

20 August 2024

Submissions
Electricity Authority
P O Box 10041
Wellington

Via email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—Addressing more frequency variability in New Zealand’s power system

NewPower Energy Services Ltd and subsidiary Infratec NZ Ltd appreciates the opportunity to make this submission on the Electricity Authority’s (Authority) consultation on addressing more frequency variation in New Zealand’s power system.

NewPower is a subsidiary of WEL Networks Limited, New Zealand’s sixth largest distributor. NewPower subsidiary Infratec NZ Ltd is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned NZ’s first utility scale battery energy storage (BESS) facility at Huntly, connected to WEL Networks’ distribution assets. By way of context for this submission, NewPower is the operator of this new 35MWh rated BESS which will operate 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 66 MW of utility-scale solar farms connected to distribution networks in New Zealand for clients with an additional 60MW currently under construction. We also commissioned the 4MW Naumai solar farm in Northland in Q3 2024. All generation except the Rotohiko BESS are exempt stations, being under 30MW net export. We have provided detailed Asset Capability Statements to the System Operator (SO) (consistent with the Code). And, despite being below the 30MW net export threshold, have incurred not insignificant costs for each solar farm associated with detailed technical testing by both the distributor and SO both during the design stage and commissioning of these generating stations.

NewPower agrees with the Authority that *“evolving technologies, particularly inverter-based resources, are a key enabler of electrification. Examples of inverter-based resources include battery energy storage systems, solar photovoltaic generation, and wind generation”*. It is important that everyone understands the current and future technical capability of these technologies to deliver reliable¹ electricity. NewPower has been instrumental in upskilling the Electricity Authority and

¹ As defined by the Electricity Authority: “‘Reliability’ refers to both the continuity of electricity supply (ie, the rate and duration of electricity outages, including because of insufficient fuel for electricity generation), and the quality of electricity supply (eg, the frequency and voltage of electricity).”, page 7 of the consultation cover paper https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

Transpower (Grid Owner and System Operator) in the operation of New Zealand's first utility scale battery and is open to sharing its expertise about battery and solar technology at any time.

Key points in our submission

In summary, NewPower and Infratec:

1. strongly support Option 3 which is to “Procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz) and procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events”. This solution addresses Issue 1 which is only focused on managing “more variability in frequency within the normal band”. Procuring more instantaneous reserves will assist with managing contingent and extended contingent events – a separate issue from Issue.
2. recommend the SO reconsider its power systems analysis for this consultation taking into account its recommendation in June 2023 that *“asset owners looking to connect IBRs greater than 1 MW are recommended to use GFM inverter technology to ensure their asset remain stable following system events”*.
3. The Authority and SO review their assumptions about the technical capabilities of BESS to support frequency keeping outside the normal band. In our view, the results and the SO's own studies understate the benefits of BESS.
4. reject Option 1 to lower the threshold of 30MW net export at all and particularly to 5MW. At this initial stage² we believe there are inconsistent assumptions in the modelling and our analysis of costs imposed by a lower threshold means costs are very likely to exceed any benefits of this Option, especially when compared with the counterfactual of Option 3.
5. reject Option 2 to introduce a maximum deadband beyond which a generator must contribute to frequency keeping and instantaneous reserves. Our analysis of costs imposed by a ‘tighter’ deadband exceed any benefits of this Option.

Each of these points is discussed further in this response and includes worked examples and our response to the Authority's consultation questions. This version of the submission has had commercially confidential information redacted.

² Referred to as ‘initial’ given the Authority is asking if the option warrants further investigation.

General Comments

Problem definition

The Authority is proposing 3 alternative options to address Issue 1 – they could be alternatives or could all be adopted. The definition of Issue 1 is:

*“An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause more variability in **frequency within the ‘normal band’** of 49.8–50.2 Hertz (Hz), which is likely to be exacerbated over time by decreasing system inertia.” [emphasis added]*

Issue 1 is about maintaining frequency within the normal band in the presence of increasing generation output variability and declining system inertia. The options address this Issue and another separate issue which is around frequency support during under frequency events. Issue 1 needs to be redefined or possibly split into two issues:

1. Maintaining frequency in the normal band.
2. Frequency support during frequency excursions outside the normal.

This is important as the conclusions of the System Operator (SO) Study 1 do not support Option 1 (as far as Issue 1 is defined). Report 1 studies underfrequency excursions outside the normal band which has little to do with maintaining frequency within the normal band.

Option 3 is the only proposed option that addresses both maintaining frequency in the normal band **and** supporting frequency during an excursion outside the normal band.

NewPower notes that inverter-based resources are loads as well as generation, inverter-based and power electronic loads will make up a larger percentage of total load due to decarbonisation. This options paper has only focused on intermittent / inverter-based load's impact to frequency variation, NewPower suggests that the Electricity Authority also considers intermittent loads in regard to frequency variability as well as generation (especially in dynamic studies).

Option analysis

It appears the Authority is proposing 3 options to address Issue 1 that could be alternatives, but also could all be adopted. The Authority is also asking for feedback about whether each option should be “further investigated”. NewPower notes that sound regulatory practice requires analysis comparing the relative costs and benefits of the three options. It is not good regulatory practice to commit to further investigation of only one option and undertake a cost benefit analysis of only that one option (unless the counterfactual is no change to the status quo).

A further option could be a transmission-based solution. For example, Transpower could install more synchronous condensers or grid forming inverter devices.

We suggest there is a case for comparing the costs of more synchronous condensers (or other transmission-based solutions) with requiring APOs on generating units as part of the cost-benefit analysis.

Modelling assumptions and timeframes

Studies 1, 2A&B, & 3 are based on assumptions about the future generation mix. Studies 1 & 3 have a utility scale solar level of 1.0 GW whilst 2A&B have 2.585 GW. The SO should provide an explanation for such disparity in the values used (not just utility scale solar). Currently the Options are not being tested against consistent conditions.

The nature of renewable energy and IBRs has not just changed the grid. New solar and BESS developments are having a disruptive effect on the project planning and development timeframes with projects having much shorter timescales. The pipeline of announced solar projects amounts to over 5 GW at present; this excludes BESS, wind and behind the meter residential, commercial and industrial solar installations.

With project timescales of 2-4 years, the urgent need for new generation capacity and the large generation pipeline, the proposed timescales of regulatory change are much too slow. Some Code changes are expected to take 2- 3 years (or more) by which time over half the installed capacity could be IBR; Whakamana I Te Mauri Hiko has this as high as 7,360 MW.

We do not agree with the Authority that Option 1 and 2 will “deliver ‘quick(er) wins’ “ or that we have the next five years to consider and implement other options³. There is a real danger that the regulations will lag the rate of change, leading to higher energy costs for New Zealand, and a lower quality of supply.

These opposing timeframes (short generation development and slow regulatory change) make Option 3 significantly more attractive. Option 3 is an evolution of an existing market. The Authority is already starting on an enhancement to frequency keeping and expects Stage 1 to be completed within about a year – by September 2025.⁴

The EA also recently made changes to output forecasting by intermittent generation. These changes are yet to bed in and the expected outcomes to be realised. The EA considers “Improving the accuracy of intermittent generation forecasts and offers are a key building block to ensuring intermittent generation makes the best possible contribution to a renewables-based electricity system that delivers sustainable, reliable and affordable electricity to consumers”⁵. This must contribute to the SO’s efforts to managing market coordination of demand and supply.

NewPower query the process the EA and SO used to go from the long-list -> medium-list -> short-list (options process) and how a short-list of 3 options can be determined without undertaking a cost-benefit analysis. The short-list appears to be purely based on technical aspects: feasibility and timeframes with a very qualitative stab at implementation costs. Further, it is not clear what the next

³ Paragraph 3.8 Electricity Authority consultation cover paper
https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

⁴ See paragraphs 3.20 to 3.40 in this 18 July 2024 Decision Paper
https://www.ea.govt.nz/documents/5263/Decision_paper_Potential_solutions_for_peak_electricity_capacity_issues.pdf

⁵ Source: Paragraph 3.11 Decision Paper, 11 July 2024
https://www.ea.govt.nz/documents/5244/Review_of_forecasting_provisions_for_intermittent_generators_in_the_spot_market_se5mcdm.pdf

steps would be once all the feedback has been received. Is the purpose to make the short list even shorter and only further investigate one or two of the options?

Key points

NewPower strongly supports Option 3

Option 3 is a commitment to procure more frequency keeping to manage frequency within the normal band (49.8–50.2Hz), and to procure more instantaneous reserve to keep frequency above 48Hz for contingent events and above 47Hz (in the North Island) and 45Hz (in the South Island) for extended contingent events. Our strong preference is market-based solutions. This option builds on a well-functioning market that is successfully managing frequency variations both within and outside the normal band. The EA rates this option as “*strongly feasible with no risk of unintended consequences (no changes to the Code or to assets, negligible implementation cost)*”.

The SO’s procurement of frequency keeping when it is needed will place a monetary value on technologies that offer these services; incentivising this technology to stay connected; and other technologies / products to be developed to solve any frequency keeping or voltage issues. A market solution will deliver frequency keeping when it is needed (infrequently) rather than having all generation capacity incur a cost to be compliant with a static technical standard.

NewPower also supports this market-based solution for voltage ancillary service.

We note frequency excursions are mostly caused by load or the HVDC. Is the EA planning to place additional technical requirements/costs on these participants as well? Also, it is unclear at this stage how quickly and by how much the requirement for frequency keeping will increase and how quickly this growth in demand will happen.

