INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

[redacted]

20 August 2024

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

By email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—Addressing more frequency variation in New Zealand's power system

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) proposed three options to address more frequency variation in New Zealand's power system.[1]

The IEGA comprises about 30 members who are either directly or indirectly associated with predominantly small-scale power schemes connected to local distribution networks throughout New Zealand for the purpose of commercial electricity production. IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, who have made significant economic investments in renewable generation plant and equipment. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand. We are price takers in the electricity market – the majority of our members do not have the financial or human capacity to operate 24/7 dispatching into the wholesale market.

Our members are innovative, entrepreneurial and passionate about New Zealand's renewable advantage and potential who have made significant economic investments in generation plant and equipment throughout the country. They have a portfolio of new economic renewable generation projects consented or under investigation which have a smaller environmental footprint than grid-connected generation and provide an incremental, rather than a step change, increase in supply more aligned to increasing local demand for electricity.

Members' own and operate the full range of renewable generation technologies: hydro, wind, geothermal, solar and biomass and energy storage.

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[1] The Committee has signed off this submission on behalf of members.

Comments on Options

Option 3 – procure more frequency keeping

The IEGA **strongly supports Option 3** 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.

The Authority states preference is given to market-based approaches to providing the required service / output, to promote innovation and transparency of the full costs and benefits of an option / solution.[2]

This competitive market-based solution is already successfully managing frequency. There are numerous advantages with procuring more frequency keeping over time when variability increases, namely:

- this is the least regrets option – the market already exists, and it is feasible, easy to enhance / expand / implement and has little or no risk of unintended consequences
- the existing market procurement and processes make it flexible, scalable and relatively easily reversible. The SO has contracted MFK and backup SFK until December 2025 giving it the flexibility to tender for a different volume in 12 months-time
- the cost of manging frequency variations will be directly related to the actual performance of the power system over time
- offers in the market already exceed the current need. The SO currently has 4 ancillary service agents contracted to provide 30MW of frequency keeping and 11 agents to offer Instantaneous Reserves. The offer stack for FIR is currently often over 500MW - historic data is available on the EMI website.[3]
- market-based pricing will provide financial incentives to grow the capability of new technologies or existing plant to be involved.
- SO analysis results reveal the additional FIR required under modelled scenarios if the technical equipment was not installed. The increase in FIR between 2023 and 2035 is minimal (~135MW) as a proportion of forecast increase in total installed capacity (~7,000MW)
- promotes competitively neutral amongst technologies / fuels – anyone has the option to participate in the SO's procurement tender for ancillary services. The Authority is already investigating removing the 4MW minimum band size
- A market-based approach should incentivse investment in activities that can participate in the market. The Authority is already implementing changes to manage five-minute variability and expanding participation in this product to include smaller providers and a wider range of technologies
- having the ability to procure more frequency keeping will be durable across a range of uncertain future scenarios – especially important as the timing of connection of new technologies and capacity is uncertain

[2] Evaluation criteria, Table 1 of consultation cover paper https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

[3] A very limited sample of EMI data for 20 trading periods on 15 August showed North Island offers for FIR were 3 times cleared volumes with ~60% of this volume offers at less than $10/MWh.

- is a ‘quick win’ which does not require any Code amendment
- success of this solution is independent of any assumptions about future generation technologies and locations in 2035 and performance of the power system as the market can be relied on / incentivised to manage actual frequency performance.
- extends the financial incentive to retain existing synchronous generation or technologies that can participate in the frequency and voltage support markets.
- the Authority already has a work programme to enhance the frequency keeping ancillary service. This work can continue and be adaptive to actual market conditions over time
- the allocation of frequency keeping costs to generators causing the actual excursions will incentivse participants to try harder to be compliant
- the System Operator used to procure 75MW via MFK – this has been reduced to 30MW (15MW in each island) without any material deterioration in the quality of system frequency[4]. There is nothing to say that the additional 45MW (over 2 times the current market) is not still available / willing to participate
- the SO’s analysis assumes that all new generation <30MW will not be connected to the transmission grid, that is it is connected to a distribution network.[5] Distributors already have a responsibility to support the SO in achieving its AOPOs at the GXP. That is, the distributor is responsible for and incentivised to manage frequency and voltage within its own network.
- the SO expects a rapid increase in behind-the-meter solar pv generation – the impact of this IBR generation on power quality will be managed by the frequency keeping market while option 1 and 2 do not address this
- Transpower Grid Owner has plans to increase the capacity of the HVDC. This could lead to an increase the HVDC’s Frequency Keeping Control (FKC) capacity.

In summary, the Authority describes this option as “***strongly feasible*** *with no risk of unintended consequences (no changes to the Code or to assets, negligible implementation cost*”.[6] [emphasis added]

This option has the additional advantage that it addresses frequency variation within the normal band as well as outside the normal band – when the Issue being addressed is only frequency variation within the normal band.[7]

In addition, we note that Transpower’s submission[8] on the Authority’s future power system review stated:

> *“While the transition is accelerating, at this stage it is important that the industry and market can adapt to deliver benefits for consumers rather than being directed down a certain path. Our view is that* ***incremental (low or no regret) changes should be adopted first****. These include:*

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4 Paragraph 6.13(a) page 31 of consultation paper

5 Page 15 System Operator Report on Studies (1 and 3), June 2024

6 Table 3, page 39 of consultation paper. We note the Authority considers the other two options to be less feasible and more expensive: Option 1 to be “*moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation costs)*; and Option 2 to be “*feasible with uncertain risk of unintended consequences*”.

