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

Issues and options consultation paper

19 May 2026

ELECTRICITY
AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on issues with, and options to improve, common quality and wholesale market trading arrangements for utility-scale standalone battery energy storage systems (BESSs) and utility-scale BESSs co-located with, and connected to, a utility-scale electricity generating station (BESS-hybrid stations).

BESSs and BESS-hybrid stations will play an important role in the management of New Zealand's power system as increasing amounts of variable and intermittent generation (eg, solar photovoltaic and wind generation) connect to the power system. BESSs are a unique power system technology. Operational experience has shown that existing Code arrangements do not adequately support their efficient operation, either as standalone entities or as part of a BESS-hybrid station. In addition, existing Code arrangements create some uncertainty for BESS owners and operators, and BESS-hybrid station developers, as to their obligations under the Code.

Addressing this uncertainty and promoting the efficient operation of BESSs and BESS-hybrid stations is a high priority for the Authority.

This paper accompanies the *Wholesale market arrangements for BESS - Code amendment consultation* paper. The two papers have been published together for feedback to present a clearer, more complete view of the Authority's work on arrangements for BESSs and BESS-hybrid stations.

We are consulting on issues and options in three areas

We are consulting on issues and options in three areas:

- asset owner performance obligations (AOPOs) for 'idle' BESSs and BESS-hybrid stations
- AOPOs for BESS-hybrid stations and transmission-connected generating stations
- wholesale trading arrangements for BESS-hybrid stations.

AOPOs for 'idle' BESSs and BESS-hybrid stations

Section 4 considers issues and options associated with the question of whether AOPOs should apply to BESSs and BESS-hybrid stations that are in an 'idle' operating state. The Code does not explicitly address this matter.

For BESSs and BESS-hybrid stations, this operating state is materially different to traditional generation and can occur for extended periods.

Addressing this question is expected to reduce compliance and transaction costs, clarify operational systems requirements for the System Operator and asset owners, and support efficient investment.

AOPOs for BESS-hybrid stations and transmission-connected generating stations

Section 5 considers issues and options associated with how the frequency and voltage AOPOs apply to BESS-hybrid stations that are consuming or producing electricity. It also considers a change to the voltage support obligations in respect of transmission-connected generating stations. This change would move the point of compliance for voltage support from the generating unit terminals to the transmission network connection point.

Existing AOPOs were not designed with BESS-hybrid stations in mind, creating uncertainty about how key frequency and voltage obligations apply in practice.

The aim of clarifying these AOPOs is to provide greater regulatory certainty for investors, ensure consistent treatment across BESS-hybrid station configurations and other generating station types, and give the System Operator confidence that BESS-hybrid stations will have the capability to support system security.

Wholesale trading arrangements for BESS-hybrid stations

Section 6 considers issues and options associated with clarifying wholesale trading arrangements for BESS-hybrid stations.

Industry participants and developers are raising queries and concerns with the Authority over how existing trading, scheduling, and dispatch arrangements apply to BESS-hybrid stations.

The Code does not clearly define how BESS-hybrid stations are expected to trade in the wholesale electricity market. There is uncertainty about whether offering at the technology-specific component level would require more complex metering, whether market scheduling reflects physical injection and offtake constraints, and whether station-level dispatch should complement technology component-level offers.

This uncertainty may create operational challenges and disadvantage BESS-hybrid stations relative to other generating station types. It risks being a disincentive to invest in BESS-hybrid stations.

Addressing these issues helps deliver an affordable and secure supply of electricity to consumers

Addressing the issues in this paper supports a more affordable and secure electricity supply for consumers in the long run. By clarifying the Code’s rules for BESSs and BESS-hybrid stations, these assets can be used more efficiently to:

- help balance a power system with increasing variability in electricity demand and supply
- support the power system’s stability and resilience
- reduce unnecessary barriers to investment in assets connected to the power system.

Over time, this helps ensure sufficient and timely investment in BESSs and BESS-hybrid stations, with benefits flowing to consumers in the form of downward pressure on costs and improved security of supply.

We are open to feedback on any additional issues to be addressed

While this paper explores issues and options in these three areas, we are open to hearing about other issues we should take into account, either directly related to this consultation or in future work related to BESSs and BESS-hybrid stations. See paragraphs 1.6 to 1.14 below for details on how to submit.

Feedback is due by 30 June 2026

We welcome feedback on any or all aspects of this issues and options paper by **5pm, 30 June 2026**. Please use "Issues and options paper – BESS and BESS-hybrids" in the subject line in your email to OperationsConsult@ea.govt.nz.

Recognising the technical nature of this material, we have allowed a 6-week consultation period. During this time, we will be available to hold individual briefings with interested stakeholders. If this would be useful for you, please let us know by **5pm, 29 May 2026** and include any topics you would like covered.

Separately, during this consultation period, we will be available to hold individual briefings with interested stakeholders. If you are interested, please let us know by **5pm 23 June 2026**.

To express your interest in either or both options you can contact us at OperationsConsult@ea.govt.nz with "BESS EOI" in the subject line.

Next steps beyond this consultation

Following this consultation, the Authority will decide which options set out in sections 4, 5 and 6, if any, should be developed into proposed Code amendments.

We expect to publish a consultation paper on any proposed Code amendments in late 2026, followed by a decision paper setting out our final decisions and supporting rationale in 2027.

Contents

1. Purpose of this paper

We seek your views on issues and options related to BESSs and BESS-hybrid stations

1.1. The purpose of this paper is to consult with interested parties on issues and options relating to:

(a) utility-scale standalone battery energy storage systems (BESSs)

(b) utility-scale BESS-hybrid stations, comprising utility-scale BESSs co-located with, and connected to, a utility-scale electricity generating station.

1.2. Specifically, the Electricity Authority Te Mana Hiko (Authority) is seeking feedback on issues and options relating to:

(a) common quality obligations for *utility-scale BESSs and BESS-hybrid stations* (Sections 4 and 5)

(b) wholesale trading arrangements for *utility-scale BESS-hybrid stations* (Section 6).

Box 1: Utility-scale BESSs and BESS-hybrid stations

For the purposes of this consultation paper, utility-scale BESSs and BESS-hybrid stations are those with a capacity of 10MW or more that connect directly or indirectly to a network.

This excludes, for example, smaller BESSs and BESS-hybrid stations connected to households or small businesses. These are typically used for back-up power or to generate (usually by rooftop solar photovoltaic (PV) generation) and store electricity for self-consumption.

1.3. The common quality and wholesale trading issues and options in this paper are presented together because of their inter-dependencies. Feedback from submitters will inform our consideration of any subsequent Code amendment proposals on the matters set out in this paper.

1.4. We wish to highlight that, although focused primarily on utility-scale BESSs and BESS-hybrid stations, the options presented in this paper also address issues that are relevant to electricity generation more generally. This includes possible amendments to some Code definitions (eg, ‘generating unit’ and ‘generating station’), as well as possible amendments to the voltage support obligations in clause 8.23 of the Code, which apply in respect of transmission-connected generating stations.

1.5. Alongside this paper, we are consulting on proposed changes to the wholesale trading arrangements in Part 13 of the Code, designed to better accommodate utility-scale BESSs. We encourage submitters to consider that paper first when responding to the issues and options presented in this paper.

How you can inform our thinking

Submissions can be made using our template

1.6. We prefer to receive submissions in electronic format (Microsoft Word) using the template in Appendix F. Submissions in electronic form should be emailed to OperationsConsult@ea.govt.nz with "Issues and options paper – BESS and BESS-hybrids" in the subject line.

1.7. If you cannot send your submission electronically, please contact the Authority at OperationsConsult@ea.govt.nz or 04 460 8860 to discuss alternative arrangements.

1.8. To express your interest in an individual briefing or webinar, you can contact us at OperationsConsult@ea.govt.nz with "BESS EOI" in the subject line.

Your submission will be published, may be shared with other organisations, and can be requested under the Official Information Act

1.9. Please note we intend to publish all submissions we receive. If you consider we should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, we will discuss this with you before deciding whether to not publish that part of your submission.

1.11. However, please note that all submissions we receive, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means we would be required to release material not published unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

1.12. In addition, please note we may share submissions or other information, including parts of submissions not published, with another public service agency, statutory entity, the gas industry body or an overseas regulator in accordance with section 47A of the Electricity Industry Act 2010. We would only do so if the submissions or other information could assist that organisation in the performance of its functions, and if we are satisfied that appropriate protections are in place for maintaining the confidentiality of anything provided (including information that is personal within the meaning of the Privacy Act 2020).

Feedback on proposals is due by 5pm, 30 June 2026

1.13. Please deliver your submission by 5pm, **30 June 2026**

1.14. Authority staff will acknowledge receipt of all submissions electronically. Please contact us at OperationsConsult@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Background – BESSs and BESS-hybrid stations

The Code regulates BESSs in a generic way

2.1. In 2022 the Authority amended the Code to enable energy storage systems (ESSs) to be offered as instantaneous reserve in the reserves market. We defined an ESS as all equipment functioning together as a single entity that can take electricity from a network, store the energy in another form, and provide injection (where 'injection' means the flow of electricity into a network).

2.2. The 2022 Code amendment was designed to be forward-looking, enabling energy storage technologies other than a BESS to offer instantaneous reserve.[1]

2.3. To date, BESSs are the only form of utility-scale ESS connecting to the power system. We are progressing a number of BESS-specific workstreams, reflecting the different technical characteristics of a BESS compared to other forms of ESS (eg, pumped hydro storage).

2.4. In mid-2025 we published a regulatory roadmap for our BESS-related work out to mid-2027. The roadmap also discussed some BESS-related initiatives within the electricity industry that are being led by others.[2]

2.5. This consultation paper relates to the following workstreams in the BESS regulatory roadmap:

(a) reviewing the common quality requirements in Part 8 of the Code

(b) BESS-related wholesale electricity market enhancement work.

More BESSs are connecting to New Zealand's power system

2.6. Utility-scale BESSs have been operating in the New Zealand electricity market since 2023. Both new entrant generation companies and existing industry participants have been investing in BESSs.

2.7. There are four BESSs currently operating in, or being commissioned to operate in, New Zealand's wholesale electricity market:

(a) WEL Networks' 35MW/35MWh BESS (operated by NewPower Energy) near Huntly power station, commissioned in 2023, which was New Zealand's first utility-scale BESS

(b) Meridian Energy's 100MW/200MWh BESS at Ruakākā, Northland, commissioned in 2025

(c) Contact Energy's 100MW/200MWh BESS at Glenbrook, commissioned in March 2026

(d) Genesis Energy's 100MW/200MWh BESS at Huntly, planned to be commissioned in August 2026.

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[1] See the Authority's draft decision paper Enabling energy storage systems to offer instantaneous reserve.

[2] A regulatory roadmap for battery energy storage systems.

2.8. We expect the number of BESSs connected to New Zealand's power system will continue to grow in the coming years.[3] Transpower's connection queue shows a significant volume of BESS capacity in various stages of development.[4]

The Code is progressively being updated to accommodate BESSs

2.9. Since 2018 the Code has progressively been updated to accommodate BESSs, as follows:

(a) 2018 – the Authority published our view that, when discharging, a BESS met the definition of 'generating unit' in the Code. This meant the owner or operator of a BESS was able to offer energy into the wholesale electricity market.

(b) 2018 – the Authority published our view that, when charging, a BESS met the definition of 'interruptible load' in the Code. This meant the owner or operator of a BESS was able to offer interruptible load into the instantaneous reserve market.

(c) 2022 – the Authority amended the Code to enable ESSs to be offered as instantaneous reserve[5] in the reserves market while charging or discharging.

(d) 2024 – the Authority amended the transmission pricing methodology to better enable the efficient implementation of energy storage and other emerging technologies and to ensure investment is directed into the right places at the right time (these changes came into effect in April 2026).

(e) 2025 – the Authority amended Part 8 of the Code to clarify that an ESS is treated as generation for the purposes of Part 8 of the Code when the ESS is charging or discharging. This is to enable the capabilities of an ESS to be better realised in relation to supporting common quality on the power system.

2.10. Following the Authority's consultation on issues and options for improving wholesale electricity market arrangements for BESSs, we are now publishing a proposed Code amendment alongside this consultation paper.

Some future BESSs are planned to be co-located with generation

2.11. New Zealand's utility-scale BESSs and generating stations have so far been built and operated separately. However, several BESS-hybrid stations are at various stages of connecting to New Zealand's transmission and distribution networks. A BESS-hybrid station typically comprises variable and/or intermittent renewable generation[6] like a wind farm or solar photovoltaic (PV) farm co-located with a BESS.

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[3] Electricity Authority: Generation investment pipeline.

[4] What's the latest with grid connections? | Transpower.

[5] Instantaneous reserve comprises two categories of reserve:

(i) interruptible load, which describes all forms of offtake reserve

(ii) generation reserve, which describes all forms of injectable reserve.

[6] For the purposes of this paper:

- variable generation means generation that relies on a resource that is not stored and varies over time in a predictable manner (eg, the diurnal nature of solar PV generation)
- intermittent generation means generation that relies on a resource that is not stored and varies over time in an unpredictable manner (eg, the effect of passing overhead clouds on solar PV generation).

The uptake of BESS-hybrid stations in New Zealand is consistent with overseas experience.

2.12. Most BESS-hybrid stations in development, or planned for development, in New Zealand are solar PV BESS-hybrid stations. However, we recognise that wind BESS-hybrid stations and other combinations exist internationally.

2.13. Several drivers are behind the uptake of BESS-hybrid stations, including:

(a) decreasing BESS equipment costs

(b) increased opportunities for selling power purchase agreements compared with intermittent generation alone

(c) efficiency gains relative to building separate BESS and generating plants, for example through optimising costs of inverters and other equipment.

2.14. There are also power system benefits from coupling BESS with intermittent generation. Internationally, BESSs and BESS-hybrid stations now provide power system services that otherwise may be in deficit following the retirement of increasing amounts of conventional synchronous generation technology. These services include inertia, fast frequency response, operating reserves (regulation and spinning reserves), and fast-response firming capacity. Appendix D summarises experience with BESS-hybrid stations in Europe, Canada and the United States.

2.15. More technical detail on BESS-hybrid stations is provided in section 3 of this paper.

Our immediate focus is on BESS-hybrid stations

2.16. Generally speaking, a hybrid station comprises a storage system of any technology co-located and coordinated with a generating station of any technology.

2.17. In this paper, we are concerned specifically with BESS-hybrid stations, as these are the type of hybrid station connecting to the power system in the near future.

2.18. The Authority will, as appropriate, investigate common quality and trading arrangements for other types of hybrid station via one or more future workstreams.

Regulatory arrangements for BESSs and BESS-hybrid stations are unclear

2.19. Advice from the System Operator and the Common Quality Technical Group has identified several broad issues that are causing ambiguity for existing and potential operators of BESSs and BESS-hybrid stations.

2.20. In our November 2025 consultation on issues and options for wholesale electricity market arrangements for BESSs,[7] we identified that BESSs may require bespoke Code obligations in recognition of them being both generation and load. We also noted constraints on the operation of BESSs related to the short-term nature of their stored energy (ie, their state of charge (SoC)).

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[7] Wholesale market arrangements for battery energy storage systems | Our consultations | Our projects | Electricity Authority.

2.21. Several submissions on our BESS regulatory roadmap[8] and BESS wholesale electricity market issues and options consultation papers indicated there is value in considering regulatory arrangements for BESS-hybrid stations alongside those for BESSs. Submitters noted benefits from:

(a) mitigating the risk of misalignment of obligations between standalone BESSs and BESS-hybrid stations

(b) clarifying how BESS-hybrid stations might be expected to operate in the wholesale electricity market.

2.22. We agree there is value considering wholesale electricity market arrangements for BESS-hybrid stations now, as clarifying operational rules is likely to reduce investment risk for potential new plant. We also agree there is value in ensuring consistent operational policies for BESSs that are standalone and BESSs that are part of a BESS-hybrid station. Consequently, we have accelerated our work on appropriate wholesale electricity market arrangements for BESS-hybrid stations, as evidenced by the publication of this paper alongside our proposed Code amendments for (standalone) BESS wholesale electricity market arrangements.

2.23. The Authority is also aware of the need to progress our work on common quality and wholesale electricity market arrangements for BESSs and BESS-hybrid stations as expeditiously as possible. We have assigned a high priority to this work.

Some matters in this paper are relevant to electricity generation more generally

2.24. As already noted, this consultation paper's focus is on discussing issues and options related to:

(a) common quality obligations for utility-scale standalone BESSs and BESS-hybrid stations when not consuming electricity from, or injecting electricity into, a network (ie, idle)

(b) common quality obligations and wholesale market arrangements for utility-scale BESS-hybrid stations that are consuming electricity from, or injecting electricity into, a network.

2.25. The options set out in this paper are limited to addressing the immediate need for appropriate arrangements for BESSs and BESS-hybrid stations.

2.26. However, these options include matters relevant to electricity generation more generally. This includes possible amendments to some Code definitions (eg, 'generating unit' and 'generating station'). It also includes possible amendments to the voltage support obligations that apply in respect of transmission-connected generating stations.

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[8] A regulatory roadmap for battery energy storage systems

Matters that are out of scope

2.27. In this paper, we are looking at specific issues already identified and options to address these, rather than speculative or future market design questions.

2.28. However, other issues or solutions may be considered separately in future workstreams. Therefore, we are open to hearing about other issues we should take into account in future work related to BESSs and BESS-hybrid stations.

2.29. In this paper, we are not directly considering the following matters:

(a) aggregators and virtual power plants

(b) distribution network policy issues, including distribution level flexibility

(c) development of new market products (eg, capability market)

(d) broader reform of wholesale electricity market design beyond matters specific to BESSs and BESS-hybrid stations

(e) non-utility-scale or consumer-level storage.

3. Terminology used in this paper

This paper uses a number of key terms

3.1. The discussion in this paper makes use of several key terms, listed in Table 1.

3.2. Terms in **bold** are existing Code definitions. Terms in *italics* are new definitions proposed in the Code amendment consultation paper accompanying this paper.

Table 1: Key terms

Term	Definition	Source
Energy Storage System (ESS)	**Energy storage system** means all equipment functioning together as a single entity that is able to take **electricity** from a **network**, store the energy in another form, and provide **injection**	Current defined term in the Code, inserted by the Code amendment: 'Enabling energy storage systems to offer instantaneous reserve' (2022)
Battery Energy Storage System (BESS)	*Battery energy storage system means an* ***energy storage system*** *in which the energy is stored exclusively in electro-chemical form* [equivalent to a **generating unit**]	2026 consultation on the proposed Code amendment: 'Wholesale market arrangements for BESS'
BESS station	*BESS station means 1 or more battery energy storage systems that are directly connected to a* ***network*** [equivalent to a **generating station**]	2026 consultation on the proposed Code amendment: 'Wholesale market arrangements for BESS'
BESS owner	*BESS owner means a person who owns battery energy storage systems, or any person who acts, in respect of Parts 13, 14 and 15, on behalf of any person who owns such battery energy storage systems* [equivalent to a **generator**]	2026 consultation on the proposed Code amendment: 'Wholesale market arrangements for BESS'
BESS-hybrid station	BESS-hybrid station means an electricity generation and storage entity that is composed of at least one *battery energy storage system* and one **generating station** that is not an **energy storage system**, and which is operated as a single entity, typically behind a single **point of connection** [no equivalent Code definition]	Definition used for discussion purposes in this paper

(Technology) component	The plant within a *BESS-hybrid station* that together operate as a single resource type or technology type (eg, wind, solar PV, *BESS*).	Definition used for discussion purposes in this paper

Most modern electricity generation resources are inverter-based

3.3. Traditionally, electricity generating stations were made up of one or more machine-based synchronous generating units. Most of the Code obligations relating to common quality (Part 8) and wholesale trading (Part 13) have been developed around this traditional paradigm.

3.4. Most modern generation resources generate electricity as either alternating current (AC), or as direct current (DC) with power electronic inverters used to inject network-synchronised AC electricity into the network to which the generation is connected. Electronic devices that use inverters are collectively known as inverter-based resources.

Box 2: 'Inverter' and 'inverter-based' resources

An '**inverter**' is an electronic device that converts DC electricity to AC electricity. Electronic devices that convert AC electricity to DC electricity are known as 'rectifiers'.

An '**inverter-based resource**' is equipment that uses an inverter when functioning. Examples include wind generation, solar PV generation and BESSs.

3.5. Inverter-based resources of several distinct technology types may be coordinated using a common control system to form a hybrid generating station. A hybrid generating station may be 'AC-coupled' or 'DC-coupled'.

AC-coupled hybrid stations have an inverter for each technology component

3.6. For an AC-coupled hybrid generating station, each technology-specific component has separate inverters, which are coordinated using one or more power plant controllers.[9]

3.7. In an AC-coupled BESS-hybrid station there is a physical distinction between the generating station technology component and the BESS technology component. This distinction is useful for considering the policies that should be applied for BESS-hybrid station operation.

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[9] Multiple power plant controllers may be employed at a hybrid generating station, but we believe this is inconsequential for the purposes of developing operational policies for hybrid generating stations.

DC-coupled hybrid stations have an inverter for multiple technology components

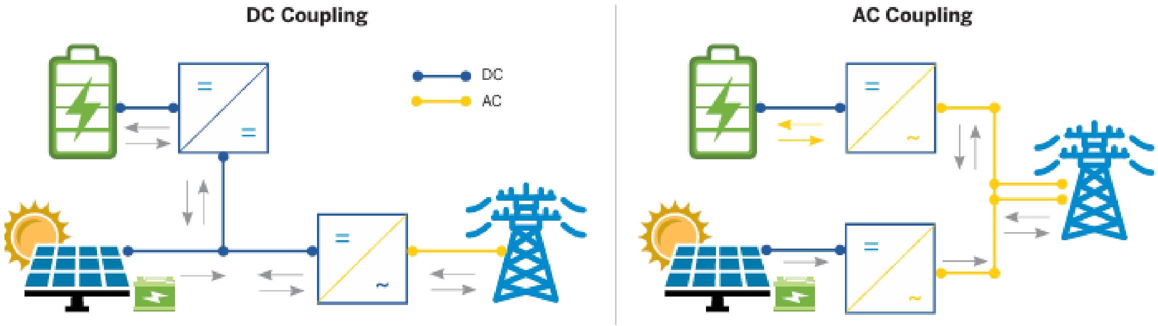
3.8. For a DC-coupled hybrid generating station, more than one technology-specific component uses the same inverter, for example a BESS and a solar PV generating unit combine to form a 'BESS-hybrid unit'.

3.9. A DC-coupled hybrid generating station does not have physical separation of the technology-specific components, but each component may be treated as conceptually separate for the purposes of developing the hybrid generating station's operational policies.

3.10. A 'BESS-hybrid unit' can be thought of as all the equipment behind a single inverter that acts to produce or consume electricity. A BESS-hybrid unit is distinct from a BESS or a traditional-technology generating unit in that it employs multiple generating or storage technologies behind an inverter.