In our view, there are numerous advantages⁶ with this Option 3:

- the market will deliver the required response when frequency fluctuates and as, or if, variability increases over time
- the solution already exists (it is a ‘quick win’⁷) and can be enhanced over time as uncertainty dissipates about the actual generation mix, timing of capacity increases, technology change etc and any impacts on frequency emerge
- the competitive ancillary services market assists with managing costs for consumers and grows this value stream for flexibility providers, including BESS.

Offers in the instantaneous reserves market already far exceed demand. The average aggregate total FIR offer volumes were 350MW above the average dispatched volume of (180 MW) in the past 2-3

⁶ Source: Page 39 https://www.ea.govt.nz/documents/5151/Paper_1-Addressing_more_frequency_variability_in_New_Zealands_power_system.pdf

⁷ The EA’s approach is said to be to “enable options that can deliver ‘quick(er) wins’ to be progressed ahead of options that require a longer gestation, and which are not necessarily needed within the next five years”. Paragraph 3.8 Cover paper https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

years. The surplus of frequency keeping offer volumes is also larger than the surplus of the FIR market.

We note the Authority has already decided to redefine the existing MFK product into a product to manage five-minute variability and expand participation in the frequency keeping market to include smaller providers and a wider range of technologies. The EA expects this will allow the SO to procure more resource from a wider range of providers to be available to manage variability risk, such as the wind dropping away within a five-minute period. Work by the EA and SO was due to start in July 2024 and stage 1 be completed by September 2025. This decision is an extension of Option 3 and appears to replace Option 1 in the list in Table 4: Options retained from the long list of frequency-related options but not short listed.⁸ It seems inconsistent to rely on the frequency keeping market for periods up to real time and not for co-ordination in actual real time. The Authority acknowledged this in a response *“although it will also assist with supporting frequency management”*.

In addition, the SO appears to have ‘faith’ in the competitive frequency keeping market. It recently sought feedback on options to enhance the frequency keeping market; asking *“are the SO’s current frequency keeping tools and processes fit for purpose and do they encourage greater participation and competition in this service?”* NewPower (and WEL Group) supported the SO working on enhancing the frequency keeping market.⁹

Use of Grid Forming Inverters should be mandatory

The consultation paper makes no mention of Grid Forming (GFM) or Grid Following (GFL) technologies. The hardware is almost identical, but the way they are controlled (firmware) is very different.

Currently GFL technology is the mature technology and the first choice for developers, but this technology has drawbacks such as the lack of inertia which is an inherent issue the options in the consultation paper are trying to address. Grid Following inverters are like slaves, they just follow whatever the grid does in terms of frequency unless told to do something different. They need the grid there to follow, or they will stop working.

GFL inverters are currently fitted everywhere, and the majority of comments about the future are about this technology.

Grid Forming inverters are masters. They can form their own grid if needed, and the way they run their grid is setup in their controllers. This means they behave totally differently and can increase system strength. GFM technology allows IBR to produce inertia and ensure that the system is not adversely degraded by IBR penetration. GFM also has other advantages relevant to the other papers currently under consultation (voltage and harmonics) and would benefit multiple areas of power quality.

⁸ Page 40 https://www.ea.govt.nz/documents/5151/Paper_1-Addressing_more_frequency_variability_in_New_Zealands_power_system.pdf

⁹ See submissions on this page <https://www.transpower.co.nz/evolving-market-resource-co-ordination-closed>

The SO has used the region of Northland as a case study to simulate / model the impact of a higher proportion of inverter-based resources on the power system in that region. In this June 2023 report¹⁰ the SO concluded that:

"Our view is that GFM inverter technology is far more capable of supporting the secure and reliable operation of New Zealand's power system, especially in weak areas of the grid where they have been shown to remain stable after system events. Asset owners looking to connect IBRs greater than 1 MW are recommended to use GFM inverter technology to ensure their asset remain stable following system events."

Given that this recommendation is over a year old and is based on an SO power system study of Northland, it seems strange that no mention of this report has been made by the Authority.

There is growing experience with this type of technology in large grids and managing the technology. Australia is now requiring these inverters via its system strength rules. NewPower submits there is a lot that can be done with GFM technology, and this is what (in the study) Transpower recommended using for new projects.

This technology could be expected to reduce system costs by providing a wide range of services¹¹, which is why Australia are pushing it now before they have too many GWs of Grid Following inverters.

We also note that the SO refers to "weak areas of the grid". In our view it is Transpower Grid Owner's responsibility to manage weak transmission grid infrastructure to ensure power quality (as opposed to imposing asset standards on each individual generator). If a generator is a lowest cost solution to a "weak area of the grid" the Grid Owner should be signing a Grid Support Agreement with this generator.

We also note that GFM inverters are not without their complications in terms of their tuning to ensure no dynamic instability and potential additional costs from suppliers.

BESS provide frequency response and reserves

Study case 5 clearly shows the advantages of BESS for frequency response and reserve due to its speed of response. The advantages of BESS in areas like this need developing to allow them to operate at their most efficient. The reserve payments should factor in the cost efficiencies that having high speed response offers provides. This could be enacted via a fast-acting product or via scaling factors for speed and droop settings.

As the speed of the BESS response increases, the amount of reserve required is reduced. The more aggressive the droop settings (lower is more aggressive) the greater the energy contribution from BESS.

As BESS do not provide energy, they provide services around the shifting of energy to when it is required. Traditionally frequency response has been a staple part of the revenue stack for BESS due

¹⁰ Source: https://static.transpower.co.nz/public/bulk-upload/documents/Preparing%20for%20an%20increase%20in%20inverter-based%20resources%20v1.0.pdf?VersionId=bLFY0dB4Za1FfNAEh1V_75DOZ3_vmPb5

¹¹ In the very short-term there may be costs associated with testing this ubiquitous technology while the SO builds its understanding.

to the advantages it brings with the speed of response and the ability to set the droop curve as required to suit the system needs.

The amount of energy used and the measured throughput during operations needs to be carefully monitored and predicted to ensure that contractual commitments can be met, and warranties complied with. Although the discharged energy during frequency keeping is usually small, it can be significant for a BESS where daily throughput is limited.

Reject Option 1 of reducing the excluded station threshold below 30MW

NewPower does not support any change to the current 30MW net export threshold for excluded generating stations.

The recommendation of a size threshold of 5 MW net export from Study 1 is questionable as there is little difference in system performance compared with the other thresholds and the accuracy of the modelling is not stated. It is possible that the modelled results for different thresholds falls within modelling error levels.

The current threshold of 30MW net export must be being measured at a GXP – where Transpower can see the output of the generation plant that is connected to a distribution network. If the generation plant has a battery and manages export it may never meet a net export threshold. The potential price outlook with higher solar penetration (e.g. duck curve) is likely to incentivise integrating storage with solar generation. Given forecast increases in demand for electricity a generator and their distributor may be incentivised to manage generation and load within the network so that the threshold is not exceeded at the GXP. We query if this threshold is applied at a fixed level forever when the generator is commissioned it could differ significantly from the actual level of 'net export' which will change year by year and likely decline as the load on the network increases.

The consultation paper says repeatedly that generation asset owners will be able to apply for dispensations if the net export threshold is lowered to 5MW. This is not a costless alternative. Each new generating station will have to decide if the cost of complying with additional requirements to support frequency are less than the cost of the initial testing involved with seeking a dispensation and the future cost of testing to maintain the dispensation. The SO will have to be resourced to process these applications to ensure this step does not create a barrier or delay to commissioning much needed new generation capacity. There is also uncertainty about whether or when the SO might change its approach to dispensations – raising the requirements for a dispensation or ceasing to issue dispensations. Our estimate of the cost of this ongoing process is included in our answer to Q2 below.

We also note that the SO has suggested that it might be appropriate to raise the 30MW threshold for dispatch requirements in Technical Code C of Schedule 8.3 of the Code.¹²

We disagree with the proposed approach to VPPs. A VPP will just run separate control systems to be below 5 MW, but on aggregate be greater than 5 MW. Any Code needs to look at this from a participant / ownership level to ensure a VPP is not given an unfair advantage relative to single site generation stations.

¹² Section 4.3.2 of the System Operator report "Evolving market resource co-ordination in Aotearoa New Zealand" June 2024 <https://www.transpower.co.nz/evolving-market-resource-co-ordination-closed>

Also note that string inverters can make up a large generator. The current proposal means that each of these small inverters (~200-300 kW) will have to comply with standards for a 5 MW+ generator in terms of frequency keeping.

Reject Option 2 of a tight deadband for BESS

There are a number of reasons we reject this option for BESS:

- There is the potential for BESS to void its warranty for mandatory frequency keeping (without deadband or small deadband). i.e. the daily throughput limit
- The extra wear and tear this will impose on the BESS, where state of health reduces with discharge much faster than other generation types meaning a fair solution to all technologies is harder to implement.
- Study case 5 shows BESS speed with aggressive droop gives much better response (which needs to be valued)
 - Less MW disconnect as the frequency stays higher
 - The SO can procure less reserve, so BESS MWs are effectively worth more than slow ones
 - Droop settings are easy to change on a BESS; The 'DS3' programme in Ireland had five droop settings preprogrammed into the BESS that the SO could change in an instant as they required

The reserve product(s) needs to reflect and reward the performance of the technologies. Faster responses with more aggressive droop curves give good performance but increase BESS degradation. The faster more aggressive providers give more, potentially rewarding slower responses, that means less 'work' carried out (and lower costs incurred) by slower providers.

Frequency keeping is designed for generators to regulate their output up and down, with payments for energy served / injected (as usual) while operating and receiving a payment for frequency keeping. This design works for regulating by energy generators, e.g. hydro, but isn't designed for technologies that have finite energy supplies or regulate bi-directionally i.e. charging and discharging. A BESS can be idle (0MW output) and if required to support frequency will incur energy costs when charging.