7 Issue 1: “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.” Page 2 of consultation paper

8 Page 1 https://www.ea.govt.nz/documents/4952/Transpower_ZEeTxiw.pdf

- *undertaking a first principles assessment of ancillary services to ensure the system operator has access to the tools needed to provide a secure and reliable system;"* [emphasis added]

Option 1 – lower the 30MW nominal net export threshold

The IEGA **does NOT support any change to the 30MW nominal net export threshold** for excluded stations. We provide below qualitative and quantitative analysis of the costs of changing the threshold.

Imposing disproportionate costs on this sector of the generation market would become a barrier to entry jeopardising future investment plans and/or influence owners to discontinue generating. Costs are disproportionate relative to scale, both from the perspective of the:

- costs to become compliant are the same across any size generation plant – these uniform costs are easily absorbed by larger generators with larger throughput and revenue. For example, a technical study of a hydro turbine to confirm compliance is estimated to cost $70,000 to $100,000 irrespective of the size of the turbine; AND
- impact this generation plant has on the total power system: is a non-compliant 8MW hydro power station going to negatively impact a 17,000MW power system in 2035?

The systems were not built with the ability for these facilities as the 30MW threshold was in place. Installers would have purchased equipment and controls that provide a stable steady output and not governed options. Many resource consents have ramp rate restrictions that prevent sudden changes in output river flow.

The System Operator recommends a 5MW threshold on the basis it will "*reduce the need for the SO to schedule additional reserves*". This conclusion is reached without any consideration of the costs and benefits associated with requiring existing (and new) generation to be compliant with frequency keeping requirements.

The consultation papers only include qualitative assertions about the potential benefits from changing the threshold. Stakeholders should be provided with detailed quantitative estimates as soon as possible as, at this stage, our view is that costs (including costs to be incurred by the System Operator) are very likely to exceed any benefits. This is especially so when the costs of Option 1 (and 2) are compared with the costs and benefits of procuring more frequency keeping (Option 3).

Option 2 – apply a tight deadband requirement

The IEGA **does not support Option 2** to apply a tight deadband requirement on new generating plant and to require compliance with this deadband requirement from existing generating plant. This deadband requirement would apply to any generating station that is not an excluded station (that is this option is related to Option 1 to reduce the 30MW nominal net export threshold for excluded generating stations).

Retrospective application of Option 2 on existing generating stations with nominal net export above the excluded generating station threshold imposes costs:

- to comply; or
- to seek and maintain a dispensation from the System Operator.

It seems odd for the Authority to be proposing a permanent technical solution (implement deadbands) when:

- its earlier preference was for a tender-based procurement approach to maintain system security and an acceptable level of frequency quality (para 5.16 of consultation paper)
- which was delayed as the Authority commenced initial scoping for a review of the purpose and effectiveness of the frequency keeping ancillary service (para 5.19 of consultation paper); AND
- the Authority has now decided to start work (in July 2024) on enhancing the frequency keeping product "to manage five-minute variability and expanding participation in this product to include smaller providers and a wider range of technologies. This would allow the system operator to procure more resource from a wider range of providers to be available to manage variability risk".[9]

That is, a number of interrelated workstreams have been implemented or are in progress that could be expected to eliminate the need for any physical technical solution (especially given the time it will take to make physical changes to plant or apply for / test / approve dispensations). This is discussed in Appendix 1.

Concluding remarks about the Options

In concluding, we suggest the consultation paper is internally inconsistent. The options are proposed to address the problem of more frequency variation within the normal band from an increasing amount of variable and intermittent resources as more wind generation, solar pv and energy storage systems connect over the next 5-10 years. But the Authority says in the paper that modern inverter technology "can provide frequency control" and operate "in the same way that conventional synchronous generation can".[10] [11]

Further, the SO's modelling is inconclusive and the modelled quantity of possible frequency excursions very small relative to the size of the market such that the conclusions are probably within any modelling error range.

The IEGA's recommendations are the Authority:

- urgently investigate a requirement to use Grid Forming Inverters[12] on new IBR generation plant; and
- rely on the successful competitive frequency keeping market to address any actual increase in frequency variation within the normal band (and outside the normal band) over time.

[9] Paragraphs 3.20 – 3.70, Decision Paper on Potential solutions for peak electricity capacity issues,18 July 2024
[10] Paragraphs 4.5 and 4.6 of consultation paper
[11] The Authority notes that early wind generation technology did not have the capability to support frequency. However these turbines probably already have dispensations. Table 22 in the consultation paper shows Mahinerangi wind farm and White Hill have dispensations.
[12] Note the System Operator recommended in its June 2023 report that "a*sset 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".* 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

Estimate of costs

Option 1 and Option 2 require generating station owners to:

- invest in modifying equipment or operation of existing generating stations and test compliance;
- seek variations on resource consents to enable a different operating model to be compliant; OR
- apply for a dispensation which requires testing by the SO and experts, committing time and resources to making a dispensation application, and testing etc regularly to confirm compliance with the dispensation.

In addition, the cost benefit analysis of these options must include costs incurred by the System Operator, such as:

- additional resources to process dispensation applications
- commissioning experts to undertake or review the results of tests
- modifications or a capacity upgrade to the Reserves Management Tool (or other software / hardware) given significantly more data will be held about more generation plant.[13]

We refer you to NewPower's submission which includes detailed information about the costs of these options and the impact on the financial viability and returns of a generic 30MW solar farm and a battery energy storage system.

With respect to existing hydro power stations, it is important to note that every generating station is unique. The work required to be compliant will be different at every generating unit making up a generating station as well as determining how to manage water through the station or scheme to be able to support frequency.

