

**30 June 2026**

Operations Consultation Team  
Electricity Authority Te Mana Hiko  
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### **Issues and Options Paper - BESS and BESS-Hybrids**

Dear EA Operations team,

Lodestone Energy appreciates the opportunity to submit on the issues and options paper for common quality and wholesale market arrangements for BESSs and BESS-hybrid stations. Our completed submission form is attached.

As New Zealand's first utility-scale solar developer, now progressing the integration of battery energy storage with our operating and future solar farms, we have a direct interest in regulatory arrangements that accommodate solar-plus-BESS hybrid stations clearly, proportionately and without bias toward legacy generation technologies.

We support the broad direction of the paper. In particular, we support the proposed five-level asset structure; assessing common quality obligations at the station's point of connection; moving the clause 8.23 point of compliance to the connection point; and the preferred wholesale trading, dispatch and metering options.

Two themes run through our responses: obligations should be proportionate to a participant's size and system impact and supported by a clear cost-recovery pathway; and existing and in-flight assets need appropriate legacy and transitional arrangements so they are not exposed to retrospective change.

We would welcome the opportunity to discuss any aspect of our submission, and would value continued engagement as the Authority develops proposed Code amendments, particularly on workable metering arrangements for DC-coupled stations.

Regards,



**Peter Apperley**  
**GM Engineering & Technology**

## Format for submissions

### Common quality and wholesale market arrangements for BESSs and BESS-hybrid stations – Issues and options consultation paper

Submitter	Lodestone Energy Limited
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#### Section 3: Terminology

Questions	Comments
Q3.1. Do you support the proposed 5-level structure for generating asset definitions?	<p>Yes. As New Zealand's first utility-scale solar developer, now progressing the integration of BESS with our operating and development pipeline solar farms, the additional definitional layers reflect how modern inverter-based and hybrid plant is actually designed, controlled and operated.</p> <p>The existing 'generating unit' and 'generating station' definitions were developed for machine-based synchronous generation and do not map cleanly onto plant where key operational and market functions occur at the technology-component or hybrid-station level.</p> <p>We particularly support the inclusion of Level 5 (the hybrid generating station). Without an explicit hybrid-station concept, co-located solar-plus-BESS assets sit awkwardly between existing definitions, creating exactly the kind of ambiguity over where Part 8 and Part 13 obligations attach that this consultation is seeking to resolve.</p> <p>A clear, technology-agnostic structure that can be applied consistently across AC- and DC-coupled configurations provides regulatory certainty that investors and lenders need.</p>
Q3.2. Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?	<p>The principal risk is in implementation rather than in the structure itself. As the new layers are propagated through the Code, care is needed to ensure the additional definitional grouping levels do not inadvertently create new or duplicated compliance points. For example, obligations that attach at both the technology-component and station levels for the same physical capability. The drafting should make it explicit for each obligation which level it attaches to, so that the structure clarifies, rather than multiplies, obligations.</p> <p>We support the Authority's intention to use descriptive, asset-based definitions in any future Code drafting rather than 'level 1/2' terminology. We also encourage the Authority to confirm how the structure interacts with the definitions being settled in the companion (standalone BESS) Code amendment, so the</p>

Questions	Comments
	two workstreams remain aligned and a single consistent set of terms emerges.
Q3.3. Do you have any feedback on the System Operator's recommendations in its <i>Hybrid Plant Integration</i> report?	<p>We broadly support this analysis. The recommendation for an additional grouping level between the generating unit and generating station is well-founded and consistent with international practice for inverter-based and hybrid resources.</p> <p>We have no substantive concerns with the report's technical direction. Our main interest is that the conceptual structure is implemented in a way that preserves design and operational flexibility for hybrid stations and does not lock in assumptions about how such stations will be operated before New Zealand has meaningful operational experience with them.</p>