- To allow 'indefinite' bids BESS would operate in a charge / discharge manner to manage SoC
- The BESS (or other technology using this model) operator doesn't just have to take the risk of lower prices while discharging, but also the risk of high prices while charging
- If the BESS operator has to carry this energy risk, then their prices will be higher as they have to price a higher risk than operators using the conventional model
- Frequency keeping is complex for BESS due to the different quadrants of operation, and energy costs associated with charging the BESS and opportunity costs.

Frequency response and reserves are a large part of the BESS revenue stack. This is part of the core function of a BESS (not an additional service that a large generator provides); it is not efficient to expect the BESS to provide this for free unless the effect is comparatively small i.e. very high droop and a low MW limit so the throughput and SoC effects are small.

The problem created by a mandatory frequency response when the BESS is operating close to its warranty conditions, while honoring its bids/offers for energy or reserves is a large issue. This could place the operator in the difficult position of not being able to honor their commitments and lose revenue or not being able to discharge their mandatory requirements or adding a larger safety factor

in to cover mandatory frequency response, which would reduce revenue, and increase costs to the consumer.

Worked examples

Frequency keeping for BESS with costs (deadband vs no deadband)

The following is a simulation to show the effect of having no deadband on the frequency response of BESS versus having a deadband and is based on real frequency data recorded by the Rotohiko BESS for a 24-hour period:

- throughput due to frequency keeping with a lower deadband of 49.81 Hz – **0.2 MWh**
- throughput due to frequency keeping with no deadband – **4.3 MWh**

For the example with no deadband the use of the 4.3 MWh throughput for frequency keeping will mean that the BESS has less of its daily throughput to use for arbitrage and reserves. If we assume an average arbitrage value of \$150/MWh the opportunity cost would be \$660 per day on average to the BESS, or \$241k annual lost revenue. This will have a detrimental impact to the BESS financial returns, which are already at the margin given the new entry technology cost penalties and market not being mature (i.e. a mature market is promoted by Option 3). This is before the wear and tear cost for BESS throughput is factored in which is in the range of [redacted] for each MWh discharged from the BESS (due to battery degradation and other factors).

Assuming the extra discharge of 4.3 MWh means extra batteries to maintain the previous output, and batteries are a third of the total cost of a BESS project; then total costs rise by up to 7%, raising the Levelised Cost of Storage (LCOS) from [redacted]. The LCOS is the total lifecycle costs divided by the total amount of energy 'sold'. The higher the LCoS, the higher the costs to the consumer.

Making similar assumptions, the 0.2 MWh discharge per day gives a 0.3% increase in total costs, LCOS raises from [redacted].

In total, with no deadband (always responding) could add up to [redacted] to the LCOS, while the status quo deadband could add up to [redacted] to LCOS. The difference of [redacted] being the cost that the generator must bear if no deadband was enforced.

We query why a smaller deadband is being proposed for only new generation - at the greater of 0.1 Hz or the OEM deadband. This is an additional cost for new plant which could reduce competition against existing gentailers. The definition of 'new' and implementation date are also important issues to resolve.

Commercial Impact to solar of running with 10% headroom

The following financial analysis is based on a generic 30 MW solar farm assuming it is run with 10% headroom (i.e. 10% reduction in generation). This reduction in generation output results in material commercial impact to project.

[redacted]

Running intermittent generation with headroom will cause the Levelised Cost of Energy (LCOE) of these intermittent generators to increase, and there is the risk it will prevent them from reaching financial close.

The 10% headroom strategy is likely not the best strategy to solve the issue. Additionally, with this proposal, there is still no guarantee that all of the headroom will be available at the time of a frequency variation due to drops in wind or cloud cover shadowing over a solar farm.

Overall, NewPower submits that short-term solutions (options 1 and 2) will come at additional cost to generators that may not be needed for the long-term solution and ultimately will increase consumer energy costs. Option 3 is a least regrets option that is *“strongly feasible with no risk of unintended consequences (no changes to the Code or to assets, negligible implementation cost).*

This is a highly technical topic and important issue to address at least cost to New Zealand consumers. NewPower would welcome the opportunity to discuss our detailed submission with the Authority and System Operator.

Yours Sincerely,

A handwritten signature in black ink, appearing to read 'Darren O'Neill', written in a cursive style.

Darren O'Neill
Product Development Manager
NewPower Energy Services Ltd

APPENDIX 1 – NewPower's response to the Authority's questions

Questions	Comments
Q1. Do you agree the Authority should be short listing for further investigation the first frequency-related option to help address Issue 1? If you disagree, please explain why?	<p>No. Issue 1 is not properly defined. Option 1 is not directly related to Issue 1 (as defined in the consultation paper).</p> <p>Option 1 proposes a reduction in the threshold for 'excluded generation stations' to 5MW net export so that more smaller generating stations comply with frequency-related obligations.</p> <p>No analysis of how excluded generation stations connected to the transmission grid affect frequency within the normal band has been presented in the consultation paper.</p> <p>Transpower's Quarterly Performance Reports show that the causer of over 80% of the frequency excursions in the nine months to 31 March 2024 were transmission assets or Tiwai poutine operation – with the balance being larger generation plant (including Huntly which may be the Huntly units that have been issued dispensations by the SO).</p> <p>Option 1 causes issues with compliance for intermittent generators below 30 MW. With the only options for compliance being leaving generation headroom or co-locating BESS. Both of these options are uneconomic in NewPower's view.</p> <p>NewPower does not support any change to the 30MW net export threshold. The SO analysis is inconclusive as it shows minimal difference in system performance from lowering the threshold.</p>
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	<p>The benefits or costs of lowering the excluded generation station threshold with regard to maintaining frequency in the normal band have not been assessed. The reduction in frequency keeping costs and other benefits needs to be assessed and compared with the costs for smaller generators to be compliant.</p> <p>NewPower estimates that all the activities below would cost approximately in the range \$150k to \$200k for each generating station to prove its compliance with frequency keeping requirements:</p> <ul style="list-style-type: none"> Engaging consultants to complete dynamic studies and providing the System Operator with the dynamic frequency response model <ul style="list-style-type: none"> Usually takes a few iterations Control system changes and pre-testing (not including any control system upgrades)

Questions	Comments
	<ul style="list-style-type: none"> • On-site frequency response testing <ul style="list-style-type: none"> ○ Site mobilisation ○ Hiring testing kit and recording kit • Summary report to show generator is compliant <p>Another concern NewPower has with Option 1 is that it would require more generators to be modelled in the System Operator's Reserve Management Tool (RMT). Can the RMT system cope with this volume of information?</p> <p>A further concern is the availability of consultants to perform the required studies and produce generator frequency response models by the deadline set by the EA Code change.</p> <p>There will be increased transaction costs for generator owners and the SO.</p> <p>This includes (but not is limited to) the costs of making existing non-compliant plant compliant or costs of obtaining dispensations.</p> <p>NewPower submits this will increase barriers to entry for smaller generation.</p> <p>This option will have a large impact on intermittent generators who will either have to reduce power output at all times or install BESS. This will significantly increase the Levelised Cost of Energy (LCOE) and potentially delay decarbonisation (as increased LCOE will require higher average spot prices to justify investment).</p> <p>There will also be delays in project completion, as there will be more projects requiring detailed assessment and involvement by the SO, which already has limited resources in this space.</p>
<p>Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?</p>	<p>Routine testing and provision of additional ACS information which are increasingly onerous as the size of generation reduces.</p> <p>See our answer to Q2 for an estimate of these costs.</p> <p>Increased monitoring costs imposed by the SO.</p> <p>The likely cost to intermittent generators in this range of capacities will be significant, as either they will have to run sub-optimally (lost energy) or install BESS. A robust cost-benefit analysis requires the EA to show that the cost of running intermittent generators this way does not outweighs the cost of intermittent generators bearing the cost of additional frequency keeping.</p>

Questions	Comments
	<p>Also, some existing inverters may not have the controls options to run sub-optimally, and therefore there will be a large control system upgrade need which will be expensive.</p> <p>Important to note that if intermittent generation were to run sub-optimally (below maximum power point) there is still no guarantee that it will be able to ramp up as the buffer may disappear due to changing sun / wind.</p> <p>Increased costs associated with establishing an ICCP connection for each of these sites.</p> <p>Cost of doing connection/grid studies also likely to increase as a result of lowering the limit, as the generator will need to comply with the SO requirements, so things like model validation and other detailed studies would become mandatory for compliance.</p>
Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an underfrequency event for six seconds?	<p>It is not clear from the consultation paper whether the AS/NZS 4777.2 standard or the Code is proposed to be modified.</p> <p>There is no obvious need to align the standard and the Code as long as the SO can properly account for the performance of inverters compliant with AS/NZS 4777.2.</p> <p>This standard is for smaller inverters. It would require some significant changes to cover central inverters operating at higher voltages. It could be expected to be a lengthy process before this standard is sited. There is also an additional cost in getting manufacturers to comply with a NZ standard.</p> <p>The EA should be wary of locking out inverter options when other inverters can support frequency, as well as be wary about the impact on OEM.</p> <p>AS/NZS 4777.2:2020 has the requirement for the inverter to supply rated power between 45 Hz and 52 Hz. This requirement would seem to be sufficient to meet the requirements of 8:19 (if this is the intended clause).</p> <p>There is no requirement in Part 8 for generating stations to ride through underfrequency events for 6 seconds. There is a requirement in 8.25 A for generation assets to ride through faults for 6 seconds.</p>
Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	<p>Yes. The benefits (e.g. reduced wear and tear) to the owner of the generating station will depend on technology.</p> <p>One such example is BESS. BESS degrade with energy throughput, so additional frequency keeping throughput due to a tight band would have a larger degradation cost to the BESS than other traditional generators. (See our worked</p>

