30 June 2026

Submissions
Electricity Authority

By email: OperationsConsult@ea.govt.nz

Common quality and wholesale market arrangements for BESSs and BESS-hybrid stations

Meridian appreciates the opportunity to provide feedback on the Authority's issues and options consultation paper on common quality and wholesale market arrangements for BESSs and BESS-hybrid stations.

Meridian's responses to the Authority's consultation questions are appended.

Meridian draws the Authority's attention specifically to the suggestion that clause 8.23 of the Code could be amended to move the point of compliance for voltage support AOPOs from generating unit terminals to the point of connection. This would be a significant change with wide-ranging implications for generating plant design, transformer tap settings, control philosophies, metering arrangements, and reactive power capability requirements for different generation technologies (including existing generation assets). The proposal would have implications far beyond the scope of the consultation paper on BESS and BESS-hybrid stations. In Meridian's opinion the workability, costs, and benefits of the change have not been adequately assessed and deserve further analysis and consultation before any proposal is progressed further.

Please contact me if you have any queries regarding this submission.

Nāku noa, nā

Sam Fleming
Head of Regulatory Affairs

Responses to consultation questions

Section 3: Terminology

Questions	Comments
Q3.1. Do you support the proposed 5-level structure for generating asset definitions?	Yes. Meridian supports the intent of the proposed structure and agrees that additional definitional groupings are required to reflect how modern inverter-based and hybrid plants are designed and operated. However, we consider further development of the definitions is needed before implementation. In particular, the distinction between certain grouping levels and how operational and market obligations would apply at each level requires additional clarification. We consider further consideration should be given to the proposed Level 1 and Level 2 definitions. For inverter-based technologies, plant architectures can vary significantly between central-inverter and string-inverter designs, which may have implications for how generating units and generating systems are defined. Clarification is also needed on how the proposed levels would apply to existing and future hybrid plant configurations, and how obligations such as AOPOs would be allocated across the different levels.
Q3.2. Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?	While Meridian supports the direction of the proposed structure, we foresee implementation challenges in developing definitions robust enough to accommodate both existing and emerging technologies. Existing definitions already create ambiguity for inverter-based and hybrid assets. Introducing additional levels without clear delineation of obligations risks increasing complexity or creating uncertainty about where technical, operational, and market requirements apply.

	In particular, consistent application across Parts 8 and 13 will be important to avoid duplication or gaps in obligations. Further consideration is required to ensure the proposed levels, particularly Levels 1 and 2, can accommodate different inverter-based plant architectures and future technology developments. We consider the proposed structure should be supported by clear guidance on how obligations map to each level, to ensure the framework remains practical and usable.
Q3.3. Do you have any feedback on the System Operator's recommendations in its *Hybrid Plant Integration* report?	At a high level, we support the direction of the recommendations, but consider further development of the definitions and their practical application is needed before implementation.

Section 4: Asset owner performance obligations for 'idle' BESSs and BESS-hybrid stations

Questions	Comments
Q4.1. Do you agree with how the Authority has defined the 'idle' operating state of a BESS and a BESS-hybrid station? Please give reasons if you do not agree.	Meridian agrees with the intent of defining an idle operating state. However, we consider further clarification is required around both the definitions of "electrically connected" and "idle". We agree that an asset which is not electrically connected should not be required to comply with frequency or voltage support obligations. However, the meaning of "electrically connected" for inverter-based resources requires further definition. For example, a BESS may be energised and supplying auxiliary loads while its inverters are not operating, making it unclear whether the asset is electrically connected for the proposed definition.

