20 August 2024

Electricity Authority
By email: fsr@ea.govt.nz

Consultation Paper – Addressing larger voltage deviations in New Zealand's power system

Meridian Energy Limited (**Meridian**) appreciates the opportunity to comment on the Electricity Authority's (**Authority**) consultation paper 'Addressing larger voltage deviations in New Zealand's power system'.

We support the Authority's review of common quality obligations in the context of increasing intermittent generation. It is timely to ensure system settings are consistent with the expected increase in intermittent generation.

In general, Meridian favours the use of market-based mechanisms to ensure that common quality outcomes are achieved at least cost and participants are compensated for costs incurred in providing system support. A market-based approach is generally preferable to imposing regulated requirements on generators or other service providers which may result in unavoidable and unrecoverable costs being incurred and/or an increase in applications for dispensation. We therefore support the inclusion by the Authority of the assessment criteria that 'the option is a market-based approach'.

However, we note that, according to the Authority's own assessment, none of the three options proposed to be shortlisted to manage larger voltage deviations in New Zealand's power system are market-based approaches. While we accept that some regulated obligations may need to be imposed in the interim, Meridian's view is the Authority should be seeking over the longer term to establish a market-based framework to incentivise the provision of voltage support. We recommend that these longer-term objectives are considered before making any final decisions on the options proposed to ensure that any interim measures are necessary and are consistent with the desired future state for voltage support arrangements.

Our responses to the Authority's specific consultation questions are included as Annex One.

This submission is not confidential and can be published in full. Please contact me if you would like to further discuss any of the matters discussed in our submission.

Nāku noa, nā

Matt Hall
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Meridian Energy

Annex One: Meridian responses to the Authority's specific consultation questions

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.	As part of any network connection investigation, the impacts on the ability to manage network voltage are considered. As such, appropriate measures may be put in place to ensure this. Our experience is this already happens for materially sized generation connections.
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.	There are several material aspects that impact the ability of a generating station to provide voltage support. These include the location of the generating station on the distribution network, and the nature of other voltage control systems and equipment on the distribution network. Examples of issues that we have observed in this space include: • An inability to exercise reactive power range without pushing local voltage outside the Code requirements; and • Interaction between a generating station voltage controller and existing voltage controls on the network. The ability of a distribution network-connected generating station to provide voltage support to the grid will be impacted by these matters. The first priority will be to manage the voltage limits of the immediate network to which the generating station is connected.
Q3. Do you consider there should be a capacity threshold (eg, a nominal net export or nameplate capacity of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having/not having a capacity threshold.	We consider a capacity threshold would be appropriate. It may make sense to align this with the capacity threshold adopted for frequency keeping obligations. However, we note that a distribution network is already likely to impose requirements on connecting plant, depending on the plant's capacity.
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	This change is likely to allow more generation stations using equipment supplied internationally to comply as this standard

reactive power range of ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?	more closely aligns with common international specifications. It should be noted that there are many situations where larger generating stations on distribution networks cannot exercise their full reactive range due to the local impact on voltage.
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.	This option proposes imposing voltage control obligations on Battery Energy Storage Systems (BESS) irrespective of operating mode (load / generation / idle). When idle, this is essentially obligating a BESS to operate as a statcom while providing no ability to recover any costs associated with providing this service. This is in contrast to other providers of such services who receive compensation. There are also many large loads on the network that provide no voltage support (other than possibly power factor correction). As such, this approach seems to place an unfair burden on BESS.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	As noted above, this approach would impose costs on BESS without providing any opportunity to recover these costs. We do not consider this to be a sustainable approach.
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?	The costs will depend on the size of the relevant generating station. Larger stations will generally have the capabilities required, while smaller stations may incur costs in achieving this capability. There will also be ongoing costs on all captured stations from determining and demonstrating compliance.
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?	As noted above, this option would impose voltage control obligations on BESS irrespective of operating mode (load / generation / idle). This will impose costs on BESS while providing no ability to recover these costs. We do not consider this to be a sustainable approach.
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.	Meridian agrees with shortlisting this option for further consideration.

Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	We broadly agree with the costs and benefits as outlined by the Authority.
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?	As noted above, this option would impose voltage control obligations on BESS irrespective of operating mode (load / generation / idle). This will impose costs on BESS while providing no ability to recover these costs. We do not consider this to be a sustainable approach.
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.	Meridian considers this question will be best answered by distributors.
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.	Meridian's view is this shouldn't be necessary given the existing fault ride through envelopes in clause 8.25A are modelled based on the location of the relevant generating station on the power system.
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.	We consider a capacity threshold would be appropriate. It may make sense to align this with the capacity threshold for generating stations and energy storage systems connected to local distribution networks to support voltage. However, we note that proving compliance would potentially require complex system studies, which could be disproportionately expensive for smaller capacity generating stations.
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.	Meridian agrees with shortlisting this option for further consideration. We note that the requirements to prove compliance with the fault ride through obligations can be onerous, and that this may be additionally burdensome on smaller plant. We recommend that any decision to extend fault ride through obligations to smaller plant should also consider the appropriateness of

	associated testing, monitoring and compliance obligations.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	We broadly agree with the costs and benefits as outlined by the Authority.
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 noted above, the requirements to prove compliance with the fault ride through obligations can be onerous, and this may be additionally burdensome on smaller plant. We recommend that any decision to extend fault ride through obligations to smaller plant should also consider the appropriateness of associated testing, monitoring and compliance obligations.
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?	Meridian notes that none of the three options assessed are market-based options. As noted in our covering letter, we have a preference for market-based options to ensure that common quality outcomes are achieved at least cost and participants are compensated for costs incurred in providing system support. While we accept that some regulated obligations may need to be imposed in the interim, Meridian's view is the Authority should be seeking over the longer term to establish a market-based framework to incentivise the provision of voltage support. We recommend that these longer-term objectives are considered before making any final decisions on the options proposed to ensure that any interim measures are necessary and are consistent with the desired future state for voltage support arrangements.

20 August 2024

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Consultation Paper – Addressing more frequency variability in New Zealand's power system

Meridian Energy Limited (**Meridian**) appreciates the opportunity to comment on the Electricity Authority's (**Authority**) consultation paper 'Addressing more frequency variability in New Zealand's power system'.

We support the Authority's review of common quality obligations in the context of increasing intermittent generation. It is timely to ensure system settings are consistent with the expected increase in intermittent generation.

In general, Meridian favours the use of market-based mechanisms to ensure that common quality outcomes are achieved at least cost and participants are compensated for costs incurred in providing system support. A market-based approach is generally preferable to imposing regulated requirements on generators or other service providers which may result in unavoidable and unrecoverable costs being incurred and/or an increase in applications for dispensation. We therefore support the inclusion by the Authority of the assessment criteria that 'the option is a market-based approach'. We consider, in agreeing on solutions, this criteria should be strongly weighted to reflect the significant advantages of such an approach.

In line with this, Meridian does not support the option to introduce a maximum deadband of +/- 0.1 Hz (while allowing for inherent deadbands). Meridian's view is that it would be preferable to retain current governor response obligations while moving directly to a capability market for governor response, which will be a fairer and more efficient solution. Adopting interim changes will only defer the motivation to progress to a market-based arrangement, while imposing greater costs on existing generators. We discuss this point further in our responses to the Authority's specific consultation questions, attached as Annex One.

This submission is not confidential and can be published in full. Please contact me if you would like to further discuss any of the matters set out in our submission.

Nāku noa, nā

Matt Hall
Manager Regulatory Affairs
Meridian Energy

Annex One: Meridian responses to the Authority's specific consultation questions

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?	Yes, we agree with shortlisting the option to extend frequency-keeping obligations to additional, small generating stations. This will assist with maintaining system frequency and create a more level playing field amongst generators. We consider that making this change through the Code is preferable to relying on an application from the System Operator on a station-by-station basis, which would require additional and ongoing effort. A Code change will also more clearly signal to future investors the requirements on small plants.
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	We broadly agree with the Authority's summary of costs and benefits.
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?	We expect there will be costs involved in equipment or control upgrades and testing for existing plant captured by these requirements. There will also be ongoing costs in relation to compliance, monitoring and testing. Some of these costs may be significant and disproportionate to the relatively little frequency support provided by these smaller plants. These costs should be closely considered in determining the appropriate threshold to ensure any change doesn't result in greater overall costs than benefits.
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?	Meridian does not have a view at this stage; we note there is very little discussion on this issue in the consultation paper.
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 Authority notes that it has previously consulted on deadband settings, at which time it concluded that, subject to costs and practicalities, a capability market for governor response (and other future forms of control response) would be the best solution. It is now proposing to impose a maximum permittable deadband until such time as a market mechanism is developed. Meridian's view is that it would be preferable to retain current governor response obligations while moving directly to a capability market for governor response,

