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20 August 2024

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CC:
Future Security and Resilience Feedback, Electricity Authority
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Feedback on Review of common quality requirements in the Code – Paper 2 - Addressing larger voltage deviations in New Zealand's power system

Thank you for the opportunity to provide feedback on the Electricity Authority (the Authority) Review of common quality requirements in the Code. What follows is our feedback to *Paper 2 - Addressing larger voltage deviations in New Zealand's power system*, which we have prioritised over the other papers.

We agree that the existing arrangements for coordinating voltage across GXPs can be improved and we suggest that the Authority prioritise a review that clarifies the shared responsibility between the SO, grid owner, and distributors. Ideally a comprehensive review would make it clear what actions each party can take and to what extent they are responsible for voltage, power factor, and reactive power. This would include guidance about when and where different types of equipment should be deployed to make the coordination of voltage and power factor at GXPs as efficient as possible.

This varies slightly from the Authority's recommendation, because we recommend including the transmission grid owner in that review to provide clarity on which party should be making an infrastructure investment and to reduce the risk of transmission and distribution equipment 'competing' with each other to try and manage power quality on either side of a GXP.

Responses to specific questions in the consultation:

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.

Vector currently utilises droop settings for all generation connecting to the network. The majority of generation uses the volt-var and volt-watt settings from ASNZS4777.2. This information can be found in the documentation supporting DG connection applications on our website.[1]

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.

We support the recommendation that DG have an obligation to support voltage when connecting at the same voltage as the GXP. This is an obligation Vector imposes on all generation connecting to our network.

We do not support the issuing of reactive power instructions in order to control reactive power in other parts of the network (i.e. the GXP), as it would put the local voltage at risk.

Q3. Do you consider there should be a capacity threshold (eg, a nameplate capacity or nominal net export 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.

As noted in the consultation document, distributors currently have the capability, through our network connection and operation standards, to impose voltage-support obligations for distribution connected generation. We expect that distributors and the system operator will come to arrangements on the power factor obligations on EDBs, and then distributors should be left to make the appropriate decisions for imposing obligations on DG through the connection and operation standards.

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?

We see no reason to impose different voltage support obligations on generating stations or energy storage systems based on whether they are connected to the transmission or distribution network. There will be more benefit to having a consistent national standard that applies in all situations.

[1] https://www.vector.co.nz/personal/electricity/distributed-generation

Consistency of these standards would also make coordination between SO and distributor more consistent. Additionally, the AS/NZS 4777.2 standard already requires inverters be capable of supporting a range of +-60%.

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.

Yes, we would be following international best practice in enforcing voltage support obligations on DG. However, these obligations should not extend to direct reactive power instructions from third parties. It is also arguable whether direct visibility of a plant's reactive power status is needed by parties outside of network it connects to.

Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?

Extending the voltage support AOPOs specified in 8.23 of the Code to those connected at distribution networks will improve the power quality of the electricity networks at the local injection point.

Absent obligations on the owners of DG there will be additional investments needed by grid owners to accommodate the increased variability in voltage caused by DG.

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?

There are a multitude of factors that affect the process and assessment of costs for parties connecting to the local distribution network. Aside from the marginal cost increases for compliant inverters, meeting the obligations in 8.23 of the Code, and potentially supporting the obligations to receive dispatch instructions from distributors, the types of cost these owners will face will depend on what, where, and how they are trying to connect to the distribution network.

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?

No comment.

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.

Yes, however we encourage a deeper study to refine the roles that the SO and grid owner should take in maintaining voltage at GXPs which then clarifies the scope that distributors will be expected to undertake to maintain power factor or reactive power operational limits. Many distributors will have planned investments in equipment to manage power factor during regional peak periods, and these investments will be embedded into the forecasted investment needs during DPP4 currently under approval from the Commerce Commission. Substantial changes to those expectations may result in material changes to those future investment needs.

We believe the intent behind this second voltage-related option is for the System Operator and distributors to collaborate in determining the appropriate obligations for maintaining power factor or reactive power operational limits at GXPs and to establish a prudent timeframe for those obligations to be fulfilled based on the different pace of growth in DG at GXPs across New Zealand.

We note that the reasoning for extending the obligations on energy storage facilities to include the charging and idle states, in addition to discharging states, have strong parallels to our previous suggestions to the Authority of the importance of formally including third-party aggregators as participants in the Code. Virtual power plants (VPPs) operated by third-party aggregators typically consist of large fleets of behind-the-meter battery storage systems and in the future may include exporting from electric vehicles with vehicle-to-grid capabilities (V2G). At present these aggregators are not covered by the Code and have no obligations to engage with their host distributors on the intended operation of their equipment. We have already experienced an unannounced test by a third-party aggregator, which did not cause any damage but resulted in atypically high voltage levels at the upper limit of the permissible operating range. This will occur more frequently as more aggregators begin managing consumer devices.