Hydro power stations impacted by a reduction in the 30MW threshold include stations with multiple generating units. Each unit will have to be compliant, even if it is below 5MW for the entire power station to be compliant. Every site will require different modifications so there is no real standard price/cost to be compliant.

Some – and probably more than expected – just won't physically be able to comply. The layout of penstocks and canals mean it is not possible.

The stations were not designed to meet these requirements. Generator sizes can mean simplified controls (no governors). If a generator had to be changed then there would need to be larger foundations. To retrofit foundations would cost in excess of $0.5 million.

The ongoing testing requirements are not scaled. Even if testing was half the cost for a 5MW compared to a 30MW machine the cost as a percentage of earnings would still be so much higher.

[13] We note that Transpower claims it costs the equivalent of 1% of annual settlement residual amounts to process these payments – amounting to over a $1m in some years. This cost was only revealed after the Authority made its decision to require Transpower to process these payments.

Many smaller units are not part of wider fleets. They are single investors who might only have the one station. The proposals in this consultation paper will cripple them financially - even the costs of getting a dispensation.

For new generation projects (less than 30MW and above any new threshold) a change to the threshold is a barrier to entry and anti-competitive for this scale of generation. A range of different consultants would have to be engaged and this will add significantly to the cost of construction.

The steps involved in 'testing' alone include:

- Engaging consultants to complete dynamic studies and providing the System Operator with the dynamic frequency response model
  - Usually takes a few iterations
- Control system changes and pre-testing (not including any control system upgrades)
- On-site frequency response testing
  - Site mobilisation
  - Hiring testing kit and recording kit
- Summary report to show generator is compliant

These costs would be a total of approximately $70,000 per unit. There would be a saving when there are more than 2 machines on site. However, some schemes have two different size units so could not be 'type' tested. Others have two identical units so it would be good if the SO agreed one test could cover both.

The following information about 4 existing hydro power stations demonstrates the significant cost of achieving compliance and that there is no one standard price or standard solution.

- 2 units of 3.25MW at one station:
  - Mechanical / hydraulic governors _*may*_ work but would probably not meet any Code
  - A compromised solution would be to replace hydraulics, actuators and add an electronic governor: cost $700,000 across the two units
  - Anything beyond this will require new turbines: cost $15 million

- 3 units of 2.6MW at one station:
  - The existing hydraulic systems do not have positioners
  - A reasonable solution will require new hydraulic packs and electronic governors: cost $500,000 across the three units

- 2 units of 3 MW at one station:
  - To convert to be governed:
    - Testing to confirm canal and penstock capability: cost $80,000
    - Install controls and hydraulics, including testing: cost $500,000 per unit, total $1 million

- an 8.3MW turbine at one station:
  - The existing 5 nozzle control do have positioners, however the deflector is a cut out deflector not suitable for governing
  - A deflector change is required to make a meaningful change, assuming this is physically possible: cost $1 million

There are already shortages of people with the right expertise in NZ and this testing will only increase that pressure on limited resources (impacting timing and cost). Is it better for these consulting experts to be contributing to the design and construction of new generation capacity – or to be sidelined into making changes to existing plant – when NZ urgently needs new generation capacity?

Many of the hydro power stations are run-of-river. To be able to support frequency will require a change to the way water is managed through the station or scheme. This is likely to require a variation to resource consents. A single variation application is estimated to cost over $200,000 – this amount is paid as the variation application is made with no guarantee the application will be successful.

Concerns about System Operator modelling assumptions

The consultation paper claims "*There will be a proportional increase in the number of generating stations exporting less than 30MW to a network*"[14] We query whether the NUMBER of generating stations exporting less than 30MW impacts frequency performance – it is the capacity of these stations.

The System Operator concludes a threshold of 5MW is better than a threshold of 10MW because "*(a) The number of generating stations with a capacity below 5MW is high – ie, more than 50% of the generating stations below 10MW have a capacity under 5MW*".[15]

This conclusion is not borne out by the data in Figure 9-1[16] which shows the size of generating stations modelled by the System Operator (ie hypothetical). Of the 64 stations the SO assumes are connected in 2035, 32 stations are below 5MW and the balance between 5 and 30MW. The System Operator's recommended 5MW threshold (which the IEGA disagrees with) would catch approximately 50% of the number of generating plant assumed to be less than 30MW by 2035.

The System Operator is assuming 522MW of generation capacity at or below 30MW in 2035 in its 'Sumer midday' and Winter peak scenarios.[17] This is less than 3% of the forecast total installed capacity by 2035. The SO assumes all new generation capacity less than 30MW is connected to distribution networks and not the transmission grid.[18] There is no specifics about the technology of this new plant – other than the expectation it will be inverter-based. It is hard to imagine that generation plant making up less than 3% of total installed capacity could be responsible for an increase in frequency variations.

This compares with dispensations that already apply (and will continue to apply) to 12.8% of total current capacity (1,111MW or 17.8% of North Island capacity greater than 30MW and 208MW or 5.8% of total South Island capacity greater than 30MW (7 and 4 generating stations respectively)).[19]

[14] Paragraph 2.13(a) of consultation paper
[15] Paragraph 4.23 of consultation paper
[16] Page 43 of SO report on Studies (1 and 3)
[17] Table 15, page 27 of SO report on Studies (1 and 3)
[18] Page 15 of SO report on Studies (1 and 3)
[19] Table 6 and 7 Page 15 of SO report on Studies (1 and 3)

We have tried to understand this generation capacity and location mix given the Issue being addressed is supposed to be about the impact on frequency of the proportionate increase of intermittent wind and solar connections to distribution networks.