#### 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.	<p>Yes. The definition is clear and workable.</p> <p>We agree with the observation (paragraph 4.7) that a BESS-hybrid station may be idle at the station level even though a technology component is active – for example, where the solar component is charging the BESS entirely from on-site generation with no net injection or offtake at the point of connection.</p> <p>We support the idle state being assessed at the station's point of connection, consistent with our position on station-level obligations more generally (see Q5.1 and Q5.5).</p>
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.	<p>No. Frequency management obligations should not apply to an idle BESS or idle BESS-hybrid station (consistent with Option 1B) unless the BESS owner has been contracted by the System Operator or via the market to supply this as a service.</p> <p>When a BESS or hybrid station is idle it is not cleared for dispatch, is not contributing to the supply-demand balance, and there is no associated revenue stream from the energy or ancillary services markets against which the cost of maintaining a frequency response could be recovered.</p> <p>This reflects a principle Lodestone has consistently advanced in our submissions on CACTIS and on distributed generation pricing: compliance obligations must be proportionate, evidence-based, and supported by a clear cost-recovery pathway. Imposing frequency obligations on an idle asset would impose operational and wear-related costs without a commensurate, recoverable system benefit. This approach</p>

Questions	Comments
	<p>would risk dampening investment signals by treating BESS and hybrid stations less favourably than conventional assets that have no equivalent idle state.</p> <p>If the Authority is minded to require any obligation while idle, we consider voltage support (which requires only that the asset remain energised) to be materially less costly than frequency response, and the more appropriate of the two (i.e. Option 1C in preference to 1A).</p>
<p>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.</p>	<p>No. Mandatory voltage support obligations should not be imposed on an idle BESS or hybrid station as a matter of course (Option 1B).</p> <p>However, as stated above, the cost of providing voltage support while idle is materially lower than that of frequency response, since it requires only that the asset remain energised rather than the provision of active power.</p> <p>If the Authority concludes that some idle-state capability should be retained for system security reasons, our preference is that this be procured and remunerated as an ancillary service, or otherwise made subject to a clear cost-recovery mechanism, rather than imposed as an unremunerated AOPO.</p> <p>This approach preserves competitive neutrality across asset types and ensures the cost of any capability the system genuinely values is transparently signalled and recoverable, rather than being recovered indirectly through higher prices in other periods.</p> <p>Consideration would also need to be given to the treatment of idle BESS / BESS-hybrid stations that are embedded in distribution networks. Voltage support obligations for embedded BESS systems (idle or otherwise) should be between the BESS owner and relevant EDB, not the System Operator.</p>
<p>Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?</p>	<p>We highlight the behavioural risk the Authority itself notes: if obligations differ between operating states, asset owners face an incentive to manage their declared operating state to manage compliance exposure, and there is a transition risk where a different obligation set applies on entering or leaving the idle state.</p> <p>A clean rule – no AOPOs while genuinely idle (Option 1B) – minimises both the monitoring burden on the System Operator and the scope for these distortions, and is simpler to implement than state-contingent obligations that require new real-time indications to identify when an asset is idle.</p> <p>We also note the interaction with the idle definition for hybrid stations: where a hybrid station is charging its BESS solely from on-site generation, the rule should be unambiguous that</p>

