Pioneer energy | RENEWABLES

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20th August 2024

Electricity Authority

By email fsr@ea.govt.nz,

RE: CONSULTATION PAPER—ADDRESSING LARGER VOLTAGE DEVIATIONS AND NETWORK PERFORMANCE ISSUES IN NEW ZEALAND'S POWER SYSTEM

Introduction

Pioneer Energy appreciates the opportunity to make this submission to the Electricity Authority on this frequency consultation paper. The proposed 30 MW rule change captures several of our sites.

Pioneer has eighteen hydro stations embedded in local distribution networks and three wind farms to a total of 94.7MW. Our largest station is normally grid connected but can and does operate embedded when the grid connection is unavailable. All sites operate within established requirements set by local distribution network operators.

The paper identifies issues 2, 3 and 4 as arising from accepting new intermittent generation connections that do not comply and assigns the responsibility of fixing these to existing small and embedded generation. Our generators are not big enough nor close enough to GXPs to fix this issue. We consider it unreasonable to assume the cost caused by others by way of a rule change.

Pioneer is a member of the IEGA and supports the submissions made by the IEGA.

Submission

EIPC rules 8.22 and 8.23 refer to grid voltage requirements. The proposed changes capture embedded generators where the ability to provide voltage support at the GXP is limited by the distribution network between the GXP and the generator.

Our embedded generators within the distribution networks are already required to meet distribution company requirements. Compliance with transmission grid requirements and standards within distribution networks is mostly impossible because of the high impedance and voltage limits of the distribution network.

We suggest the Authority pursue market-based solutions to provide solutions close to the GXP and to retain responsibility for managing this issue where this is physically realistic. This approach allows the potential for us to identify stations where support to distribution network operators is possible and economic, rather than needing to focus on sites where no practical benefit is possible.

Submission Questions & Comments

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.	Obligations are already being addressed in the absence of a Code requirement. Distributors already have published requirements and address voltage support out of necessity. Rather than blanket rules covering plant connected to distribution networks, the challenge will be the meaningful coordination of many disparate systems and technologies within distribution networks, and how these can usefully contribute to supporting the grid.
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.	No, rather these should be required to support the local distribution network voltage which is an existing process with distribution network operators.
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	No. This is already addressed through distribution network operator connection processes.

any implications of having / not having a capacity threshold.	
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?	Clause 8.23 is expressed in terms of GXP voltages. This is largely irrelevant to embedded generation requirements set to meet distribution network requirements. Expressing the requirements of 8.23 in a way that is meaningful will be complex, expensive, and can be expected to result in negligible benefit at a high cost.
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 as this captures generators too deeply embedded for contribution to the grid voltage to be effective.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	The need for existing installations to comply with new requirements has not been justified. Existing installations are unlikely to be able to be change capability in any meaningful way. Existing installations will incur new compliance costs, for no benefit.
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?	For existing installations, there will be one-off compliance costs associated with determining whether existing equipment complies with new requirements. In many cases compliance will exceed a simple nameplate check. As is already the case with grid connected voltage support AOPOs in clause 8.23, multiple factors including voltage range, transformer and reticulation connection arrangements make this determination non-trivial. If dispensations require economic justification, then there will be additional costs in carrying out design to a level where costing is possible and then costing.

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?	We have no opinion about energy storage systems.
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.	The proposed option 2 amendments relate predominately to the system operator and distributors, for which we have no opinion.
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	No opinion.
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 opinion.
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.	Unlikely, since the issues related to poor fault ride performance are presently attributed to the system operator only. Distributed generation sites are often connected on parts of networks where N-1 redundancy does not exist. Protection schemes are setup to ensure faults are cleared.
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	No. As noted for Q12, protection schemes are set up to clear faults. This is a different priority to transmission where redundancy under a range of scenarios is required.

considerations? Please give reasons for your answer.	
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, rather retain the existing 30MW threshold.
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.	No. Emphasis in distribution networks is typically clearing the fault and anti-islanding protection.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	The existing equipment will ride through all faults to its maximum capability already. Existing installations will incur new compliance costs, for no benefit. The additional compliance costs will also be a burden on new installations.
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?	For existing installations, there will be one-off compliance costs associated with determining whether existing equipment complies with new requirements followed by any ongoing reporting / testing costs. Assessment is non-trivial, with the cost expected to be high. In most cases, the outcome of assessment will not be able to affect any meaningful change. In many cases seeking dispensation will be the correct approach. This will also incur a cost.

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?	Operation of the embedded generation to meet voltage requirements already requires working closely with distribution network owners. Once the specific constraints are addressed to meet distribution network requirements are addressed, there is no room left to address transmission and GXP issues. Existing generating stations will not be able to comply with options 1 and 3. Cost of compliance will be high and to the detriment of consumers.

Yours sincerely

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20th August 2024

Electricity Authority

By email to fsr@ea.govt.nz,

RE: CONSULTATION PAPER—ADDRESSING MORE FREQUENCY VARIABILITY IN NEW ZEALAND'S POWER SYSTEM

Introduction

Pioneer Energy appreciates the opportunity to make this submission to the Electricity Authority on this frequency consultation paper. The proposed 30 MW rule change captures several of our sites.

The following table shows the size distribution of our generators and stations. We have no generators above 30MW and a single station that is usually grid-connected.