3.11. Figure 1 presents a schematic of AC-coupled and DC-coupled hybrid generating stations.

Figure 1: Schematic of AC-coupled and DC-coupled hybrid generating stations[10]



Updating generating asset definitions

3.12. The Code's existing definitions of 'generating unit' and 'generating station' were developed for a power system dominated by machine-based synchronous generation with relatively simple, well-defined boundaries around operational components. While the current definitions of generating unit and generating station remain largely sufficient for machine-based synchronous generation, they are becoming increasingly problematic when applied to inverter-based resources and BESS-hybrid stations.

3.13. This is because modern inverter-based resource installations often comprise multiple layers of aggregation and control. In BESS-hybrid stations, particularly those with DC-coupled configurations, key operational and market functions occur at levels that sit between the traditional concepts of a generating unit and a generating station. This creates ambiguity around where technical, operational and market obligations apply under Parts 8 and 13 of the Code.

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[10] Source: Telos Energy, via ESIG (2022).

3.14. The System Operator has identified that the use of inverter-based electricity generation technologies requires at least one additional definitional grouping level between the generating unit and the generating station. This is to adequately reflect how modern plant is designed and operated.

3.15. The System Operator has recommended a four-level conceptual structure for generating asset definitions in its 2025 report *Hybrid Plant Integration* (attached as Appendix B). The System Operator's recommended structure is summarised below (Levels 1–4), with the addition of a fifth level, which the Authority considers would be desirable:

(a) Level 1 – *Generating unit*: an individual wind turbine, synchronous machine or inverter associated with a single source of fuel/energy.

(b) Level 2 – *Generating system*: a group of generating units connected via a common circuit or feeder, often being the level at which credible contingency risk arises or particular telemetry is required.

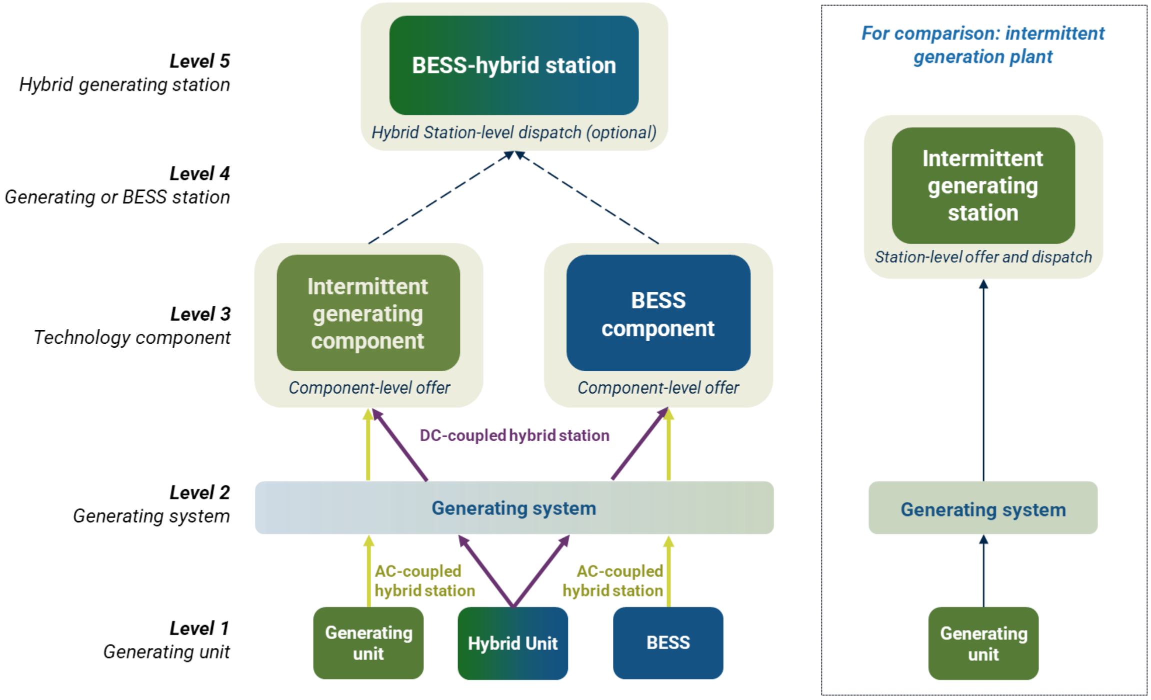
(c) Level 3 – *Technology-specific component*: aggregation of all plant of a particular resource or technology type within a generating station (eg, all BESS or solar PV generation), typically the level at which plant controllers operate.

(d) Level 4 – *Generating station/BESS station*: the full site at a single point of connection on a network, including all generation, storage and associated control systems, but not a hybrid station.

(e) Level 5 – *Hybrid generating station*: the combination and co-location of technology-specific components, or a generating station and BESS station functioning as a single entity, and potentially operating in the market similarly to a block or station dispatch group.

3.16. The five levels are shown in Figure 2. This structure can accommodate AC-coupled and DC-coupled hybrid generating stations.

Figure 2: Schematic representation of 5-level classification system



3.17. Clarifying these groupings in the Code would require drafting changes across multiple parts of the Code. However, the Authority considers this level of change to be reasonable, since it would reflect the structural change occurring on the power system. This would also be a foundational step for future work on performance obligations, monitoring, modelling and wholesale electricity market participation.

3.18. The Authority's preference is a solution that is flexible enough to apply throughout the Code, including Parts 8 and 13.

3.19. As an aside, we note any future Code amendments would use descriptive asset-based definitions, rather than references to 'level 1', 'level 2' or similar terminology.

BESS-hybrid stations

3.20. While definitions vary across international jurisdictions, the North American Electric Reliability Corporation (NERC) defines a 'hybrid station' as "a generating resource that is composed of multiple generation or energy storage technologies controlled as a single entity and operated as a single resource behind a single point of connection."[11]

3.21. In this paper, we are particularly interested in BESS-hybrid stations, being hybrid generating stations that employ BESSs as the form of energy storage technology.

3.22. For the purposes of the discussion in this paper, we have adapted the NERC definition to be specific to BESS-hybrid stations operating on the New Zealand power system (see Table 1 above).

3.23. By way of elaboration, we have defined a BESS-hybrid station as an arrangement where at least one BESS is co-located with, and connected to, at least one electricity generating station.

3.24. Specifically, we consider that a BESS-hybrid station includes the following elements:

(a) consists of more than one resource, which may include different types of generation (wind, solar PV, hydro, fossil-fuelled, etc.) and/or controllable end-use loads

(b) includes energy storage that is operationally significant in that it can materially affect the generating station's profile of net injection or offtake to/from the network, its participation in the wholesale electricity market, and/or its ability to comply with its AOPOs

(c) is typically located behind a single point of connection on the network

(d) incorporates controls that coordinate the output across multiple resources to maximise value to the power system and/or BESS-hybrid station owner.[12]

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[11] From the North American Electric Reliability Corporation (NERC), retrieved from the Energy Systems Integration Group (ESIG) report *Unlocking the flexibility of hybrid resources* (2022).

[12] From Energy Systems Integration Group (ESIG): *Unlocking the Flexibility of Hybrid Resources* (2022). Note, ESIG's definition, taken from the National American Electric Reliability Corporation (NERC), includes an additional element that a hybrid "is operated and coordinated to appear as a single resource to the System Operator". This consultation paper discusses how this element may not be relevant in the New Zealand context.

3.25. As with standalone BESSs, BESS-hybrid stations operate bi-directionally (ie they both consume and inject operationally significant quantities of electrical energy).

Consultation questions:

Q3.1 Do you support the proposed 5-level structure for generating asset definitions?

Q3.2 Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?

Q3.3 Do you have any feedback on the System Operator’s recommendations in its *Hybrid Plant Integration* report?

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

Introduction

4.1. Part 8 of the Code contains AOPOs that asset owners must comply with in order to support the System Operator in meeting its principal performance obligations.[13] These obligations include requirements to:

(a) contribute to frequency regulation (clause 8.17)

(b) support frequency during under-frequency events (clause 8.19)

(c) support voltage, including by exporting/importing reactive power (clause 8.23).

4.2. On 1 May 2025, clause 8.1B was inserted in the Code.[14] Under this provision, an ESS[15] that is not an 'excluded generating station'[16] is treated as generation for the purposes of Part 8 of the Code when the ESS is charging or discharging. The objective of this Code amendment was for the Code to enable the capabilities of an ESS to be better realised in relation to supporting common quality on the power system.

4.3. However, clause 8.1B does not explicitly address the capabilities of an ESS that is electrically connected to the network but neither consuming nor producing electricity – ie, the ESS is in an 'idle' operating state.

4.4. As discussed earlier (see paragraphs 2.1 to 2.5), this paper is part of the Authority's work on BESS – the specific and increasingly prevalent sub-category of ESS connecting to the power system. Therefore, although clause 8.1B applies to ESS more broadly, the Authority is at present interested in what, if any, AOPOs should be placed on a BESS or a BESS-hybrid station that is in the 'idle' operating state. This section focuses on this question.

4.5. As noted in section 2, we will consider this question for other forms of ESS and ESS-hybrid stations as the need arises.

4.6. For the purposes of this paper, the Authority defines the 'idle' operating state of a BESS and a BESS-hybrid station to be one in which the BESS or BESS-hybrid station is electrically connected to the network, but is not injecting or consuming active power or reactive power, and is not cleared for dispatch in the energy and/or ancillary services markets.

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[13] Part 7 of the Code places high-level, output-focussed 'principal performance obligations' on the System Operator – see clauses 7.2A to 7.2D in Part 7 of the Code.

[14] See our Part 8 Code terminology and network information decision paper, and the Common_quality_related_amendments_-_Certified_instrument_-_1_MAY_2025.pdf.

[15] As noted in Table 1, the Code defines an ESS as all equipment functioning together as a single entity that is able to take electricity from a network, store the energy in another form, and provide injection (where 'injection' means the flow of electricity into a network).

[16] An excluded generating station is exempt from certain obligations under Part 8 of the Code, including frequency management and fault-ride through AOPOs.

4.7. We note that a BESS-hybrid station may meet this definition even though its technology-specific components do not – for example, the wind or solar PV technology component is producing electricity that is being used to charge the BESS.

Should any AOPOs apply when a BESS or a BESS-hybrid station is idle?

4.8. Currently, the frequency- and voltage-related AOPOs in the Code do not specifically refer to the operating state of the assets subject to the obligations. The implicit assumption in the drafting of these AOPOs is that an asset has only one operating state (eg, injection for a generating unit/station; consumption for a load), and the AOPO applies when the asset is in that one operating state.

4.9. A BESS has three operating states under which it can provide common quality support – charging, discharging, and idle. The question that naturally arises is whether the frequency- and voltage-related AOPOs apply when the BESS is operating in any of these states or just in a subset of them.

4.10. Currently, the Code clearly places AOPOs on a BESS that is charging or discharging. The question is, should AOPOs be placed on a BESS that is in the idle operating state? This question also applies to a BESS-hybrid station in the idle operating state.

4.11. The purpose of doing this would be to build on the Code amendment that placed AOPOs on ESSs while consuming or producing electricity. That is, the objective would be to better enable the capabilities of BESSs and BESS-hybrid stations to be realised in relation to supporting common quality on the power system.

Options for AOPOs when standalone BESSs and BESS-hybrid stations are idle

4.12. The Authority recognises the application of AOPOs to BESSs and BESS-hybrid stations while idle has both benefits and costs from a System Operator perspective. In particular, more differentiated AOPOs where obligations vary by operating state or technology configuration can increase operational complexity and cost for the System Operator. This includes the need to modify and maintain forecasting, modelling, telemetry/real-time indications, and compliance monitoring systems. Potentially this might include additional real-time indications to identify when a BESS or BESS-hybrid station is operating in an idle state, and to manage greater uncertainty when assessing asset performance following power system events.

Option 1A: Apply both frequency management and voltage support AOPOs when idle

4.13. Under this option, a BESS or BESS-hybrid station would be required to comply with existing voltage and frequency-related AOPOs whenever it is in the idle state.

4.14. This option would maximise the availability of frequency management and voltage support capability from BESSs and BESS-hybrid stations. It would avoid the need for changes to the System Operator's modelling tools and real-time operation tools, and the indications and measurements provided to the System Operator by the owners/operators of BESSs and BESS-hybrid stations.

4.15. However, this option would treat BESSs and BESS-hybrid stations differently from other assets on the power system that do not operate in an idle state. The practical implication of this for the owners of BESSs and BESS-hybrid stations is that they face the costs associated with complying with the frequency- and voltage-related AOPOs. There is a possibility these owners may not have a clear means or pathway for recovering these costs through participation in the wholesale energy market and/or ancillary services market.

4.16. This option's potential benefits include:

(a) increased availability of frequency management and voltage support for the power system from electrically connected assets

(b) relatively low-cost frequency management and voltage support capability from inverter-based resources that are technically able to provide it while idle.

4.17. This option's potential costs or risks include:

(a) operational and wear-related costs for BESSs and BESS-hybrid stations in the idle operating state

(b) dampening of investment signals for BESSs and BESS-hybrid stations, including due to a perceived inconsistency in the application of AOPOs across assets not actively participating in the power system's operation

(c) behavioural or operational incentives for asset owners to alter controller or operating states solely to manage exposure to AOPOs, potentially increasing complexity for operational monitoring and compliance assessments.

Option 1B: Neither frequency management nor voltage support AOPOs apply when idle

4.18. Under this option, a BESS and a BESS-hybrid station would not be required to comply with either the frequency management or voltage support AOPOs unless it was dispatched to inject or consume active power or provide ancillary services.

4.19. This option reflects the view that, when a BESS or BESS-hybrid station is idle, it is not materially contributing to the electricity demand and supply balance, and it does not have an associated revenue stream from which to recover the costs of complying with the AOPOs. Any such costs would therefore need to be recovered indirectly, for example by increasing prices for services provided during other time periods. This could disadvantage BESSs and BESS-hybrid stations relative to other generation technologies and reduce competitive pressures in the electricity market.

4.20. This option's potential benefits include competitive neutrality across assets connected to the power system.

4.21. This option's potential costs or risks include:

(a) reduced availability of frequency management and voltage support for the power system from electrically connected assets

(b) loss of relatively low-cost frequency management and voltage support capability from inverter-based resources that are technically able to provide it while idle

(c) additional implementation and ongoing operational costs for the System Operator, including changes to modelling, telemetry/real-time indications configurations, and monitoring processes required to distinguish between BESS / BESS-hybrid station operating states.

Option 1C: Apply either frequency management or voltage support AOPOs when idle

4.22. Under this option, a BESS and a BESS-hybrid station that is electrically connected but idle would be required to either:

(a) comply with the frequency management AOPOs, or

(b) comply with the voltage support AOPO.

4.23. The main purpose of this option would be to reflect a material difference in the cost of meeting the frequency management AOPOs relative to the voltage support AOPO while idle. For example, the cost associated with voltage support might be considered to be lower than meeting the frequency management AOPOs, on the basis that the former requires the BESS / BESS-hybrid station only to remain energised, whereas the latter requires the provision of power.

4.24. This option's potential benefits include:

(a) increased availability of frequency management or voltage support for the power system from electrically connected assets

(b) relatively low-cost frequency management capability, or voltage support capability, from inverter-based resources that are technically able to provide it while idle.

4.25. This option's potential costs or risks include:

(a) operational and wear-related costs for BESSs and BESS-hybrid stations in the idle state

(b) dampening of investment signals for BESSs and BESS-hybrid stations, including due to a perceived inconsistency in the application of AOPOs across assets not actively participating in the power system's operation

(c) additional implementation and ongoing operational costs for the System Operator, including changes to modelling, telemetry/real-time indications configurations, and monitoring processes required to distinguish between BESS / BESS-hybrid station operating states

(d) behavioural or operational incentives for asset owners to alter controller or operating states solely to manage exposure to AOPOs, potentially increasing complexity for operational monitoring and compliance assessments

(e) a risk that errors in transitioning out of an idle operating state, in which a different set of AOPOs may apply compared with charging or discharging states, could result in frequency management or voltage support not being available when expected, with potential implications for power system security.

Consultation questions:

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.

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.

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.

Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?

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.

5. Applying the AOPOs to BESS-hybrid stations

Introduction

5.1. This section summarises key issues associated with applying the existing AOPOs in Part 8 of the Code to BESS-hybrid stations that are injecting electricity into, or consuming electricity from, a network, and options to resolve these issues. It builds on the discussion in section 4. Informing our thinking are two reports prepared by the System Operator, attached as Appendix B and Appendix C, and input we have received from the Common Quality Technical Group.

5.2. The options put forward in this section relate to clarifying the following AOPOs on owners of BESS-hybrid stations that are in the injection or consumption operating state:

(a) contributing to frequency regulation (clause 8.17)

(b) supporting frequency during under-frequency events (clause 8.19)

(c) supporting voltage, including by exporting/importing reactive power (clause 8.23).

5.3. We wish to clarify the AOPOs in a manner that can be applied consistently across different types of BESS-hybrid stations and their injection/consumption operating states. Greater clarity of the AOPOs would:

(a) provide increased certainty for investors in BESS-hybrid stations, including a better understanding of their Code compliance obligations

(b) provide the System Operator with increased confidence that BESS-hybrid stations will support the System Operator in planning to meet, and meeting, its principal performance obligations under Part 7 of the Code.

5.4. Some AOPOs may impose operational or opportunity costs on BESS-hybrid station owners. The Authority considers it important that AOPOs be justified by clear common quality benefits and be designed so that, where possible, costs associated with meeting AOPOs can be recovered through the energy and/or ancillary service markets.

5.5. BESS-hybrid stations were not contemplated when the AOPOs were developed. As a result, there is uncertainty about how the AOPOs apply to BESS-hybrid stations, including whether and how the AOPOs apply to:

(a) each technology-specific component within a BESS-hybrid station, and

(b) the BESS-hybrid station's operating states.

5.6. If not addressed, these uncertainties risk inefficient investment and operational outcomes, and higher costs for consumers.

BESS-hybrid station-level obligations versus technology-specific component obligations

5.7. The technology-specific components of a BESS-hybrid station (eg, a wind farm and a BESS, or a solar PV farm and a BESS) may have different physical capabilities and control characteristics to each other. Existing common quality obligations typically refer to a generating unit or a generating station. In the case of a BESS-hybrid station, this creates ambiguity as to whether compliance with an AOPO is to be assessed:

(a) for the BESS-hybrid station as a whole, or

(b) for each of the technology-specific components that make up the BESS-hybrid station (ie, whether the wind/solar PV farm component is considered separately from the BESS component).

5.8. This ambiguity affects how the frequency- and voltage-related AOPOs are applied, monitored and enforced.

Different operating states

5.9. BESS-hybrid stations may operate in a wider range of states than traditional generation, as follows:

(a) injecting active power into the network

(b) charging a BESS by consuming active power from the network

(c) charging a BESS without consuming active power from the network (ie, charging a BESS only from on-site electricity generation)

(d) being electrically connected to the network while neither injecting nor consuming active power or reactive power to/from the network (see section 4).

5.10. Currently, the Part 8 AOPOs do not distinguish clearly between these four operating states. This creates uncertainty for both asset owners and the System Operator about how the AOPOs should be applied, monitored and enforced.

Frequency management AOPOs

5.11. The frequency management AOPOs in Part 8 of the Code require generators to contribute to frequency regulation while synchronised (clause 8.17) and frequency support in under-frequency events while electrically connected (clause 8.19). Additional Code requirements supporting these AOPOs are set out in the Part 8 technical codes.

5.12. Clause 8.17 requires generators, while synchronised, to make the maximum possible injection contribution to maintain frequency within the 'normal band' (49.8–50.2 Hertz). Clause 8.19 requires electrically connected generating units to remain synchronised and to sustain pre-event output during under-frequency events.

Key issues with applying frequency management AOPOs to BESS-hybrid stations

Unclear Code terminology

5.13. Some of the terminology used in describing the frequency management AOPOs may create uncertainty and potential for confusion. This is particularly the case for terms such as 'generating unit', 'synchronised' and 'maximum possible injection'.

5.14. While many of these interpretation issues are not unique to BESS-hybrid stations, they are more visible in hybrid configurations because technology-specific components within a BESS-hybrid station can respond to frequency in different ways and under different constraints. For example, the response of a BESS to changes in frequency can differ materially from that of a wind farm, including in terms of available headroom, short duration overload capability, under-frequency ride through performance, and the duration over which or frequency with which a response can be sustained.

Headroom requirements

5.15. Whether clause 8.17 of the Code requires generators to ensure that their generating assets always have sufficient headroom to respond to changes in frequency is potentially open to interpretation. The System Operator observes that some generating stations always seek to operate at their maximum continuous megawatt (MW) output power. The question arises over whether the owners of these stations are complying with their obligations under clause 8.17 if station output cannot be increased when frequency drops.

5.16. The System Operator’s current working interpretation is that, if a generator’s assets are operating at their maximum continuous MW output power, maintaining pre-event output during an under-frequency event is sufficient for the generator to comply with the clause 8.17 requirement to make the maximum possible injection contribution. However, this interpretation is not explicitly set out in the Code – a matter that generation owners have raised with the System Operator.

BESS-hybrid station components compensating for each other when frequency changes

5.17. The typical BESS-hybrid station arrangement of pairing intermittent generation with a BESS means the BESS-hybrid station is likely to have flexibility in how it responds to changes in frequency (ie, how its output increases/decreases).

5.18. Currently, there is uncertainty about whether the Code permits the components of a BESS-hybrid station to respond differently to changes in frequency. For example, during an over-frequency event, it may be operationally efficient to ramp down the generation component’s output while holding the BESS output constant, to minimise unnecessary cycling of the BESS.

5.19. The System Operator views this as an acceptable outcome, but it is not clearly provided for under the current wording of clause 8.17.

5.20. Another matter is whether the BESS component of a BESS-hybrid station is expected to compensate for the limited frequency response capability of intermittent generation that is operating at maximum output.

5.21. The System Operator considers that requiring such compensation under the AOPOs would impose an AOPO burden on BESS-hybrid stations that standalone generating stations or standalone BESS do not face. This could discourage efficient BESS-hybrid station configurations and increase costs without delivering commensurate power system benefits, with those additional costs ultimately passed on to consumers.

Options for applying frequency management AOPOs to BESS-hybrid stations

5.22. Against this background, the Authority has identified the following options for how frequency management AOPOs should apply to BESS-hybrid stations when injecting or consuming active power. The Authority seeks stakeholder feedback on the benefits, costs and implementation considerations of each option.

Option 2A: Station-level frequency management obligations for BESS-hybrid stations

5.23. Under this option, frequency management AOPOs would apply at a BESS-hybrid station's point of connection to the network. That is, compliance would not be assessed based on the response of each technology-specific component of the BESS-hybrid station.

5.24. Asset owners would determine how frequency management was supported across the generation and BESS components of the BESS-hybrid station, provided the overall response of the BESS-hybrid station met the relevant AOPO(s). This would enable asset owners to optimise plant operation, manage equipment wear and tear, and avoid unnecessary cycling of the BESS.

5.25. For the avoidance of doubt, when frequency fell, the BESS component of a BESS-hybrid station would not be required to compensate for generation operating at its maximum continuous MW output power.

5.26. Assessing compliance at the generating station's point of connection would also avoid practical measurement and monitoring challenges that can arise for DC-coupled BESS-hybrid station configurations, where internal power flows between technology-specific components are not directly observable at the network connection point.