Questions	Comments
	example in the cover letter.) Also energy throughput used for frequency keeping will reduce the daily throughput available for energy arbitrage for BESS. BESS will need to receive frequency keeping revenue at least equal to degradation and opportunity cost of arbitrage. See our worked example in our cover letter.
Q6. Do you consider the Authority should be short listing the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	Yes. It is not obvious that the current normal band is optimal for today and the future.
Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why.	Potentially. NewPower's preference is to make the permitted frequency deadband the same as normal frequency range (i.e. deadband of +/- 0.2 Hz). A smaller deadband will have unintended consequences for some generator technologies. The EA needs to consider the generator technology and the affect this band will have on the generator (and quantify the real costs, opportunity costs, wear & tear, etc).
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	Costs: <ul style="list-style-type: none"> • Increased dynamic studies by consultants (see our answer to Q2) • Compliance and testing • Prohibitive wear & tear costs for BESS • Significant opportunity cost for BESS • Large cost to intermittent generators to comply (i.e. loss of energy generated or install BESS) • If generation aren't compensated for the real costs incurred to deliver this frequency response, the costs associated will be passed onto consumers likely through increased energy prices Benefits: <ul style="list-style-type: none"> • Clarification of requirements and consistent application by generation owners.
Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	Costs mentioned in Q8 and also the following extra costs: <ul style="list-style-type: none"> • Control system changes and compliance testing. Potentially even control system replacements / upgrades. Control system upgrade costs could be in the range \$100k -\$300k+.

Questions	Comments
	<ul style="list-style-type: none"> Costs of having to apply for a dispensation for generators that can't comply or deem it too costly to comply if expensive upgrades are needed. <p>These additional costs will make smaller generators uneconomic.</p>
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	<p>This option is preferred as we believe it requires little to no Code changes. Also, it allows for actual frequency keeping costs to be visible (rather than passed into energy prices by generators).</p> <p>The existing competitive market will be enhanced to ensure the actual costs associated with frequency keeping are transparent (as opposed to limited or no information about the costs for existing and new generating stations to be technically compliant).</p>
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	<p>NewPower owns and operates the Rotohiko BESS. This BESS is capable of entering the frequency keeping market, but due to the small size of the market, and the risk of covering the energy costs, it has not decided to enter at present.</p> <p>If the frequency keeping market was modified for new technologies and was sized based on total frequency keeping need, BESS would be more enticed to enter this market.</p>

20 August 2024

Future Security and Reliability team
Electricity Authority
P O Box 10041
Wellington 6143

Via email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—The governance and management of harmonics in New Zealand's power system

NewPower Energy Services Ltd and subsidiary Infratec NZ Ltd appreciates the opportunity to make this submission on the Electricity Authority's (Authority) consultation on governance and management of harmonics in New Zealand's power system.

NewPower is a subsidiary of WEL Networks Limited, New Zealand's sixth largest distributor. NewPower subsidiary Infratec NZ Ltd is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned NZ's first utility scale battery energy storage (BESS) facility at Huntly, connected to WEL Networks' distribution assets. Infratec has also constructed and commissioned approximately 66 MW of utility-scale solar farms connected to distribution networks in New Zealand for clients with an additional 60MW currently under construction. We also commissioned the 4MW Naumai solar farm in Northland in Q3 2024.

NewPower and Infratec agree it is timely to review management of harmonics in the NZ power system. We request that the Authority and System Operator (SO) continue to involve relevant stakeholders (especially generators) in analysing the issues and developing solutions so that any short-listed options for further investigation are practical and achievable. For example, if a generator is emitting harmonics over any regulated limit a pragmatic approach should be able to be taken based on an assessment of the real-world impact of this deviation.

This could be a major piece of work given the date of previous studies and the changing composition of the transmission grid and generation mix. However, the Authority and SO should be prepared to adopt overseas approaches if appropriate rather than 're-invent the wheel'.

NewPower suggests the first stage should be to take nation-wide power quality measurements to understand the 'state of the nation'. There is currently little information, and any proposed changes should be based on up-to-date information.

General comments on consultation paper

More work needs to be done on understanding the cost-benefit trade-offs implicit in a harmonics management framework. The consultation paper concludes that *“it appears reasonable to expect that the cost of harmonics on New Zealand’s economy could be material”* based on studies in Europe, North America and Australia that are over 20 years old¹. Further, the Australian study *“indicated the losses due to poor power quality, especially as a result of harmonics, can amount to **several million dollars per annum**”* [emphasis added] but this cost must be considered relative to total system costs.

Reference 9² indicates the costs of poor power quality are high but the costs related to harmonics are very small as a proportion of power quality costs. The survey data analysed in the paper is close to 20 years old. Technology has moved on considerably in this time; the widespread adoption of LED lighting, inverter drives and switched mode power supplies has changed the demand characteristics of final users across the distribution networks.

From reference 9: Cost of PQ wastage EU-25 by PQ Phenomenon & cost category

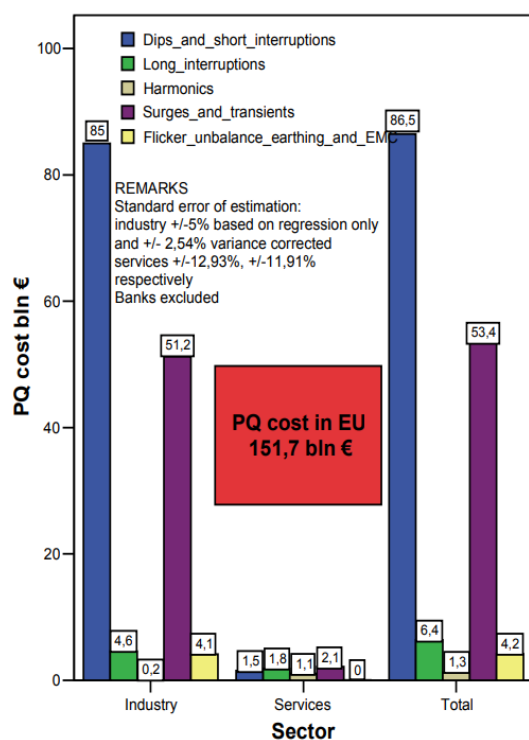
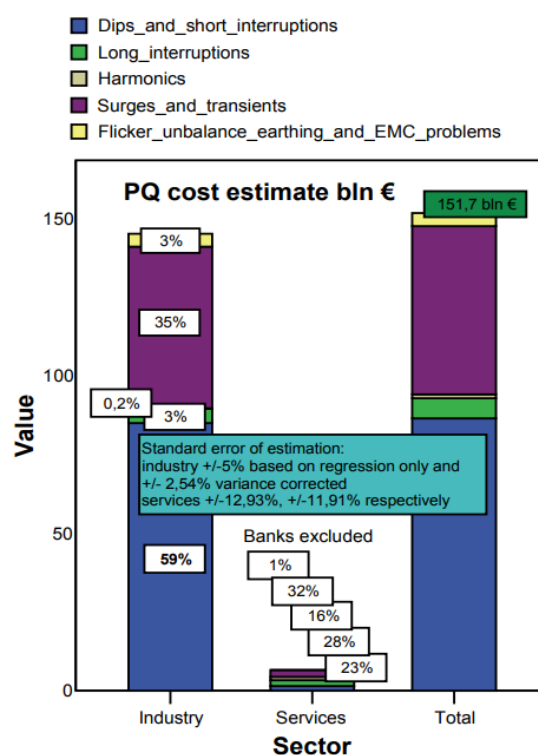


Figure 6. Cost of wastage caused by poor PQ in EU-25: Summary



Likewise, Reference 10³ uses data that is over 20 years old. The document notes that 69% of all establishments in the DE, CPM, and F&ES sectors report no costs associated with power quality problems in a typical year. For a handful of large and highly sensitive establishments, however, losses from power quality phenomena are significant. Any analysis should consider if it is more

¹ Paragraph 3.9

https://www.ea.govt.nz/documents/5153/Paper_3_The_governance_and_management_of_harmonics_in_New_Zealands_power_system.pdf

² PAN EUROPEAN LPQI POWER QUALITY SURVEY, Roman Targosz and Jonathan Manson, C I R E D 19th International Conference on Electricity Distribution Vienna, 21-24 May 2007.

³ The Cost of Power Disturbances to Industrial & Digital Economy Companies, Submitted to: EPRI’s Consortium for Electric Infrastructure for a Digital Society (CEIDS) By Primen, June 29, 2001.

economically efficient to address harmonics at a system-wide level or for sensitive establishments to invest in protection.

The NZ ECP 36:1993 Standard is more applicable to consumers with harmonic emissions that may affect other consumers. There is no justification for the harmonic levels in the Standard. The Standard addresses traditional harmonics problems of the time e.g. problems in electrical equipment and interference with fixed line telecommunications.

One of the concerns with increasing amounts of inverter-based generation and energy storage devices on the power system is that harmonics emissions may cause problems with other inverters leading to a less stable power system. This problem is different to the traditional harmonic problems and may require a different approach.

The 61000 series Standards referred to in the Electricity (Safety) Regulations 2010 Act 61000 seem to apply to low voltage connections:

- IEC 61000–3–2: Limits - Limits for harmonic current emissions (equipment input current ≤ 16 A per phase).
- IEC/TS 61000–3–4: Limits - Limitation of emission of harmonic currents in low-voltage power supply systems for equipment with rated current greater than 16 A.
- IEC 61000–3–12: Limits - Limits for harmonic currents produced by equipment connected to public low-voltage systems with input current >16 A and ≤ 75 A per phase.