	Meridian considers that the idle state should be defined by market participation and dispatch status rather than by a physical operating state. In particular, a BESS that is not dispatched for energy or ancillary services should be considered idle, regardless of whether auxiliary systems remain energised. This would provide a clearer and more practical basis for applying obligations and avoid ambiguity associated with different inverter and control system configurations.
Q4.2. Do you consider that frequency management obligations should apply to an idle BESS and an idle BESS-hybrid station? Please give reasons if you do not agree.	No. Meridian does not consider that frequency management obligations should apply to an idle BESS or BESS-hybrid station. When a BESS is idle, it is not participating in the market and lacks a clear revenue stream to recover the costs of providing frequency response. Applying obligations in this state could impose costs without corresponding market signals, potentially distorting operational decisions. We also note that providing a frequency response while idle will affect the BESS state of charge by requiring charging or discharging. This may interfere with the operator's ability to manage state of charge and optimise future market participation. We consider frequency obligations should apply when the BESS is charging, discharging, or otherwise participating in ancillary service markets, where capability and costs can be reflected in offers.
Q4.3. Do you consider that voltage support obligations should apply to an idle BESS and an idle BESS-hybrid station? Please give reasons if you do not agree.	No. Meridian does not consider that voltage support obligations should apply to an idle BESS or BESS-hybrid station. In the idle state, the BESS does not participate in the market and lacks a mechanism to recover the costs of providing voltage support. Applying

	obligations in this state risks incurring costs without corresponding market signals, potentially distorting operational and investment decisions. We also note that the ability of a BESS to provide voltage support while idle should not be assumed. While some inverter-based technologies can provide reactive power support in this state, doing so may require specific plant design, operating settings, control system configurations, and performance tuning. These capabilities are not necessarily inherent across all technologies or future installations. We are concerned that the capabilities demonstrated by assets currently operating in the market may be treated as a precedent for all future BESS installations. In our view, obligations should be based on clearly defined requirements and appropriate commercial arrangements, rather than assumptions about technology capability. Existing contractual or market mechanisms remain the more appropriate means of procuring voltage support where required.
Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?	Meridian considers there are additional implementation challenges that have not been fully explored in the paper. If an idle state is defined by a physical operating condition, determining and monitoring an asset's operating state is likely to be more complex in practice than the proposed definition suggests. For example, a BESS may be drawing material auxiliary load while the inverters are not operating, raising questions about whether the asset should be considered idle. We consider some implementation costs could be mitigated by using dispatch outcomes to determine operating state. For example, a BESS could be considered idle where no energy or

	ancillary service quantities are dispatched, reducing the need for additional telemetry, monitoring, and control system changes.
Q4.5. What do you consider to be the key benefits and costs associated with applying frequency- and voltage-related AOPOs to BESSs and BESS-hybrid stations in the 'idle' operating state? Please quantify these benefits and costs if possible.	Meridian considers the key benefits and costs depend on the operating characteristics of the asset and the services being provided. Applying frequency and voltage support obligations in the idle state could increase the availability of system support. However, this benefit depends on the asset's actual capability and operating state. An idle BESS may have its inverters offline, and the ability to provide these services should not be assumed. The primary costs relate to operational impacts on the BESS. Frequency response will affect the state of charge through additional charging and discharging. This may affect operational flexibility, battery management strategies, and the asset owner's ability to manage warranty and performance requirements. Both frequency and voltage support may also require changes to operating philosophy, plant configuration, or control system settings. These costs are not readily recoverable where the asset is not dispatched for a market service. Where the System Operator identifies a need for additional system support, existing contractual mechanisms provide a more appropriate means of procuring these services than applying default obligations to idle assets. On balance, we consider the costs and operational impacts of applying obligations in the idle state outweigh the benefits.

Section 5: Applying the AOPOs to BESS-hybrid stations

Questions	Comments
Q5.1. Which option for applying frequency AOPOs to BESS-hybrid stations that are in the injection or consumption operating state do you support? Please give reasons for your answer.	Meridian supports Option 2A, where frequency management AOPOs apply at the BESS-hybrid station point of connection. We consider a station-level approach to be the best way to reflect the asset's impact on the power system and to support efficient operation. It allows the asset owner to manage frequency response across generation and BESS components in a coordinated way, without imposing unnecessary intra-station compliance requirements. This approach promotes operational flexibility and reduces compliance complexity. Clear metering and performance assessment requirements will be important, particularly for ensuring consistent treatment of AC-coupled and DC-coupled hybrid stations.
Q5.2. Do you consider there to be options for applying frequency AOPOs to BESS-hybrid stations in the injection or consumption operating state that are preferable to those identified by the Authority? Please give reasons for your answer.	We consider a station-level approach to be the most practical and efficient.
Q5.3. Do you foresee any implementation issues or unintended consequences associated with applying the frequency AOPOs to BESS-hybrid stations in the injection or consumption operating state that are not identified in this paper?	Meridian considers there are additional implementation challenges that have not been fully explored in the paper. In particular, further consideration is needed around control system coordination, compliance testing, and the associated metering and performance measurement requirements. Demonstrating compliance at the point of connection for a hybrid station may require coordination across multiple technology components and control systems.