5.27. This option's potential benefits include:

(a) better reflecting the power system impact of the BESS-hybrid station compared to a technology component-based approach

(b) promoting flexibility in BESS-hybrid station design and operation (eg, allowing differentiated responses from the technology-specific components that minimise unnecessary BESS cycling)

(c) reducing compliance costs for asset owners and the System Operator compared to a technology component-based approach (eg, reducing compliance monitoring costs).

5.28. This option's potential costs or risks include the need to clarify how station-level performance is assessed against existing Code requirements.

Option 2B: Component-level frequency management obligations for BESS-hybrid stations

5.29. Under this option, frequency management AOPOs would apply to each generation and BESS component within a BESS-hybrid station. That is, compliance would be assessed based on the response of the technology-specific components of the BESS-hybrid station.

5.30. As with Option 2A, when frequency fell, the BESS component of a BESS-hybrid station would not be required to compensate for generation operating at its maximum continuous MW output power.

5.31. This option's potential benefits include improved visibility of the capabilities of a BESS-hybrid station's technology-specific components.

5.32. This option's potential costs or risks include:

(a) discouraging flexibility in BESS-hybrid station design and operation

(b) inefficient or impractical obligations where technology-specific components lack the physical capability to respond to changes in system frequency

(c) greater reliance on equivalence arrangements[17] to enable efficient plant behaviour

(d) increased compliance costs for asset owners and the System Operator compared to the adoption of a station-level approach (eg, increased compliance monitoring costs).

Consultation questions:

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.

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.

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?

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.

Voltage support obligations

5.33. Clause 8.23 of the Code places voltage support obligations on generators whose assets are connected to the transmission network. These obligations are intended to support voltage stability, and apply to inverter-based resources as well as traditional machine-based synchronous generation.

Key issues with applying the voltage support AOPO to BESS-hybrid stations

5.34. Generally, BESS-hybrid stations can provide voltage support that is similar to a standalone generating station or standalone BESS. From a technical perspective, the ability of a BESS-hybrid station to supply reactive power at its point of connection to the network is inherently no different to other inverter-based resources.

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[17] An equivalence arrangement is an approved alternative to a prescribed AOPO or technical obligation, where the asset owner demonstrates that the proposed arrangements achieve an equivalent level of system and common quality performance.

5.35. In many cases, the maximum continuous MW output power of a BESS-hybrid station at its point of connection to the network is lower than the sum of the maximum continuous MW output power of each of its technology-specific components. This situation commonly arises because BESS-hybrid stations are constrained by:

(a) export limits at the point of connection to the network

(b) shared inverters, transformers and collector systems[18]

(c) network connection agreements that limit total BESS-hybrid station power injection into the network

(d) design choices intended to optimise a BESS-hybrid station's contribution to the power system and the associated value to the asset owner rather than to maximise power injection into the network.

5.36. As a result, while a BESS-hybrid station may have a large amount of installed generation and energy storage capacity behind the meter, it may not be physically capable of exporting the full combined capacity of those components. This distinction is important when determining how voltage support obligations should be assessed, as obligations that are not aligned with export capability may distort investment and connection decisions and increase costs without corresponding power system benefits.

5.37. In practice, BESS-hybrid stations (particularly AC-coupled configurations) may also be designed or operated so that different technology components contribute differently to voltage support. For example, the BESS component of an AC-coupled wind-BESS hybrid station may have a shorter electrical path to the BESS-hybrid station's point of connection to the network than the wind farm component. In this case, the BESS is better placed to export and import reactive power than the wind farm, which may be a more efficient outcome from both a system security perspective and an economic standpoint.

5.38. However, such an arrangement may not easily be accommodated under the existing voltage support obligations in clause 8.23 of the Code. As currently drafted, clause 8.23 may be interpreted as requiring each component of a wind BESS-hybrid station or solar PV BESS-hybrid station to export/import the same minimum amount of reactive power. This interpretation is based on each technology-specific component of the BESS-hybrid station being treated as a generating unit for the purposes of assessing compliance with clause 8.23.

5.39. This creates a risk that voltage support obligations are disproportionate to the BESS-hybrid station's physical export capability, leading to inefficient plant design or operation and higher compliance and capital costs that are ultimately borne by consumers.

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[18] Collector system refers to the internal electrical network within a generating station that connects individual generating units and/or BESS components to the station's point of connection to the network.

Options for applying the voltage support AOPO to BESS-hybrid stations

5.40. Against this background, the Authority has identified two possible options for how the voltage support AOPO could apply to BESS-hybrid stations. The Authority seeks stakeholder feedback on the benefits, costs and implementation considerations of each option.

Option 3A: Station-level voltage support obligations for BESS-hybrid stations

5.41. Under this option, the voltage support AOPO would apply at a BESS-hybrid station's point of connection to the network. That is, compliance would not be assessed based on the response of the technology-specific components of the BESS-hybrid station.

5.42. This option is consistent with the revised approach to assessing compliance with clause 8.23 discussed in the System Operator's report attached as Appendix C. Prior to the advent of wind and solar PV generation, the larger generating stations and generating units in New Zealand were located close to the grid injection point with the generating unit transformers and/or generating station transformer in close proximity to the network. In contrast, wind farms and, to a lesser extent, solar PV farms have a more dispersed layout, with generating unit transformers located further from the network than for machine-based generation.

5.43. This option's potential benefits include:

(a) aligning voltage support obligations with where voltage impacts are experienced on the network

(b) reducing the risk of imposing voltage support obligations that are disproportionate to a BESS-hybrid station's export capability

(c) promoting flexibility in BESS-hybrid station design and operation (eg, allowing differentiated responses from the technology-specific components, such as BESS exporting or importing more reactive power than the co-located wind/solar PV farm)

(d) treating BESS-hybrid stations consistently with other inverter-based generating stations

(e) better aligning a BESS-hybrid station's voltage support AOPOs with the station's physical capability to recover costs through the energy and ancillary services markets, reducing the risk of costs being incurred without a clear means or pathway for recovering these costs through participation in the wholesale energy market and/or ancillary services market

(f) reducing the need for equivalence arrangements and their associated transaction costs

(g) reducing compliance costs for asset owners and the System Operator compared to the adoption of a component-based approach (eg, reducing compliance monitoring costs).

5.44. This option's potential costs or risks include:

(a) reduced visibility of technology component capabilities if not supported by appropriate information disclosure requirements

(b) for some BESS-hybrid station configurations, particularly DC-coupled stations, providing reactive power at the point of connection may require a reduction in active power output where both active and reactive power are constrained by the same inverter capacity.

Option 3B: Component-level voltage support obligations for BESS-hybrid stations

5.45. Under this option, the voltage support AOPO would apply to each technology-specific component within a BESS-hybrid station. That is, compliance would be assessed based on the response of the individual generation and BESS components of the BESS-hybrid station.

5.46. This option's potential benefits include improved visibility of the capabilities of a BESS-hybrid station's technology-specific components.

5.47. This option's potential costs or risks include:

(a) voltage support obligations are not aligned with where voltage impacts are experienced on the network or with the BESS-hybrid station's export capability

(b) an increased risk of inefficient plant design or operating outcomes, including over-investment in capability that delivers limited additional benefit to the power system

(c) higher compliance, capital and transaction costs, which are ultimately borne by consumers

(d) treating BESS-hybrid stations inconsistently with other inverter-based generating stations

(e) increased complexity for asset owners and the System Operator

(f) greater reliance on equivalence arrangements

(g) increased compliance costs for asset owners and the System Operator compared to the adoption of a station-level approach (eg, increased compliance monitoring costs).

Consultation questions:

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.

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.

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?

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.

Updating clause 8.23 to better accommodate new and evolving technologies

5.48. The question of how the voltage support AOPO applies to BESS-hybrid stations raises the broader question of how this AOPO applies to other new and evolving technologies.

5.49. The Authority is considering revising clause 8.23 so the voltage support obligations apply at the generating station's transmission connection point rather than at the generating unit terminals. This is to better reflect newer, more distributed generation technologies.

5.50. When clause 8.23 was developed, there were no wind or solar PV generating stations connected to New Zealand's transmission network. The voltage support AOPO reflects a power system where transmission-connected generating stations and their generating units were located close to the grid injection point. Placing the voltage support obligation at the terminals of a generating unit was similar to placing the obligation on the low voltage side of the connection transformer.

5.51. As noted in paragraph 5.42, wind farms and, to a lesser extent, solar PV farms have a more dispersed layout. Generating unit transformers are located further from the network than for machine-based generation. The distance between the generating units and the generating station's point of connection to the network means the characteristics of the wind or solar PV farm's lines and/or cables can alter the reactive power before it reaches the connection transformer.

5.52. The System Operator report attached as Appendix C considers the implications of this for existing generation connected to New Zealand's transmission network, should the existing reactive power export/import requirement be changed:

(a) from +50%/-33% of maximum continuous MW output power, measured at the generating unit terminals

(b) to ±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).

5.53. Reactive power export and import limits of ±39.5% at the point of connection would be approximately equivalent to the existing +50%/-33% limits at the generating unit terminals. The Authority notes the Australian National Electricity Market's (NEM's) automatic access standard[19] is ±39.5%, although a generator participating in the NEM may negotiate a lower technical requirement as part of connecting its generating station to the power system.

5.54. The System Operator's analysis finds that if the reactive power export and import limits were changed to ±39.5%, additional dispensations would be needed for North Island generation and fewer dispensations needed for South Island generation. The

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[19] Generating stations that meet the ±39.5% standard would not be denied access to the power system because of this technical requirement.

Authority notes that amending the voltage support obligation in clause 8.23 would require all existing dispensations to be reviewed.

5.55. The System Operator's analysis finds that if the reactive power export and import limits were changed to ±33%, fewer dispensations would be needed for North Island and South Island generation.

5.56. Reactive power export/import limits of ±33% at the point of connection would align with the default reactive power requirement on embedded generation that is coming into effect on 1 July 2026.[20] This would remove an incentive for generation to be connected to distribution networks rather than the transmission network, albeit at the expense of some voltage support. On this point, an option might be to use the following reactive power export and import limits:

(a) ±33% for transmission voltages below 110 kilovolts

(b) ±39.5% for transmission voltages at and above 110 kilovolts.

5.57. A key consideration associated with moving the point of compliance for voltage support to the high voltage side of the connection transformer is the lower reactive power import requirement on generation. The System Operator has expressed concern that the loss of reactive power import support currently provided by transmission-connected generating stations could adversely impact the System Operator's ability to manage high voltages on the transmission network. The System Operator has also noted that continuing to frame clause 8.23 as a minimum reactive power capability requirement would enable the System Operator to continue utilising any inherent reactive power capability of generating stations that exceeded the minimum requirement.

5.58. The Authority acknowledges this concern. We consider the use of 'legacy clause' arrangements may be an appropriate means by which to ensure existing reactive power import support was not lost under the point of compliance change discussed above.

Consultation questions:

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.

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.

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[20] See the Authority's 10 March 2026 decision paper and Code amendment Promoting reliable electricity supply - A voltage-related Code amendment.

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?

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.

Q5.13. Do you consider that legacy arrangements would be needed for existing generation? Please give reasons for your answer.

6. Wholesale trading arrangements for BESS-hybrid stations

Introduction

6.1. The wholesale trading arrangement rules in Part 13 of the Code describe generators' obligations around offering into the wholesale electricity market and (large) consumers' obligations around bidding for electricity from the wholesale market.

6.2. Where possible, the Code is technology-agnostic. For example, there is little differentiation in obligations on the owners/operators of thermal generating stations and hydro generating stations. Intermittent generating stations are an exception. The Code recognises that the owners/operators of these generating stations rely on weather forecasts when submitting intermittent generation offers to the market. This introduces more uncertainty compared to other forms of generation that have either certain or near-certain fuel/resource availability.

6.3. As noted in section 3, for AC-coupled BESS-hybrid stations, each technology-specific component is a separate physical entity with its own inverter. This enables easy real-time telemetry and metering of each technology-specific component. For DC-coupled BESS-hybrid stations, individual hybrid units comprise both BESS and generation technology components. Measuring the AC injection or offtake by each technology component requires more complex arrangements.

6.4. Industry participants, including the System Operator,[21] have raised several issues related to how BESS-hybrid stations may operate in the wholesale electricity market. Participants' uncertainty over how the Part 13 rules apply to BESS-hybrid stations could cause operational difficulties and may mean BESS-hybrid station owners are disadvantaged compared to the owners of conventional generating stations.

Issue: It is ambiguous how BESS-hybrid stations would trade in the market

6.5. Under the existing wholesale electricity market arrangements, there are different trading obligations for each technology component within a BESS-hybrid station. For example, intermittent generators have different offering obligations than conventional generators. The trading arrangements for BESSs are currently under development.

6.6. The trading obligations that would apply to the overall BESS-hybrid station are ambiguous. For example, under the current Code definitions, participants could think of a BESS-hybrid station that includes intermittent generation as being an intermittent generating station, despite including a BESS.

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[21] Refer to the System Operator's 2025 report *Hybrid Plant Integration* (attached as Appendix B).

6.7. This ambiguity could result in perverse outcomes for:

- (a) forecasting future asset capability
- (b) making energy offers (and bids for BESSs that are charging)
- (c) following dispatch instructions
- (d) contracting for ancillary services.

Options for how BESS-hybrid stations would trade in the market

Preferred option 4A: BESS-hybrid station owners typically offer by individual technology components

6.8. To remove ambiguity from offering arrangements, the Authority's preferred option is to require that BESS-hybrid stations typically offer each of their technology-specific components separately, **applying trading obligations to each technology component as if each component was a standalone generating station**.

6.9. We would also propose allowing a BESS-hybrid owner to offer as a conventional generating station or as an intermittent generating station or as a BESS station, if this aligns to how the station is to be operated and the System Operator does not require component-level offering.

6.10. We are currently consulting on proposed revisions to the offering requirements for BESS stations, with details provided in this paper's companion paper. Under our preferred Option 4A these offering requirements would also apply to the BESS component of a BESS-hybrid station.

6.11. Potential benefits of this option include:

- (a) reduced risk, by leveraging established trading arrangements
- (b) support for operational flexibility
- (c) allowing for single station offering where this makes sense
- (d) instantaneous reserve and frequency keeping markets remain accessible to the owner/operator of the BESS-hybrid station.

6.12. Potential costs or risks of this option include increased costs for traders from needing to bid and offer multiple technology components of BESS-hybrid stations.

Benefit: Reduced risk, by leveraging established trading arrangements

6.13. Given the current lack of operational experience with BESS-hybrid stations in New Zealand, and the many ways in which BESS-hybrid stations could operate, we are cautious about introducing bespoke market arrangements at this stage. Doing so would carry a significant risk of re-work and the potential for introducing more ambiguity into the wholesale electricity market arrangements. We believe there is merit in leveraging existing arrangements until operational experience with BESS-hybrid stations identifies any issues that require revised market settings.

Benefit: Support for operational flexibility

6.14. Based on feedback from the System Operator and other industry participants, we consider that separate component offering would best address issues with interpreting operational requirements. The System Operator noted in its 2025 report (Appendix B) that this approach promotes flexibility for the BESS-hybrid station owner, and enables the owner to best reflect operating costs in its offers. It also integrates well with the System Operator's tools for assessing contingent event risk and instantaneous reserve requirements. Separate component offering may also make offering and co-optimisation of energy and instantaneous reserve easier.

6.15. Prospective BESS-hybrid station owners have expressed the desire for operational flexibility for their stations, noting that there are many different potential operating modes.

Benefit: Allowing for single station offering where this makes sense

6.16. Although our preference is for offering each technology component separately, it may be sensible in some cases for a BESS-hybrid station owner/operator to provide a single offer for its BESS-hybrid station. Several factors may influence this decision, including:

(a) whether the BESS-hybrid station owner intends to use their BESS to 'firm' their intermittent generating station output (the BESS makes up any shortfall in expected generation output)

(b) whether the BESS-hybrid station only charges its BESS from its own generation component and not from the network

(c) if the capacity of one of the BESS-hybrid station's technology components is below the threshold for providing offers, and the System Operator does not require separate offers for each component in order for the System Operator to meet its principal performance obligations or the dispatch objective.

6.17. In these cases, we propose to allow the BESS-hybrid station owner to elect to offer as a conventional generating station or as an intermittent generating station or as a BESS station, depending on how the BESS-hybrid station is to be operated. We also propose allowing the System Operator to require the owner/operator to offer at the technology component level if this is necessary for the System Operator to meet its principal performance obligations under Part 7 or the dispatch objective under Part 13.

6.18. These arrangements may evolve over time with changes to the technologies employed by the BESS-hybrid station owner, or when an intermittent generator becomes a BESS-hybrid owner because of the addition of a BESS station to the intermittent generating station.

6.19. Where the BESS-hybrid station owner/operator elects to operate the BESS-hybrid station as an intermittent generating station, they would be required to meet the existing requirements and constraints of an intermittent generating station. This would include being required to forecast the station's injection into the network while taking into account the expected operating conditions of the BESS. In particular, trading a BESS-hybrid station as an intermittent generating station would require the owner/operator to incorporate the BESS component's SoC into its forecast of generation potential.

6.20. This proposal is similar to current arrangements, which provide for generators (other than intermittent generators) to be able to offer their generating plant either by generating station or by generating unit. Intermittent generators are currently required to offer intermittent generating plant at the station level.[22]

6.21. The current arrangements also provide for the System Operator to require embedded generators to offer into the wholesale electricity market or provide other information to support the System Operator to meet its principal performance obligations or achieve the dispatch objective.[23] We propose extending these provisions to apply to how BESS-hybrid stations are offered into the wholesale electricity market.

Benefit: Instantaneous reserve and frequency keeping markets remain accessible

6.22. A BESS-hybrid station owner could elect to offer instantaneous reserve if they were contracted to do so by the System Operator. The instantaneous reserve response (the rate at which injection increases in response to a contingent event, amongst other things) would be likely to be different for each of the technology components in the BESS-hybrid station, depending on how the station's plant controller is configured.

6.23. For this reason, we consider offering by technology component is fundamental to a BESS-hybrid station being able to provide instantaneous reserve. It would best ensure the System Operator could schedule instantaneous reserve from the BESS-hybrid station in a way that best supported the System Operator's ability to meet its principal performance obligations. The alternative – station-level offering of instantaneous reserve – appears to have some implementation difficulties, particularly if the BESS-hybrid station included an intermittent generation component.

6.24. A BESS-hybrid station owner could also elect to offer frequency keeping if they were contracted to do so by the System Operator. The current arrangements for scheduling frequency keeping may support the combination of intermittent generation and BESS as a single dispatchable frequency keeper. This is on the basis that the BESS technology component of the BESS-hybrid station could provide injection (ie, 'up' regulation) while either the intermittent generation technology component or the BESS technology component could provide injection reduction (ie, 'down' regulation). This is similar to how a BESS-hybrid station could meet any frequency management AOPOs.[24]

6.25. Currently, the System Operator's market dispatch system tools do not support a BESS providing frequency keeping while it is charging. This constraint has been discussed in previous consultations[25] and would apply to BESS-hybrid stations that were intended to be offered as frequency keeping providers. The Authority is investigating improvements to these tools through other projects. Any

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[22] Refer to clause 13.11 of the Code.

[23] Refer to clause 8.25 of the Code.

[24] Discussed in section 5 of this paper.

[25] Wholesale market arrangements for battery energy storage systems | Our consultations | Our projects | Electricity Authority.

improvements would also increase the operational range of a BESS-hybrid station providing frequency keeping.

6.26. Implementing technology component-based offering for energy and instantaneous reserve would not impact the scheduling of frequency keeping, as frequency keeping is currently scheduled separately from these products. The System Operator would be able to contract for a BESS-hybrid station to provide frequency keeping from either the whole station or from one of its technology components.

Cost: Increased costs for traders needing to offer and bid multiple components

6.27. Offering by technology component could come at a cost for BESS-hybrid station owners compared with an arrangement whereby the entire station was offered as one entity. Additionally, under current arrangements BESSs are required to trade as two entities – one representing load (offtake) and one representing generation (injection).

6.28. In our companion consultation paper, which discusses trading arrangements for BESSs, we have proposed simplifying the offer arrangements for BESSs, by introducing a bi-directional offer form. Essentially this would enable a BESS owner/operator to trade an entire BESS as a single entity in the wholesale electricity market. Our preference is for this arrangement to also apply to the BESS component of a BESS-hybrid station.

Alternative option 4B – creating new obligations for BESS-hybrid stations

6.29. An alternative approach would be to create a new set of trading obligations specifically for BESS-hybrid stations.

6.30. The potential benefit of this alternative option would be to create trading obligations that maximise the trading options for BESS-hybrid stations, and clarify operational requirements around forecasting the station’s future power generation capability.

6.31. A potential risk associated with this alternative option is that it could be overly complex compared with our preferred option. Creating bespoke obligations in the absence of lived experience risks making assumptions about how BESS-hybrid stations will be operated and traded in the wholesale electricity market. This could unintentionally create barriers to investment in these assets and their participation in the wholesale electricity market.

Consultation questions:

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 for BESS-hybrid stations? If not, why not?

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?

Issue: Station dispatch may complement component-level offering, but the benefits are unclear

6.32. Under Part 13 of the Code, a generator may choose to have its generating plant dispatched as a station dispatch group.[26] A generator operating its generation assets in this way may depart from dispatch set points for the generating units within the station dispatch group, provided the station meets the sum of the active power dispatches across generating units, and complies with station security constraints.[27]

6.33. A BESS-hybrid station owner that trades their BESS and generation technology components separately may wish to operate the BESS-hybrid station as a station dispatch group. This could enable the BESS to be used to maintain power output during an unexpected lull in wind or solar PV generation. It could also reduce BESS charging load from the network when output from the generation technology component is higher than expected.

6.34. Under our proposed principle of offering by technology component, each technology component would follow the trading arrangements applicable to a standalone generating station.

Option 5A: amending station dispatch arrangements

6.35. To best enable operational flexibility, we could amend the existing station dispatch arrangements in Part 13 of the Code to:

(a) provide for BESS-hybrid stations to elect to operate in the same way as station dispatch groups

(b) make any flags[28] sent to intermittent generation components of a BESS-hybrid station equivalent to station security constraints – that is, on receipt of a flag, the generation technology component would be required to follow its component dispatch

(c) update the arrangements for dispatch and dispatch compliance to accommodate deviations from dispatch that might be observed.

6.36. Potential benefits of this option include:

(a) greater flexibility in dispatch – being able to operate within a station dispatch group could provide more flexibility in the operation of the BESS technology component, provided station dispatch is maintained[29]

(b) the ability for BESS-hybrid station owners to decide what is the most appropriate operating model for their station, rather than having to conform to a particular arrangement.

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[26] Refer to clause 13.64 of the Code.

[27] Station security constraints may be issued to require an individual generating unit, or units within a generating station, to follow dispatch. This would be to provide ancillary services or accommodate network capacity limitations.

[28] Refer to the definition of **flagged** in clause 1.1 and clause 13.73(1A) of the Code

[29] A BESS-hybrid station owner would already have some flexibility for the intermittent generation component to deviate from dispatch. Refer to clause 13.82(2)(d) of the Code.