	which will be a fairer and more efficient solution. Adopting interim changes will only defer the motivation to progress to a market-based arrangement, while imposing greater costs on existing generators. Setting a maximum deadband may also give rise to a risk that existing providers of governor response extend their deadband to the maximum allowed level where current deadband settings are within that proposed maximum. This would increase overall costs of procuring frequency keeping support. However, in the case that the Authority decides to progress with changes, we agree that the permitted maximum dead band should be based on the technology of the generating station. This would help ensure that requirements match the capabilities and costs of providing governor response for each type of plant. In particular, Meridian notes wind turbines effectively do not have an inherent deadband and would incur significant 'wear and tear' costs if an unsuitable maximum deadband is imposed. Wind turbines will generally respond faster than hydro to frequency changes due to their low inertia and will therefore end up undertaking proportionally more work than a hydro unit with the same dead band. We recommend maintaining existing settings for wind turbines. Further, we consider use of Battery Energy Storage Systems (BESS) for frequency keeping should be a last resort option as it will: • Reduce the expected state of charge of the battery which in turn will reduce the capacity that can reliably be offered into the market to support periods of peak demand; and • Result in frequent partial 'cycling' of the battery which will reduce the battery lifetime and impact on the warranty.
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.	Meridian would support further consideration of this option. As the Authority notes, previous analysis of this option is now 20 years old. It would be helpful to update this analysis in the context of current market rules and technologies as part of a wider frequency keeping work programme.
Q7. Do you agree the Authority should be short listing the second frequency-	Meridian does not support short listing the option to introducing a maximum deadband of +/- 0.1 Hz (while allowing for inherent deadbands). As noted in our

related option to help address Issue 1? If you disagree, please explain why.	response to Question 5, Meridian's view is that it would be preferable to retain current obligations while moving directly to a capability market for governor response, which will ultimately be a fairer and more efficient solution. Adopting interim changes will only defer the motivation to progress to a market-based arrangement, while imposing greater costs on existing generators. It would also transfer more frequency management towards inherent plant response and away from the established frequency keeping market. This would represent a clear move away from a market-based approach. Further, Meridian considers there is sufficient time to progress a capability market for governor response as the underlying changes identified by the Authority (i.e. growth in intermittent generation) will only emerge over time and current frequency management capability is adequate for current system needs.
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	The Authority's description of the costs of this option likely understates the issue. The Authority notes that, in its previous consultation, generators indicated the cost of complying with a tighter dead band could come to many millions of dollars. Meridian considers, even when allowing for inherent deadbands, a tighter deadband will result in significant wear and tear on existing equipment. This impacts wind turbines in particular, which effectively do not have an inherent deadband. It will also have a negative impact on the commercial considerations for new BESS projects. Meridian recommends progressing to a market-based solution for incentivising governor response so that the lowest cost providers are employed to provide support.
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?	With respect to wind turbines, Meridian's analysis suggests there can be an exponential relationship between the number of pitching operations and the tightening of a deadband, resulting in significant wear and tear. These costs are difficult to quantify but will be material. In addition, imposing frequency controls on wind turbines inevitably results in wind being spilled. This is a system inefficiency as such resource cannot be stored or recovered. This is particularly impactful during dry periods, when there is a need to maximise preservation of hydro storage.
Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option	Overall, we support use of existing market-based arrangements. As noted by the Authority, this approach provides transparency around the economic cost of normal frequency management and allows providers of

(Procure more frequency keeping and instantaneous reserve under status quo arrangements)?	frequency keeping to factor in the costs of this service to their market offers. In addition, as noted above, we consider the Authority should move towards a capability market for governor response, which will ensure existing providers of governor response are appropriately compensated for the benefits and costs of this service.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	Overall, we agree with the Authority's assessment which appears to indicate that Option 3 is the preferred option. We disagree with the Authority's assessment of Option 3 against Criteria 3. The fact that geothermal might have higher costs in providing frequency keeping services does not mean that this approach is not technology neutral. Rather, it allows each technology to offer according to its capability and costs. While on a longer timeline for implementation, Meridian supports further investigation of procuring frequency-related services that leverage the capability of new inverter-based technology. In particular, we would support investigating the establishment of a new ancillary service market product for one second reserve, as listed in Table 2. We consider this option should remain on a long-list for further investigation as it presents an opportunity to foster new capabilities from new and emerging technologies in supporting a stable and robust system.