Medium voltage connections for larger DG and DER seem to be covered by NZ ECP 36:1993. We query what Standards apply for distribution or sub-transmission inverters?

Inverter manufacturers have some ability to tailor harmonic current emissions from their equipment. This ability can be used to game any harmonic emission limits in Standards or provide help in mitigating harmonic problems.

Conversely, looking at how generators and demand customers plan their new installations with regard to seeing how the choice of transformers, inverters and switching frequencies could potentially reduce or limit harmonics and inter effects.

Whilst there are challenges from the increase of IBR, there are also opportunities. Looking holistically at the system, the recent EA consultation papers on voltage and frequency have also highlighted issues with reactive power provision, inertia, short circuit level and harmonics. These are actually all areas that IBR can help respond to, providing VARS, synthetic inertia, reactive fault current, harmonic cancellation etc. Looking at these problems together, there is potential for IBR to be performing multiple tasks at once, especially if there was an incentive given for 'excess' capacity in the IBR to perform these functions where they are in high demand.

This cover letter should be read in conjunction with our response to the Authority's consultation questions in the attached Appendix.

This is a highly technical topic and important issue to address at least cost to New Zealand consumers. NewPower would welcome the opportunity to engage in the detailed analysis that needs to be undertaken to formulate a short-list of options for a least cost solution for the long-term benefit of consumers.

Yours Sincerely,

A handwritten signature in black ink, appearing to read 'Darren O'Neill', written in a cursive style.

Darren O'Neill
Product Development Manager
NewPower Energy Services Ltd

APPENDIX: NewPower's response to Consultation Questions

Question	Comments
Q1. Do you consider the Authority has accurately summarised New Zealand's existing key regulatory requirements for harmonics? If you disagree, please explain why.	Yes.
Q2. Do you agree the Authority has identified the main challenges with the existing arrangements for the governance of harmonics? If there are any additional challenges, please set these out in your response	<p>Yes.</p> <p>It is good that the paper identifies the limitations of the existing Standards in their applicability to certain sizes and types of installations. The fact that there may be some conflict between the Code and existing Standards has also been highlighted, which is good.</p> <p>What is still not 100% clear is how the issue of integration of IBRs and their associated harmonics will be fully addressed. We are not clear if any of the Standards specifically address this issue, so it may be something additional that needs further consideration.</p>
Q3. Do you consider the existing regulatory framework for the governance of harmonics in New Zealand is compatible with the uptake of inverter-based resources? Please give reasons for your answer.	<p>No. The existing framework needs to be updated for clarity and to accommodate technology changes.</p> <p>The problem of harmonic issues with IBR needs to be clarified as the issues and mitigations are likely materially different from those of more traditional harmonic issues.</p>
Q4. Do you have any feedback on the Authority's suggested way forward to help address the challenges with the existing arrangements for the governance of harmonics?	<p>There should be stronger clarification of costs and benefits. Should Standards be selected to meet the requirements of the most sensitive parties affected by harmonics or be based on the requirements a more typical connected party?</p> <p>A suggestion may be to develop clear guidelines for stakeholders to aid in understanding and applying whatever Standard(s) are adopted.</p> <p>We request that the Authority and SO continue to involve relevant stakeholders (especially generators) in analysing the issues and developing solutions so that any short-listed options for further investigation are practical and achievable.</p>
Q5. Do you have feedback on any of the elements of good industry practice relating to a framework for managing harmonics? This may include feedback relating to elements you consider are missing	<p>Owners of inverter-based resources need certainty around the likely costs associated with harmonic mitigation that they will be required to pay.</p> <p>There needs to be a process to manage changes in the harmonic characteristics of the network. As a collection of minor changes to the system may have larger effects on</p>

Question	Comments
<p>from the summary provided in section 5 of this paper.</p>	<p>harmonic levels in other areas, there needs to be consensus on how such situations are treated, and how any rectification or mitigation works are funded.</p> <p>There is a need for flexibility around, and pathways for, managing non-compliant plant.</p> <p>Also, there is a need for proportionality in the effort and costs for required harmonic impact assessments.</p> <p>Distributors can be given more certainty of recovery of costs (e.g. as part of RAB) where harmonic problems can be efficiently mitigated by the distributor.</p> <p>Having a centralised database of background harmonic levels would be useful to generators when carrying out harmonics assessments.</p>
<p>Q6. Do you agree with a ‘whole of system’ approach to allocating harmonics, so that any differences in harmonic allocation methodologies between electricity networks do not cause excessive harmonics? If you disagree, please explain why.</p>	<p>Yes.</p> <p>It is desirable that a similar harmonics allocation approach is applied in each distribution network so that developers will have lower costs in managing harmonics issues.</p> <p>It also makes things more predictable for generators as the same rules will apply across all distribution networks.</p>
<p>Q7. Do you have any feedback on the suitability for New Zealand’s power system of the harmonics standard NZECP 36:1993, or the AS/NZS 61000 series of harmonics standards?</p>	<p>NZ ECP 36:1993 is obsolete and needs to be updated or abandoned. The Standard pushes a deterministic approach to compliance (e.g. installations are compliant or not).</p> <p>It is not certain how well the 61000 Standards work series works for MV connected DER.</p> <p>The AS/NZS 61000 series of Standards is more aligned with international standards than NZ ECP 36 and it addresses a wider range of harmonic issues, so it might provide a more robust framework for managing harmonics going forward.</p>
<p>Q8. Do you have any feedback on the alternative approaches to limiting harmonic emissions, including alternative approaches you consider to be appropriate for New Zealand’s electricity industry?</p>	<p>Yes.</p> <p>None of the options as described fully solve the expected issues.</p> <p>The open network approach has some good benefits around connecting and responding to actual issues, but managing the network, the generators and the loads would potentially be unmanageable and result in real time problems rather than problems in the planning process. The costs of compliance are removed from the planning stage, but then could be introduced at any stage. Given the potential costs, this could act like the ‘Sword of Damocles’ for the projects with uncertain costs becoming a barrier to investor backing.</p>

Question	Comments
	<p>Requiring net absorption has a major flaw, in that it looks individually at generators, not holistically at the system. If similar IBR are used (New Zealand doesn't have the biggest range of products for items like central inverters), then it is expected they will have similar performance. There may then be certain harmonics well absorbed by these IBR, and certain harmonics that are exported. All generators may be compliant, but the overall system is suffering at the range that the similar IBR and technologies export at, and any 'easy win' ranges will have excess capacity ie the focus by each generator is to achieve the easiest, cheapest net absorption, not the best system performance.</p> <p>Charging emitters has some benefits, but as with the open approach, could have issues in identifying the emitters / causers and fairly allocating costs to them.</p> <p>Pre-emptive installation of filters will simply act as a barrier cost, and whilst it may be helpful in some situations; there are a number of issues with these filters that are starting to be identified in practice. This looks to be an inefficient use of resources and will consequently halt or slow viable new renewable generators.</p>

20 August 2024

Submissions
Electricity Authority
P O Box 10041
Wellington

Via email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—Addressing larger voltage deviations in New Zealand’s power system

NewPower Energy Services Ltd and subsidiary Infratec NZ Ltd appreciates the opportunity to make this submission on the Electricity Authority’s (Authority) consultation on addressing larger voltage deviations in New Zealand’s power system.

NewPower is a subsidiary of WEL Networks Limited, New Zealand’s sixth largest distributor. NewPower subsidiary Infratec NZ Ltd is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned NZ’s first utility scale battery energy storage (BESS) facility at Huntly, connected to WEL Networks’ distribution assets. By way of context for this submission, NewPower is the operator of this new 35MWh rated BESS which will operate 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 66 MW of utility-scale solar farms connected to distribution networks in New Zealand for clients with an additional 60MW currently under construction. We also commissioned the 4MW Naumai solar farm in Northland in Q3 2024. All generation except the Rotohiko BESS are exempt stations, being under 30MW net export. We have provided detailed Asset Capability Statements to the System Operator (SO) (consistent with the Code). And, despite being below the 30MW net export threshold, have incurred not insignificant costs for each solar farm associated with detailed technical testing by both the distributor and SO both during the design stage and commissioning of these generating stations.

NewPower agrees with the Authority that *“evolving technologies, particularly inverter-based resources, are a key enabler of electrification. Examples of inverter-based resources include battery energy storage systems, solar photovoltaic generation, and wind generation”*. It is important that everyone understands the current and future technical capability of these technologies to deliver reliable¹ electricity. NewPower has been instrumental in upskilling the Electricity Authority and Transpower (Grid Owner and System Operator) in the operation of New Zealand’s first utility scale battery and is open to sharing its expertise about battery and solar technology at any time.

¹ As defined by the Electricity Authority: “‘Reliability’ refers to both the continuity of electricity supply (ie, the rate and duration of electricity outages, including because of insufficient fuel for electricity generation), and the quality of electricity supply (eg, the frequency and voltage of electricity).”, page 7 of the consultation cover paper https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

Key points in our submission

In summary, NewPower and Infratec:

1. **does not support Option 1 and Option 2.** An extra interface for distributed generation to the transmission System Operator (TSO) as well as the distributor it is connected to is unnecessary and illogical. The TSO should control to the GXP – that is the point at the end of assets owned and under the control of Transpower – and the distributor, or Distribution System Operator (DSO), control the network that it owns beyond the GXP. Without this demarcation there will be duplication, confusion and potentially opposing instructions and obligations for connected parties. The TSO should send its requirements to the DSO who then applies their own requirements to distributed generation and distributed energy resources (including consumer connected Consumer Energy Resources).
2. have the opinion that the status quo in terms of regulation and distributor best practice is sufficient to manage voltage in distributor networks and at GXPs. Currently distributors have voltage limits on their networks and will manage distributed generation to ensure these limits are not exceeded.
3. have experienced distributors being more restrictive on voltage limits for distributed generation than the voltage limits stipulated by the code for distributors. This can lead to distributed generators improving voltage quality for distributors without compensation and loss of energy generation due to voltage limits. This should be addressed in the upcoming Part 6 code review (i.e. standardised voltage limits should be applied consistently to generation, demand, and distributors control capability)
4. recognises that Option 3 of mandating fault ride through levels for distributed generation less than 30 MW would be beneficial, but the fault ride through limits and curves must be reasonable, realistic and consider typical limitations of different types of generation technology. The fault ride through requirements should be based on faults that occur frequently enough to qualify as contingent events.