6.37. Potential costs or risks of this option include difficulty forecasting future capability. Varying BESS output could impact the ability of the BESS-hybrid station owner to anticipate the SoC of the BESS technology component and thereby provide adequate offers for subsequent trading periods. It would also hinder the System Operator's ability to calculate the BESS's SoC.[30]

Implications for updating offers within gate closure

6.38. One solution to the potential forecasting uncertainty arising from permitting station dispatch could be to allow BESS-hybrid station owners to update their offered BESS technology component quantities within the gate closure period. This would reflect station dispatch operation.

6.39. We believe providing for BESS-hybrid stations to be able to be operated like station dispatch groups would give BESS-hybrid station owners the most flexibility in their operations. However, these provisions would also need to accommodate the requirements of the System Operator's scheduling and dispatch processes, including being able to forecast the future SoC of the BESS technology component of a BESS-hybrid station.

6.40. In our companion consultation paper, we discuss options for how BESS stations should be traded, so that their offers best reflect their expected future capability. In the longer term our preferred approach would be for the System Operator to calculate BESS SoC based on real time telemetry and expected scheduling of generation and offtake.

6.41. In the shorter term, before upgrades to the System Operator's market dispatch systems can be implemented, we propose that BESS offers and bids for injection and offtake MW should account for the expected SoC of the BESS. These offered quantities should be updated regularly, including within the gate closure period, where system conditions have caused deviations from the expected SoC.

6.42. For technology component-level offering of BESS-hybrid stations, the Authority's preference is for any decision we implement for standalone BESS stations to apply to the BESS component of a BESS-hybrid station.

6.43. If station dispatch was employed for a BESS-hybrid station, the BESS generation or consumption could vary from the dispatched quantity. This would cause the expected SoC calculated by the System Operator for future periods to be inaccurate, impacting the accuracy of the forecast schedules. As a consequence, this may:

(a) invalidate the post-gate closure security assessments the System Operator had performed for the next two trading periods (assuming one hour gate closure). This could result in the System Operator not having appropriate mitigations in place to support power system security, increasing the risk of disruptions to consumers' electricity supply

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[30] This is proposed as a scheduling requirement in our companion paper to this consultation.

(b) increase uncertainty in resource commitment decisions, such as for slow-start thermal generators. This could lead to inefficient decisions, resulting in less affordable electricity to consumers in the long run.

6.44. It may be appropriate for BESS-hybrid stations operating like a station dispatch group to be permitted to update their offers within the gate closure period more freely.

6.45. If SoC constraints are implemented, and the expected SoC deviation from utilising station dispatch is significant, the System Operator may need to re-run forward schedules to accurately estimate the future SoC.

Consultation questions:

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?

Issue: Market scheduling should incorporate injection constraints

6.46. A DC-coupled BESS-hybrid station may be commissioned with its total injection capacity being less than the sum of the injection capacities of its technology-specific components. For example, a BESS-hybrid station of 120MW capacity, consisting of 100MW of solar PV generation capacity and 20MW of BESS capacity, may only have 100MW of inverter capacity.

6.47. This has implications for our preferred option of requiring the technology components of BESS-hybrid stations to typically be offered separately. With separate offers, the System Operator's dispatch engine[31] would only have information about the combined injection capacity of each technology component.

6.48. Without a formulation change, the System Operator's dispatch engine would have no information to enable it to limit the sum of the technology component injection capacity to reflect the BESS-hybrid station's inverter capacity. The inverter capacity limit would need to be modelled separately, based on additional information provided to the System Operator by the BESS-hybrid station owner/operator.

6.49. How this is modelled could have implications for both the dispatch of the BESS-hybrid station and the prices at the market node that represents the BESS-hybrid station. We believe there are three options for including this information in the scheduling of the wholesale market offers:

(a) applying a 'market node constraint' (our preferred option),

(b) model a dynamic capacity constraint with an offered inverter capacity, or

(c) applying a 'transmission constraint'.

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[31] Known as 'Scheduling, Pricing and Dispatch' ('SPD').

Options for BESS-hybrid station scheduling in the wholesale market

Option 6A – implement a static market node constraint

6.50. For each BESS-hybrid station offering its technology components separately, we propose the System Operator should implement a permanent market node constraint that is used alongside other scheduling constraints in the market dispatch tool. The general form of these constraints would be

Injection(Gen) + Injection(BESS) – Offtake(BESS) + IR(Gen) + IR(BESS) <= Inverter Capacity

where 'IR' means Instantaneous Reserve, which can be either Fast Instantaneous Reserve (FIR) or Sustained Instantaneous Reserve (SIR).

6.51. It would be the responsibility of the BESS-hybrid station owner to inform the System Operator of any changes to the stations inverter capacity in a timely manner, so the System Operator could update its modelling in a timely manner. These changes could be temporary (eg, due to maintenance outages), or permanent (eg, due to equipment changes). This information could be shared through existing operational channels such as the Planned Outage Coordination Process (POCP).

6.52. Potential benefits of this option include:

(a) ensuring that the overall injection capacity of the BESS-hybrid station is modelled appropriately, while

(b) ensuring the energy price realised at the network point of connection is an appropriate reflection of the need for generation investment.

6.53. Potential costs or risks of this option include:

(a) operational costs arising from the need to maintain market node constraints for each BESS-hybrid station

(b) an inability to rapidly update the injection capacity of the BESS-hybrid station in response to a sudden change in this capacity.

Option 6B – model a dynamic capacity constraint with an offered inverter capacity

6.54. An alternative arrangement for providing the required information into the market dispatch process is for the inverter capacity limit of the BESS-hybrid station to be included in the station's offers. A BESS-hybrid station owner would, for each of a BESS-hybrid station's technology components, include both a technology component maximum injection limit and an overall BESS-hybrid station maximum injection limit.

6.55. This arrangement would be implemented in a similar manner to the market node constraint option. If per-technology component offering was implemented, there would need to be some validation that the BESS-hybrid station's injection limit is the same in each separate technology component offer.

6.56. Potential benefits of this option include:

(a) it allows asset owners to provide the limit information more dynamically

(b) it allows the System Operator to implement the limit automatically within the market dispatch engine.

6.57. Potential costs of this option include:

(a) changes would be required to the System Operator's market dispatch systems to accommodate and use the new information

(b) changes would be required to market participants' systems.

Option 6C – implement a transmission constraint

6.58. Another alternative is to include the limit as part of the information the System Operator uses to model the transmission network, as a transmission constraint.

6.59. The potential benefit of this option is that it would be a more automated means of modelling inverter constraints.

6.60. Potential costs or risks of this option include:

(a) a risk of undervaluing the generation provided by the BESS-hybrid station, if the transmission constraint 'binding' resulted in a much lower energy price at the market node. In this situation the marginal price at the point of connection would be set by the lower of the offer or bid prices of the BESS-hybrid station.

(b) if the transmission constraint became binding, the dispatch of the technology components of the BESS-hybrid station may not align with the BESS-hybrid station owner's intentions for managing the SoC of the BESS technology component. This in turn would hinder the System Operator's ability to predict the future SoC of the BESS technology component of the station.

Consultation question:

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?

Issue: Technology component offering may require expanded metering arrangements

6.61. For AC-coupled BESS-hybrid stations, each inverter handles a single technology type. Metering the AC injection into, and offtake from, the network for each inverter can be summed across each of the BESS-hybrid station's technology components and compared to the offered and dispatched quantities for each technology component. This allows the existing Code provisions around constrained costs to be applied to BESS-hybrid stations without modification, with each technology component treated separately for wholesale market clearing and settlement purposes.

6.62. For DC-coupled BESS-hybrid stations, each inverter handles both technology components (ie, generation and BESS) together. AC-side metering cannot distinguish between the contribution to injection of each technology component. Additionally, AC-side metering would only capture the net injection and offtake at the point of connection. It would not record the amount of electricity the generation technology component provided when charging the BESS technology component, as this would be occurring behind the inverter.

6.63. This has implications for constrained costs.[32] Constrained costs are paid to generators whose generating stations are dispatched to generate out of merit order (ie, their offer price is higher than the final price for the trading period). Similarly, compensation may be paid to BESSs as purchasers, either for being constrained on (dispatched to charge despite their bid price being less than the final price), or for being constrained off (dispatched to not charge despite their bid price being greater than the final price).[33]

We have considered two options for BESS-hybrid metering arrangements

Preferred option 7A – adjustments to DC-side metering

6.64. We propose that technology component-level offering for BESS-hybrid stations will require DC-side metering arrangements that adjust the volume information provided to the reconciliation manager for the purpose of determining reconciled quantities. The AC-metered quantities from the BESS-hybrid station would be divided into the separate technology components for the purposes of comparison against dispatched quantities. This would enable constrained amounts to be determined.

6.65. The benefit of this option is ensuring that the BESS-hybrid station owner is appropriately compensated for variations between dispatch outcomes and final pricing outcomes for each technology component of the BESS-hybrid station.

6.66. The potential costs of this option include:

(a) DC-coupled BESS-hybrid station owners would need to invest in systems that enabled the creation of volume information for each technology component of the station

(b) costs associated with developing new metering arrangements and obligations.

Alternative option 7B – calculating constrained costs based on net AC-side metering

6.67. The alternative approach would be to combine the injection and offtake quantities (‘net metering’) for all components of the BESS-hybrid station in determining constrained costs.

6.68. The benefit of this option is the absence of any development costs. BESS-hybrid stations would be treated the same as other generating stations and BESSs in the calculation of constrained payments.

6.69. The principal cost of this option is that net metering would result in only the overall injection or offtake of a BESS-hybrid station being considered for a trading period.

6.70. In the case of DC-coupled BESS-hybrid stations, if net metering was used for the constrained cost calculations, the constrained payments would differ from constrained payments calculated on the basis of each technology component being considered separately.

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[32] Detailed in clauses 13.192 to 13.212B of the Code.

[33] Note also we had proposed changes to the constrained cost regime for BESS in our previous consultation, but we are proposing to not pursue these further – refer to the companion paper to this consultation.

6.71. This could result in a perverse outcome in instances where the BESS technology component was cleared to charge out of merit order (compared to the final price for the trading period) but the BESS-hybrid station was overall providing net injection into the network. The BESS-hybrid station owner would not be compensated for the charging of the BESS, and the charging of the BESS would mean the station's net injection was lower, resulting in lost revenue. Appendix A presents a hypothetical example of this occurrence.

Consultation question:

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?

7. Next steps

7.1. Following this consultation, the Authority will decide which options set out in sections 4, 5 and 6, if any, should be developed into proposed Code amendments.

7.2. We expect to publish a consultation paper on any proposed Code amendments in late 2026, followed by a decision paper setting out our final decisions and supporting rationale in 2027.

Appendix A The need for component-level metering for DC-coupled BESS-hybrid stations

Constrained cost situations for generators and purchasers mainly occur due to variability in dispatch across a trading period

A.1. Trading period final prices are calculated as the time-weighted average of dispatch prices within a trading period.[34]

A.2. A generator or purchaser may get dispatched for some but not all of a trading period if the dispatch prices change significantly through the trading period. For instance, if the dispatch prices are increasing throughout the trading period and go from being less than to greater than the generator's offer price, the generator can be dispatched later in the trading period.

A.3. Generators and purchasers are compensated for the disparity between dispatch outcomes and trading period final prices through payment of constrained costs. Constrained-on payments are made to generators who are dispatched (ie dispatch price exceeds offer price) but the trading period final price is ultimately less than the offer price. Purchasers can receive both constrained on and constrained off payments.[35]

A.4. It is useful to consider how constrained payments might be calculated under two assumed offering arrangements for a hypothetical BESS-hybrid station:

- the station is offered by technology component – ie, offers are made for the generation component, and offers and bids are made for the BESS component
- the station is offered as a single station with bids for offtake from the network and offers for injection into the network.

Illustrative example

A.5. In a simplified example, consider a BESS-hybrid station which has:

- a single bid of 24MW at $95/MWh (representing the BESS charging load)
- a single offer of 100MW at $108/MWh (which could be injection provided by the BESS and/or the generation technology component).

A.6. For a given hypothetical trading period:

- when the dispatch price is below the bid price, the BESS-hybrid station will be dispatched to charge (consume energy)
- when the dispatch price is above the offer price, the BESS-hybrid station will be dispatched to generate (inject energy)
- when the dispatch price is between the bid price and the offer price, the BESS-hybrid station will be dispatched to neither charge nor inject energy.

A.7. This means that, for the given trading period, the following dispatch prices will result in the following dispatched MW quantities at the BESS-hybrid station's point of connection to the network:

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[34] Refer to clause 13.134A in the Code.

[35] Refer to clauses 13.192 to 13.212B in the Code.

5 Minute Interval	Dispatch Price (/MWh)	Dispatched Offtake (charging) (MW)	Dispatched Injection (MW)
1	$0.01	24	0
2	$0.01	24	0
3	$100.00	0	0
4	$150.00	0	100
5	$150.00	0	100
6	$110.00	0	100

A.8. For this given hypothetical trading period, the trading period final price is $85/MWh if we assume each dispatch interval is of equal duration. The following trading period quantities are realised:

- 24MW is dispatched to consume for 10 minutes out of 30 minutes (2 dispatch intervals), resulting in consumption of 24 * (10/30) * 0.5 = 4MWh
- 100MW is dispatched to inject for 15 minutes out of 30 minutes (3 dispatch intervals), resulting in injection of 100 * (15/30) * 0.5 = 25MWh
- the net metered energy injected by the BESS-hybrid station is 25 – 4 = 21MWh.

A.9. If the trading period final price and the dispatch price for the entire trading period were the same (ie, $85/MWh), the BESS-hybrid station would be dispatched to charge at 24MW for the whole period (since the trading period final price of $85/MWh is less than the bid price of $95/MWh). This would result in consumption of 12MWh, and no injection at the BESS-hybrid station's point of connection.

A.10. Therefore, the owner of the BESS-hybrid station may be entitled to constrained payments for both its (charging) offtake and its injection because the BESS-hybrid station was dispatched to both:

- consume less energy than it would have ideally,[36] and
- inject more energy than it would have ideally.

A.11. Specifically, the owner may be entitled to constrained off compensation for consuming less than its ideal quantity, and constrained on compensation for injecting more than its ideal quantity, as shown in the table below.

Constrained quantity	**Code reference**	**Formula**	**Calculated quantity**
Off (charging)	Cl 13.194(2)	(12 – 4) * (95 – 85)	$80
On (injection)	Cl 13.204(1)	(25 – 0) * (108 – 85)	$575
Total			**$655**

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[36] "Ideally" meaning in reference to its bid and offer prices.

A.12. If the BESS-hybrid station was offered as a single station, the net injection/offtake for the entire station must be considered when calculating constrained costs. For the given hypothetical trading period, there is a net injection of 21MWh dispatched in excess of the ideal injection of 0MWh. Therefore, the constrained payment will be (21 – 0) * (108 – 85) = **$483**. This results in lost revenue of $172 to the BESS-hybrid station owner for the hypothetical trading period, compared to calculating constrained costs for each technology component.

A.13. Because only the net injection/offtake is considered, the charging load that was dispatched is not compensated. Additionally, only 21MWh of the total injection of 25MWh is compensated.

A.14. For this reason, the Authority believes that BESS-hybrid station owners should be paid constrained costs as if the stations were traded as separate technology components. For DC-coupled BESS-hybrid stations, this requires adequately metering the BESS and generation contributions separately, as discussed in section 6 above.

Other information regarding constrained cost payments

Some constraints that are applied in rare situations lead to constrained off payments to purchasers

A.15. Constrained off situations can also occur in rare circumstances when the System Operator applies constraints that directly limit the purchaser's dispatchable capacity. These constraints can lead to constrained off situations because they can result in purchasers being dispatched out of merit order.

A.16. These constraints can be applied after the unexpected failure of load plant, as a temporary measure before the purchaser has updated their bid.

A.17. They could also be applied in other unexpected events requiring quick action from the System Operator to alleviate a localised threat to power system stability. In such events the System Operator may need to use a simple constraint so it can alleviate the situation quickly. Once the System Operator has managed the immediate threat, it should be able to develop a more appropriate constraint that does not lead to constrained off situations.

Most constraints do not lead to constrained on or constrained off payments

A.18. Most constraints applied by the System Operator are reflected in the dispatch prices. This means most constraints do not cause generators and dispatchable purchasers to be dispatched out of merit order and, therefore, do not result in constrained payments.

A.19. For example, if the System Operator applies a transmission constraint to a specific region, a dispatchable purchaser might be constrained. This means that they would have been dispatched to consume had the constraint not been applied. However, this constraint also results in lower electricity prices in the affected region. This ensures an efficient price signal to encourage new loads to connect in the region and new generation to connect elsewhere. In this case providing constrained off payments would distort this price signal and, therefore, be inefficient.

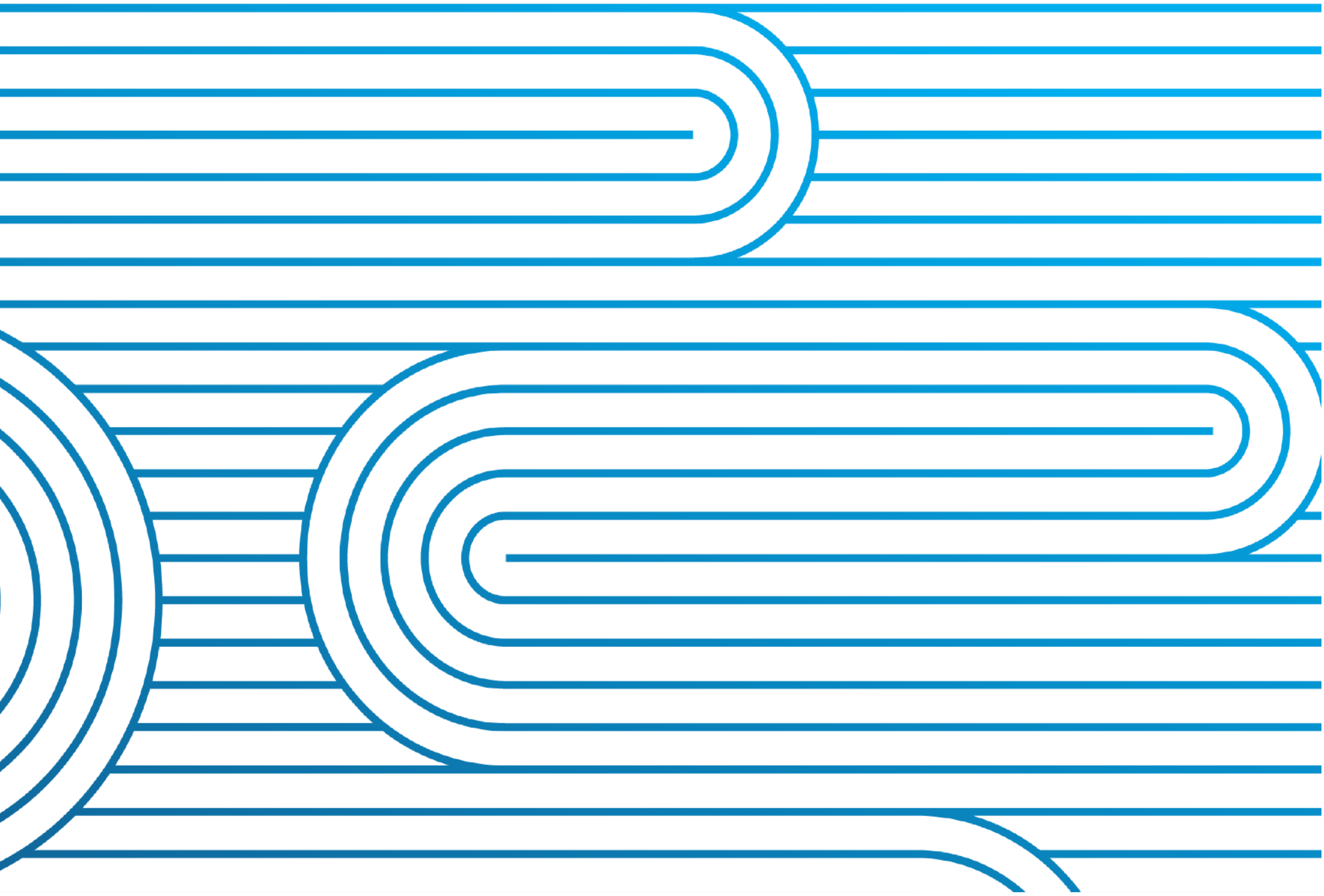
Appendix B System Operator’s report – Hybrid Plant Integration

Hybrid Plant Integration

This document presents the potential issues in integrating hybrid plants into the New Zealand power system, and the System Operator's recommended next steps

Version: 2

Date: April 2026



Executive Summary

This report presents the System Operator's analysis of issues associated with integrating hybrid plants – combined generation and BESS - into New Zealand's Power System. This report identifies issues in several areas of the Code and in operational tools and processes. The report is primarily focused on common quality and operational issues. Market issues are discussed; however, detailed market design is beyond the scope of this report. A summary of key issues and the System Operator's recommendations is presented in Table 1.

Table 1: Key Issues and Recommendations

Key Issue	Recommendations / Discussion
Ambiguity in defined terms, i.e. 'generating unit,' 'generating station,' 'intermittent generating station', 'Maximum Continuous Output', 'synchronised' and 'energy storage system' for hybrids.	R1. Clarify that the term 'generating unit' refers to individual inverters and 'generating station' refers to all units (BESS and generation) at a single point of connection R2. Consider introducing two intermediate categories between station and unit to allow more granular obligations R3. Adopt the definition of Maximum Continuous Output proposed by the Authority in their Voltage Decision Paper We have no specific recommendation for definitions of 'synchronised' or 'energy storage system', however we raise the issues for discussion.
Lack of clarity regarding how hybrid plants can offer and be dispatched	R4. Authority to complete detailed market design for hybrid plants R5. In the interim, allow hybrid plants to offer and be dispatched generation and BESS separately, with the wind and solar generation treated as intermittent and the BESS as non-intermittent. Also allow DC-coupled hybrids to be treated as a single non-dispatchable station, provided the BESS is of sufficient size to manage the variability of the generation
Obligations of a BESS or hybrid when idle	R6. Define 'idle' as a BESS which is at 0MW and not cleared for any ancillary service, and in a hybrid plant when the BESS is being charged from the generation and no power is exported to the grid R7. Clarify that an idle BESS or hybrid plant is required to provide voltage support but not frequency support
Interpretation of Clause 8.17, including is the BESS required to compensate from the lack of response from intermittent generation operating at maximum the resource allows	R8. In the interim, require hybrid plants to respond with a droop based on plant maximum, and BESS not required to compensate generation R9. Authority to lead development of frequency strategy, to address broader issues with 8.17 and its interaction with current and future ancillary services

Key Issue	Recommendations / Discussion
Voltage Support (Clause 8.23) obligations may impose disproportionate costs if based on combined BESS and generation rating if station output is limited	R10. Base reactive power requirement on station MCO
Staged commissioning (adding BESS to existing generation or vice-versa) - requirements for commissioning process unclear	R11. For AC-coupled hybrids, require full commissioning process R12. For DC-coupled hybrids, require a commissioning plan. Exact requirements to be determined on a case-by-case basis
For hybrid plants with two PPCs, it may not be clear if they receive one or two voltage setpoints	R13. We will dispatch one voltage setpoint for the station, and it is the Asset Owner's responsibility to manage their equipment
Hybrid plants are technically capable of providing instantaneous reserves and frequency keeping, but there may be issues with Code provisions relating to the central forecaster, and in System Operator tools	R14. Authority to review central forecaster provisions to determine if they allow intermittent generation to provide reserves We do not have specific recommendations regarding potential tool issues. We will address tool issues as they arise, noting that it is unlikely tool issues will stop a hybrid plant being commissioned. The specifics of the issues and potential solutions depend on market design details.
Internationally, it is common that the sum of the BESS and generation capacity is significantly more than the plant maximum output	We support this arrangement conceptually, although we note there may be some tool issues in managing the plant capacity limit, depending on market design.
Modelling Requirements for DC-coupled plants	Generally, in RMS models it will be acceptable to model the inverter without modelling the DC side, provided the frequency response can be modelled accurately. In EMT models, generally the DC side should be modelled. Asset Owners should discuss the right modelling approach with their OEM.
Operational Communication Requirements	Hybrid plants need to provide indications of the total amount of BESS and generation to allow accurate modelling of frequency response. Operational Communication Requirements for IBR more generally are addressed in the proposed CACTIS (a separate FSR workstream).