Questions	Comments
	no injection/consumption-state AOPOs are triggered at the point of connection, to avoid uncertainty over which obligation set applies.
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.	<p><b>Benefits.</b> The principal benefit of applying AOPOs while idle would be the incremental availability of relatively low-cost frequency and voltage support from connected inverter-based resources.</p> <p>We expect this benefit to be modest, given idle periods are, by definition, periods in which the asset is neither dispatched nor contributing to the energy balance, and given the System Operator can procure equivalent capability through the ancillary services markets where it is genuinely needed.</p> <p><b>Costs.</b> The costs fall on asset owners and include operational and wear-related costs (particularly for frequency response, which requires the provision of power). Additional costs include the absence of a clear market-based recovery pathway, dampened investment signals from inconsistent treatment relative to conventional assets, and additional System Operator implementation and monitoring costs to distinguish operating states.</p> <p>These potential costs include:</p> <ul style="list-style-type: none"> <li>• The opportunity cost for any energy discharged from the BESS in order to provide the frequency support that might have been otherwise utilised for other higher value services.</li> <li>• Energy purchase costs and round trip efficiency losses for any energy that needs to be replaced in the BESS.</li> <li>• Additional battery storage capacity degradation caused by excessive cycling.</li> </ul> <p>Lodestone is not in a position to provide site-specific quantification at this stage, as our BESS integration projects are still in development. As a general matter, however, we consider the costs of mandatory idle-state obligations outweigh the modest, and largely substitutable, benefits supporting Option 1B.</p>

## Section 5: Applying the AOPOs to BESS-hybrid stations

Questions	Comments
Q5.1. Which option for applying frequency AOPOs to BESS-hybrid stations that	Lodestone supports Option 2A – station-level frequency management obligations.

Questions	Comments
are in the injection or consumption operating state do you support? Please give reasons for your answer.	<p>Compliance should be assessed at the BESS-hybrid station's point of connection to the network, with the asset owner determining how the response is delivered across the solar and BESS components.</p> <p>Station-level assessment best reflects the actual power system impact of the station, which is what the System Operator experiences at the connection point. This preserves design and operational flexibility – for example allowing the solar component to ramp while holding the BESS steady during an over-frequency event to avoid unnecessary cycling and battery degradation. It also avoids the measurement and monitoring difficulties that component-level assessment creates for DC-coupled configurations, where internal flows are not observable at the connection point.</p> <p>We strongly support the Authority's position (paragraph 5.25) that the BESS component should not be required to compensate for generation operating at its maximum continuous output. Requiring such compensation would impose a burden on hybrid stations that standalone plant does not face and would penalise efficient hybrid configurations.</p>
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.	<p>No. We consider Option 2A (station-level) to be the appropriate approach and do not see a preferable alternative.</p> <p>We would, however, encourage the Authority to ensure that, where a hybrid station owner elects to demonstrate compliance through an equivalence arrangement, the process for doing so is transparent and low-cost, so that the station-level approach does not generate unnecessary transaction costs.</p>
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?	<p>The main implementation concern is ensuring the Code clearly articulates how station-level performance is assessed against requirements originally drafted around individual generating units – in particular the terms 'generating unit', 'synchronised' and 'maximum possible injection'.</p> <p>We support the System Operator's working interpretation that maintaining pre-event output is sufficient where a station is already at its maximum continuous output, and we consider this interpretation should be made explicit in the Code, to remove the ambiguity generation owners have already identified.</p>
Q5.4. What do you consider to be the key benefits and costs associated with the options for applying	<p><b>Benefits.</b> Station-level frequency obligations better reflect the station's system impact, promote flexibility in hybrid design and operation, minimise unnecessary BESS cycling (with associated degradation savings), and reduce compliance-</p>