Further, the above is interesting, but of most relevance is that the Authority believes that "*modern inverter technology means that wind turbines, along with solar photovoltaic generation and battery energy storage systems (in both charging and discharging mode) can provide frequency control. Therefore, these technology types can assist to limit system frequency changes due to imbalances between generation and demand, in the same way that conventional synchronous generation can".*[20] That is, the Authority expects new IBR generation plant to be able to provide frequency control.

Modelling results

The IEGA is also unclear about the results. Study cases 0, 1, 2, 3 and 3A analyse the impact of different thresholds. The maximum impact of losing generation connected to distribution networks is a loss of 108MW and a requirement for additional FIR of 133MW (maximum) [21] - on a system of ~17,500MW. Volumes offered currently in the frequency keeping market would easily cover this loss – let alone how frequency keeping volumes are likely to grow as new capacity is added by 2035. Procuring more reserves would be far more efficient than triggering AUFLS (as assumed in the study).

The 2035 modelled TOTAL FIR is an increase of 134MW and 23MW[22] compared to the modelled results for 2023.[23] Again, a small quantity of additional FIR compared to the increase in total generation capacity of ~7,000MW.

Concluding remarks

The Authority is already implementing other changes to manage the impact of intermittent variability on power system coordination. More information on these workstreams is in Appendix 1. The IEGA suggests it is inconsistent for the Authority to commit resources to these projects but not rely on the frequency keeping market as the primary method to address Issue 1. Essentially the problem definition is the same across all these projects.

The System Operator's conclusions are based on 522MW of generation plant with a capacity of 30MW or less in 2035 – all connected to distribution networks.[24] This is less than 3% of the forecast total installed capacity in 2035. Imposing new and retrospective Code requirements that require physical technical modifications on this capacity to meet frequency and voltage obligations is, in our view, like using a hammer to crack a nut.

The IEGA concludes that the same reasons apply now to not lowering the threshold to 5MW as applied over 20 years ago when the rules were developed by an industry working group – as outlined in the consultation paper:

[20] Paragraph 4.5 of consultation paper
[21] Page 28 of SO report on Studies (1 and 3)
[22] Table 18 of SO report on Studies (1 and 3)
[23] Table 11 of SO report on Studies (1 and 3)
[24] Table 15, page 27 of SO report on Studies (1 and 3)

"4.11. Some stakeholders raised concerns with 5MW being used for the threshold for complying with frequency-related AOPOs and technical codes. These concerns related to:

(a) the apparent absence of any cost-benefit justification for using 5MW Addressing more frequency variability in New Zealand's power system

(b) the potential compliance cost for existing generating stations if 5MW were to be adopted

(c) the use of 5MW being likely to impose significant costs on distributed generation, which could impede the development of distributed generation."

The main difference now is that we have a successful competitive frequency keeping market that provides a least regrets, lower cost solution to managing frequency variations – instead of any physical technical solution.

The IEGA **strongly recommends** the Authority:

- urgently investigate a requirement to use Grid Forming Inverters[25] on new IBR generation plant; and
- rely on the successful competitive frequency keeping market to address any actual increase in frequency variation within the normal band (and outside the normal band) over time.

The IEGA represents generators with assets connected to distribution networks. Members are therefore disproportionately impacted by the proposals in this consultation paper. Our membership is also not represented on the Authority's Common Quality Technical Working Group.

The IEGA response to the Authority's questions is in Appendix 2 but this cover letter is the substance of our submission. We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb
Chair

[25] Note the System Operator recommended in its June 2023 report that "a*sset 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".* 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

Appendix 1: Related workstreams being implemented by the Authority

The Authority is already implementing other changes to manage the impact of intermittent variability on power system coordination. The IEGA suggests it is inconsistent for the Authority to commit resources to these projects but not rely on the frequency keeping market as the primary method to address Issue 1. Essentially the problem definition is the same across all these projects.

On 23 July the Authority announced its decisions[26] on work programmes to address security of supply during peak demand (firming). Variability of intermittent generation, opportunities from consumer participation and increasing two-way flow of electricity are issues these decisions are addressing. These issues are essentially the same as Issue 1 being addressed by this consultation.

We suggest that all the Authority's analysis and conclusions about the positive benefits of improving frequency keeping for security of supply during peak demand periods are equally relevant to Option 3. These changes being implemented will improve frequency keeping 24/7 – not just during the short period of 'peak demand'.

The redesign of frequency keeping is to:

- manage 5-minute variability in generation (frequency keeping is currently dispatched for a 30-minute period)
- increase the quantity of frequency keeping procured (currently 15MW in each island); and
- have no minimum offer requirement (currently 4MW) so that more technologies / participants are involved, increasing competition.

The policy development for this stage 1 is expected to be completed by the end of September 2025.

In our view, this project is essentially Option 1 in 'Table 4: Options retained from the long list of frequency related options but not short listed'.[27] The decision has been made and the work is being prioritised.

Table 4: Options retained from the long list of frequency-related options but not short listed

	Option	Assessment
1.	Lower the minimum frequency keeping threshold below 4MW and have a national market for frequency keeping.	Over the next 12–24 months, the Authority plans to look at the regulatory settings for encouraging competition in frequency regulation services as part of a separate project to the review of common quality requirements in Part 8 of the Code. This option will be considered as part of the work to be undertaken in that separate project.