	We expect significant practical work will be required to define testing methodologies, measurement requirements, and compliance assessment processes for hybrid stations.
Q5.4. What do you consider to be the key benefits and costs associated with the options for applying frequency AOPOs to BESS-hybrid stations that are in the injection or consumption operating state? Please quantify these benefits and costs if possible.	No further benefits/costs other than what are already noted.
Q5.5. Which option for applying the voltage support AOPO to BESS-hybrid stations that are in the injection or consumption operating state do you support? Please give reasons for your answer.	Meridian supports Option 3A, in which voltage-support AOPOs apply at the BESS-hybrid station point of connection. We consider that aligning voltage support obligations with the station's export capability at the point of connection is appropriate. This approach reflects how voltage impacts are experienced across the network and ensures that obligations are consistent with the asset's physical capability. A station-level approach also supports operational flexibility and avoids imposing impractical or inefficient requirements on individual technology components. By contrast, a component-level approach risks unnecessary complexity and may result in obligations that are misaligned with how hybrid stations are designed and operated.
Q5.6. Do you consider there to be options for applying the voltage support AOPO to BESS-hybrid stations in the injection or consumption operating state that are preferable to those identified by the Authority? Please give reasons for your answer.	No. Meridian does not consider that there are preferable options to those identified by the Authority. Alternative approaches risk introducing complexity or obligations that are misaligned with how hybrid stations operate in practice.
Q5.7. Do you foresee any implementation issues or unintended consequences associated with applying the voltage support AOPO to	Meridian considers there are additional implementation challenges that have not been fully explored in the paper.

BESS-hybrid stations in the injection or consumption operating state that are not identified in this paper?	There is a risk that voltage support obligations could be interpreted to require contributions from individual components that do not reflect physical capability or optimal plant operation. This could lead to inefficient plant design or operation. Further consideration is also needed around control system coordination, compliance testing, and the associated metering and performance measurement requirements. Demonstrating compliance at the point of connection for a hybrid station may require coordination across multiple technology components and control systems. We expect significant practical work will be required to define testing methodologies, measurement requirements, and compliance assessment processes for hybrid stations.
Q5.8. What do you consider to be the key benefits and costs associated with the options for applying the voltage support AOPO to BESS-hybrid stations that are in the injection or consumption operating state? Please quantify these benefits and costs if possible.	A station-level approach provides benefits through alignment with network impacts, improved operational flexibility, and reduced compliance complexity. It also supports more efficient cost recovery and reduces reliance on equivalence arrangements. The primary risk is the potential need to manage trade-offs between reactive power provision and active power output, as well as the costs associated with increased complexity in ongoing compliance monitoring and testing. A component-level approach provides improved visibility, but risks misalignment with network impacts, inefficient outcomes, and higher compliance and capital costs.
Q5.9. Do you consider that clause 8.23 should be revised to move the point of compliance from the generating unit terminals to the point	Meridian supports the intent of aligning voltage support obligations with actual network impacts. However, we consider that moving the point of compliance