Below is an excerpt from our submission to the Authority on the recent draft guidelines for flexibility markets[2] where we expand on the importance of coordination with any party managing load:

> *We have submitted several times to the Authority that EDBs need to be empowered to direct the response to emergency situations by the DER Managers on their networks – from widespread grid emergencies to local, LV issues (e.g. car versus pole) and imminent interruptions that can be avoided. Ensuring the lights remain on, taking steps to avoid cascade or widespread failure and restoring services if they do are, at the very heart of the distribution services an EDB provides to customers (and retailers). These powers are akin to the System Operator's ability under the Code to manage grid emergencies.*
>
> *In order to maintain quality and reliability while building more efficient networks, EDBs need the power to avoid emergencies (referencing DDA cl 5.6 and expressed as "imminent" interruptions in the definition of System Emergency Event) by ensuring distribution-level constraints (physical and power quality) are understood and adhered to by parties managing DER on distribution networks (DER Managers). This needs:*
>
> - *A mandatory, 24/7 operating envelope at each ICP, that must be adhered to by DER Managers*
> - *DER Managers to ensure offers into wholesale markets, and any other actions, stay within their operating envelopes*

[2] https://blob-static.vector.co.nz/blob/vector/media/vector-2024/202407-vector-feedback-to-draft-flexibility-guidelines.pdf

We repeat and reiterate those calls here.

Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?

We don't expect significant bi-directional power flows to occur on our urban GXPs, due to the level of downstream demand and the diversity of that demand due to the high number of connected consumers. However, we do agree that the existing obligations are inefficient for coordinating voltage across GXPs. Clarifying a shared responsibility between the SO, grid owner, and distributors would be beneficial.

These obligations should make it clear where it is most appropriate to have voltage supporting equipment installed and encourage the coordination of voltage and power factor at GXPs. Of note we think it is important that the Authority also includes the transmission grid owner in sharing responsibility to enable this coordination efficiently to ensure that the investment in physical equipment to support voltage occurs in an appropriate place on the networks and prevents equipment from unwittingly 'competing' with each other to manage voltage on either side of the GXP.

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?

No comment.

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.

No, the distribution network is more focussed on the safety settings (anti islanding) and generally sees the ride-through obligations for frequency and voltage stability as the grid operator's domain. There is an inherent challenge in getting the settings right between having DG shut off for safety reasons and remain on for grid stability reasons.

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.

Yes, there could be default ride-through curves, with the provision that these do not impede protection settings and in particular the anti-islanding function.

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.

If a threshold is defined, it should only apply to DG connected at the same voltage as the GXP, rather than across the whole distribution network. The benefit of having these systems equipped to ride through faults is that this can prevent losing generation connected to N-1 infrastructure unnecessarily under a contingency. Note that not all generation may have the capability to set more complicated ride-through curves.

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.

Yes, where reasonable we should be adopting international best practices such as implementing the fault ride-through protections built into modern inverters.

Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?

Extending fault ride-through settings to distribution connected DG will improve system stability at relatively low cost to consumers.

Q17. What costs are likely to arise for 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?

We anticipate relatively low costs for the owners of generation stations to comply with the fault ride-through AOPOs as it will likely just require a configuration of available settings. There will be related costs in distributors reviewing the impact on network protection equipment, but it is unclear whether those additional costs would be considered BAU or if they would be eligible for a reopener with the Commerce Commission.

Concluding thoughts

While Vector has chosen to respond in full to Paper #2 on voltage support we did review the full consultation including papers 1 and 3 covering frequency support and harmonics. We felt that the questions around frequency support in paper 1 were likely best addressed by the system operator and owners of generation and therefore elected not to provide a full response. We felt that the context provided in paper 3 on harmonics support provided a reasonable foundation for future discussions around how best practices should be modified or adopted for New Zealand, but given the Authority is not intending to prioritise work at this time, we chose not to provide a full response to that paper at this time. We would, however, like to be involved in the conversation when it does occur.

We welcome a dialogue with the Authority at any time as you are reviewing responses and considering your decision related to all three areas of the consultation and are happy to provide any insights that can help guide the workplan going forward. [redacted]

Thank you for considering this feedback. We look forward to hearing from you.

Ngā mihi

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