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Electricity Authority
Wellington
By email: OperationsConsult@ea.govt.nz

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

Transpower welcomes the opportunity to provide feedback on the Authority's consultation, "Common quality and wholesale market arrangements for BESSs and BESS-hybrid stations" published 19 May 2026. This submission reflects the reviews of Transpower as System Operator.

We strongly support the Authority providing clarity on both the common quality and wholesale market arrangements for BESSs and BESS-Hybrid stations – this will help asset owners. However, changing obligations for BESS and BESS-Hybrid in 'idle' state will introduce more complexity and system changes when there are other priorities which will deliver greater benefits to New Zealand consumers. In particular, it is important to continue developing market arrangements and ancillary services products to better enable BESS to compete in the market and to support grid stability, taking advantage of their technical capabilities in these areas.

Our responses to the questions are given in full in the attached table, but we would like to highlight key aspects of our submission here.

Clarifying generating asset definitions

We support the Authority adding other levels of generating asset definitions to clearly define configurations of inverter-based resources (IBR). We recommend the Authority consider the following to increase clarity and future-proof the definitions:

- To use single line diagrams to help to clarify the definitions. This will allow the Authority to test whether the definitions can be applied consistently across all configurations, including DC-coupled, AC-coupled, and co-located arrangements.
- To account for emerging technologies and configurations, such as IBR plant co-located with large load, to avoid further time-consuming revisions to the definitions.
- To separate the definitions for Part 8 and Part 13 to make them easier to understand and apply.

Obligations for BESS and BESS-hybrid in 'idle' state

We recognise it is important to clarify to asset owners what obligations apply whilst BESS are 'idling' – when they remain connected, but are not consuming or injecting electricity. This is particularly important given the projects under development or signalled, as the Authority sets out in its consultation.

The Authority has set out the following options:

- Assigning the same obligations to BESS whilst idling as BESS has in other states.
- Assigning more differentiated obligations where the obligations vary in different states (within this there are options for BESS to face no obligations whilst they idle or to provide one of frequency or voltage obligations).

The consultation paper has rightly identified the costs and benefits of the different options with the trade-offs being between two main factors:

- If BESS asset owners *must meet obligations* whilst idle they will be providing frequency and voltage management whilst not directly recovering costs, but suffering wear and tear on their assets, and potentially damping of investment signals for BESS.
- If the BESS owners are relieved of some or all of their obligations whilst idling, there are consequent costs associated with complexity and changes to System Operator tools, additional notifications needed from BESS assets.

We agree with the identified costs and benefits but there are relevant issues that we think need to be considered by the Authority.

First, BESS and BESS-hybrid stations currently spend less than 5% of time in 'idle' and we expect them to spend less time as market participation increases. Second, there is already a full schedule of changes needed to the system operator tools, including the market system, and any change needs to be prioritised against other enhancements. Future enhancements may well involve new market or ancillary service products that will allow BESS and BESS-hybrid stations to participate more actively, increasing revenue opportunities whilst reducing time spent idling.

We would also like to stress, that, if BESS and BESS-hybrid plant do not want to meet obligations when they are neither consuming or injecting, they already have the option to open the relevant circuit breakers and temporarily disconnect in order to avoid obligations.

We support applying AOPOs to BESS-hybrid stations at the station level

There are both benefits and shortcomings applying AOPOs at station level or component level. However, applying AOPOs at station level is more practical and easier to monitor and especially for a DC coupled hybrid station. It also reduces the efforts from an Asset Owner to provide indications and measurements for operation and compliance needs especially for indications at the DC side of the hybrid station.

Commissioning testing can be carried out at station level which is more straight forward and simple as compared to testing at component level.

We understand that there are advantages in BESS-hybrid offering at the *component level*. We suggest the Authority works to ensure applying AOPO obligations at station level can still enable offering energy and instantaneous reserve at component level.

Other clause revisions

We support the Authority revising clause 8.23 to address issue when applying this clause to IBR station and to remove ambiguity between different part of the Code. However, we suggest the Authority to ensure the revised clause will work for synchronous generating station and BESS-hybrid generating station both AC or DC coupled hybrid station.

We also suggest the Authority to review clause 8.17 and advise the industry on the interpretation of the phase "maximum possible injection" and how this can apply to BESS or BESS-hybrid generating station.