Each of these points is discussed further in this submission and includes worked examples and our response to the Authority's consultation questions. This version of the submission has had commercially confidential information redacted.

General Comments

The consultation paper describes 3 issues and 3 options, copied below for completeness. It appears that Option 3 (amending the 30MW threshold) is only relevant to Issue 4 (managing fault ride through). NewPower submits that good regulatory practice requires consideration of at least two options to address one issue. We suggest the status quo is the alternative to Option 3.

Issues:		Options:	
2	An increasing amount of variable and intermittent resources, primarily in the form of wind and solar photovoltaic generation, is likely to cause larger voltage deviations , which are exacerbated by changing patterns of reactive power flows	1	Assign voltage support obligations to some additional parties
3	Increasing amounts of inverter-based variable and intermittent resources will reduce the transmission network's system strength thereby increasing the likelihood of network performance issues if inverter-based resources disconnect from the power system	2	Manage the import and export of reactive power at a grid exit point
4	Over time increasingly less generation capacity is expected to be subject to fault ride through obligations in the Code, as more generating stations export less than 30MW to a network (thereby falling below the current threshold requiring compliance with the Code's fault ride through obligations)	3	Lower the 30 MW threshold for generating stations to be excluded by default from complying with the fault ride through asset owner performance obligations in clauses 8.25A and 8.25B of the Code

NewPower **does not support Option 1 and Option 2**. An extra interface for distributed generation to the transmission System Operator (TSO) as well as the distributor it is connected to is unnecessary and illogical. The TSO should control to the GXP – that is the point at the end of assets owned and under the control of Transpower – and the distributor, or Distribution System Operator (DSO), control the network that it owns beyond the GXP. Without this demarcation there will be duplication, confusion and potentially opposing instructions and obligations for connected parties. The TSO should send its requirements to the DSO who then applies their own requirements to distributed generation and distributed energy resources (including consumer connected Consumer Energy Resources).

We agree it is appropriate for the TSO to have knowledge of generation and load resources connected to the distribution network that influence voltage but as Transpower said in its submission to the EA on the future power system consultation²:

“To ensure a secure, reliable, and cost-effective transition to a more distributed energy system, strong coordination between the SO and the emerging distribution system operators (DSOs) is essential.

Coordination does not mean that we, as SO, seek to ‘control’ the entire system. Rather, we are referring to having common digital capabilities across the SO and DSOs so that we, as SO, can support the overall operation of the power system through effective coordination and information sharing across the system.

As New Zealand moves towards a more complex system with higher DER penetration, it becomes critical to improve data exchange between the SO and DSOs. This will help manage the

² Source: Page 2, 11 April 2024 https://www.ea.govt.nz/documents/4952/Transpower_ZEEtXiW.pdf

challenges posed by DER, such as the 'hidden load' effect¹ and potential for rapid demand changes; it's helpful too in understanding reverse flows across and within GXP as a result of high levels of DER exports."

In NewPower's opinion the status quo in terms of regulation and distributor best practice is sufficient to manage voltage in distributor networks and at GXPs. Currently distributors have voltage limits on their networks and will manage distributed generation to ensure these limits are not exceeded. **But NewPower notes that distributors are more restrictive on voltage limits for distributed generation than the voltage limits stipulated by the code for distributors. This can lead to distributed generators improving voltage quality for distributors without compensation and also loss of generation due to voltage limits.**

Also, distributors are already required to manage the power factor at GXPs to certain limits. Reactive power flows at the GXP are managed consistent with the default transmission agreement so that the reactive power flows do not unduly draw on (or add to) the reactive resources of the transmission grid. In NewPower's experience all distributor Connection Agreements contain voltage and power factor limitations for the generator (effectively the reactive power limit for the generator).³ So, in NewPower's view, most of these options are trying to solve an issue that doesn't exist. It is not clear from the consultation paper that the SO is experiencing voltage and reactive power that is not being adequately regulated on the distribution network.

NewPower is in favour of grid and network support contracts (for voltage support etc) and believes they should be encouraged. Having such contracts / markets will ensure the price / cost for voltage support is transparent. Where distributed generators improve the quality of voltage on the grid or network should be valued. See worked example later on in this response paper highlighting the real costs of voltage support from an inverter-based generator.

NewPower responded to Transpower's Upper South Island Non-Network Solution RFP (in April 2024). This RFP included finding a solution to a voltage issue in the Upper South Island. Transpower advised that it was not going to progress with the Non-Network Solution at the current time. NewPower asks the Electricity Authority to consider encouraging non-network solutions to be implemented as these often lead to better economic outcomes.

NewPower recognises that Option 3 of mandating fault ride through levels for distributed generation less than 30 MW would be beneficial, but the fault ride through limits and curves must be reasonable, realistic and consider typical limitations of different types of generation technology. The fault ride through requirements should be based on faults that occur frequently enough to qualify as contingent events.

Distribution network protection considerations should take precedence over Code fault ride through requirements. NewPower thinks that fault ride through requirements for distributed generation are better placed in distributor standards than the Code, noting that there must be a national standard. The EA should analyse whether it is more efficient to include fault ride through obligations in Connection Agreements rather than the Code.

NewPower thinks this will need more careful consideration, especially for smaller plants or plants with string inverters, as these may not be able to easily comply with the code FRT requirements. There is no issue in including the code FRT requirements for information in the distributor

³ This is our practical experience during connection of solar pv to the distribution networks of PowerCo, WEL Networks and Northpower with our Connection Agreements detailing how voltage is to be managed.

connection standards, but the specific obligation on the generator needs to maybe rather be a scaled down version of the code fault ride through requirements based on network specific requirement

From a practical perspective, IBRs' capacity for regulating voltage is inversely linked to its active power output. Therefore, supporting the voltage will reduce energy exports and raise the LCOE. NewPower has provided some worked examples later in this submission to show the real costs of producing reactive power from an IBR and also the commercial impacts on a distributed generator that is voltage constrained at the point of connection.

Our other concerns include:

- liability from following voltage / reactive power instructions from the SO for distributed generation on distribution network. For example, should a feeder on the distribution network trip due to an instruction from the SO, who is liable for the lost generation and the loss of supply to customers? For example, if the SO regularly instructs increased reactive power from a generator on the distribution network to solve a transmission issue, this could limit their active power and hence revenue. Is there any compensation for this?
- concern that option 2 differs from the intent of the default connection agreement and this may mean that existing Connection Agreements must change.
- concern around controlling the reactive power flows at a GXP: What does this mean for distributed generation connected to the GXP? Will this become more restrictive as voltage control is more difficult for the DSO to manage if the SO is directly issuing instructions to manage the GXP?
- does this mean that distributors (and therefore DER) are required to solve Transpower's voltage issues on the transmission system?
- issues for voltage constrained sites that need the ability to have no restrictive voltage control to be able to generate. See worked example later in document.

The options consultation paper makes no mention of grid forming (GFM) or grid following (GFL) technologies. Currently GFL technology is the mature technology and the first choice for developers, but this technology has drawbacks around fault ride through, and other areas not directly relevant to this topic.

Transpower recommended in their report 'Preparing for an increase in inverter-based resources, 27th June 2023' that all IBR over 1 MW should be GFM. This recommendation is based on an in-depth study of fault ride through performance of GFM and GFL. Given that this recommendation is over a year old, it seems strange that no mention of this report has been made in the consultation papers. Given the other issues facing the New Zealand grid such as inertia, short circuit level, fault ride through and harmonics, a technology that can solve multiple issues (GFM inverters) should be evaluated in more depth as a viable option to solve potential voltage and frequency keeping issues.

There is growing experience with this type of technology in large grids and managing the technology. Australia is now requiring these inverters via its system strength rules. NewPower submits there is a lot that can be done with GFM technology, and this is what (in the study) Transpower recommended using for new projects.

This technology could be expected to reduce system costs by providing a wide range of services⁴, which is why Australia are pushing it now before they have too many GWs of Grid Following inverters.

We also note that GFM inverters are not without their complications in terms of their tuning to ensure no dynamic instability and potential additional costs from suppliers.

The consultation paper does not consider the market-based option of using the voltage support ancillary service to manage the issues. In our view this is a valid option based on a competitive market that can be flexible to changing power system dynamics and incentivise assets owners to offer this service. Transpower's website reveals *"We do not consider it necessary to procure voltage support in any zone at this time as we consider the reactive equipment currently available to be sufficient to enable us to meet our PPOs"*.⁵ However, contracts and a method of procurement are already in place.

Worked Examples

Cost of Producing Reactive Power from IBR

Inverters will consume real power to produce reactive power. One particular inverter model that NewPower has on its generation sites consume ~20 kW of real power acquired from the spot market for every 1 MVar of reactive power that is produced. Also, the intermittent generator won't be able to hedge the reactive power cost without some form of availability contract or reactive power / voltage market and solar farm inverters have no natural hedge during the nighttime hours, but can continue to provide voltage support using market supplied energy. Also, NewPower suspects that mass EV charging overnight will exacerbate voltage management issues during off peak and overnight trading periods.

