generating units within an excluded generating station, make the* ***maximum possible injection*** *contribution to maintain frequency within the normal band (and to restore frequency to the normal band)."* In clause 8.17 does "maximum possible injection" for an intermittent generator mean maximum export power or the maximum the intermittent generator can do given the available weather conditions? This is an important to clarify as if "maximum possible injection" for an intermittent generator means maximum export power, then all intermittent generators must have BESS installed to satisfy this requirement, which would be highly uneconomic.

	The Authority states in the consultation paper at 5.14 that "*Intermittent generators are considered to meet the clause 8.19 requirement to maintain pre-event output by continuing to generate at their available capacity, provided their output is in line with their forecast output."*. The current code and changes do not seem to cover this. NewPower suggests that the Authority explicitly states in the code changes how compliance of clause 8.19 for intermittent generators will work. The statement "output is in line with their forecast" does not align with the clause 8.19 wording "ensuring that each of its generating units can and does, at a minimum, sustain pre-event output". There is no guarantee that the intermittent generator can sustain pre-event output due to changing weather conditions.