Yours sincerely

Katherine Moore

Head of Power Systems Group

Appendix A – Responses to Questions

Submitter	**Transpower NZ Ltd.**

Questions	**Comments**
Q3.1 Do you support the proposed 5-level structure for generating asset definitions?	Yes. System Operator strongly supports the Authority's proposal to expand current generating asset definitions to the five definitions described in the paper. The proposal will provide more clarity for assets owners on the application of common quality obligations and technical requirement in CACTIS like modelling and operational communications requirements.
Q3.2 Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?	Yes. There are many possible configurations for inverter-based generating stations, and the technologies are evolving. Presenting definitions solely in descriptive form, as outlined in the paper, may introduce ambiguity in their application. We recommend that the Authority includes single line diagrams alongside the descriptive definitions to improve the clarity of these definitions. This will allow the Authority to test whether the definitions can be applied consistently across all configurations, including DC-coupled, AC-coupled, and co-located arrangements. In addition, we encourage the Authority to account for emerging technologies and configurations, such as IBR plant co-located with data centres or other large load, to avoid frequent and time-consuming revisions to the definitions. We also suggest that the Authority separate the definitions for Part 8 and Part 13 to make them easier to understand and apply.
Q3.3 Do you have any feedback on the System Operator's recommendations in its Hybrid Plant Integration report?	No.
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.	We agree with the Authority that in an "idle" operating state, BESS or BESS-hybrid should have *no exchange of active and reactive power* with the network although the asset is physically connected to the power system and is not cleared for dispatch in the energy and/or ancillary services markets. This is equivalent to the synchronous generating unit that is disconnected from the power system that has no interaction with the power system. However, active power and reactive

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	power flow can be different at the point of connection compared to the terminal of the inverter. Any asset connected to the network should share common quality obligations to support the security and reliability of electricity supply. In general, voltage obligations enable the System Operator to regulate an asset's reactive power to manage system voltage, while frequency obligations enable it to regulate an asset's active power output to maintain system frequency. We therefore suggest defining the "idle" state so that voltage obligations are assessed against reactive power and frequency obligations are assessed against active power. We recommend that BESS and BESS Hybrid stations have the same obligations in all operating states. However, any definition of idle state should also specify where active and reactive power are measured when determining the operating state of a BESS or BESS-hybrid, to account for system losses and the asset's auxiliary loads.
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.	Yes, the obligations applying to 'idle' state should be the same as the obligations apply to charging and discharging state. This is to avoid complicated operational needs. Furthermore, BESS plant are currently idling only 5 percent of the time and we envisage that BESS or BESS-hybrid will likely operate in 'idle' state less often in future as more market products like frequency keeping and other frequency reserve products will be available for BESS or BESS-hybrid to offer to recoup investment. An alternative solution, which would avoid tool and process changes would be to request the assets to open the circuit breaker when operating in "idle" state – essentially electrically disconnect, similar to the operation of synchronous generating unit. Managing a BESS or BESS-hybrid station is simpler if it has no frequency obligation while in the 'idle' operating state. However, the asset owner would still need to notify the System Operator through ICCP when the asset enters the "idle" state so this signal can be used to disable frequency support in our models and for post-event and compliance investigation

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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.	Yes. Please note some of our comments to Q4.2 also apply here. In addition, if an asset does not have voltage support obligation when operating in "idle" state, the coordinator will need to dispatch other assets to balance reactive power from the BESS during transitions through operating states.
Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?	The Authority may have underestimated the work associated with implementing different obligations across different operating states. It is also important to note that If the Authority proceeds with no obligations for the 'idle' state, this may create a precedent for similar treatments for other asset types – such as solar or wind plant. This would add complexity to power system operations and increase the risk of operational errors that could lead to system disturbances. Work would be needed by both the System Operator and asset owners. The System Operator would need to update its operational tools to reflect the obligations in Part 8 (Common Quality). Asset owners would also need to provide signals when an asset changes state so those tools can be updated accordingly. These signals would also be essential for event investigations and Code compliance assessment. We recommend the Authority considers whether different obligations under an "idle" state are needed, as BESS and BESS-hybrid stations currently spend little time in this state and are likely to spend less time in this state as market participation increases. The Authority has asked the System Operator to upgrade the Multiple Frequency Keeping (MFK) tool to enable full BESS participation by December 2027, and there is also a need to develop a fast frequency reserve product to address low-inertia conditions as inverter-based resources increasingly displace synchronous generation. Any implementation effort should be justified by clear industry benefits. A better approach would be to accelerate market products that allow these assets to participate more actively, increasing revenue opportunities while reducing time spent idling. Again , we note that assets owners could choose to open their circuit breakers while idling to avoid offering obligations and to avoid expensive changes to system operator tools and processes.