The IEGA would be concerned if the Future Security and Reliability team were unconnected to this work by another part of the Authority (silos) and more inclined to focus on solutions that were within their control (ie. technical solutions using the input of a highly technical working group).

Other Authority projects that are complimentary to Option 3 are:

- DOING: reviewing instantaneous reserve cost allocation to increase incentives for intermittent generation providers to invest in flexibility
- DONE: improving the accuracy of intermittent generation forecasts to support resource coordination and accurate price signals

[26] https://www.ea.govt.nz/documents/5263/Decision_paper_Potential_solutions_for_peak_electricity_capacity_issues.pdf
[27] Page 40 of consultation paper

APPENDIX 2: IEGA RESPONSE TO CONSULTATION QUESTIONS

<table>
<tr><th>Questions</th><th>Comments</th></tr>
<tr><td>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?</td><td>No. The IEGA does not support any change to the 30MW net export threshold. The System Operator analysis is inconclusive as it shows minimal difference in system performance from lowering the threshold.

Issue 1 is not properly defined. Option 1 is not directly related to Issue 1 (as defined in the consultation paper).

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 negatively impact the financial viability of existing and new generation plants. At a time when NZ urgently needs new generation capacity, this proposal creates a real potential for existing plant to cease operation and IEGA members are deterred from investing in new generation projects.

Further comments in the cover letter.</td></tr>
<tr><td>Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?</td><td>The benefits or costs of lowering the excluded generation station threshold with regard to maintaining frequency in the normal band have not been assessed by the Authority.

In our view the costs of Option 1 will exceed any benefits, especially in comparison to Option 3 of procuring more frequency keeping.

The cover letter includes 4 estimates of costs for existing hydro generation plant being compliant. This is a small but reliable sample of the potential financial impact.

The IEGA submits the Authority must include comprehensive information from the System Operator on its costs for this option. We expect the System Operator will require additional resources to complete modelling and testing of all plant caught by a change in the threshold – either to ensure compliance with the Code or for dispensations.

The System Operator’s Reserve Management Tool will also be modelling substantially more data. Does the current Tool have the capacity, or will a costly upgrade be required?

Expert consultants will be in demand from the System Operator and generation plant owners to perform the required studies and produce generator frequency</td></tr>
</table>

Questions	Comments
	response models by the deadline set by the EA Code change. There will be increased transaction costs for generator owners and the System Operator. The IEGA submits this will increase barriers to entry for smaller generation. There will also be delays in project completion, as there will be more projects requiring detailed assessment and involvement by the System Operator, which already has limited resources in this space. At a time when new generation capacity is urgently needed.
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?	See our answer to Q2 and the cover letter for an estimate of these costs. Routine testing and provision of additional ACS information which are increasingly onerous as the size of generation reduces. Increased monitoring costs imposed by the SO. 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 Authority 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. 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. 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. Increased costs associated with establishing an ICCP connection for each of these sites. Cost of doing connection/grid studies are also likely to increase as a result of lowering the limit, as the generator will need to comply with the System Operator requirements, so things like model validation and other detailed studies would become mandatory for compliance.

Questions	Comments
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?	See NewPower's submission.
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.	The IEGA does not support this Option 2. Regulation should take into account the technology when appropriate.
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.	The IEGA does not support this Option 2. Option 3 is our strong preference.
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.	The IEGA does not support this Option 2. Option 3 is our strong preference.
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	See NewPower's submission.
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?	See NewPower's submission.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	The IEGA strongly supports Option 3. See the cover letter for analysis of the benefits of a competitive frequency keeping market.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	The Authority's assessment of options clearly shows that Option 3 should be preferred. The Authority assesses Option3 as "***strongly feasible*** *with no risk of unintended consequences (no changes to the Code or to assets, negligible implementation cost*".[28] [emphasis added]

[28] Table 3, page 39 of consultation paper. We note the Authority considers the other two options to be less feasible and more expensive: Option 1 to be "*moderately feasible with a low risk of unintended consequences (<2 years to change the Code, <3 years to change assets, <$20m implementation costs)*; and Option 2 to be "*feasible with uncertain risk of unintended consequences*".

[redacted]

20 August 2024

Submissions
Future Security and Reliability team
Electricity Authority
P O Box 10041
Wellington 6143
By email: fsr@ea.govt.nz

Dear team,

Re: Consultation Paper—Addressing larger voltage deviations and network performance issues in New Zealand's power system

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) proposed three options to address the three issues identified relating to larger voltage deviations and network performance issues in New Zealand's power system.[1]

The IEGA comprises about 30 members who are either directly or indirectly associated with predominantly small-scale power schemes connected to local distribution networks throughout New Zealand for the purpose of commercial electricity production. IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, who have made significant economic investments in renewable generation plant and equipment. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand. We are price takers in the electricity market – the majority of our members do not have the financial or human capacity to operate 24/7 dispatching into the wholesale market.

Our members are innovative, entrepreneurial and passionate about New Zealand's renewable advantage and potential who have made significant economic investments in generation plant and equipment throughout the country. They have a portfolio of new economic renewable generation projects consented or under investigation which have a smaller environmental footprint than grid-connected generation and provide an incremental, rather than a step change, increase in supply more aligned to increasing local demand for electricity.

Members' own and operate the full range of renewable generation technologies: hydro, wind, geothermal, solar and biomass and energy storage.

[1] The Committee has signed off this submission on behalf of members.

The IEGA rejects all three proposed options

The IEGA is unclear if an Option addresses more than one Issue. For example, it seems like Option 3 addresses fault ride through – Issue 3 but may not address Issue 2 or 3.