Table.7.Our.Generators.and.Stations

	Individual Units				Stations				TOTAL
	0-5	5-10	10-30	>30	0-5	5-10	10-30	>30	MW
Hydro	24	1	2	0	15	3	1	0	78.0
Wind	20	0	0	0	1	2	0	0	16.7

Complying with resource consents and the complexity of our water management regimes means that our ability to change output of our generators for reasons other than water management are limited. Governors are not installed on most of our generators as these have not been required and their operation conflicts with water management.

Our generators do provide a natural contribution to low frequency events as described in section 8.19 of the Electricity Industry Participation Code as we set protection to keep the generators online and maintain flow. Compliance with additional technical codes will not increase the contribution of these generators to frequency stability but will add significant capital and operational costs.

We anticipate the actual improvement in frequency support possible from the rule change will fail to deliver meaningful change.

Pioneer is a member of the IEGA and supports the submissions made by the IEGA.

Submission

Given the challenges of increasing frequency support from most of our generators our submission is for authority to retain the existing exemption and pursue procurement of stability services identified in option 3.

Examples

The following two examples illustrate the types of issues that will arise from the proposed changes. This is not a complete list.

Ellis Station

Ellis Station generators, G5 and G6, are individually rated at 3.25MW and have mechanical governors. These are 1940s governors which respond to basic raise / lower pulses from the control system. This station nominally falls within the range of the proposed rule change. Retrofitting code compliant governing systems to these generators will require major modifications, with limited benefits.

The Ellis station has a small intake structure very little storage, output changes that do not relate to water flow are limited.

From past work, we expect the cost of new hydraulics, actuators and an electronic governor to be $700,000. This will be a compromised solution, given the age of the existing equipment. The risks associated with modifying the existing turbines would likely see the requirement new turbines, estimated cost $15,000,000.

The Ellis station will ride through frequency events with current protection settings.

Monowai

Monowai has three 2.6MW generators. This station is fed from Lake Monowai via 6.9km of natural riverbed, a pond feeding 0.9km of canal followed by 1.2km of penstocks. Wicket gates are directly controlled to manage spill at the top of the canal. This station has no governors.

The pond at the top of the canal has a 500l/s consent limit. Flows above this limit are lost to generation. To minimise loss the pond level control loop directly moves the generator wicket gates to achieve effective flow control. This is incompatible with governor control. Governor control on this scheme would see excess water spilled down the river and would reduce annual generation. The benefits of governor control at this site to the grid would be limited. The station will already ride through frequency events with current protection settings.

The existing hydraulics for operating the wicket gates on these turbines are raise / lower solenoid values. To add a governor the hydraulic packs will need to be replaced to provide gate positioners. Estimated cost $500,000 across the three units.

Upper Fraser

Upper Fraser was commissioned in 2019. This is an 8MW, five jet Pelton turbine with a 5.5km penstock. The intake is 1115m above sea level. Flow through the station is 2,000l/s. This is a new station with modern controls, excitation system and protection relays. The generator does not have a governor, the turbine does not have a governing deflector.

We minimize flow changes because of the small storage and to assist in maintaining a residual flow. This storage is effectively smaller in winter when flows drop to the turn-down limit of the turbine. We avoid flow changes in winter because this causes the intake screen to ice up. Recovering from trips in winter is hampered by snow and ice on the high-country road access. Direct spear valve is required for stable water level control loops.

When communications to the intake fails the control system manages intake level through penstock pressure at the station, allowing for varying head losses in the penstock as power output changes. Changes in power output create pressure fluctuations that make effective control during communications outages impossible.

The existing deflector is a cut in type not suitable for governing. The housing is not designed for continuous operation of the deflectors. Estimated cost of $1,000,000, assuming change is possible.

The Upper Fraser station will already ride through frequency events with its current protection settings.

These generators do not have the capability to meet the technical codes.

Submission Questions & Comments

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?	No. As described above, our stations in this size range are not able to provide improved contribution. These stations are constrained by consent requirements and water management and will not be able to contribute additional frequency support.
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	No benefits. Significant capital and operational costs. Adding governors where these do not exist will require investigation. We anticipate costs will be prohibitive.

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?	Investigation required to quantify costs. Investigation costs will be large and will be require on a per generator basis as few are common. See above for specific station cost estimates.
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 under-frequency event for six seconds?	Cons: will require investigation and analysis, where stations already comply there will be no improvement, where stations do not comply making them comply is expected to be expensive or impossible.
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.	Yes. Not all technology can provide the same response.
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.	No. Synchronizing generators without governors creates some challenges. Changing the frequency band has the potential to make this more difficult.
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.	No.
Q8. What do you consider to be the main benefits and costs	We expect that the cost will be very high and the improvement in performance will be negligible.

associated with the second frequency-related option?	
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?	As for Q3. Significant cost required to estimate the cost.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	This option places allows us to focus where improved contribution might be economically possible. This option also provides the most flexibility in terms of accepting new technology solutions and targeting these at locations with the most need.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	Options 1 and 2 depend on the idea that meaningful change in contribution is possible be merely changing the exemption from 30MW. This fails to recognize the different constraints common to embedded generators and the fact that these capabilities are locked in during construction.

Yours sincerely

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