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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.	All assets connected to the power system share common quality obligations to maintain security and stability. Removing those obligations from one asset type shifts the equivalent burden, and cost, to other asset owners. If the System Operator must procure additional ancillary services to maintain security and stability, those costs will be passed on to other participants and consumers. It is therefore fair that all assets connected to the power system contribute equally to maintaining system security and reliability. Beyond meeting obligations, BESS and BESS-hybrid stations can improve power system security and reliability if their capabilities are fully utilised. Developing more market products would support greater participation, reduce time spent in the "idle" state, and enable these assets to provide more voltage and frequency support.
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.	Applying AOPOs at station level for BESS-hybrid station is more straight forward and easier to manage and operate. Applying AOPOs at station level avoids testing and indications at components level. This also reduces effort to model the asset at component level. However, applying AOPOs at station level also has drawbacks. The obligations should be accompanied by requirements that give the System Operator greater visibility, so changes in frequency or voltage support caused by equipment outages can be reflected in security assessments. For example, outages of inverters or BESS modules will reduce the station's reactive power capability, and our asset models will need to scale to reflect this.
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.	No.
Q5.3. Do you foresee any implementation issues or unintended consequences	No

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associated with applying the frequency AOPOs to BESS-hybrid stations in the injection or consumption operating state that are not identified in this paper?	
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.	Any assets that are connected to the power system and participate in the market should have the same level of obligations to provide common quality services to maintain power system stability. A stable power system enables all assets to participate in the market to deliver electricity to meet the demands.
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.	See Q 5.1.
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
Q5.7. Do you foresee any implementation issues or unintended consequences associated with applying the voltage support AOPO to BESS-hybrid stations in the injection or	No

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consumption operating state that are not identified in this paper?	
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.	See Q5.4.
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 of connection to the transmission network (on the high voltage side of the connection transformer)? Please give reasons for your answer.	We support revising clause 8.23 so this AOPO can be applied more appropriately to inverter-based resource stations. The current clause applies the voltage support obligation at generating unit level, which is impractical and difficult to test, monitor, and model. It also does not account for losses within the collector networks of wind and solar farms, making it harder to dispatch reactive power to manage grid voltages.
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.

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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?	As the revised clause would apply to the AOPO at station level, we ask the Authority to clarify how it would apply to conventional synchronous generating stations. We also ask the Authority to clarify whether the term "connection transformer" in the revised clause applies to conventional synchronous generating stations, which typically use only a generator transformer to connect the generating unit to the network.
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.	No.
Q5.13. Do you consider that legacy arrangements would be needed for existing generation? Please give reasons for your answer.	We do not consider legacy arrangements necessary, as the revised clause is unlikely to change the voltage support capability of existing generating units or impose completely new obligations on the existing generating units. A straightforward provision could instead apply the new obligations only to new generating units or stations that are electrically connected from an agreed date. Any assets with dispensation should remain the same to avoid the need to review all dispensations.
Q6.1. Do you agree with the preferred option of requiring BESS-hybrid stations to offer by technology component except in certain circumstances, over the alternative option of creating new obligations	We support requiring BESS-hybrid stations to offer by technology component in principle, as this better reflects the distinct operational characteristics of each component and aligns more closely with the existing dispatch framework. However, further consideration would be required before allowing a BESS-hybrid station to elect to be treated as an intermittent generation (IG) station.

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for BESS-hybrid stations? If not, why not?	The IG framework is designed around variable resource availability, with distinct Code and operational treatments, whereas BESS operation is controllable, intertemporal, and constrained by state of charge (SoC). Applying the IG framework to BESS-hybrid stations could therefore create ambiguity in gate closure arrangements, dispatch expectations, compliance assessment, forecasting, and the management of forward obligations across dispatch intervals and trading periods.
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 generally agree with the characterisation of the benefits and costs of the preferred option. However, further consideration is needed if a BESS-hybrid station is permitted to elect IG treatment. In particular, the stated benefit of participation in instantaneous reserve and frequency keeping markets may not arise under the current framework, as IG stations do not currently participate in those markets. The paper should therefore distinguish more clearly between the benefits of component-based treatment and the more limited outcomes that would apply under IG treatment. As noted in section 6.25, full BESS participation in the frequency keeping market will be developed over time. That could provide additional market benefits for BESS owners, including when charging or idling, provided sufficient stored energy is available to deliver the service while preserving capability for later dispatch when most needed. Those benefits may be reduced or lost if a BESS-hybrid station instead elects IG treatment. More broadly, treating a BESS-hybrid station as IG could also mean losing wider system and market benefits from active BESS participation, including more flexible dispatch, better intertemporal use of stored energy, and greater ability to support system security and market efficiency when conditions are tight. It should also consider whether the current gate closure and dispatch settings for IG stations could create unintended incentives for a BESS-hybrid station to elect that treatment. If the Authority wishes to explore this further, it may also be useful to consider whether IG dispatch treatment would require any improvements, e.g. a more explicit real-time IG forecast which can be used as a cap limit in dispatch.
Q6.3. Do you agree station dispatch arrangements should be extended to accommodate BESS-hybrid stations that are offered by	We agree in principle that station dispatch arrangements should be extended to accommodate BESS-hybrid stations offered by technology component. This would better support the physical operation of a co-located plant and allow the