If it is the case that there is only one Option being proposed to address each Issue this is not sound regulatory practice – we assume the status quo is the counterfactual.

The IEGA **strongly rejects Option 3** to lower the 30MW threshold for generating stations to be excluded from complying with fault ride through obligations. This is essentially the same as Option 1 in the consultation paper on 'Addressing more frequency variation' asl lowering the threshold for voltage support will lower the threshold for frequency obligations. **Our comments to reject Option 1 in our frequency submission must therefore be read in conjunction with this submission.** The IEGA's focus has been on the cost of meeting obligations for frequency keeping. As the System Operator expects all generation less than 30MW to be connected to the distribution network this submission is focused on the implications of Options 1 and 2 duplicating current obligations of distributors.

To summarise the IEGA feedback on Option 3 the IEGA concludes that the same reasons apply now to not lowering the threshold to 5MW as applied over 20 years ago when the rules were developed by an industry working group – as outlined in the consultation paper:

> *"4.11. Some stakeholders raised concerns with 5MW being used for the threshold for complying with frequency-related AOPOs and technical codes. These concerns related to:*
> *(a) the apparent absence of any cost-benefit justification for using 5MW Addressing more frequency variability in New Zealand's power system*
> *(b) the potential compliance cost for existing generating stations if 5MW were to be adopted*
> *(c) the use of 5MW being likely to impose significant costs on distributed generation, which could impede the development of distributed generation."*

The IEGA **submits Option 1 and Option 2 should also be rejected**. The Code already requires distributors to be compliant with clause 8.22 of the Code, requiring voltage to be supported within a maximum range of ±5% or ±10%. The proposal is that clause 8.23 applies to all generation – so distribution network connected generation may be receiving instructions from the System Operator to support its AOPOs that are in conflict with how the distributor is managing its network to be compliant with clause 8.22.

A duplicate interface for distributed generation with the System Operator as well as the distributor it is connected to is unnecessary and illogical.

There is already a cascade of obligations to manage voltage:

i. The System Operator controls voltage on the transmission grid to the Grid Owner's GXP – the point at which assets owned and under the control of Transpower connect to a distributor's network
ii. Distributors already have obligations to the System Operator to maintain stipulated power factors at the GXP – contracted via the default transmission agreement
iii. Distributors manage this obligation to the System Operator by placing obligations on connected parties – including distributed generation. Obligations on distributed generation

are included in their Connection Agreement reflecting the distributor's Connection and Operation Standards.

Without this demarcation there will be duplication, confusion and potentially opposing instructions and obligations for distribution network connected distributed generation.

The IEGA submits current arrangements are efficient and sufficient. The System Operator should tell the distributor, or Distributed System Operator (DSO), its requirements who then applies their own requirements to their connected distributed generation and distributed energy resources (including consumer connected Consumer Energy Resources).[2]

The consultation paper suggests these options are being proposed because it will become more challenging "for distributors to manage voltage on their networks".[3] No evidence has been provided by the Authority substantiating this outlook or that this is a view held by distributors.

Connection Agreements, as well as Connection and Operation Standards can, and are, being used by distributors to place voltage obligations on distributed generation and distribution connected energy storage assets. With the obligations distributors already have to manage voltage at the GXP they are strongly incentivised to take into account and manage for any distributed generation or energy storage systems connected within their networks at whatever voltage – or otherwise be in breach of their obligations to the System Operator.

Preferred option is to procure voltage support and inertia from ancillary service agents

The IEGA strongly recommends the Authority investigate the option of the System Operator procuring voltage support and inertia from ancillary service agents. The System Operator has the procurement and contractual documentation ready for voltage support and states "*We may enter into voltage support contracts with parties who can offer voltage support compliant with our technical requirements and the Code. Voltage support is procured on a firm quantity procurement basis (via a monthly availability fee and/or a single event fee for a specified MVAr availability).*" [4]

The Authority states preference is given to market-based approaches to providing the required service / output, to promote innovation and transparency of the full costs and benefits of an option / solution as an evaluation criterion for the frequency management consultation paper.[5] If the option of procuring voltage support had been proposed the same preference for market-based approaches would apply.

A competitive market-based solution has numerous advantages to support voltage as variability or management issues change / increase over time, namely:

- this is the least regrets option – the System Operator already has the documentation as well as a wealth of experience in tendering and procuring ancillary services

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[2] We note the options in the consultation paper are very unlikely to apply to Consumer Energy Resources – which is the sector where proportionality the highest growth in inverter-based generation is forecast by the System Operator (from understanding paragraph 2.5(a) of the consultation paper).

[3] Paragraphs 2.2 and 4.7 of consultation paper

[4] https://www.transpower.co.nz/system-operator/information-industry/electricity-market-operation/ancillary-services/voltage

[5] Evaluation criteria, Table 1 of consultation cover paper https://www.ea.govt.nz/documents/5154/Future_Security_and_Resilience_-_Review_of_common_quality_requirements_in_the_Code.pdf

- a voltage support market is feasible, easy to enhance / expand / implement and has little or no risk of unintended consequences
- the existing market procurement and processes make it flexible, scalable and relatively easily reversible
- the cost of manging voltage variations will be directly related to the actual performance of the power system over time
- market-based pricing will provide financial incentives to grow the capability of new technologies or existing plant to be involved
- promotes competitively neutral amongst technologies / fuels – anyone has the option to participate in the System Operator's procurement tender for ancillary services
- a market-based approach should incentivse investment in activities that can participate in the market
- having the ability to procure more voltage support will be durable across a range of uncertain future scenarios – especially important as the timing of connection of new technologies and capacity is uncertain
- is a 'quick win' which does not require any Code amendment
- success of this solution is independent of any assumptions about future generation technologies and locations in 2035 and performance of the power system as the market can be relied on / incentivised to manage actual voltage performance.
- extends the financial incentive to retain existing synchronous generation or technologies that can participate in the frequency and voltage support markets.
- the Authority already has a work programme to enhance the frequency keeping ancillary service. This work can continue and be adaptive to actual market conditions over time
- the System Operator expects a rapid increase in behind-the-meter solar pv generation – the impact of this IBR generation on power quality can be managed by the voltage support market while the three options being proposed do not address this