Contents

1.0 Introduction

New Zealand’s utility-scale battery energy storage systems (BESS) and generation have so far been built and operated separately. By contrast, it is common overseas for BESS to be combined with generation (typically solar or wind) to form a hybrid plant. There are several proposed hybrid plants at various stages of connecting to New Zealand’s transmission and distribution networks, and we expect many more in the coming years. Several drivers are behind this uptake, from the decreasing costs of BESS, to increased flexibility for intermittent generation and lower costs compared to separate BESS and generation plants. It is timely to provide clarity to industry on common quality and market obligations for participants to have a common understanding of hybrid plant obligations and to assist developers to make sound investment decisions.

Hybrid plants were not considered when the Electricity Industry Participation Code (the Code) was written, hence the current challenges of clarity and applicability with respect to hybrid plants.

A similar ambiguity problem exists for BESS. The Electricity Authority (the Authority) has recently amended the Code to apply generator obligations to a BESS when it is injecting or charging, but this work did not investigate obligations on an ‘idle’ BESS.

This report presents relevant technical information to the Authority and the Common Quality Technical Group (CQTG). It identifies issues relevant to hybrid plants, options to address those issues, and the System Operator’s recommendations. Parts 1, 8, and 13 of the Code, along with operational issues not directly related to the Code, are covered. Market issues (Part 13) are discussed and some recommendations are made, however in-depth market design remains beyond the scope of this report.

2.0 Key Terms

This section defines key terms to describe hybrid plants and their characteristics. It also discusses terms used in the Code which are not clearly defined when applied to hybrid plants, which need to be resolved in order to provide clarity to participants on their obligations in relation to hybrid plants.

2.1 Types of Hybrid Plant

Broadly, hybrid plants can be classified as AC-coupled or DC-coupled. In an AC-coupled hybrid plant, the generation and BESS each have separate inverters. There is typically one plant controller, although it is also possible to have separate power plant controllers (PPCs) for the BESS and generation. In an AC-coupled plant, it is also possible for the generation to stem from either an inverter-based resource (IBR) or a synchronous machine.

In a DC-coupled hybrid plant, each inverter has generation and a BESS connected on the DC side. In a DC-coupled plant, the generation component is almost always a configuration of photovoltaic (PV) panels. DC-coupled plants can be further classified as bi-directional (i.e. can absorb power from the grid) or uni-directional (i.e. can only export and so only charge BESS from PV).

Figure 1 and Figure 2 below show typical AC-coupled configurations, while Figure 3 shows a DC-coupled hybrid. These diagrams feature PV generation, though other types are possible.

Note that in literature and some international jurisdictions, the terms ‘AC-coupled hybrid’ and ‘co-located’ are used either interchangeably or refer to differing market arrangements rather than physical configurations. In this report, the term ‘AC-coupled hybrid plant’ refers to a plant which has one PPC (Figure 1) while the term ‘co-located plant’ refers to a plant with separate generation and BESS PPCs (Figure 2) which do not communicate.

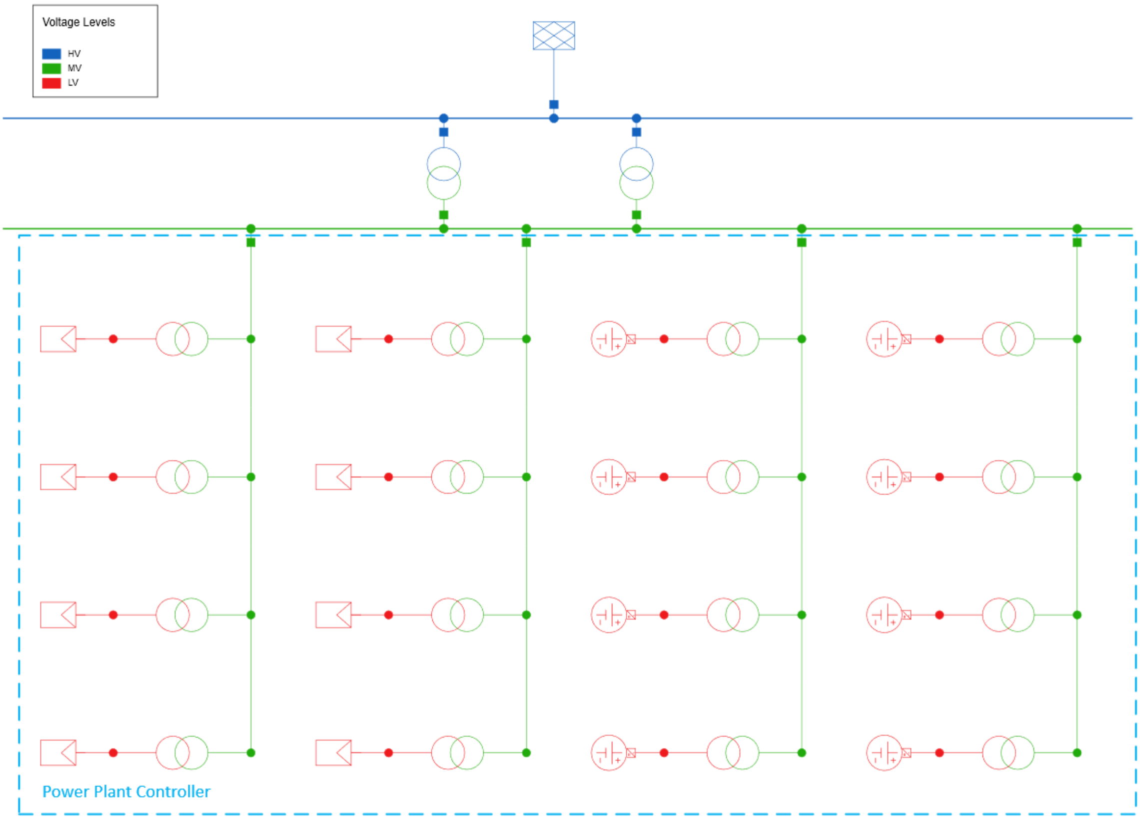


Figure 1: AC Coupled Hybrid Plant

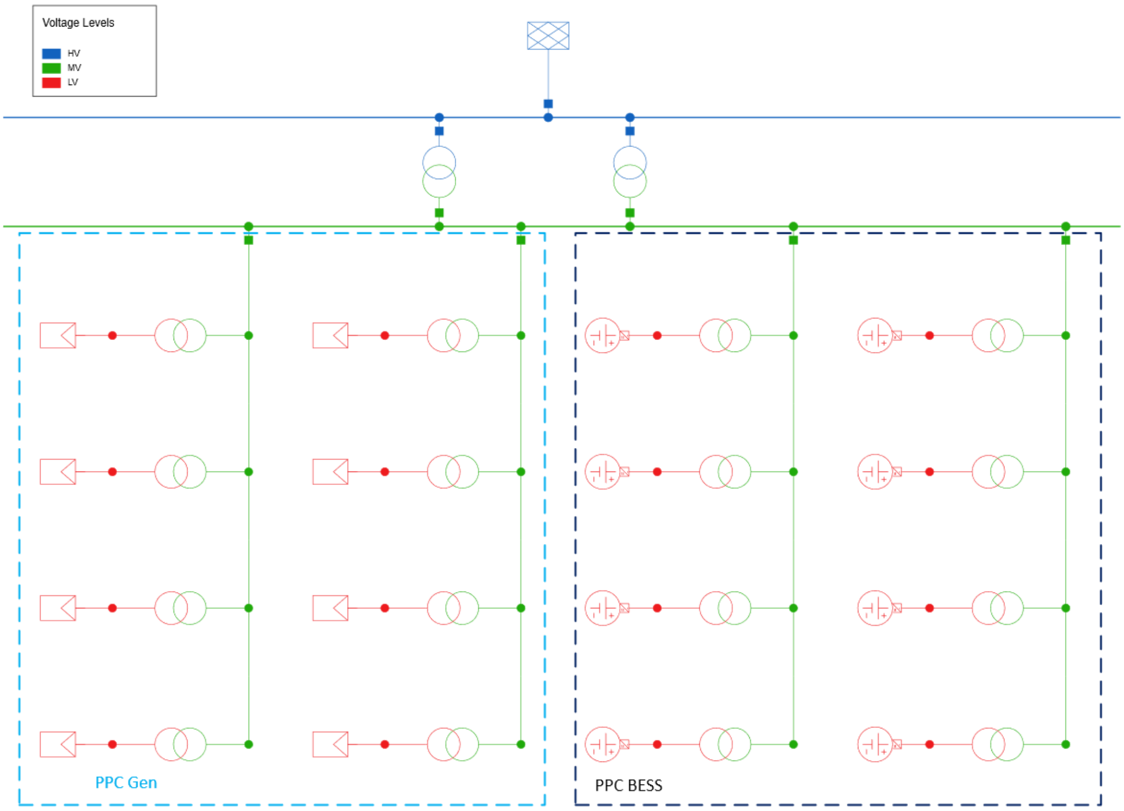


Figure 2: Co-located Plant

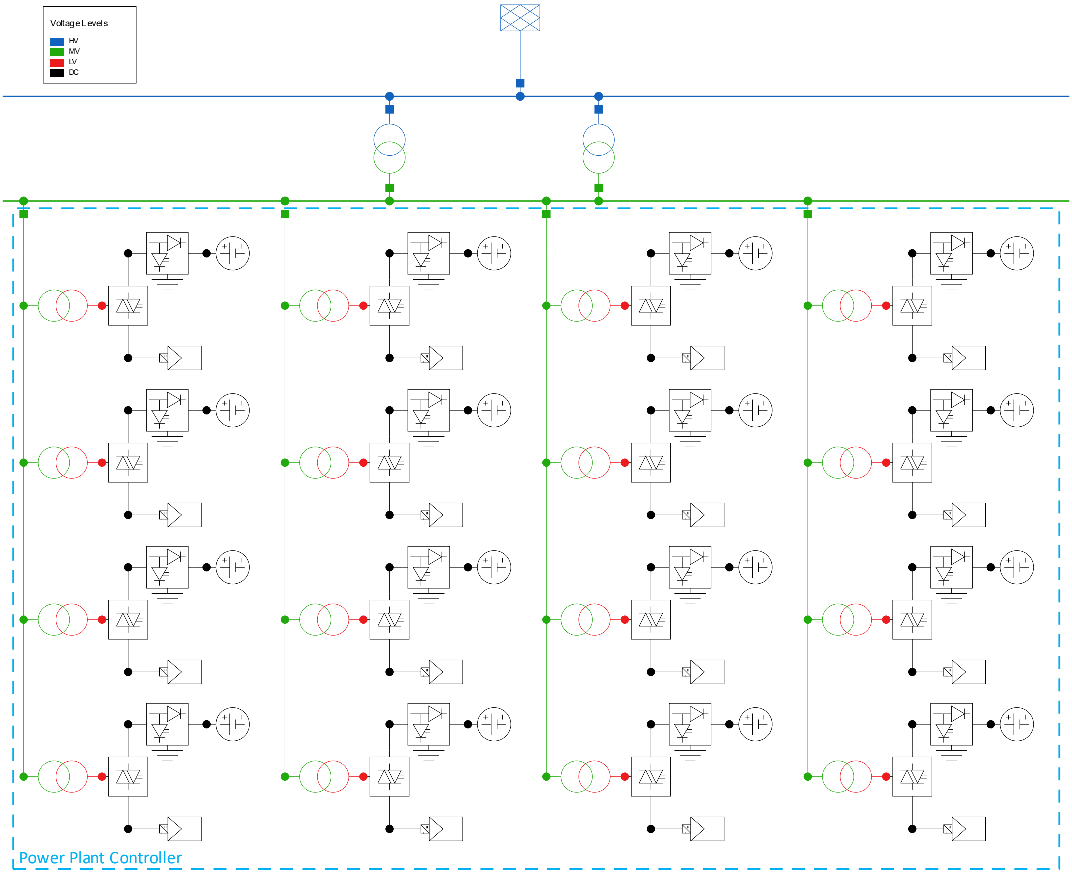


Figure 3: DC-Coupled Hybrid Plant

Internationally, both AC- and DC-coupled hybrid plants commonly have a total installed capacity of generation and BESS higher than the maximum market offer [1]. This arrangement is typically due to a capacity limit on the station transformers and/or contracted transmission capacity[1], and is a way for developers to keep costs low while benefitting from the flexibility provided by the BESS. Similarly, in DC-Coupled hybrid plants, it is common for the PV array peak output to be greater than the inverter rating; at peak solar output the energy that can't be exported is used to charge the BESS.

2.2 Generating Unit

The current Code definition for "**generating unit** means all equipment functioning together to produce **electricity.**" This definition is ambiguous for hybrid plants, as it is for IBR more generally.

To start, consider the layout of a typical wind farm, as shown in Figure 4. Here, 'generating unit' could be interpreted to mean any of:

- Each individual wind turbine, which does produce electricity at the terminals. This may or may not include the turbine step-up transformer. See the green markings below.
- Each feeder of wind turbines. This could be considered to meet the "all equipment functioning together" criteria. See the blue markings below.

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[1] Note that in New Zealand, there is open access transmission, and any constraints are resolved in the market. Internationally, it is common for generators to contract for a guaranteed level of transmission capacity.

- The entire plant can be considered as one generating unit. There is typically a plant controller which controls all turbines, which could be considered “all equipment functioning together.” This may or may not include the station transformers, as in the yellow markings below.

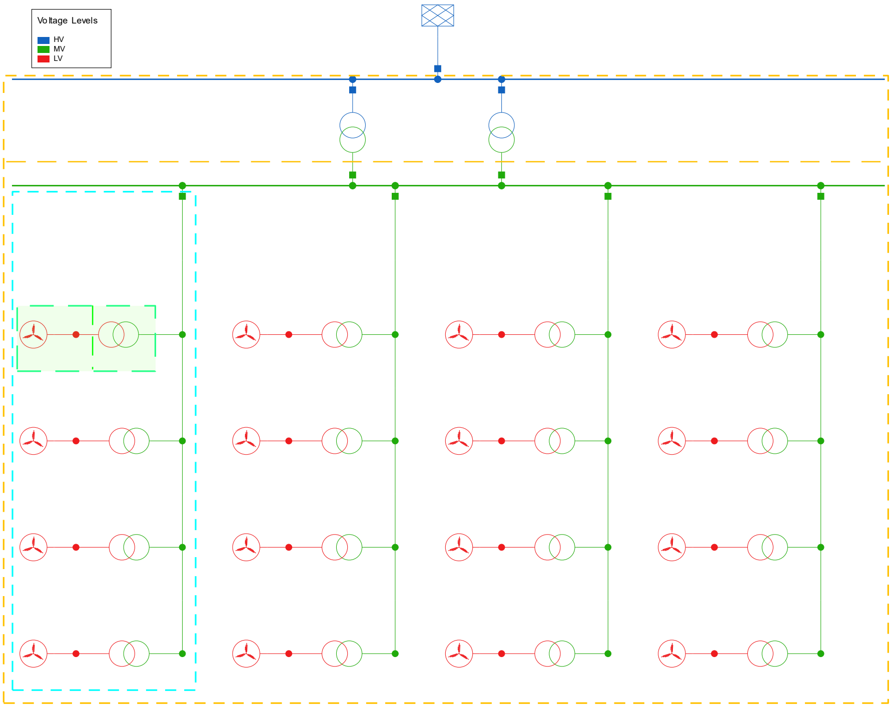

Figure 4: Typical Wind Farm Layout, with different possible ‘generating unit’ definitions marked

Current interpretations differ depending on the context. For the purposes of assessing compliance with Part 8, the typical interpretation is that the feeder or station is the generating unit/s. This is because:

- Voltage support obligations (Clause 8.23) are assessed at the ‘generating unit terminals.’ If ‘generating unit’ were interpreted as each individual turbine, the amount of reactive power available to support the grid will be significantly less due to losses in the collector network. To ensure consistency with synchronous machines (which do not typically have a significant collector network), it is better that voltage support obligations apply at the plant level.
- Clauses 8.17, 8.19, 8.23, and Technical Code A contain multiple references to ‘generating unit frequency control’ and ‘generating unit voltage control’ or similar. Typically, asset owners implement these functions at the plant controller, so it is more useful – and more pragmatic from the System Operator’s compliance viewpoint – to consider the response of the plant overall rather than the individual turbines.

Regarding compliance with Part 13, it is necessary to consider each turbine or string as a separate generating unit. This is because:

- Intermittent status is assigned at the station level. A generating station is defined as “one or more **generating units** that are directly connected to the **grid** or to a **local network** and that inject into the **grid** or a **local network** (as the case may be) at a single point of **injection**.”
- Clause 13.11 specifies that intermittent generators cannot offer by unit. This clause rules out an interpretation that the whole station is one unit. A further implication of this clause

is that if each feeder were to be offered separately (which may be advantageous for risk optimisation purposes), the feeders could also not be considered as generating units. This leaves the interpretation that each turbine must be considered a generating unit.

Extending this analysis to hybrid plants, the same issues apply, along with the following:

- For both AC- and DC-coupled plants, offering the generation and BESS separately could potentially provide flexibility to the market. For this to occur, each component would have to be considered a separate generating unit, an interpretation that remains uncertain in the current Code. This issue is further analysed in Section 2.3
- For DC-coupled plants, interpreting PV and Storage components as separate generating units (as is required for separate offers) is not compatible with Part 8. The reactive power requirements in Clause 8.23 could not sensibly be applied on the DC side of an inverter. Neither could frequency control requirements.
- If the generation is being used to charge the BESS, it is unclear how this should be treated when calculating ‘generating unit net’, particularly for DC-coupled hybrids**.**

Because the Code employs the term ‘generating unit’ so frequently, a temporary interpretation with respect to hybrid plants provided by the Authority may be necessary if one were to be commissioned before any hybrid plant policy is developed and implemented. Note that it is possible to define the same term differently in different parts of the Code, however the System Operator does not recommend this approach because it can lead to unnecessary confusion.

2.3 Generating Station and Intermittent Generating Station

The Code definition for generation station (quoted in section 2.2 above) suggests that all hybrid plant configurations, including co-located assets, would be considered one generating station. This is potentially inconsistent with the definition of ‘intermittent generating station’ as “a **generating station** that relies on a variable resource that is not stored and in respect of which a **generator** has not been approved by the **system operator** under clause 13.3F as a **dispatch notification generator**.”

It is unclear if any hybrid plant meets the definition of intermittent – while the BESS *is* storing energy, it is arguably not storing the resource (i.e. solar irradiance). Logically, it would follow that any hybrid or co-located plant is either entirely intermittent or entirely not intermittent. The Code in its current state excludes the interpretation common internationally that the generation component can be considered intermittent and the BESS component can be considered non-intermittent.

A further complication is that Clause 13.11 specifies that intermittent generators must offer by station, not by unit. It follows that for the BESS and generation to be offered separately; the station cannot be considered intermittent and therefore must meet dispatch. In practice, this could only be achieved if the BESS compensates for PV/wind variability, thereby rendering the individual components non-compliant with dispatch instructions and the plant needing to be station-dispatched (otherwise the PV component would have to constantly change offers within gate closure).

We propose that the Authority consider an interim Code change to specify how a hybrid plant can operate in the market until policy regarding hybrid plants is fully developed and implemented. Our interim proposal is that generation and BESS components of a hybrid plant be treated separately, and the intermittent portion be treated as intermittent generation. This allows the advantages of the intermittent generation classification, i.e. maximum utilisation of resources, the IG flag etc. to continue to apply to the generation component, while allowing the BESS to participate fully in the energy and ancillary services markets. To avoid potential issues in dispatch and metering, we propose that DC-coupled hybrid plants be allowed to elect to participate as a single dispatchable station, provided that the BESS is of sufficient size to manage the inherent variability of the solar. This proposal would allow for hybrid plants to participate under existing rules and without significant tool issues, until more in-depth market design can be completed. To implement this proposal, an additional grouping would need to be defined in the Code, as discussed in section 2.4.

2.4 Possible Groupings

As discussed in the previous sections, there are several issues with the currently defined groupings (i.e. ‘generating unit’ and ‘generating station’). There is also a need for at least one intermediate grouping between station and unit. Figure 5 below shows various grouping possibilities, marked in different colours and labelled as levels 1-4. Although a co-located plant is depicted, the analysis is applicable to all IBR.

For synchronous machines, the existing ‘generating unit’ and ’generating station’ grouping remains generally sufficient.

Figure 6 shows these groupings applied to a DC-coupled hybrid plant.