of connection to the transmission network (on the high voltage side of the connection transformer)? Please give reasons for your answer.	from the generating unit terminals to the point of connection represents a significant change that extends beyond BESS and hybrid assets. The proposed approach differs from how compliance has traditionally been assessed for existing generation and may have wider implications for generating plant design, transformer tap settings, control philosophies, metering arrangements, and reactive power capability requirements. These implications have not been fully explored in this consultation and may vary significantly between generating technologies and sites. While this consultation identifies evolving technologies as the trigger for considering this change, the proposal would affect a much broader range of existing generation assets. We do not consider that the implications, costs, and benefits of this change can be adequately assessed within the scope of this consultation. Given the broad applicability of the proposal across the generation fleet, Meridian recommends the Authority undertake a separate consultation, supported by a detailed cost-benefit assessment, before progressing any amendments to clause 8.23.
Q5.10. Do you consider there to be an alternative that is preferable to a reactive power export/import requirement of ±39.5% or ±33% of maximum continuous MW output power, measured at the generating station's point of connection to the transmission network (on the high voltage side of the connection transformer)? Please give reasons for your answer.	No. Meridian does not consider there is sufficient information at this stage to identify a preferable reactive power export/import requirement. Our primary concern is not the specific percentage requirement, but the broader proposal to move the point of compliance from the generating unit terminals to the point of connection. As noted in our response to Q5.9, this is a significant change with potential implications across the existing generation fleet, including hydro, thermal, wind, solar, and BESS assets.

	The interaction between reactive power obligations, transformer impedance, transformer tap ranges, control philosophies, and measurement arrangements requires further assessment. For example, many generators do not currently have revenue metering at the high-voltage side of the connection transformer, and it is unclear what additional metering or compliance requirements may result from the proposed change. We also note that reactive power obligations can have wider impacts on plant design and generation development opportunities. These considerations extend beyond BESS and hybrid assets and have not been fully explored in this consultation. Given the broad applicability of the proposal and the potential impacts on all generation technologies, Meridian recommends the Authority undertake a separate consultation on these changes to clause 8.23, including the appropriate reactive power export/import requirements, supported by a detailed assessment of costs, benefits, and implementation implications.
Q5.11. Do you foresee any implementation issues or unintended consequences associated with moving the point of compliance under clause 8.23 from the generating unit terminals to the point of connection to the transmission network that are not identified in this paper?	Meridian considers there are likely to be implementation issues and unintended consequences beyond those identified in the paper. In addition to the potential reduction in reactive power import capability during high-voltage conditions, the proposed change may have broader implications for existing plant design, generator voltage ratings, transformer tap settings, transformer impedance selection, control philosophies, metering arrangements, and compliance assessment. These impacts are not limited to BESS and hybrid assets and may affect a wide range of existing generation technologies.

	We have not had sufficient opportunity through this consultation to assess the potential impacts on the existing generation fleet, including hydro assets. We also note that reactive power obligations can influence future opportunities for generation development and plant upgrade decisions. Given the broad applicability of this proposal and its potential implications across the wider generation fleet, Meridian considers these issues would be more appropriately assessed through a dedicated consultation on clause 8.23, supported by a detailed assessment of costs, benefits, and implementation impacts.
Q5.12. What do you consider to be the key benefits and costs associated with moving the point of compliance under clause 8.23 from the generating unit terminals to the point of connection to the transmission network? Please quantify these benefits and costs if possible.	Meridian considers that it is not yet possible to assess the benefits and costs of this proposal adequately. Moving the point of compliance from the generating unit terminals to the point of connection has potentially wide-ranging implications for existing, planned, and future generation assets. These may include impacts on transformer design, tap changer settings, control philosophies, measurement and indication systems, compliance arrangements, and development opportunities. Given the broad applicability of the proposal and the potential impacts across the wider generation fleet, Meridian considers a separate consultation and detailed cost-benefit assessment are required before the benefits and costs can be fully understood and evaluated.
Q5.13. Do you consider that legacy arrangements would be needed for the existing generation? Please give reasons for your answer.	Yes. Meridian considers that legacy arrangements would be needed if the proposed changes proceed. Transitional arrangements will be important to avoid unintended impacts

	on existing generation assets and the loss of capability currently relied upon by the System Operator. Given the broad applicability of the proposed changes, legacy provisions would provide greater certainty than relying solely on dispensations. However, the need for extensive legacy arrangements may indicate that the proposed obligations are not appropriate for all existing assets. This reinforces our view that the proposed changes should be considered through a dedicated consultation, with further assessment of their impacts across the wider generation fleet, not just BESS and hybrid stations.