Transpower even suggest this as an option in their submission to the Authority on the future power system consultation "given potential future system strength challenges, should the system operator consider procuring voltage support services?" [6]

Further, in answer to the question 6 "Do you consider existing power system operation obligations are compatible with the uptake of DER and IBR generation?" Transpower's entire approach to this question is about using ancillary services as the solution.

The System Operator's latest 2024 'System Security Forecast - N-1 Thermal and Voltage Study' assesses the robustness of the New Zealand power system over the next three years and concludes:

- "Nearly 90% of new committed generation are inverter-based resources, giving about 700 MW of additional capacity. The N-1 contingency studies show that new connections during the SSF study horizon have not caused any significant thermal violations or voltage stability issues. "
- Voltage stability remains an issue in the Upper North Island due to load

[6] Answer to Q6, https://www.ea.govt.nz/documents/4952/Transpower_ZEeTxiw.pdf

- "There are no foreseen issues with managing the upper South Island load under intact network conditions during the study period." [7]

This study includes assumptions about new transmission investments. It's unclear if the System Operator studies in the consultation paper include the same assumptions.

The outcome of this latest assessment of system robustness means that there is plenty of time to start procuring voltage support from ancillary service agents.

Transmission assets for managing voltage

Transpower has demonstrated a preference for investing in transmission based (and owned) assets to manage voltage issues that have been identified / addressed thus far (eg STATCOM for Upper North Island and Waikato voltage management). This preference also means the System Operator has concluded "*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*."[8]

The IEGA suggests transmission-based assets to manage voltage may be the more efficient investment compared with any of the Options being consulted on – we suggest this should be considered before any of the proposed options are further analysed. Transpower then has direct control of the operation of these assets. There is also the possibility that Transpower may still decide to invest in these assets despite any changes to the requirements on distributed generators.[9]

Inverter technology

The consultation paper explains[10] that the "most common form of inverters in NZ are 'grid following'" and that "To protect themselves from damage, these 'grid-following' inverters are more likely to disconnect during a power system fault that causes a distorted voltage waveform than are synchronous generators and 'grid-forming' inverters. Thus, low system strength is likely to result in an increased likelihood of 'grid-following' inverter-based resources disconnecting from the power system".[11]

Footnote 8 explains that "*'grid-forming' inverter forms a voltage angle independently of the network to which it is connected and controls its output voltage so as to synchronise with, and remain synchronised with, the network*".[12] As with our submission on the frequency variations consultation paper, the IEGA **recommends the Authority urgently investigate a requirement to use grid-forming inverters on new IBR generation plant**. As the Authority states – this would make IBR resources the same as synchronous generation technology that synchronises and remains synchronised with either the distribution or transmission networks.

[7] Page 7, Published July 2024 https://static.transpower.co.nz/public/bulk-upload/documents/N%20-%201%20Thermal%20and%20Voltage%20Study.pdf?VersionId=76Eogz9.lkSdguOuKKnkaK7cuzcFyW9z

[8] https://www.transpower.co.nz/system-operator/information-industry/electricity-market-operation/ancillary-services/voltage

[9] See paragraph 2.7 of the consultation paper

[10] Paragraph 2.2 of consultation paper

[11] Paragraph 2.23 of consultation paper

[12] Page 12 of consultation paper

Other comments

We note that the consultation paper does not address the following recommendations of the System Operator:

> *4.13 The system operator recommends that it and distributors have a degree of visibility of the operating status of these resources and their active and reactive power output. This visibility should be sufficient to enable the system operator to co-ordinate reactive power dispatch of transmission-connected resources so as to regulate voltage at GXPs.*

Our understanding is that this 'visibility' issue is being addressed by the Authority in another workstream. We appreciate that both distributors and the System Operator should have knowledge of what is connected to their networks. There is already a requirement to provide information to the System Operator about any generation plant equal or greater than 1MW.

> *4.14. The system operator also recommends that distributed generation, embedded generation, and energy storage systems connected to a local distribution network have the capability to accept reactive power dispatch instructions from the distributor. This is to facilitate distributors assisting with regulating voltage at the GXP.*

The IEGA rejects this recommendation. It is not clear what is envisaged as a "capability to accept reactive power dispatch instructions". More information is required as well as a formal consultation on this suggestion – which is beyond the reach of this current consultation.

Concluding remarks

In the System Operator studies of frequency variations, the System Operator modelling of 'Summer midday' and 'Winter peak' scenarios include 522MW of generation plant with a capacity of 30MW or less in 2035 – all connected to distribution networks.[13] This is less than 3% of the forecast total installed capacity in 2035. Imposing new and retrospective Code requirements that require physical technical modifications on this capacity to meet frequency and voltage obligations is, in our view, like using a hammer to crack a nut.

The IEGA rejects the options proposed by the Authority and strongly recommends the Authority robustly consider, and then consult on, these two options that are not included in the current consultation paper, namely:

- rely on a competitive voltage support market to address any <u>actual</u> deviations in voltage over time; and
- urgently investigate a requirement to use Grid Forming Inverters[14] on new IBR generation plant.