Extending this to an annual basis, if a reasonable average annual energy spot price of **\$0.15/kWh** is assumed, the cost of producing **1 MVar** on an **annual basis** (i.e. 8760 MVarh) is **\$26k**.

How does the EA expect this cost to be recovered? Should the generator pass on the costs in its energy price, or should there be some form of separate compensation or even a voltage control market?

Commercial Impact of a Voltage Constrained Generation Site

Infratec and NewPower have experienced many voltage constrained generation sites during development of solar farms. This is due to solar farm location often being located on weaker rural feeders that often do not have sufficient local control systems for managing voltage. As such networks are requesting higher than code voltage control on the generator without any compensation for network voltage support. This aspect of technology application does not seem to have been recognised in many of the consultation briefing information i.e. focus seems to be on inverter-based issues rather than solutions / opportunities distributed inverters can provide (i.e. distributors under increasing decarbonisation demands).

A real-world example of a voltage constrained site is one where the maximum generation power output is typically constrained by ~35% due to the voltage limit at the point of connection being +/-

⁴ In the very short-term there may be costs associated with testing this ubiquitous technology while the SO builds its understanding.

⁵ <https://www.transpower.co.nz/system-operator/information-industry/electricity-market-operation/ancillary-services/voltage>

2% of nominal voltage (compared to code standard +/- 5% of nominal voltage). This results in a 11.6% reduction in energy generated by the solar farm. This reduction in energy production results in approximately **19% relative decrease in the commercial returns** of the solar farm project. This level of reduction in commercial return is material and could be the difference of a generation project going ahead or not. In comparison if the solar farm voltage limit was set to the code requirement of +/- 5% there would be no loss of generation and the project would be economic.

Why is it that distributors can specify more restrictive voltage limitations for distributed generators than the code requires of distributors themselves?

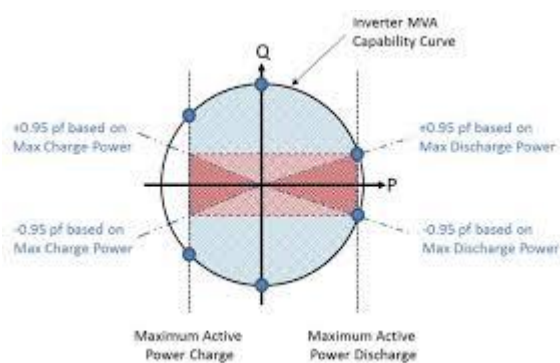
This example highlights the real impacts that any voltage related Code changes can have to distributed generation sites. NewPower asks the EA to undertake a robust cost benefit analysis and carefully consider the flow on effects of any Code changes. The same principle should apply to Transpower's grid connections and grid upgrade / non-transmission solutions (reference NewPower submission to Transpower for the Upper South Island NNS RFP process in April 2024)

Inverter Sizing for Reactive Power Requirements

IBR active / reactive power capabilities are based around current and voltage, i.e. as active power increases, reactive power capability decreases. This typically leads to the capability curve being a curve – for BESS this operates from full active power discharging (no reactive capability left) to zero active power (full reactive capability), through to full charge (no reactive power capability).

The way this is written means that IBR will always have the capability at 0 MW, but the capability will change considerably as the PV plant moves up to full active power. In practice the Connection Agreement will probably have a min / max power factor at full load which solar developers would then size the IBR to. But to ensure the voltage stability of the network doesn't move as the BESS or (to a lesser extent) PV varies the active power through its range, the reactive power should be set as a straight line ie a power factor limit. Consistency is better than the maximum. Normally full output is 0.95 power factor ie 1 MW needs a 1.05 MVA PCS. To achieve +50% means 0.85 power factor means a 1.18 MVA inverter - a 12% increase in size.

The SO study omitted PV at 0 MW.



The study clearly shows (as expected) that having DER performing voltage control leads to better local voltage regulation, and this was with IBR at 0 MW excluded.

If an IBR is performing voltage control, are charges for VARs / power factor excluded? IBR shouldn't have to pay for offering the distributor an improved voltage control. There should be a payment from the distributor to the IBR owner for offering improved voltage control.

It is important to note that IBR can help with voltage support during faults ensuring more devices / DER can ride through, helping security of supply.

This is a highly technical topic and important issue to address at least cost to New Zealand consumers. We have provided extensive information on our assessment of the costs of the EA's proposed options (while there is minimal quantification of the SO's expected benefits from the proposed options). NewPower would welcome the opportunity to discuss our detailed submission with the Authority and System Operator.

Yours Sincerely,

A handwritten signature in black ink, appearing to read 'Darren O'Neill', written in a cursive style.

Darren O'Neill
Product Development Manager
NewPower Energy Services Ltd

APPENDIX 1: NEWPOWER'S RESPONSE TO QUESTIONS

Questions	Comments
<p>Q1. Do you consider it likely that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems (when discharging) that connect to their networks? Please give reasons for your answer.</p>	<p>Yes. Distributors are responsible for voltage management on their network and the voltage received by their customers.</p> <p>From NewPower's experience, all distributors have voltage and power factor limits stipulated in Distributed Generation Connection Agreements. (See our worked examples in the cover letter.)</p> <p>Distributors also have minimum power factor requirements at their GXP's (set by Transpower) so are incentivised to manage reactive power and place voltage and reactive power requirements on their customers.</p> <p>Why does the consultation paper not consider voltage support obligations for charging for BESS, as they have four quadrant capabilities?</p> <p>The lack of standardised requirements across different regions/networks could create a complex and potentially burdensome regulatory landscape for plant owners operating multiple sites.</p>
<p>Q2. Do you agree generating stations and energy storage systems connected to local distribution networks at the GXP voltage (which varies by local distribution network) should be required to support voltage, or do you consider the obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (eg, 33kV)? Please give reasons for your answer.</p>	<p>Neither option is supported.</p> <p>Voltage related performance obligations for distribution connected generation and energy storage systems should be set by distributors according to the characteristics of their network(s).</p> <p>Voltage related obligations for distributed generation and energy sources should not fall within the Code. The proper location for voltage related obligations for distributed generation is the distributor's Connection and Operation Standards.</p> <p>It may be desirable that all distributors have a common approach to determining voltage related obligations, but this approach does not need to be developed by the EA and SO. We understand the ENA's Future Networks Forum has asked the EEA to identify opportunities for consistency across distributors' Connection and Operation Standards. NewPower supports this work being undertaken at pace and without regulatory intervention.</p> <p>Developers will always want to maximise their active power output and minimise their network costs. There should be room for working with the distribution network to achieve the common goals. Applying voltage support obligations at a standard voltage, such as 33 kV might make it easier for the network to determine compliance. From the perspective of a generator, it will likely make things more challenging and costly.</p>

Questions	Comments
	<p>An alternative is that the requirements to comply with voltage support obligations should be decided based on the potential impact a plant may have on the network voltage, as some parts of the network are weaker than others and therefore require more voltage support than other parts. If a generator is operating in a way that improves the voltage performance of part of a distribution network – this is an alternative to the distributor investing in network infrastructure (a non-network solution) and the distributor should compensate the generator for this service.</p>
<p>Q3. Do you consider there should be a capacity threshold (eg, a nominal net export or nameplate capacity of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.</p>	<p>No. The voltage related asset owner performance obligations in Part 8 of the Code are based on synchronous generation technologies and for the transmission system that existed many decades ago. It is not obvious the voltage related AOPOs are optimal today or that the voltage related AOPOs for the transmission system should be extrapolated to distributed generation connected within distribution systems.</p> <p>Any threshold should be based on the ability of the distributed generation to affect voltages across the distribution network. The DG hosting capability (i.e. how much distributed generation can be injected at different parts of the distribution network) could provide an alternative mechanism.</p> <p>Voltage related performance obligations for distribution connected generation and energy storage systems should be set by distributors according to the needs of their network(s).</p> <p>Voltage related obligations for distributed generation and energy sources should not fall within the Code.</p> <p>Capacity thresholds should be determined by distributors taking into account the characteristics of the relevant distribution network. A one size fits all approach is inappropriate.</p> <p>The SO's modelling has not provided a case for applying a generation capacity threshold relating to voltage support.</p>
<p>Q4. What do you consider to be the pros and cons of requiring generating stations / energy storage systems connected to local distribution networks to have a reactive power range of $\pm 33\%$ rather than the $+50\%/-33\%$ range specified in clause 8.23 of the Code?</p>	<p>It is not apparent that the existing $+50\%/-33\%$ reactive power range requirement is optimal or even appropriate for the future. It is not obvious what reactive power range is appropriate for distribution networks.</p> <p>A reactive power range needs to be linked to the power factor limits requirement. It is not appropriate for these to be defined independently of each other as presented in the consultation paper.</p>