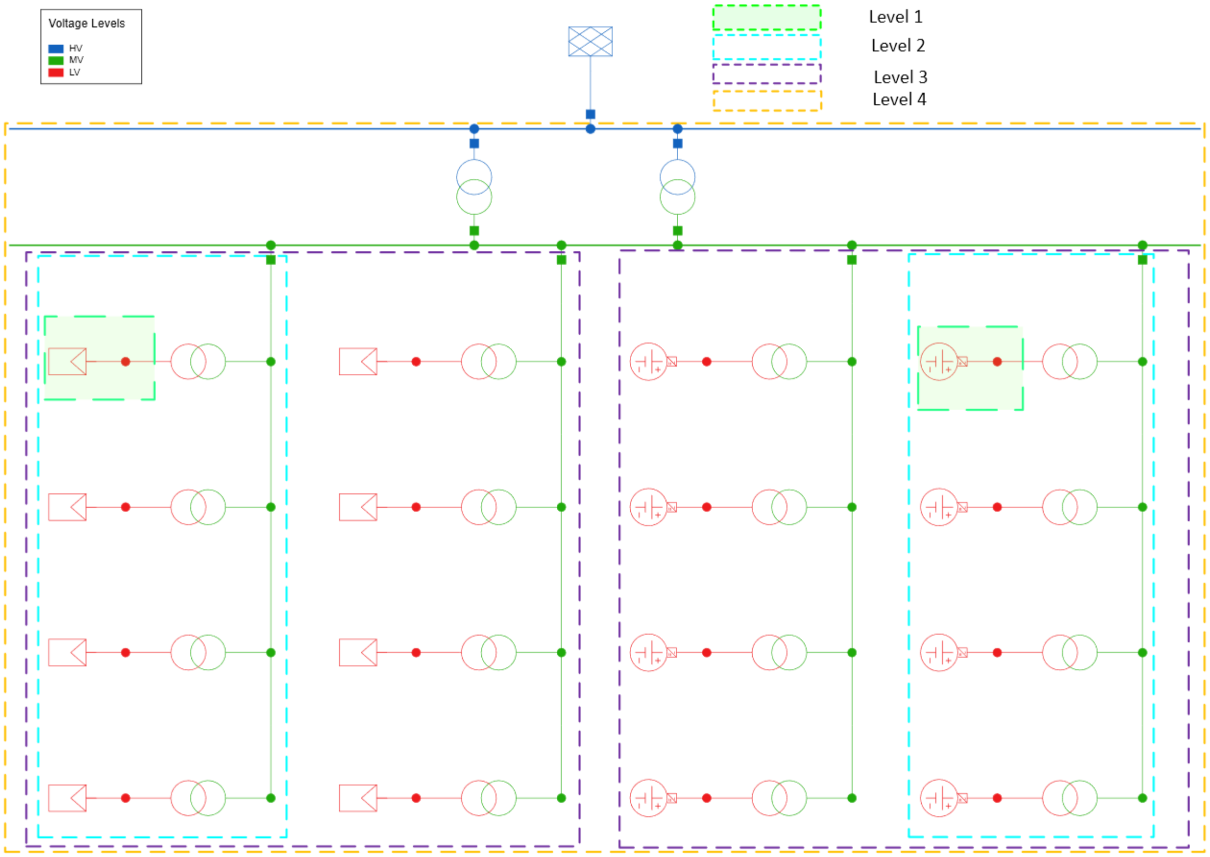

Figure 5: An AC coupled hybrid plant with possible groupings marked

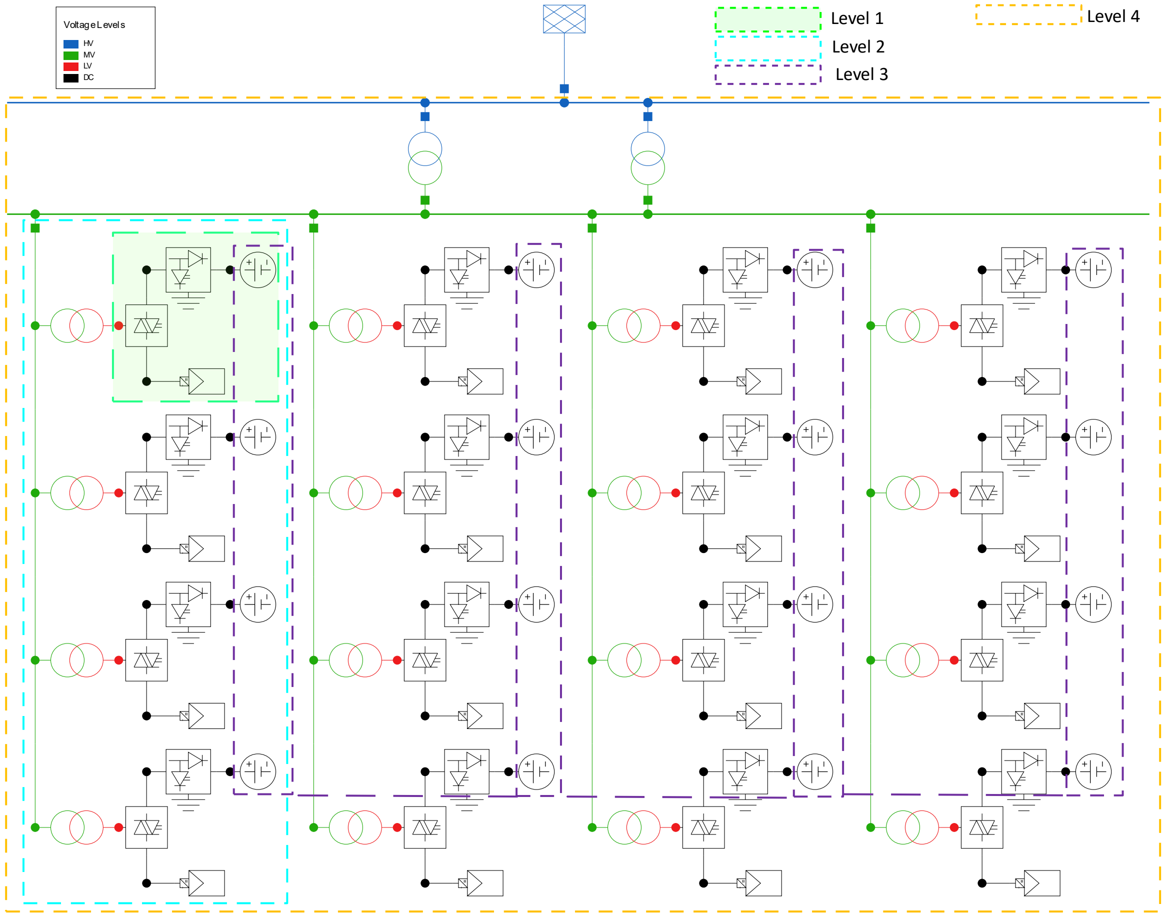

Figure 6: A DC-Coupled Hybrid Plant with possible groupings marked. For clarity, the Level 3 solar group is not marked (levels are explained below)

To avoid confusion around terminology, we refer here to the groupings as levels 1-4. In the Code, we would expect these to be defined in terms like ‘generating unit’ etc. The application of each grouping and proposed terminology is presented in Table 2.

Table 2: Proposed Groupings

Level No.	Description	Requirements	SO Proposed Term
1	The individual inverter or wind turbine	Control system must be stable and operate correctly and be modelled.	Generating Unit
2	Often called a feeder or string. A group of inverters connected via a common circuit	Indications of MW, Mvar and CB status. The level where credible event risk typically applies[2]	Generating System

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[2] For a more in-depth discussion of risk classification of IBRs, please refer to the System Operator’s recent consultation on this issue.

Level No.	Description	Requirements	SO Proposed Term
3	The group of all a particular resource in a station, i.e. the BESS or generation. Note that in a DC-coupled plant, this grouping would be on the DC side, although the grouping would only apply if the BESS and generation are offered separately	Market offers, dispatch, and intermittent status. In a co-located plant, this is the level at which the PPCs operate, therefore relevant performance and modelling requirements apply at this level	*No recommendation, for discussion by CQTG*
4	The entire station including the BESS and Generation. This is where the 'excluded generating station' threshold is applied	Indications, performance and modelling of PPC, reactive power requirements, etc.	Generating Station

We believe these groupings are adequate for all common configurations of hybrid plants and cover both Parts 8 and 13 of the Code.

We note that regardless of the terminology used and the exact definitions, it is likely that significant Code redrafting would be required. Although this report predominantly concerns Part 8 of the Code, we recognise that these definitions are used in other parts, and significant redrafting would also likely be required in Part 13.

2.5 Maximum Continuous Output

The term 'maximum continuous output' is not defined in the Code; however, it is used in Clause 8.23 to determine reactive power requirements. This is an ambiguous term when considering several aspects, from overload ratings of equipment and resource constraints, to BESS throughput limits. It is common in hybrid plants for the combined capacity of the generation and BESS to be higher than the export capacity of the inverter and/or network connection, creating further ambiguity.

The Authority has proposed the following definition in their Voltage Code Amendment Proposal:

'maximum continuous MW output power means—

(a) the maximum dispatch (in MW alternating current (a.c.)) of a generating station or generating unit for which an offer is made under Part 13 of this Code; or

(b) the maximum active power output (in MW alternating current (a.c.)) of a generating station or generating unit at its point of connection that can be maintained continuously over a 5-minute period of time under ideal operating conditions and with the generating station or generating unit maintaining compliance with this Code in the absence of any exemption, dispensation, equivalence arrangement or similar

'

The System Operator supports this definition, and this is what is meant by MCO throughout this report.

2.6 Synchronised

The Code defines the term ‘synchronised’ as “the condition whereby a synchronous **generating unit** is **electrically connected** to a **network** and the electrical angular velocity of the **generating unit** corresponds with the **network** frequency and **synchronise**, **de-synchronise, synchronising, synchronism** and **synchronisation** have corresponding meanings. Asynchronous **intermittent generating stations** must be treated as being **synchronised** for the purposes of subpart 2 of Part 8.”

The final sentence in this definition is required to ensure that common quality obligations apply to inverters. However, if a hybrid plant were not considered intermittent, this definition wouldn’t apply and therefore the hybrid plant’s obligations would be unclear. This lack of clarity also appears with respect to BESS. This definition also introduces further ambiguity about the term ‘generating unit,’ as clauses relying on the definition of ‘synchronised’ refer to generating units, even though it implies that for intermittent generation the station is ‘synchronised’ rather than the units. Finally, this definition only applies to subpart 2 and not the technical codes, further rendering some obligations unclear.

2.7 Energy Storage System and Separate Classification

The Code defines the term ‘energy storage system’ as: “all equipment functioning together as a single entity that is able to take **electricity** from a **network**, store the energy in another form, and provide **injection**.”

This definition poses two interpretation challenges for hybrid plants:

- The BESS component of a DC-coupled hybrid plant may not match this definition since it is not necessarily taking electricity from a network.
- It is unclear how ‘all equipment functioning together as a single entity’ should be interpreted, and if this means that the generation component is also part of the energy storage system. In a DC-coupled plant particularly, the BESS and generation sharing one inverter appear to be a ‘single entity.’

Note that this definition applies to all energy storage, not just BESS. Other technologies, e.g. pumped storage, also meet this definition but have very different physical characteristics to BESS.

3.0 Common Quality Obligations

3.1 Voltage Support

The System Operator recommends that hybrid plants have the same voltage support obligations as a standalone BESS or generator. There is no inherent difference in the ability of a hybrid plant to provide voltage support compared to other IBR.

An AC-coupled hybrid plant may benefit from designing and/or operating the reactive power capability of the components differently. For example, the BESS inverters may have a shorter collector network and therefore may provide more reactive power at the point of connection. This as an acceptable arrangement – however, depending on the interpretation of 'generating unit', it may not be strictly compliant with Clause 8.23. Asset owners designing their plant in this way could apply for an equivalence arrangement, though this would increase transaction costs.

The System Operator is currently working with the Authority to review point of compliance for voltage support obligations. Part of this work is to consider moving point of compliance to the station level and base it on station MCO. Hybrid plants would especially benefit from this work since it is highly possible that station MCO is significantly less than the sum of unit capacity. If voltage support obligations were imposed based on the sum of BESS and generation capacity, this could impose disproportionate costs on hybrid plants, costs which could not be recoverable due to the capacity limitation of the station. If voltage obligations were instead imposed based on station MCO, hybrid plants would have the same opportunity to recover costs as all other generation.

3.2 Frequency Support

Clause 8.19 specifies that "Subject to subclause (3), each **generator** must at all times ensure that, while **electrically connected**, its **assets**, other than any **excluded generating stations**, contribute to supporting frequency by remaining **synchronised**, ensuring that each of its **generating units** can and does, at a minimum, sustain pre-event output…"

The System Operator does not anticipate that this Clause will cause problems for hybrid plants, other than the interpretation of 'generating unit' and 'synchronised' as discussed previously. In principle, all components of the hybrid plant should comply with Clause 8.19; however, wording changes may be required to make this obligation clear.

3.3 Frequency Management

Generator obligations for frequency management are currently covered by Clause 8.17 of the Code, which specifies that "each **generator** (while **synchronised**) and the **HVDC owner** must at all times ensure that its **assets**, other than any **generating units** within an **excluded generating station**, make the maximum possible **injection** contribution to maintain frequency within the **normal band** (and to restore frequency to the **normal band**). Any such contribution must be assessed against the **technical codes**."

The most relevant section of the Technical Codes is Technical Code A Clause 1(c), which specifies that “each of its **generating units** has a speed governor and/or frequency **control system** that—

(i) provides stable performance with adequate damping; and

(ii) has an adjustable droop over the range of 1% to 7%; and

(iii) does not adversely affect the operation of the **grid** because of any of its non-linear characteristics”.

There are several issues with interpreting these clauses: some specific to hybrid plants, some more generally. There are several in-progress and upcoming workstreams which will consider some aspect of frequency management (i.e. MFK changes, inertia work, etc.). Some of the issues identified below may be better addressed through this work. The System Operator recommends that the Authority consider a frequency management strategy that features a co-ordinated approach to frequency management. Given the highly technical nature of some of these requirements, it may be that some are best placed in an incorporated document rather than the Code itself, as is the approach in the Australian NEM [3].

3.3.1 Headroom Requirement

It is unclear if Clause 8.17 requires generators to maintain headroom to provide frequency response. Intermittent generation typically operates at the maximum the resource allows (i.e. the potential generation available from the prevailing wind speed or solar irradiance) and therefore cannot increase its output to respond to underfrequency. Similarly, dispatchable generation can commonly operate at the unit maximum and therefore not provide underfrequency response.

The System Operator’s working interpretation is that, in this scenario, if a generator maintains pre-event output during an under-frequency event when operating at its maximum allowable MW output, it is compliant with 8.17. However, this is not clear in the Code and has been raised by asset owners on several occasions. This issue is applicable to all generation types, not just to hybrid plants.

There are advantages to requiring generation to maintain headroom (e.g. better frequency regulation), though there are also disadvantages (e.g. spilling renewable generation). An in-depth analysis is beyond the scope of this report but could be included in a frequency strategy. We recommend that in the interim, the Authority clarify for industry if it interprets 8.17 to require headroom to be maintained.

We note that a related issue is the obligations that BESS or hybrid plants have when idle. In the idle state, a BESS has headroom to respond to frequency. However, other technologies do not typically operate in this mode, so imposing frequency obligations on an idle BESS may be unfair. For a more in-depth discussion of this issue, see section 3.4.

3.3.2 Compensating Intermittent Response

An issue unique to hybrid plants is whether 8.17 requires the BESS to compensate for the lack of response from the intermittent generation. This concept is illustrated graphically in Figure 7. Included with this report is a PowerFactory project to demonstrate the response of the different implementations.

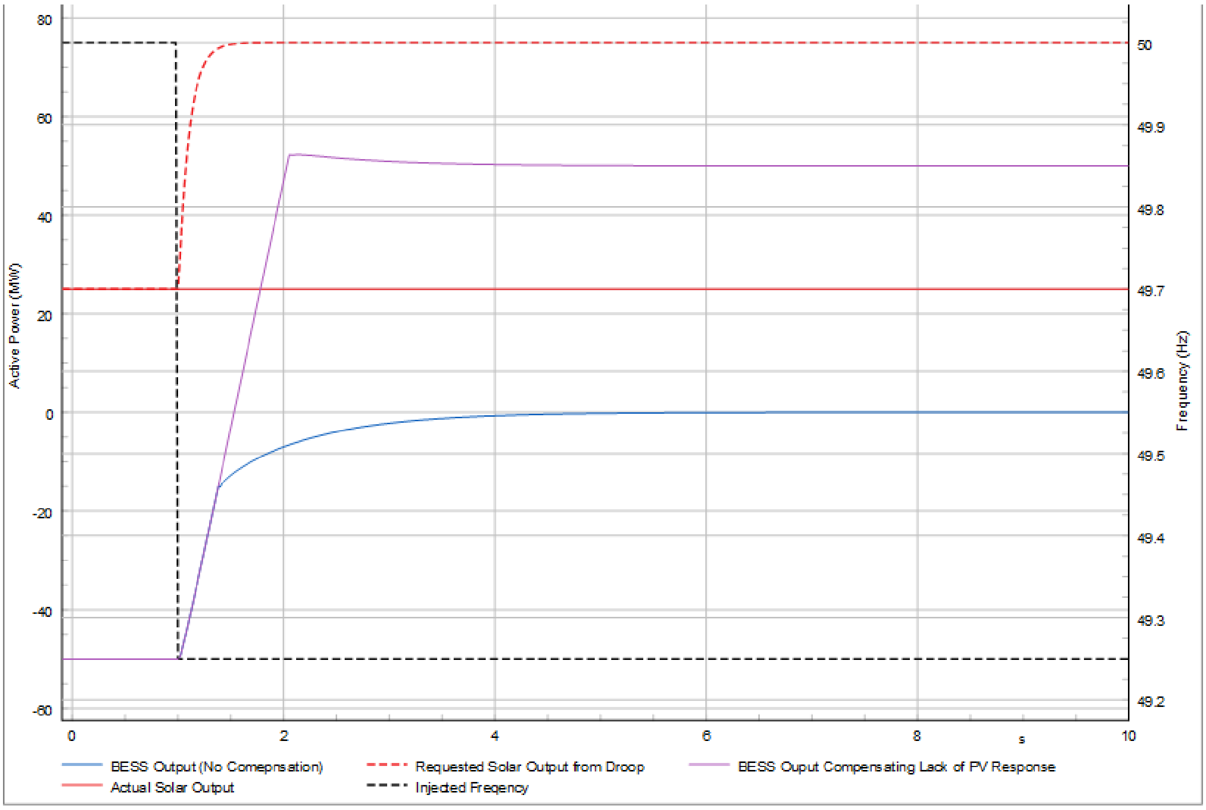

Figure 7 Response to a frequency step

The System Operator proposes that currently 8.17 should *not* be interpreted as requiring the BESS to compensate for the lack of PV response, as this would put a unfair burden on hybrid plants that standalone generation or BESS would not face. This may discourage investment in hybrid plants and/or encourage asset owners to seek Code loopholes. Once 8.17 is addressed more thoroughly, it would be prudent to revisit this proposition.

3.3.3 Response of Each Component

When providing droop response, it may be advantageous to provide a different level of response from the generation and BESS components, such as during an over-frequency event to maintain the BESS at constant power and ramp down the generation further to compensate, avoiding cycling the BESS more than necessary. As with voltage support, the System Operator would accept this arrangement, although it is not clear whether the current wording of 8.17 allows for it.

3.3.4 Over-frequency

One of the general issues with 8.17 is that it only refers to injection in response to under-frequency. The requirement for a governor implies that reduction in output in response to over-frequency is required, but this is not explicitly stated in the Code. Similarly, Clause 8.19 requires generating units to remain connected for under-frequency, but not over-frequency events.

3.3.5 Recommendation

Several of the issues raised in this section require in-depth studies to address which are beyond the scope of this report. A broader frequency management strategy should include these. Until then, the System Operator proposes that:

- Hybrid plants are required to respond to frequency with a droop based on station maximum continuous output, and the BESS component is not required to compensate for the generation's lack of response.
- During an over-frequency event, it is acceptable to maintain the BESS at constant power and ramp down the generation further to compensate, should an asset owner wish to operate their plant in this manner.

The System Operator will monitor hybrid plant frequency responses at plant or station level to assess compliance with Clause 8.17.

3.4 Obligations while Idle

The System Operator views BESS as idle when the BESS:

- is connected to a network, and
- is neither absorbing nor injecting active power, and
- is not cleared for ancillary services.

CQTG has previously agreed that an idle BESS should have voltage support obligations. The System Operator supports this because the marginal cost of providing voltage support is low.

The System Operator proposes that an idle BESS should not have frequency management obligations, though if a BESS is connected and not idle (e.g. it is at 0 MW but is cleared for ancillary services) it *should* have those obligations. Frequency management obligations typically incur some costs that an idle BESS would not have the opportunity to recover. However, by only imposing obligations on a BESS cleared for ancillary services, the costs can be recovered via ancillary services offers.

When considering a hybrid plant, there are two additional considerations. Firstly, should the plant be considered idle if the BESS component is charging from the generation component and there is no net injection or consumption from the grid? We propose that this state should also be considered idle and not have frequency obligations because there is no opportunity to recover incurred costs in energy or reserve offers. Secondly, if the PV is injecting but the BESS is at 0 MW and not cleared for ancillary services, should the BESS be considered idle? We propose that this state should also be considered idle and not incur frequency obligations, again because there is no opportunity to recover incurred costs in energy or reserve offers.

If this proposal is implemented, the System Operator would need to accurately model the different states. The System Operator would need to be provided with an indication of frequency controller status and models that are compatible with this flag. Our online tools must be configured based on the frequency controller's status. The main drawback of this setup is that verifying compliance will be difficult.

4.0 Operational Considerations

4.1 Commissioning

Hybrid plants may be commissioned in stages – that is, a BESS may be added to an already commissioned and operating solar farm or vice-versa. Commissioning new assets involves a substantial process, as outlined in the System Operator's guidelines. The application of these requirements when an existing generator or BESS is being upgraded to a hybrid plant depends on the exact details of the plant. Our view is as follows:

- In all cases, an agreed Code commissioning plan should be required. Although certain steps of the commissioning process may be omitted in some cases, a Code commissioning plan is the best way to manage these projects. The plan enables the specific requirements for a given project to be determined and ensures that all parties are all aware of requirements.
- If the hybrid plant will be AC-coupled, this constitutes a new asset and requires a complete commissioning process, including connection studies, testing, and models.
- If the hybrid plant will be DC-coupled, the amount of required commissioning will depend on the specifics of the plant:
    - If the new asset will be offered separately, or there are other changes to dispatch, this will require changes in the market system and therefore the relevant process, timelines, and testing will need to be followed.
    - The asset owner must confirm with Transpower as Grid Owner, and with the connected electricity distribution business (EDB) where relevant, that protection is still co-ordinated.
    - Regarding testing:
        - As a minimum, any new SCADA points will have to be added to the SCADA system and tested.
        - If MCO has changed, Code testing must be repeated at the new MCO. Similarly, if a BESS is added and can absorb power from the grid, Code testing must be repeated at these operating points.
        - Any additional ancillary services which are offered will require testing.
        - Any new controller functionality must be tested, i.e. if the frequency response has changed this must be tested.
    - Regarding models:
        - EMT models must be updated as these model the DC side of the inverter explicitly
        - RMS models must be updated to reflect the new behaviour of the control system. Where the behaviour hasn't changed, this must be confirmed through testing
    - Regarding connection studies:
        - If the MCO changes or the upgraded plant can absorb power from the grid where it previously couldn't, connection studies must be repeated.
        - If MCO does not change, connection studies only need to be repeated if the plant behaviours are likely to change (i.e. the frequency tuning study may need to be repeated if the addition of a BESS is expected to change the frequency response).

    - The System Operator does not expect that the fault ride through performance would be affected in this case and therefore the FRT studies need not be repeated.
- If a hybrid plant (whether AC- or DC-coupled) is planned from the inception of the project, the original connection studies should account for this. Some efficiencies may be gained by completing all connection studies (i.e. with and without the hybrid) prior to commissioning the first stage. If the hybrid is considered in the original connection studies, they may or may not need to be updated prior to commissioning the second stage, depending on the elapsed time and if there have been design changes. Other efficiencies may be gained in other parts of the commissioning process. Although this may result in a slightly higher upfront cost, it will likely save money in the long run. Asset owners should discuss the specifics of their project with the System Operator during the commissioning of the first stage.