Questions	Comments
frequency AOPOs to BESS-hybrid stations that are in the injection or consumption operating state? Please quantify these benefits and costs if possible.	<p>monitoring costs for both asset owners and the System Operator relative to a component-level approach.</p> <p><b>Costs.</b> The principal cost is the one-off effort of clarifying how station-level compliance is assessed against existing Code drafting. This is a modest, largely transitional cost.</p> <p>By contrast, the component-level alternative (Option 2B) would carry materially higher and ongoing costs through greater reliance on equivalence arrangements, inefficient obligations where a component cannot physically respond, and higher monitoring costs – costs that are ultimately borne by consumers.</p> <p>We are not able to provide site-specific quantification at this stage but consider the balance clearly favours Option 2A.</p>
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.	<p>Lodestone supports Option 3A – station-level voltage support obligations.</p> <p>The voltage support AOPO should apply at the hybrid station's point of connection, not to each technology component.</p> <p>This aligns the obligation with where voltage impacts are actually experienced on the network and with the station's physical export capability.</p> <p>As the Authority notes, a hybrid station's export capacity at the point of connection is frequently lower than the sum of its components' capacities because of shared inverters, collector systems, export limits and connection-agreement constraints. Assessing voltage support per component – effectively requiring each component to meet the same reactive power requirement – would be disproportionate to the station's actual export capability and would distort investment and connection decisions.</p> <p>Station-level assessment also allows the component best placed electrically to provide reactive power (for example a BESS with a shorter path to the connection point than the co-located solar array) to do so, which is the more efficient outcome. This is consistent with our broader position that obligations should attach to what matters technically at the connection point rather than to artefacts of a station's internal architecture.</p> <p>As per our response to Q4.5, we assume a voltage support AOPO would not apply to BESS embedded in a distribution network. Voltage support requirements should be between the EDB and the BESS owner in these cases, but Lodestone notes that the same principle should apply (voltage support requirements assessed at station level).</p>
Q5.6. Do you consider there to be options for applying	No. Option 3A is the appropriate approach.



Questions	Comments
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.	
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 consumption operating state that are not identified in this paper?	<p>For DC-coupled configurations, providing reactive power at the point of connection may require a reduction in active power output where both are constrained by the same inverter capacity.</p> <p>The Code and any associated dispatch/settlement treatment should recognise this trade-off so that hybrid stations are not penalised for it. We do not otherwise foresee unintended consequences beyond those identified in the paper.</p>
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.	<p><b>Benefits.</b> Aligning the voltage support obligation with the connection point and with export capability avoids disproportionate obligations, promotes efficient hybrid design and operation, treats hybrid stations consistently with other inverter-based stations, better aligns obligations with the station's ability to recover costs through the markets, and reduces both the need for equivalence arrangements and compliance-monitoring costs.</p> <p><b>Costs.</b> The main cost for DC-coupled stations is the active/reactive power trade-off noted at Q5.7. We consider these costs are modest and clearly outweighed by the benefits. Site-specific quantification is not available at this stage given our projects remain in development.</p>
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.	<p>Yes. Lodestone supports revising clause 8.23 to move the point of compliance for voltage support from the generating unit terminals to the generating station's point of connection to the transmission network (the high-voltage side of the connection transformer).</p> <p>The existing terminal-based obligation reflects a power system of synchronous machines located close to the grid injection point. It does not fit dispersed, inverter-based wind and solar plant, where the lines and cables between the generating units and the connection transformer materially alter reactive power before it reaches the network.</p> <p>Measuring compliance at the connection point reflects what the network actually experiences, is consistent with the station-level approach we support at Q5.5, and aligns New Zealand</p>



Questions	Comments
	with international practice (including the Australian NEM). It is the technically correct reference point for assessing a station's contribution to network voltage.
Q5.10. Do you consider there to be an alternative that is preferable to a reactive power export/import requirement of $\pm 39.5\%$ or $\pm 33\%$ 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.	<p>We do not see a preferable alternative to expressing the requirement as a percentage of maximum continuous output at the connection point. The question is which percentage. Lodestone's primary concern is that the requirement be set on a sound, evidence-based technical assessment of system need, and we support the System Operator's analysis being the basis for that calibration.</p> <p>On the specific levels, we support aligning the transmission-side requirement at <math>\pm 33\%</math> with the new default for embedded generation (effective 1 July 2026). Having higher levels of reactive power support such as <math>\pm 39.5\%</math> would require the reduction in maximum continuous MW output in order to reserve apparent power (MVA) headroom for reactive power. This would impose a significant lost opportunity cost to the generator or BESS.</p> <p>Lodestone's view, consistent with our distributed generation pricing and TPM submissions, is that the relative attractiveness of distribution versus transmission connection is a question for transmission and connection pricing, not one that should be addressed by levelling-up a common-quality obligation.</p> <p>The clause 8.23 requirement should be set at the level technically justified to support voltage stability – no higher – and any residual investment-location distortion should be addressed transparently through the pricing framework.</p> <p>The proposed split (<math>\pm 33\%</math> below 110 kV and <math>\pm 39.5\%</math> at and above 110 kV) is a reasonable way to match the requirement to where higher capability delivers commensurate benefit, provided it is supported by the System Operator's technical analysis.</p>
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?	<p>The most significant practical consequence is the one the Authority identifies: amending clause 8.23 would require all existing dispensations to be reviewed, and the System Operator's analysis indicates the pattern of dispensations needed would change (notably between the North and South Islands).</p> <p>This is a substantial transitional exercise that should be planned and resourced. We also note the System Operator's concern about the loss of reactive power import support. If that capability is genuinely valued, it should be retained through targeted means (see Q5.13) rather than by setting a higher blanket requirement.</p>