[13] Table 15, page 27 of SO report on Studies (1 and 3)

[14] Note the System Operator recommended in its June 2023 report that "a*sset 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".* 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

The IEGA represents generators with assets connected to distribution networks. Members are therefore disproportionately impacted by the proposals in this consultation paper. Our membership is also not represented on the Authority's Common Quality Technical Working Group.

The IEGA response to the Authority's questions is in Appendix 2 but this cover letter is the substance of our submission. We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb
Chair

Appendix: IEGA response to Authority questions

Questions	Comments
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.	Yes. Distributors are responsible for voltage management on their network and the voltage received by their customers. They also have obligations for minimum power factor requirements at their GXPs (set by Transpower) so are incentivised to manage reactive power and place voltage and reactive power requirements on their customers. Distributors are stipulating voltage and power factor limits in their Distributed Generation Connection Agreements. The IEGA understands that as part of the ENA Future Network Forum project the EEA has been asked to identify opportunities for consistency across distributors' Connection and Operation Standards. Undertaking this work at pace without regulatory intervention is recommended.
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.	Neither option is supported. 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). The appropriate location for voltage related obligations for distributed generation is the distributor's Connection and Operation Standards, and not in the Code. 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 a generator's perspective, it will likely make things more challenging and costly. 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.
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	No. The System Operator's modelling has not provided a case for applying a generation capacity threshold relating to voltage support. Voltage related performance obligations for distribution connected generation and energy storage systems

Questions	Comments
voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	should be set by distributors according to the needs of their network(s). Voltage related obligations for distributed generation and energy sources should not fall within the Code. Capacity thresholds should be determined by distributors taking into account the characteristics of the relevant distribution network and the part of the network being connected to. A one size fits all approach is inappropriate. Further, 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.
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 ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?	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. 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. 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.
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.	No. 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. Having voltage related obligations within the Code and Connection and Operation Standards will likely result in barriers to entry for DG and DER. 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.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	In our view, this option carries significant costs and very little benefit: The option will complicate dispatch arrangements with two parties with potentially mutually exclusive objectives trying to control the same resource.

Questions	Comments
	Liability for damage to consumer appliances or outages resulting from System Operator issued reactive power dispatch instructions to distributed generation is unresolved. This liability needs to be addressed prior to proceeding with this option. This option imposes duplicated voltage related obligations and monitoring and compliance systems from the Code and distributor's Connection and Operation Standards. It is unclear how this will benefit the consumer.
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?	Costs for distributed generation owners include: • Increased transaction costs for asset owners and system operator (ACS, monitoring, dispensations etc). • Cost of System Operator 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. In addition, there is the potential for system-wide inefficient overbuild of assets – imposing higher costs on consumers. These costs, and the SO and EDB costs must be quantified and compared with any benefit before this option proceeds.
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?	Please see NewPower's submission for information about the costs imposed on owners of BESS with a point of connection to the transmission grid.
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.	No. Reactive power flows are already effectively controlled by power factor limits imposed by Transpower on distributors at GXPs. 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.

<table>
<tr><th>Questions</th><th>Comments</th></tr>
<tr><td></td><td>Managing reactive power at the GXP could impose restrictive conditions that might limit operational flexibility and increase costs for generators.

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.

Query whether obligations should be placed on distributed generation so that it is the primary method 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.

Should GFM technology be used, this can help to improve system strength to help address issue 3.</td></tr>
<tr><td>Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?</td><td>Benefits:
Avoids direct System Operator interference with distribution voltage management which reduces risks to assets and public safety.
Helps distributors in their journey towards becoming DSOs.
Costs:
The distribution system is being asked to solve some of the SO’s voltage issues, which isn’t necessarily the most efficient solution, particularly where the DSO has multiple issues to manage.
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.</td></tr>
<tr><td>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?</td><td>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.

The usual costs associated with complying with the Code in respect of voltage related obligations would apply.

There would be the difficulty in simultaneously supporting voltage and meeting minimum power factor requirements when charging.</td></tr>
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Questions	Comments
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.	Yes. Distributors are primarily concerned with the effects of faults on their distribution networks and to a lesser extent faults occurring on the transmission network. 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 and doesn't need to be in the Code. 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.
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.	No. Distribution network protection considerations should take precedence over Code fault ride through requirements. 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.
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.	No. Changing the threshold or excluded generating stations for voltage related issues will also change the threshold for frequency obligations. The IEGA's submission on Option 1 in the 'addressing frequency variations' consultation paper must be read in conjunction with this submission.
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.	As we said in Q14, the IEGA does not support a change to the threshold for excluded generating stations. A robust cost-benefit analysis must be completed – including the costs for the System Operator of implementing and monitoring compliance with the Code relating to both frequency and voltage. We query if this is the one proposed solution to address Issue 4 – if yes then this approach is not best regulatory practice.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	See answer to Q14.

Questions	Comments
Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under 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?	As stated above we do not support any change to the 30MW threshold. All generating stations under 30MW must be treated on a level playing field – whether single site or virtual. A Virtual Power Plant is an aggregation of distributed generation will likely extend across a number of GXPs, making voltage co-ordination more difficult. Cost of monitoring performance. This may require advanced monitoring systems to accurately collect and collate data for virtual generating stations split over multiple locations.
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?	Yes. The IEGA recommends the Authority urgently assess market-based options before any more work is undertaken on the physical / technical / non-market based options proposed. The IEGA'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. 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.