Note that the Code currently requires a Code commissioning plan where there are changes "…at the **grid interface**…". In the case of a DC-coupled hybrid, the change may not be at the grid interface; however, we recommend that a commissioning plan would still be required.

4.2 Managing Capacity Limits

As previously mentioned, a common configuration of hybrid plant overseas is one where the sum of installed BESS and generation capacity exceeds the export capacity of the plant by a substantial margin. The System Operator supports this arrangement conceptually; however, we note that there may be some operational issues in implementing it, depending on market arrangements. In summary:

- If the hybrid plant is offered and dispatched as a single entity, we would expect that the offers do not exceed the export capacity and there would not be any issues.
- If the capacity limitation is due to a constraint on Transpower-owned transformers, this limitation would be managed via the existing tools. However, this may not result in the optimal dispatch of the components from the asset owner's perspective – the cheapest component would be dispatched first (or the tiebreaker provisions[3] would apply), which may or may not result in optimal dispatch. Note also that reserves are generally not constrained through this process.
- If the capacity limitation is due to asset owner equipment, this would potentially be difficult for the System Operator to manage. Currently, the tools assume that the offer at each Pnode can be delivered, i.e. it is assumed that offers do not exceed the export capacity of the plant. A potential solution is to require asset owners to offer in such a way that the combined dispatch does not exceed the capacity limit, though this may limit the plant's flexibility and potentially defeat the purpose of having separate offers in the first place.

Asset owners designing a hybrid plant in this manner should discuss how they intend to manage the capacity limitation with the System Operator during the early stages of the commissioning process.

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[3] For more information, please refer to the System Operator's recent consultation on tiebreaker provisions

4.3 Voltage Dispatch

Separate to the market issues discussed in section 6.0below, it is not entirely clear how hybrid plants will be dispatched voltage or Mvar setpoint. For a DC-coupled hybrid, it is imprudent to dispatch more than one voltage setpoint regardless of the market arrangements – the voltage control is on the AC side of the inverters, and the DC side components cannot control AC voltage. Similarly, in an AC-coupled hybrid plant, voltage control is typically implemented in the plant controller, therefore it is more sensible to dispatch a single voltage setpoint, because there is only one PPC.

By contrast, co-located plants present a bigger challenge for voltage management. Because there are independent PPCs for each component, it is theoretically possible for each component to have different voltage setpoints. However, because they are ultimately controlling the same bus, they must have the same setpoint and have some mitigation to ensure the controllers don't fight each other (e.g. a voltage droop setting). We propose that co-located plants should be dispatched a single voltage setpoint for the station, and it is up to the asset owner to determine how to implement this in their PPCs. Note that this is existing practice for synchronous machines, where typically each machine has an independent AVR, but each station only receives one voltage dispatch.[4]

4.4 Modelling

The System Operator must model hybrid plants in our online tools (TSAT, VSAT, and RMT) and offline tools (PowerFactory and PSCAD). These plants will also need to be modelled in the market system, although the details will depend on how they offer.

The first step to modelling any plant for dynamic simulation is to model it in a power flow which is used to initialise the dynamic simulation. The same power flow model is used in steady state power flow studies and contingency analysis. For synchronous generation, it is typical practice to model individual units and step-up transformers.

In system-wide studies, we typically model IBR as one aggregated inverter, one step up transformer, and an equivalent representation of the collector network. For certain studies such as harmonics and collector network design, it is necessary to model the individual inverters and collector network. Usually, only the AC side of the inverter is modelled in the power flow and in RMS studies. For EMT studies, it is necessary to model the DC side of the inverter, although often the modelling of the resource (PV panels etc.) is simplified.

The power flow modelling of hybrid plants depends on the plant topology and the purpose of the study. The following discussion focuses on the required modelling for system-wide studies. Detailed studies of collector network design and harmonics are beyond the scope of this report.

Generally, two aggregate inverters (one for BESS, one for PV) are modelled for AC-coupled hybrid plants. To model DC-coupled hybrids, the following are the most common options:

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[4] In rare cases, generators will receive a reactive power dispatch; however, voltage dispatch is the default arrangement.

1. One aggregate inverter is modelled, representing both the PV and the BESS, with only the AC side of the inverter modelled (i.e. a ‘Static Generator’ element in PowerFactory). There is a single active power setpoint that represents the combined output of the PV and BESS.
2. One aggregate inverter is modelled, but both the AC and DC sides are modelled. The active power setpoint of the PV and the BESS can be set separately. This approach is more detailed but adds significant complexity to the model.
3. Two inverters (with appropriate PQ capability curves) are modelled, one for the PV and one for the BESS. This is essentially the same approach as an AC-coupled hybrid plant. This approach is significantly simpler than option 2 and is an acceptable simplification for some studies.

For steady state planning purposes, option 1 will normally be acceptable. In this type of study, the relevant values are the combined P and Q outputs which affect steady state thermal loading and voltage on the grid. The generation source (PV or BESS) is generally not material so long as an accurate reactive capability curve is provided. However, the System Operator notably uses the same power flow models for steady state studies and to initialise RMS simulations.

For RMS simulations, it is important to accurately simulate the plant’s dynamic response to voltage and frequency disturbances. Therefore, it is necessary to know the initial condition of both the PV and the BESS if this affects the dynamic response of the plant (i.e. if the BESS responds to frequency but the PV does not). This could be achieved through options 2 and 3 and may be possible through option 1 if the plant controller model has the appropriate signals.

For EMT simulations, it is necessary to model the DC side of the inverter explicitly and to specify the DC side power output. For existing IBR, this is achieved by adjusting the DC side values such that the AC output matches the load flow that is being used to initialise the simulation. A similar approach can be used for hybrid plants. It is not clear how much detail is required to model the DC side; typically, the frequency control is not modelled in the EMT domain, and it is not clear how the initial PV and BESS outputs will affect the voltage response.

The System Operator has discussed the modelling of hybrid plants with the relevant software vendors (Powertech and Digsilent). They have both advised that for general purpose RMS studies, they do not recommend modelling the DC side explicitly (option 2). Powertech recommended either option 1 or option 3, and Digsilent recommended option 1. Digsilent also suggested that explicit modelling of the DC side may be required for specific functions, i.e. EMT analysis or resource adequacy analysis, though Transpower does not currently use these regularly.

It is most likely that the System Operator will use option 1 or option 3 in the real-time tools. For EMT models, asset owners should discuss the correct approach with their OEMs.

RMT modelling will depend on how hybrid plants are modelled in the market system, though it is also unclear how risk would be modelled.

4.5 Operational Communications

Operational Communications requirements are covered in Technical Code C. The provisions in Tech Code C are not sufficient for hybrid plants, or IBR more generally. The System Operator have proposed several changes to these requirements in the proposed CACTIS. The proposal is that hybrid plants would be required to provide indications of the total output of each resource, so that the System Operator can accurately model frequency response. Hybrid plants would also be required to provide additional indications applicable to all IBR, i.e. feeder level MW and Mvar, solar irradiance and/or wind speed, and BESS State of Charge.

5.0 Ancillary Services

5.1 Instantaneous Reserves

The BESS in a hybrid plant can offer reserves. Whether the generation component can offer reserves depends more on whether intermittent generation can offer reserves.

Although no intermittent generation currently offers reserves, there are no insurmountable technical reasons it could not. Provided excess wind or solar irradiance is available (i.e. because the generation is curtailed), the wind or solar farm control system is capable of providing reserves. To date, it has not been economically viable for intermittent generation to curtail generation to provide reserves, but this may change as more intermittent generation is commissioned and is curtailed more often. There is some uncertainty in forecasting which may limit the amount of reserves a constrained intermittent generator could offer. There may also be some issues in the market tools if intermittent generation offers reserves and with Code provisions relating to the central forecaster.

In a hybrid plant, there are two additional considerations:

- If a capacity limitation exists because of a station transformer limit, it may be possible to temporarily overload the transformer/s to inject the full generation and BESS capacity as reserves. The decision of what level of overload is acceptable is the asset owner’s[5], and provided that no protection system operates, the System Operator would allow reserve offers up to the overload rating. If the limitation is due to inverter capacity in a DC-coupled plant, reserve offers would be limited to the inverter capacity.
- If the hybrid plant submits a single offer for both components, depending on the exact configuration of generation and BESS, it may be that the reserves could be provided by either component. In this case, the System Operator is not concerned with where the reserves come from, as long as the right quantity is provided on the AC side.

Depending on how the hybrid plant is dispatched, reserve offers from one or both components may result in infeasible dispatch. There may also be some issues in modelling hybrid plants in the Reserve Management Tool (RMT), depending on how hybrid plants are offered. These issues will need to be worked through as they arise; however, it is unlikely they will be showstoppers for commissioning a hybrid plant.

5.2 Frequency Keeping

It is possible for a hybrid plant to provide frequency keeping, both from the BESS and the generation. Both multiple (MFK) and single (SFK) could be provided. A hybrid plant could provide frequency keeping in the same manner as a standalone BESS, by varying the BESS output up and down and keeping the generation constant. Alternatively, it may be advantageous to only vary BESS output up and provide down regulation by reducing generation, thereby not cycling the BESS

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[5] Assuming that the station transformers are owned by the asset owner, not Transpower as Grid Owner. If the transformers are owned by the Grid Owner, they cannot be overloaded without Grid Owner agreement.

as often. Conceptually, the System Operator supports this arrangement, although there may be some issues with implementation in the market tools.

Because frequency keeping is currently a single product[6] for up and down regulation, the hybrid plant would have to be dispatched as a single station for both components to provide MFK. If the BESS and generation are dispatched separately, only the BESS component could provide frequency keeping unless the generation was curtailed.

Note that there is currently a limitation in the market system which prohibits a BESS from providing MFK by charging, which would also apply to hybrid plants. This limitation is being addressed by the Authority's BESS market enhancements project and MFK review.

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[6] At time of writing, the Authority is leading a project to review MFK, which may consider separating up and down regulation.

6.0 Market Issues

As discussed in section **Error! Reference source not found.**, current Code definitions make it unclear what a hybrid plant's current obligations are in respect of offers and dispatch. Conceptually, there are three market design options for how a hybrid plant can offer:

1. With the generation and BESS offered and dispatched separately. In this scenario, the generation component would be considered intermittent[7], but the BESS would be considered non-intermittent.
2. With the generation and BESS offered together, and the station output is not considered intermittent. In this scenario, the BESS would be expected to compensate for the variability of the generation.
3. With the generation and BESS offered together, the station output being considered intermittent.

We discuss the pros and cons of each option in the following sections, though explanations of required Code wording and market tool changes fall beyond the scope of this report.

Note that regardless of which the Authority progresses with, there is a separate risk concern for all IBR, including hybrid plants. Generally, the credible event (CE) risk from an IBR is limited to a single feeder[8]. However, if there is only one offer for the station, the market system cannot co-optimise this risk and will treat the entire station as a CE risk. There are several potential workarounds to this issue, one of which is for asset owners to submit multiple offers. The System Operator will continue to progress work on this issue separately. This is essentially a tooling rather than a market design issue, and we do not expect Code changes will be required to resolve it.

Finally, we anticipate that any changes to market design beyond treating hybrids the same as existing generation are likely to require the System Operator and NZX to implement certain updates to their tools. Such changes would likely constitute substantial work, requiring significant lead time.

6.1 Separate Offers and Dispatch

Under this option, the generation and BESS[9] would be offered entirely separately, as though they were entirely disconnected. The generation would be considered intermittent, unlike the BESS which would be expected to meet dispatch in each trading interval.

There are several advantages to this approach:

- It allows the generation to take advantage of intermittent classification while still allowing the BESS component to provide ancillary services.

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[7] Assuming that the generation component otherwise meets the definition of intermittent e.g. is wind or solar. It is theoretically possible to couple a BESS with i.e. a hydro or thermal plant, but the System Operator does not expect this to be common.

[8] Unless the whole station is classified as a CE, eg because there is a single station transformer

[9] Currently, a BESS must have offer injection and bid load at separate Pnodes. However, at the time of writing, the Authority is consulting on a change to allow a single bi-directional offer. In this report, we assume that bi-directional offering is implemented.

- It leaves open the possibility of intertemporally optimising[10] the BESS component if intertemporal optimisation becomes a market feature in the future.
- Arguably, this option provides the best representation of short-run cost, i.e. the generation offer can reflect the (presumably negligible) cost of the fuel source (i.e. solar irradiance) while the BESS offer can represent the opportunity cost of charging/discharging.
- Separate offers allow RMT to accurately model the frequency response of each component.
- Allows for existing forecasting, offer revision, and dispatch accommodations of IG reality to be utilised.

Disadvantages also exist:

- There is potential for tools problems. This is more likely an issue for DC-coupled hybrid plants and plants with an export capacity limit.
- It may result in more complexity in offering for some asset owners, particularly those who have a PPA and do not engage with the spot market. In this instance, the BESS offer may not reflect genuine costs but instead be whatever is required to guarantee it clears, so that the asset owner can meet the terms of their PPA.
- It is not clear how the IG flag[11] would be applied, i.e. could the BESS increase its load instead of the generation decreasing? Because there is not an obligation for BESS load to bid, this may be difficult to manage in the market system.

Note that as discussed in Section 2.3, this option is not possible within the current Code.

6.2 Combined, Non-intermittent Offer

Under this option the generation and BESS would be offered and dispatched as a single entity and would not be considered intermittent (i.e. the BESS would have to compensate for generation variability).

There are several advantages to this approach:

- It will result in better frequency regulation because the variability of the generation is automatically managed.
- It is unlikely to result in infeasible dispatch and generally would be easiest to implement in market tools.
- It gives asset owners more flexibility to manage their own plant and trading strategy.

Two main disadvantages exist:

- There is a risk that not allowing the generation component to be intermittent will discourage investment in hybrid plants and/or encourage asset owners to find workarounds.
- The central forecaster would not be required to forecast the total output and if they were, would not be able as accurately.

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[10] Intertemporal optimization refers to a market in which dispatch is optimized to get the lowest price over multiple trading periods, considering time-based constraints e.g. BESS state of charge, thermal plant start up time, etc.

[11] The IG flag is a flag in the market system that is applied to intermittent generation to dispatch it below its forecast generation potential when required

- The site would not be subject to the offer obligations associated with intermittent generation

For this arrangement to be practical the BESS would have to be sufficiently sized to manage the inherent variability of the IG. In the System Operator's view, there needs to be agreement between the System Operator and the Asset Owner that station dispatch is possible. We propose that should this option be pursued as a permanent solution, we would develop a minimum IG to BESS ratio that is required to be dispatchable and include it in the policy statement.

6.3 Separate Offers, Station Dispatch

This option is similar to the above, but with separate offers for the generation and BESS. The dispatch would still be at the station level, and the BESS would have to compensate for generation variability. If the IG part was treated as IG then the station dispatch would change every 5 minutes reflecting the IG output so the BESS would only have to cover for 5 minutes not the whole period. Note this is not possible in the current Code as discussed in Section 2.3.

6.4 Combined Intermittent Offer

Under this option, the generation and BESS would be offered and dispatched as a single entity and would be considered intermittent. The main advantage of this option is it allows asset owners maximum flexibility; however, the disadvantages are that it would result in worse frequency regulation, and the central forecaster would not be able to effectively forecast output. This may be acceptable for a small BESS but is likely not acceptable for larger BESS. The System Operator does not support this option, but we have included it for completeness.

6.5 Intermittent Generation Variability

When considering market design for hybrid plants, it is useful to consider the broader market design issues around managing intermittent generation variability. The Authority have indicated their intention to repurpose the MFK ancillary service as a variability management product.

Part of the MFK refresh project is to consider cost allocation (currently MFK costs are allocated to purchasers). If the costs of managing the variability were passed on to asset owners, this may change incentives for hybrid plants such that it is advantageous to the asset owner to manage the variability of the generation with the onsite BESS. By compensating the variability with the onsite BESS instead of relying on an MFK-like ancillary service, it is likely that transaction costs will be lower.

Depending on the outcome and implementation timelines of both this work and future work relating to intermittent generation, it may be necessary to change hybrid offer arrangements to be compatible with future arrangements.

A further consideration is that depending on how the plant controller is designed and the communication delay between PPC and inverters, the variability seen by the grid may increase compared to standalone generation. If the generation is being used to charge the BESS and injected into the grid, if the generation drops to zero the BESS may start charging from the grid, thereby the grid would see a net reduction of the injected generation plus the BESS load. This is more likely to be an issue in co-located and AC coupled hybrids, because in a DC-coupled plant the communication delay will likely be lower. Note that if the components are offered separately and the entire generation output is considered a CE risk, there would always be enough reserves to cover this scenario, but this may not be the most efficient approach.

7.0 International Approaches

This section features a summary of hybrid plant operation in the Australian NEM [4] and Californian [5] [1] markets. It should be noted that one-to-one comparisons are difficult because of different market designs. Unlike New Zealand, the Australian NEM and Californian markets do not co-optimise energy and reserve dispatch. Moreover, CAISO operate a day-ahead market as well as a real-time market. Although the System Operator sees the value in comparison to other jurisdictions, it is important not to assume that other jurisdictions made 'correct' decisions or are appropriate for our context.

7.1 Australian NEM

The Australian NEM classifies hybrid plants (and standalone BESS) as an 'integrated resource provider.' For AC-coupled plants, the following apply:

- Dispatch is by unit, with separate DUIDs (Dispatchable Unit Identifier, same as a Pnode in the New Zealand context) and offer curves for the BESS and PV.
- The BESS is considered a 'scheduled integrated resource unit' (IRU) and the PV is considered a 'semi-scheduled generating unit.' The terms 'scheduled' and 'semi-scheduled' are approximately equivalent to 'non-intermittent' and 'intermittent' in New Zealand.

For DC-coupled hybrid plants, participants can choose from three options:

- As a scheduled IRU; if this option is chosen, the plant is expected to meet dispatch regardless of solar installation/forecast, i.e. the BESS is required to be in service to compensate for solar variability.
- As a semi-scheduled generating unit; if this option is chosen, the dispatch is limited by AEMO's unconstrained intermittent generation forecast. The BESS cannot be charged from the grid.
- With the plant behind the inverter having separate classifications (i.e. BESS scheduled and PV semi-scheduled) and separate DUIDs; this option could potentially result in infeasible dispatch.

In terms of common quality obligations, the same requirements that apply to BESS apply to hybrid plants. Droop is based on the nameplate capacity of the inverters.

7.2 California

The Californian electricity market allows two participation models for hybrid plants, called the 'co-located' and 'hybrid' models. The 'co-located' model treats the PV and BESS separately, with separate resource IDs (Pnodes in the NZ context) and an aggregate capability constraint at the point of interconnection. In the co-located case, the PV is considered intermittent, and the BESS is not. In the ‘hybrid’ model, a single resource ID and offer curve represent the combined output of the hybrid. Hybrid resources are not considered intermittent and must meet dispatch. Asset owners can choose which model to use, and the choice does not depend on whether the plant is AC- or DC-coupled.

Common quality obligations are the same as obligations for BESS, because both standalone BESS and hybrid plants are classified as asynchronous generating facilities.

8.0 Discussion Points

This report discusses several issues and makes some propositions for the Authority and CQTG to further consider, including:

- Definitions of generating unit, generating station, and any intermediate grouping/s
- Definition of maximum continuous output
- Definition and obligations of idle BESS and hybrid plants
- Application of voltage and frequency AOPOs to hybrid plants
- Classification of hybrid plants as intermittent generators
- Market arrangements
- Credible event risk of a hybrid plant.

Additionally, hybrid plants may cause issues in market and real-time tools. The System Operator will address these issues as they arise, although generally market design must come before tool changes.

Finally, this report identifies several issues in relation to clause 8.17 frequency management. The System Operator's view is that these issues should be addressed as part of a broader frequency strategy project.

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Appendix C System Operator’s report – Technical analysis supporting a proposed change to clause 8.23

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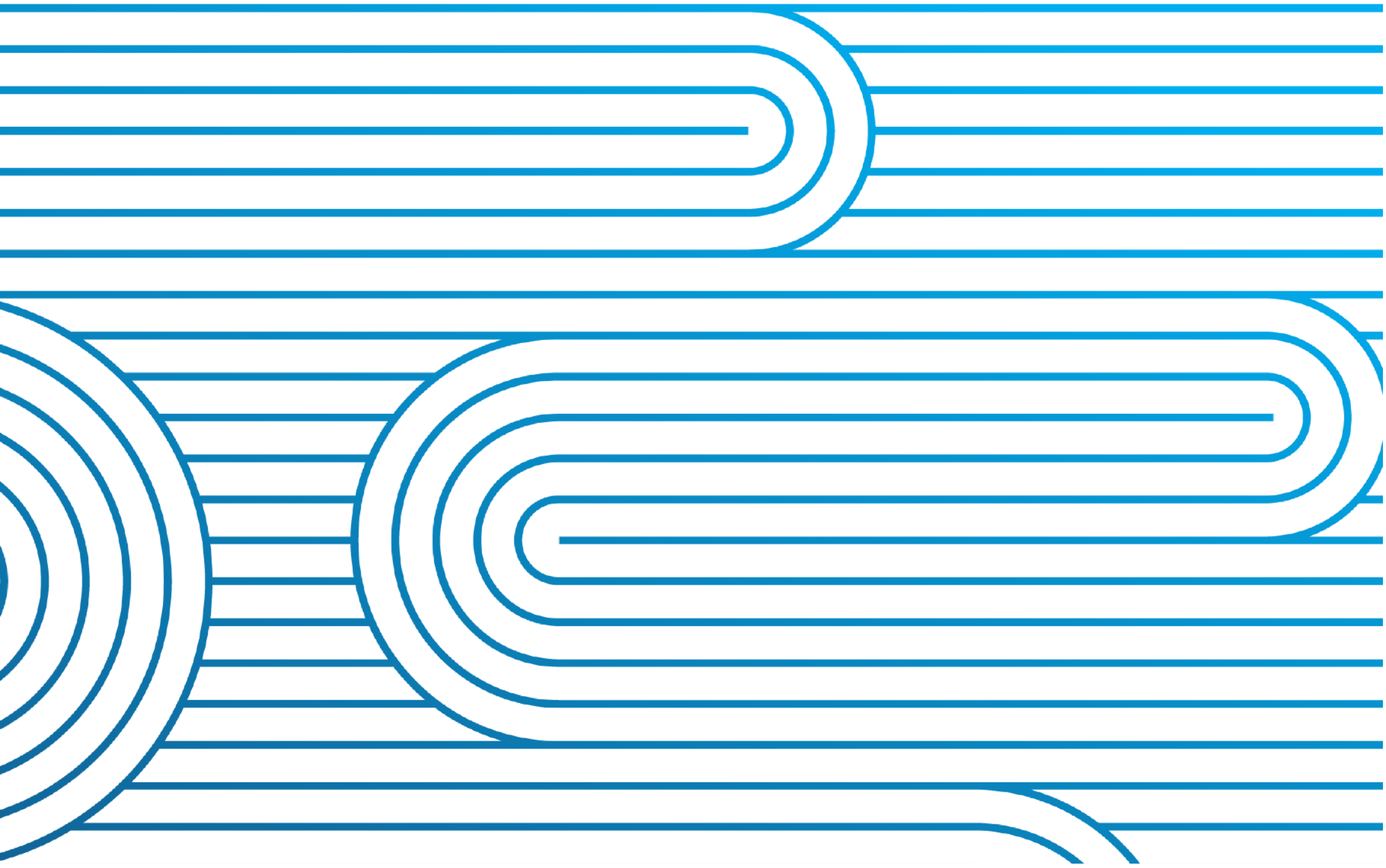
Technical analysis supporting a proposed change to clause 8.23

This document outlines the studies conducted to inform proposed changes to clause 8.23 of the Electricity Industry Participation Code.