Questions	Comments
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.	<p><b>Benefits.</b> Moving the point of compliance to the connection point produces a technically accurate, internationally aligned obligation that reflects what the network experiences, supports efficient inverter-based and hybrid plant design, and removes the distortion of obligations assessed at terminals that bear little relationship to delivered network performance.</p> <p><b>Costs.</b> The main costs are transitional: reviewing and re-issuing existing dispensations, and the System Operator's analysis and systems work to recalibrate.</p> <p>There is also the System Operator's identified risk to high-voltage management from any reduction in reactive power import capability, which we consider is best managed through legacy arrangements rather than a higher general requirement. We are not able to quantify these costs but consider them predominantly one-off and outweighed by enduring efficiency benefits.</p>
Q5.13. Do you consider that legacy arrangements would be needed for existing generation? Please give reasons for your answer.	<p>Yes. Legacy (transitional) arrangements for existing generation are essential. This is a particularly important principle and requirement for Lodestone.</p> <p>This is the same principle we advanced in our CACTIS submission: existing and in-flight assets were designed, financed and consented against the obligations in force at the time, and should not be exposed to retrospective change.</p> <p>Existing dispensations should be expressly preserved, and 'legacy clause' arrangements used – as the Authority suggests – to retain any reactive power import capability the System Operator genuinely needs, without imposing new obligations on assets not designed for them.</p> <p>Clear grandfathering also protects investor and lender confidence at a time when New Zealand needs renewable build to accelerate. We would encourage the Authority and System Operator to establish a proportionate transitional pathway, including representative or simplified demonstration of compliance for older plant.</p>

## 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 by technology component except in certain	Yes. Lodestone supports the preferred Option 4A – requiring BESS-hybrid stations to offer by technology component, with the ability to elect single-station offering in defined circumstances – over the alternative of creating bespoke new obligations (Option 4B).