Questions	Comments
	<p>No analysis of the costs and benefits for any combination of reactive range has been presented so an opinion on pros and cons of any arrangement does not have much value. We have included worked examples in our cover letter.</p> <p>Given the way IBR resources work, and their capability curve shape, this requirement needs to be better defined, so as to be relevant and not introduce undesirable characteristics as the IBR moves along the curve. Most IBR can produce $\pm 100\%$ reactive power at 0% active power. For BESS would this be defined in four quadrants?</p>
<p>Q5. Do you agree the Authority should be short listing the first voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.</p>	<p>No.</p> <p>The management of distribution network voltages is outside the ambit of the Code. This should be managed by the distributors within their Connection and Operation Standards.</p> <p>Having voltage related obligations within the Code and Connection and Operation Standards will likely result in barriers to entry for DG and DER as distributors will be more conservative in the size of DG and DER that can be connected (as they are trying to manage the voltage of their network with the overlay of the SO's requirements) and the costs of DG and DER will be increased.</p> <p>It would be more desirable to have more consistency across distributors' Connection and Operation Standards than to have these details in the Code which is very time consuming to change.</p> <p>The requirement for all generating stations and energy storage systems to support voltage might necessitate substantial investments and upgrades. These costs could affect the financial viability of new and existing projects.</p>
<p>Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?</p>	<p>In our view, this option carries significant costs and very little benefit:</p> <p>The option will complicate dispatch arrangements with two parties with potentially mutually exclusive objectives trying to control the same resource.</p> <p>Liability for damage to consumer appliances or outages resulting from SO issued reactive power dispatch instructions to distributed generation is unresolved. This liability needs to be addressed prior to proceeding with this option.</p> <p>This option imposes duplicated voltage related obligations and monitoring and compliance systems from the Code and distributor's Connection and Operation Standards.</p>

Questions	Comments
	<p>The effect of this would appear to be Transpower's voltage issues would be transferred to the distribution system, which then has to manage its own issues, as well as those imposed by Transpower. It is unclear how this will benefit the consumer.</p>
<p>Q7. Under the first voltage-related option, what costs are likely to arise for the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network?</p>	<p>Costs for distributed generation owners include:</p> <ul style="list-style-type: none"> • Increased transaction costs for asset owners and system operator (ACS, monitoring, dispensations etc). • Cost of SO connection studies making smaller distributed generation uneconomic. • More complicated communications systems may be required to deal with multiple interfaces for receiving dispatch instructions and managing priority of dispatch instructions between SO and EDB. • Additional administrative and operational costs for ensuring ongoing compliance and reporting. • Operational adjustments to meet voltage support obligations could impact revenue, particularly if it limits the generation capability of renewable plants. <p>In addition, there is the potential for system-wide inefficient overbuild of assets – imposing higher costs on consumers.</p> <p>Note that there is a cost of inverter-based generation providing reactive power:</p> <ul style="list-style-type: none"> • A particular inverter model produces 1 MVar using ~20 kW of power • Extending this to a yearly cost assuming an average spot price of \$0.15/kWh comes to \$26k per annum per 1 MVar supplied by an inverter. How does the EA expect this cost to be recovered?
<p>Q8. Under the first voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?</p>	<p>Costs for owners of BESS with a point of connection to the transmission grid include:</p> <ul style="list-style-type: none"> • the usual costs associated with complying with the Code in respect of voltage related obligations. • difficulty in simultaneously supporting voltage and meeting minimum power factor requirements when charging. • cost of modifying operational practices to ensure compliance with voltage support requirements. • costs associated with coordinating with the SO and possibly distributors to manage voltage support effectively.

Questions	Comments
	<p>Note that there is a cost of inverter-based generation providing reactive power:</p> <ul style="list-style-type: none"> • A particular inverter model produces 1 MVAR using ~20 kW of power • Extending this to a yearly cost assuming an average spot price of \$0.15/kWh comes to \$26k per annum per 1 MVAR supplied by an inverter. How does the EA expect this cost to be covered?
<p>Q9. Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.</p>	<p>No. Reactive power flows are already effectively controlled by power factor limits imposed by Transpower on distributors at GXP's.</p> <p>Often distributed generation power output is voltage limited rather than thermal line rating limited. Allowing the distributed generator to control its point of connection voltage allows the generator to export more energy. Controlling the reactive power of a voltage limited distributed generator to manage the GXP may impact the level of energy the generator can produce.</p> <p>Managing reactive power at the GXP could impose restrictive conditions that might limit operational flexibility and increase costs for generators.</p> <p>While coordination between the SO and distributor(s) is essential, the specific obligations and potential operational constraints imposed on generators needs careful consideration. This option might lead to more stringent operational requirements that could complicate the integration of renewable energy projects and affect their financial viability.</p> <p>Potential for distributed generation to be used primary to control power and reactive power flows on the transmission network. If Option 2 were to be implemented careful consideration would need to be taken.</p> <p>Should GFM technology be used, this can help to improve system strength to help address issue 3.</p>
<p>Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?</p>	<p>Benefits:</p> <ul style="list-style-type: none"> • Avoids direct SO interference with distribution voltage management which reduces risks to assets and public safety. • Helps distributors in their journey towards becoming DSOs. <p>Costs:</p> <ul style="list-style-type: none"> • The distribution system is being asked to solve some of the SO's voltage issues, which isn't necessarily

Questions	Comments
	<p>the most efficient solution, particularly where the DSO has multiple issues to manage.</p> <ul style="list-style-type: none"> • Potentially restrictive conditions at the GXP could limit the operational flexibility of renewable plants. Which would have large opportunity cost for generation. See worked example on a voltage limited solar generator.
<p>Q11. Under the second voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?</p>	<p>This question does not appear particularly relevant. An energy storage system with a point of connection to the grid is by definition not connected to a distribution network so will not directly affect a distributor's ability to manage reactive power flows across the GXP.</p> <p>The usual costs associated with complying with the Code in respect of voltage related obligations would apply.</p> <p>There would be the difficulty in simultaneously supporting voltage and meeting minimum power factor requirements when charging.</p>
<p>Q12. Do you consider it likely that distributors will, in the absence of a Code requirement, place fault ride through obligations on some or all <30MW generating stations that connect to their networks? Please give reasons for your answer.</p>	<p>Yes.</p> <p>Distributors are primarily concerned with the effects of faults on their distribution networks and to a lesser extent faults occurring on the transmission network.</p> <p>Accordingly, distributors may place obligations on DG to remain connected or even disconnect during certain distribution faults (e.g. to avoid islanding). This detail is included in distributors' Connection and Operation Standards.</p> <p>Distributors will be less concerned about DG riding through transmission faults unless the lack of ride through capability of DG affects the reliability of the distribution network.</p>
<p>Q13. Do you consider it appropriate to include in the Code fault ride-through curves for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account network protection considerations? Please give reasons for your answer.</p>	<p>Yes, provided these fault ride-through curves are realistic and consider typical limitations of different types of generation technology.</p> <p>The fault ride through requirements should be based on faults that occur frequently enough to qualify as contingent events.</p> <p>Distribution network protection considerations should take precedence over Code fault ride through requirements. NewPower thinks that fault ride through requirements for distributed generation are better placed in distributor standards than the Code, noting that there must be a national standard. The EA should analyse whether it is more efficient to include fault ride through obligations in Connection Agreements rather than the Code.</p>

Questions	Comments
	<p>NewPower thinks this will need more careful consideration, especially for smaller plants or plants with string inverters, as these may not be able to easily comply with the code FRT requirements. There is no issue in including the code FRT requirements for information in the distributor connection standards, but the specific obligation on the generator needs to maybe rather be a scaled down version of the code fault ride through requirements based on network specific requirements.</p>
<p>Q14. Do you consider there should be a threshold based on connection voltage and capacity (eg, a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations connected to distribution networks to ride through faults? Please give reasons for your answer, including any implications of having / not having a capacity threshold.</p>	<p>Potentially.</p> <p>The benefits of DG connected at the GXP nominal voltage riding through transmission faults accrues mainly to the distribution network so any fault ride through requirement based on connection voltage should be up to the distributor to specify and not be in the Code.</p> <p>Any threshold should be based on a thorough cost-benefit analysis. Increasing the threshold limit above 30 MW could prove more optimal.</p> <p>Given the way renewable generators are constructed from multiple modules, ie IBR, rather than one central device (as synchronous stations tend to be), there could be the unintended consequence that string inverters or similar end up non-compliant, as the manufacturers won't want to pay the extra costs of certification and testing, limiting the market to larger inverters, and increasing the LCOE.</p>
<p>Q15. Do you agree the Authority should be short listing for further investigation the third voltage-related option to help address Issue 4? If you disagree, please explain why.</p>	<p>Yes, but the option should consider specific ride through limits for different technology so as to not be restrictive on technology selection. Also need to co-ordinate fault ride through requirements of the distributors with the Code.</p> <p>As we said in Q13, the EA should analyse whether it is more efficient to include fault ride through obligations in Connection Agreements rather than the Code.</p> <p>Any further investigation of this option should include cost/benefit analysis for lowering the threshold to <30MW.</p>
<p>Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?</p>	<p>Costs:</p> <ul style="list-style-type: none"> Costs of making existing DG compliant or seeking dispensations. Cost of monitoring performance. <p>Benefit:</p> <ul style="list-style-type: none"> Reduced risk of potential system collapse.
<p>Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under</p>	<p>Costs of making existing DG compliant or seeking dispensations.</p>

Questions	Comments
the 30MW threshold if these generating stations must comply with the fault ride through AOPOs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?	<p>Also a Virtual Power Plant aggregation of distributed generation will likely extend across a number of GXPs, making voltage co-ordination more difficult.</p> <p>Cost of monitoring performance. This may require advanced monitoring systems to accurately collect and collate data for virtual generating stations split over multiple locations.</p>
Q18. Do you have any comments on the Authority's assessment of options to help address Issues 2, 3 and 4 identified in our 2023 Issues paper?	<p>It is disappointing that market-based options are not being considered in the consultation paper. Given the long lead time for these options, should not work on the options commence as soon as possible?</p> <p>NewPower's strong preference is the competitive market-based voltage support ancillary service to solve all the voltage issues in this consultation paper. The SO has the contracts and procurement processes in place.</p> <p>Market based options will provide potential new revenue streams for DG and DER rather than AOPO options which impose additional costs on DG and DER.</p>