Section 6 questions: Wholesale arrangements for BESS-hybrid stations

Questions	Comments
Q6.1. Do you agree with the preferred option of requiring BESS-hybrid stations to offer a technology component, except in certain circumstances, over the alternative option of creating new obligations for BESS-hybrid stations? If not, why not?	Meridian broadly agrees with the preferred approach and considers it preferable to creating bespoke obligations at this stage. For AC-coupled configurations, offering by technology component is likely to reflect how the assets are operated in practice, with generation and BESS components functioning largely as separate assets with their own controls and market participation arrangements. However, we note the benefits of this approach are less clear for DC-coupled configurations, where components share infrastructure and may not be capable of fully independent operation or metering. We also note that there is currently limited market incentive to offer AC-coupled assets as a hybrid station rather than as separate generating assets. At this stage, we see value in retaining the option to classify assets as hybrid stations. However, the value of that

	option will ultimately depend on the future evolution of trading arrangements and the market benefits available to hybrid assets.
Q6.2. Do you agree with our characterisation of the benefits and costs with our preferred option? Are there any other aspects we should consider?	We agree that leveraging existing trading arrangements reduces implementation risk and avoids the need for premature bespoke design. One additional aspect to consider is the need to align with evolving BESS-specific trading arrangements, including bidirectional offer formats. Ensuring consistency across standalone and hybrid BESS participation will reduce implementation burden and support efficient market participation over time.
Q6.3. Do you agree station dispatch arrangements should be extended to accommodate BESS-hybrid stations that are offered by technology component? What, if any, other issues do you see with the station dispatch arrangements that are in addition to those identified above?	Meridian agrees that station dispatch arrangements should be extended to accommodate BESS-hybrid stations offered by technology component. This approach supports greater operational flexibility and offers a potential pathway to improve the dispatchability and firming of intermittent generation. It allows asset owners to determine the most appropriate operating model while maintaining alignment with existing market arrangements. However, the benefits are likely to differ between AC-coupled and DC-coupled configurations. The value of hybrid operation will ultimately depend on future trading arrangements and the market value available to services such as generation firming. At present, these benefits remain uncertain and may be limited under current market settings. We agree there are risks associated with forecasting future capability, particularly in state-of-charge management and future offer accuracy. These risks will require clear expectations regarding offer updates and alignment with the System Operator's scheduling processes.

Q6.4. Considering the options above, how should the System Operator manage network injection from a BESS-hybrid station where injection is limited by inverter capacity? What implications would this have on your processes or systems?	Meridian considers that the System Operator should manage inverter capacity limits through a market node constraint aligned to the station's physical capability. This provides a clear and consistent approach which ensures total injection and offtake are constrained to reflect inverter limits, while supporting appropriate dispatch and pricing outcomes. We consider this approach preferable to relying on offer-based or transmission-constraint solutions, which introduce either additional system complexity or risk of inefficient price signals. In terms of implications, this would require asset owners to provide accurate and timely inverter capacity limits, including updates for outages or configuration changes. This is broadly consistent with existing processes and is not expected to introduce material additional burden beyond standard outage and capability management practices.
Q6.5. Do you agree with our preferred approach to calculating constrained costs for DC-coupled BESS-hybrid stations? Can you provide any insights about what metering arrangements would be required to enable this approach?	Meridian broadly agrees with the preferred approach, provided the associated metering and compliance requirements remain practical and proportionate. Accurate component-level metering will be necessary to support alignment between dispatch, settlement, and physical operation. However, it is unclear what metering requirements would be needed for DC-coupled configurations, and whether this would require revenue-grade metering beyond current arrangements. We are concerned that implementing and maintaining distributed metering across a DC-coupled site may introduce significant complexity, cost, and compliance burden. Further clarification is required on the intended metering architecture, measurement

	requirements, and how compliance would be demonstrated in practice. This is particularly important for DC-coupled configurations, where generation and BESS components share infrastructure and component-level measurement may not be straightforward.