Questions	Comments
<p>circumstances, over the alternative option of creating new obligations for BESS-hybrid stations? If not, why not?</p>	<p>Given the absence of operational experience with hybrid stations in New Zealand, leveraging established trading arrangements is the lower-risk path and avoids prematurely locking in bespoke rules that may need re-work.</p> <p>We particularly value the proposed flexibility to elect to offer as a single station where that reflects how the station is operated – for example where the BESS is used only to firm the solar component's output and is charged solely from on-site generation. This is a configuration directly relevant to Lodestone's solar-plus-BESS plans.</p> <p>Our one request is that the circumstances in which the System Operator can require component-level offering be transparent, predictable and tied to genuine principal-performance-obligation or dispatch-objective needs, so owners can plan their trading and operating models with certainty.</p>
<p>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?</p>	<p>We broadly agree with the Authority's benefit/cost characterisation.</p> <p>We add one observation: Option 4A creates an asymmetry between common-quality obligations (which we support being assessed at station level – Q5.1, Q5.5) and trading obligations (assessed at component level).</p> <p>We accept this asymmetry is justified. Component-level offering is, as the Authority explains, important to preserving access to the instantaneous reserve and frequency keeping markets and to integrating with the System Operator's tools. But the Code drafting should make the two levels explicit so the difference is understood rather than appearing inconsistent.</p> <p>We also support extending to BESS-hybrid stations the simplified bi-directional offer form proposed for standalone BESS in the companion paper, as this reduces the trading complexity that is the main cost of component-level offering.</p>
<p>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?</p>	<p>Yes. We support extending the station dispatch group arrangements to BESS-hybrid stations offered by technology component.</p> <p>The ability to operate within a station dispatch group provides valuable operational flexibility – for example using the BESS to maintain output during a lull in solar generation, or absorbing higher-than-expected solar output rather than drawing charge from the network.</p> <p>The principal issue is the impact of station dispatch on the predictability of the BESS state of charge and, therefore, on the System Operator's forward scheduling and security assessments. Given that hybrid BESS are potentially being charged by an intermittent energy resource, it would be difficult</p>

Questions	Comments
	<p>for BESS owners to assess two hours ahead what the expected charge or discharge rate of the BESS component of the hybrid system will be with the same level of accuracy as a traditional dispatchable plant or standalone BESS.</p> <p>We support addressing this through allowing hybrid stations operating as station dispatch groups to update their BESS component offer quantities within the gate closure period to reflect actual operation. We support aligning the treatment of the BESS component with whatever approach is settled for standalone BESS in the companion paper (including the longer-term move to System Operator calculation of SoC from real-time telemetry). Consistency between the standalone and hybrid BESS treatment is important to avoid misaligned obligations.</p>
<p>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?</p>	<p>Lodestone supports Option 6A – a static market node constraint – as the System Operator's means of reflecting an inverter-capacity injection limit for DC-coupled hybrid stations, on the basis it appropriately models the station's overall injection capability while ensuring the energy price at the connection point reflects the genuine need for generation investment.</p> <p>We prefer the market node constraint over the transmission constraint option (6C), which carries a risk of undervaluing the station's generation if the constraint binds and depresses the nodal price, and could lead to dispatch outcomes misaligned with the owner's SoC management.</p> <p>From a process perspective, the owner's obligation to notify the System Operator of changes to inverter capacity (temporary or permanent) via existing channels such as the POCP is workable and we ask that the notification requirements and timeframes be proportionate and clearly specified.</p>
<p>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?</p>	<p>Yes. Lodestone agrees with the preferred Option 7A – adjusting DC-side metering so that AC-metered quantities can be apportioned between the generation and BESS components for the purpose of determining constrained costs.</p> <p>As the Authority's worked example in Appendix A illustrates that net AC-side metering (Option 7B) would under-compensate DC-coupled hybrid stations relative to stations offered by component, producing a perverse outcome that would disadvantage DC-coupled configurations and distort design choices.</p> <p>On metering arrangements, our practical experience is that the ability to derive reliable per-component volume information for a DC-coupled station depends heavily on the inverter and controller capabilities of the specific equipment, and on OEM</p>

Questions	Comments
	<p>support for the necessary measurement and data outputs. As we noted in our CACTIS submission, this is not always readily available. This could particularly be the case with existing installed inverters where it is proposed to add DC-coupled BESS in future.</p> <p>We encourage the Authority to:</p> <ul style="list-style-type: none"> <li>(i) specify the metering/data outcome required rather than a prescriptive hardware specification, to accommodate diverse equipment;</li> <li>(ii) confirm whether derived or calculated component volumes (rather than physically separate metering) will be acceptable where they can be substantiated, and;</li> <li>(iii) ensure the cost of any new metering obligation is proportionate to the constrained-cost amounts at stake. We would welcome further technical engagement on workable arrangements as our DC-coupled designs develop.</li> </ul>