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technology component? What, if any, other issues do you see with the station dispatch arrangements that are in addition to those identified above?	System Operator to manage station-level outcomes more effectively. However, the detailed design will need to ensure there is no ambiguity between component-level offers and station-level dispatch outcomes. This is because extending station dispatch to a BESS-hybrid station raises additional complexity, as it involves different technologies within the same station rather than multiple units of the same technology. Further consideration is needed as to whether compliance should be assessed against component dispatch targets, the aggregate station outcome, or some combination of the two. This becomes more important where station export capability or shared inverter capacity binds, as one component may need to be reduced to accommodate the other, raising questions about how dispatch priority is determined and how any resulting deviation affects other obligations (e.g. reserves and frequency keeping service), and is treated for compliance purposes. The arrangements would also need to work clearly where the station's net position becomes negative, for example when BESS charging exceeds co-located generation output and the station becomes a net load. In those cases, it will be important to clarify whether station dispatch arrangements continue to apply in the same way and how dispatch obligations are interpreted when the net position changes sign. The interaction with reserve and frequency keeping participation would also need to be worked through carefully, including how headroom, stored energy, and deliverability are preserved if the BESS component is simultaneously providing ancillary services. A further concern is that greater use of station dispatch could reduce the accuracy of expected BESS SoC for future periods, which may affect forward schedules, post-gate-closure security assessments, and resource commitment decisions. While more frequent offer updates or re-running schedules may mitigate some consequences, these measures would not fully address the underlying issue and could increase operational complexity and reduce the certainty normally provided by gate closure arrangements. Overall, any extension of station dispatch arrangements to BESS-hybrid stations would require further detailed design to preserve clear operational accountability, maintain confidence in forward capability and security assessments, and avoid outcomes that differ materially from those intended under component-based offering.

Questions	Comments
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?	Where network injection from a BESS-hybrid station is limited by shared inverter capacity, the effective limit should be managed at the station connection point. In principle, the System Operator should dispatch and assess the station against that physical injection limit, while requiring the participant to reflect the resulting capability accurately in its component offers. This would better align dispatch outcomes with the plant's actual physical capability and avoid instructions that cannot be delivered simultaneously across all components. We do not support an approach that relies on manual intervention or ad hoc updates to reflect changes in shared inverter capability, particularly where this could create security concerns or undermine gate closure discipline and forecast integrity. The preferred approach is for shared inverter limits to be reflected directly in offers and dispatch processes so that the physical capability of the station is visible within the normal scheduling framework. Including the effective shared inverter limit in offers would help ensure that existing offer and dispatch obligations continue to apply consistently. This would provide greater clarity for participants and the System Operator, reduce the need for manual workarounds, and better support reliable scheduling, compliance assessment, and security analysis.
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?	We support the Authority's preferred approach provided the constrained cost calculation for DC-coupled BESS-hybrid stations is supported by robust, auditable metering arrangements and a clear methodology for identifying the relevant flows. For a DC-coupled arrangement, the calculation needs to distinguish between energy generated by the renewable component, energy stored in or discharged from the BESS, and net injection or offtake at the point of connection. This may require metering or measurement points that can separately identify DC-side flows between the generating component, the BESS, and the shared inverter, alongside the AC-side metering at the point of connection. The main implementation issues will be the expectations on the DC-side measurements used in the calculations and what the accuracy, calibration, certification, and audit requirements will be if the data is used for settlement and constrained cost purposes. DC metering will be something completely new to the settlement process. We recommend before drafting Code

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	changes the Authority should fully understand what is achievable, what the risks are, and how much it will cost to implement and maintain DC metering. It is only once this information is known and understood that the viability of this option and Code requirements can be determined.