Version: 1

Date: 10/02/2025



Objective

This technical report presents analysis prepared by the System Operator to inform the Electricity Authority’s consideration of proposed amendments to clause 8.23, under which:

1. The point of compliance for exporting/importing reactive power would be moved from the generating unit terminals to the generating station’s point of connection to the transmission grid. This represents a strategic shift from a unit-based requirement to a broader "station-level" requirement, ensuring the net performance of the entire generating station is measured at the station’s point of connection to the grid.
2. The existing reactive power export/import limits would be changed from +50%/-33% of maximum continuous MW output power or Maximum Continuous Output (MCO), measured at the generating unit terminals, to ±39.5% or ±33% of MCO, measured at the generating station’s point of connection to the transmission grid.

Challenge

Clause 8.23 currently specifies reactive power performance requirements for individual generating units. While this approach has historically been appropriate for synchronous machines—where the unit terminal and the low-voltage (LV) side of the connection transformer are typically co-located—it is ill-suited for emerging Inverter-Based Resources (IBR) such as large-scale wind farms.

A modern wind farm may consist of 60 to 70 individual turbines distributed over a vast geographic area. In these configurations, the connection transformers are often located several kilometres from the point of connection. This spatial separation introduces the following challenges:

- **Reactive Power Mismatch:** The distance between the generating units and the point of connection means that line/cable characteristics can alter the reactive power before it reaches the grid.
- **Compliance Complexity & Clarity:** The Code specifies that reactive power is to be measured at the generating unit terminals, and the Policy Statement assumes a two-bus system to aggregate generation at the connection transformer. Assessing compliance thus becomes challenging due to the resulting reactive power mismatch from the unit requirement in the Code. Moreover, the System Operator has requested grid-connected IBR plants to measure their reactive power compliance at the LV side of the connection transformer.

Consequently, the System Operator proposes that the compliance obligation shift from being "unit-based" to "station-based" and measured at the point of connection.

Key Findings

Reactive Power Export:

1. For existing connections, reactive power export is diminished by reactive power losses between the generating unit terminals and the point of connection (grid injection point).
2. The analysis focused on connection transformers, which can have one or multiple generating units connected to them. Based on this configuration, the results indicate:
    a. 70[1] and 36[2] installations in the North Island may not meet, respectively, the proposed 39.5% and 33% export requirements at the point of connection. There are 58 existing dispensations in the generation set (87 installations) considered in the North Island study.
    b. 40 and 36 installations[3] in the South Island may not meet, respectively, the proposed 39.5% and 33% export requirements at the point of connection. There are 45 existing dispensations in the generation set (47 installations) considered in the South Island study.

Reactive Power Import:

1. For existing transmission grid connections, reactive power import is observed to be higher at the generating station's grid injection point than at the generating unit terminals. This is an expected result and is due to the reactance of the plant (especially the transformer(s)) connected between the grid injection point and the generating unit terminals.
2. Placing the point of compliance at the grid injection point therefore may not fully utilise the generating station's reactive power import capability. The loss of the extra import support currently provided by grid-connected generating stations could adversely impact the System Operator's ability to manage high voltages on the transmission grid.

Conclusion and Recommendations

Clause 8.23 measures reactive power performance at the generating unit terminals (interpreted in the Policy Statement as being "measured at the generating plant terminal entering the generating plant transformer"), ignoring reactive power losses across the connection transformer and lines within the generating station (which may be at transmission voltage(s)). Many existing synchronous machine generating stations are designed with high impedance connection transformers. As a result, much of the reactive power support measured at the generating unit terminals is not visible at the grid interface. With IBR penetration increasing, an equivalent outcome becomes apparent as the connection transformer(s) are located far away from the grid injection point. The System Operator

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[1] 49 of these installations have existing dispensations.

[2] 28 of these installations have existing dispensations.

[3] All of these installations (40 and 36) have existing dispensations.

therefore considers it appropriate to move the point of compliance for reactive power to be at a generating station's point of connection, with a corresponding change to the minimum reactive power requirements specified in the Code. The System Operator suggests a transitional arrangement should be implemented, as imposing changes with immediate effect would place a resource constraint on industry and the System Operator due to the need to reassess and issue new dispensations.

Recommendations:

1. Move the point of compliance in clause 8.23 of the Code to be at a generating station's point of connection to the transmission grid.
2. Set the percentage value of the new limits to either ±39.5% or ±33%. Our study results do not indicate that one is better than the other. However, prescribing 33% may cause Asset Owner to design or operate their plant to the lower limit. While moving the point of compliance might improve visibility of export capability, care must be taken to avoid unintentionally reducing effective import support currently used for high-voltage management.
3. Retain clause 8.23 as a "minimum" reactive power obligation so that generating stations are expected to utilise, where practicable, the inherent reactive power capability to support grid voltage. By moving the point of compliance, this inherent capability would include the tap changing capability of the connection transformer.
4. Changes should be implemented with a grandfathering clause to mitigate human resource constraints, with the option to impose the new obligations after routine testing or when major investment/refurbishment of plant occurs (e.g. a transformer replacement or generator rewind).
5. The existing voltage range requirements should be retained.

Contents

1 Introduction

1.1 Background

Historically, New Zealand’s generating plants have been designed so that the connection transformer–the transformer connecting the generation station or unit to the grid, as referred to in Technical Code A of Schedule 8.3 of the Code–is physically located near the point of connection to the grid, limiting real and reactive power losses across the connection transformer. Emerging generating plant technologies are proving that this layout is not always a given: connection transformers are sometimes located a number of kilometres away from the point of connection to the grid. When clause 8.23 was designed, its underpinning assumptions did not consider the proximity of the connection transformers to the grid nor the differences and dispersed nature of emerging technologies compared to synchronous machines.

When a connection transformer is located some kilometres away from the point of connection to the grid, energy needs to be transferred over lines and/or cables. An inherent characteristic of lines and cables is that they absorb or generate reactive power based on their surge impedance loading. This can alter the net reactive power observed at the point of connection to the grid compared to the reactive power measured at the generator terminals.

1.2 Problem Statement

The general configuration of current generation is such that a generating unit or set of generating units are connected to a connection transformer which is then connected to the grid. With this configuration, the connection transformer and generating unit(s) transformer are the same piece of equipment.

The Policy Statement states that the reactive power capability will be measured at the “generating plant terminal entering the generating plant transformer” and assumes a two-bus system to determine compliance with clause 8.23. The term ‘generating plant transformer’ may not be clearly defined for emerging technologies such as wind and solar and it is unclear where the point of compliance for reactive capability may be for these types of plants, as the generating unit terminals are dispersed away from the collector station and connection transformer.

The current point of compliance for reactive power capability is on the LV side of the generating plant transformer (in this study the generating plant transformer is defined as the connection transformer while assuming a two-bus system. This is depicted in Figure 1 and Figure 2 below). Furthermore, collector stations and hence, connection transformers, may be located further away from the point of connection.

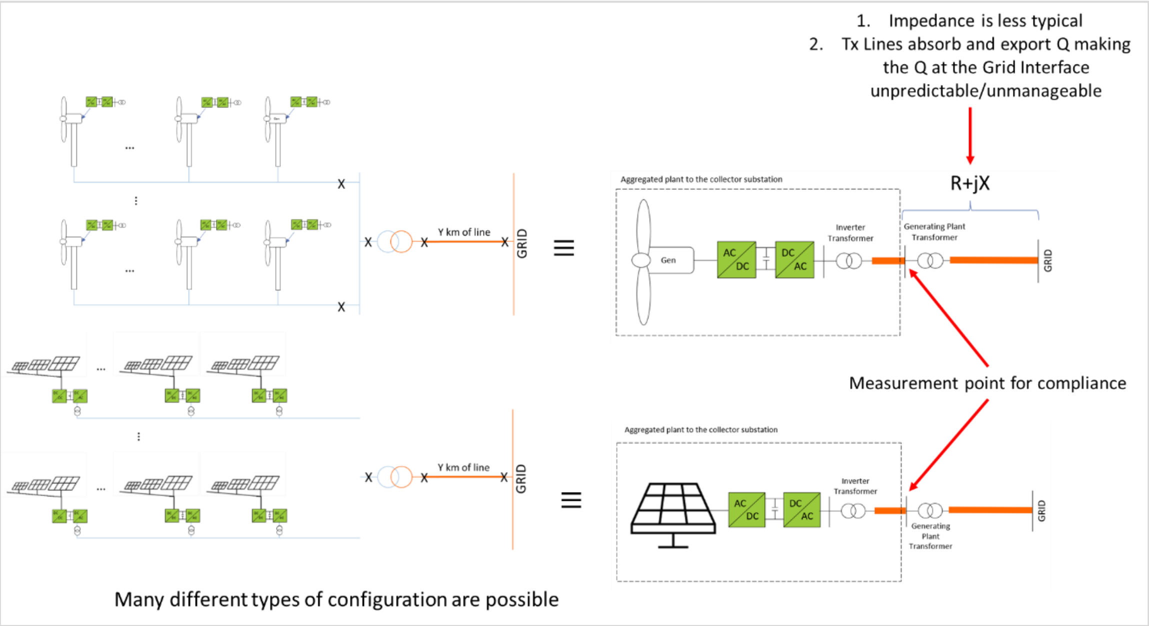

Figure 1: Existing point of MVAr compliance for generalised wind and solar plants.

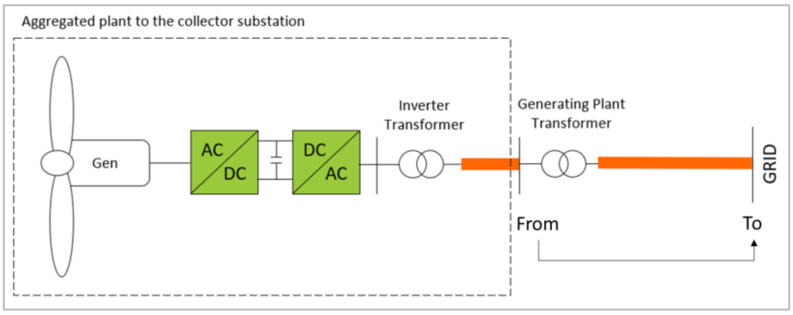

Figure 2: Proposed location for the new point of compliance.

1.2.1 Report Objective

This report outlines the System Operator's analysis to inform the following proposed changes to clause 8.23:

1. Move the point of compliance to the point of connection, thus moving from a unit-based requirement to a broader "station-level" requirement.
2. Change the existing limits from +50%/-33% to ±39.5% or ±33% of the MCO.

2 Assumptions

1. The use of the PowerFactory EMI case and its data is sufficient for this study.
2. Steady state operating conditions are used, and the loading of connection transformers are assumed to remain below 100% when estimating losses. In cases where the connection transformer loading exceeded 100%, the MCO was reduced to 98% while maintaining maximum reactive power dispatch.
3. It is assumed that all connection transformers can operate within voltage range limits specified in Code clause 8.22 without saturating the core.
4. In cases where two or more generating units are connected to a single connection transformer, all connected generating units are dispatched simultaneously across the single connection transformer to maximise the reactive power loss calculation.
5. For the steady state load flow, automatic tap changing was enabled for connection transformers whose tap changers have this capability. If automatic tap changing is disabled in PowerFactory, it is assumed that this capability is not available. Note that most connection transformers do not have on-load tap changing capability.
6. Embedded generating stations were not included in the analysis.
7. Future generation and connection transformer upgrades were not included in the analysis.
8. For historical data extracted from ".raw" files, not all data points are received as operational indications in SCADA. Any calculated values for generating unit terminal voltages are assumed to be sufficient for this part of the analysis. The purpose of this analysis was only to provide some context on the amount of reactive power export over a voltage range.

3 Limitations

1. For historical data extracted from ".raw" files, unsolved cases are not easily detected. To mitigate this, we expect the number of solves per day to be 180, as each solve should run every 8 minutes. Days with 180 solves were selected to avoid extracting data from potentially unsolved cases.
2. The accuracy of results is limited to the data in the PowerFactory casefile and accuracy of voltage estimation at the generating unit terminals.

4 Study Configuration

4.1 Methodology

We used PowerFactory to assess reactive power flow into the grid. This was achieved by dispatching a generating unit such that its active power is equal to its MCO. Thereafter, a generating unit was dispatched to import (33% of MCO) and export (50% of MCO) reactive power as measured at the generating unit terminals, unless the generating unit had an existing dispensation. The import and export requirements were set to meet the Code requirements at bus 1 and observed at bus 2 in Figure 3.

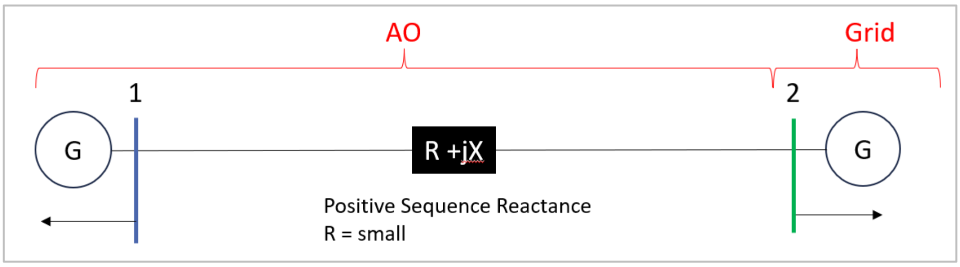

Figure 3: Illustration of the two-bus system used for MVAr compliance.

This method accounted for multiple generating units connected to a single connection transformer. For these cases, multiple generating units connected to a single connection transformer (e.g. Benmore) were dispatched together to measure the corresponding losses across the connection transformer, as the losses across the leakage reactance are proportional to the square of the current. This can be seen in Figure 4.

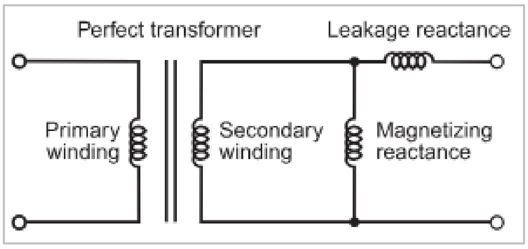

Figure 4: Transformer reactance per phase.

5 Results

5.1 Generating Unit Dispatch

The four plots shown in Figure 5 to Figure 8 aid in visualising the operating condition for each generating unit or aggregation of generating units[4] (in the case of wind farms or solar farms) in the study. Note that the assessment was conducted for each generating unit in isolation before moving to the next generating unit. In cases where multiple generating units are connected to a single connection transformer, all units connected to the connection transformer were dispatched simultaneously to correctly model the load and reactive losses across the transformer.

For each plot, the black diagonal line represents a point where $y=x$ and is used to visualise whether the dispatched MW for each generating unit is equal to the MCO. Green data points indicate the dispatched MW of each generating unit, while green data points outlined in red are cases where the dispatched MW are lower than the MCO. This was an intentional reduction in MW to alleviate overloading of the connection transformer. In addition to checking the export of each generating unit, the high-voltage (HV) terminal voltages were also observed to ensure that the study was not operating in a range where the connection transformer may go into saturation, as this would affect the accuracy of the study due to changes in losses and reactive power exported to the grid.

On each plot, the reactive power dispatch is indicated by black data points, where positive values represent export and negative values represent import. A second diagonal line is shown in red and represents $y=0.5x$ for export and $y=-0.33x$ for import. For each generating unit's MW export in green, vertically below in black is the reactive power export or import, forming a pair that represents the total dispatch state of the generating unit.

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[4] The aggregation of wind turbines and solar photovoltaics are represented by a single generator model in PowerFactory and in this report, this model is referred to as a generating unit.

North Island

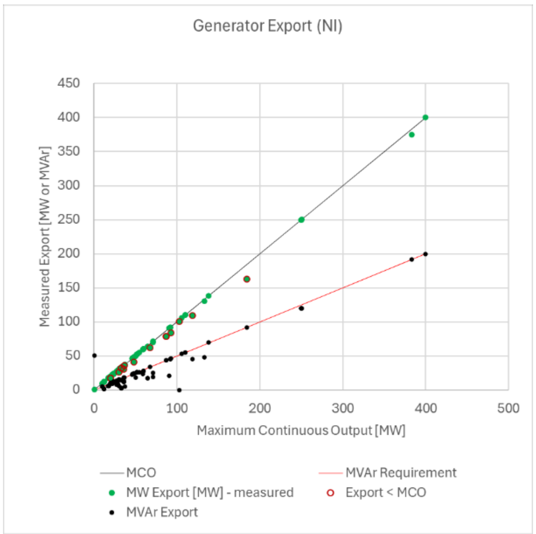

Figure 5: NI generating unit dispatch – Q Export (All).[5]

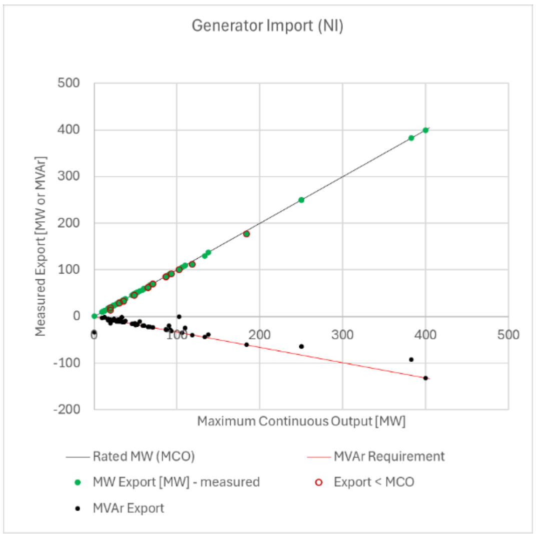

Figure 6: NI generating unit dispatch – Q Import (All).

South Island

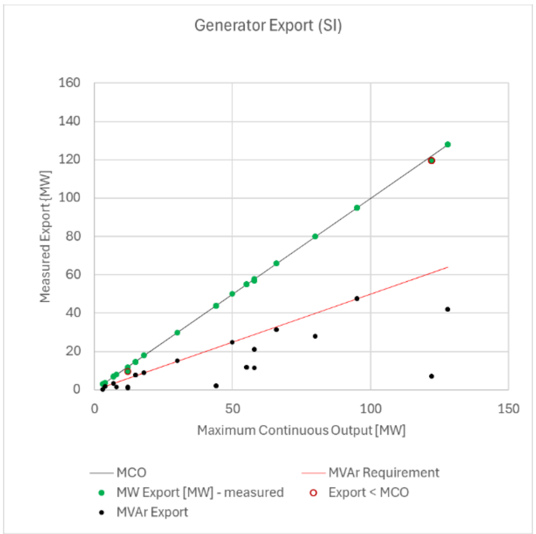

Figure 7: SI generating unit dispatch – Q Export (All).

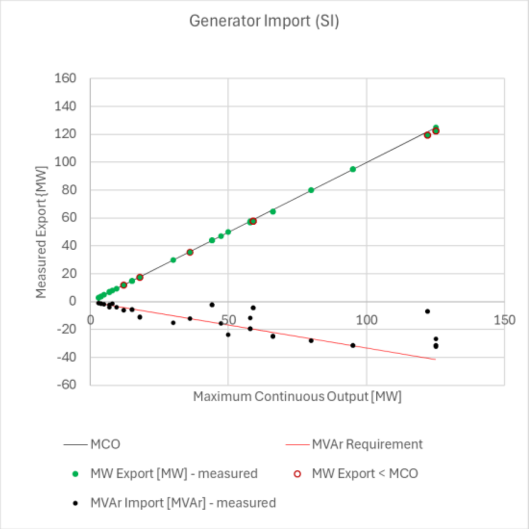

Figure 8: SI generating unit dispatch – Q Import (All).

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[5] The reactive power point (0 MW, 51 MVAr) represents a STATCOM export at a generating station and the reactive power point (102 MW, 0 MVAr) is the corresponding generation plant.

5.2 Reactive Power Assessment

The plots shown in the following figures show reactive power as a percentage of MCO (Q/MCO) on the y axis, with each connection transformer assessed on the x axis. These plots demonstrate the reactive power at the LV (purple markers) and HV (navy blue curve) terminals of the connection transformer, highlighting generating units with dispensations (circled in green), and potential new dispensation requirements under the proposed thresholds (orange squares).

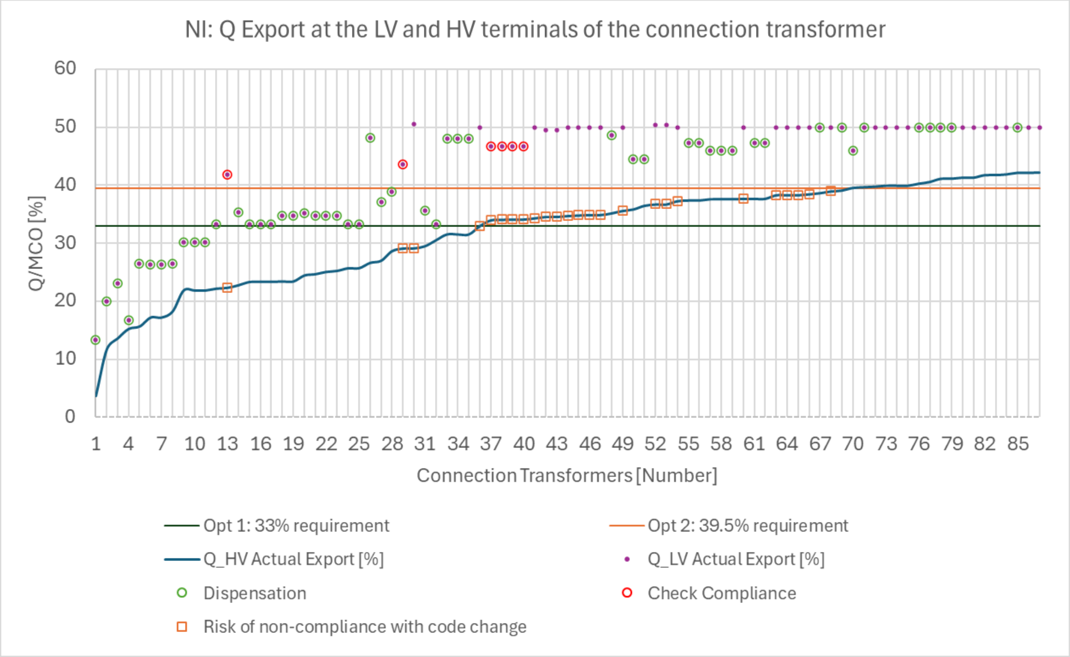

Figure 9: **North Island**, export case: Reactive power at the LV and HV terminals of the connection transformer.

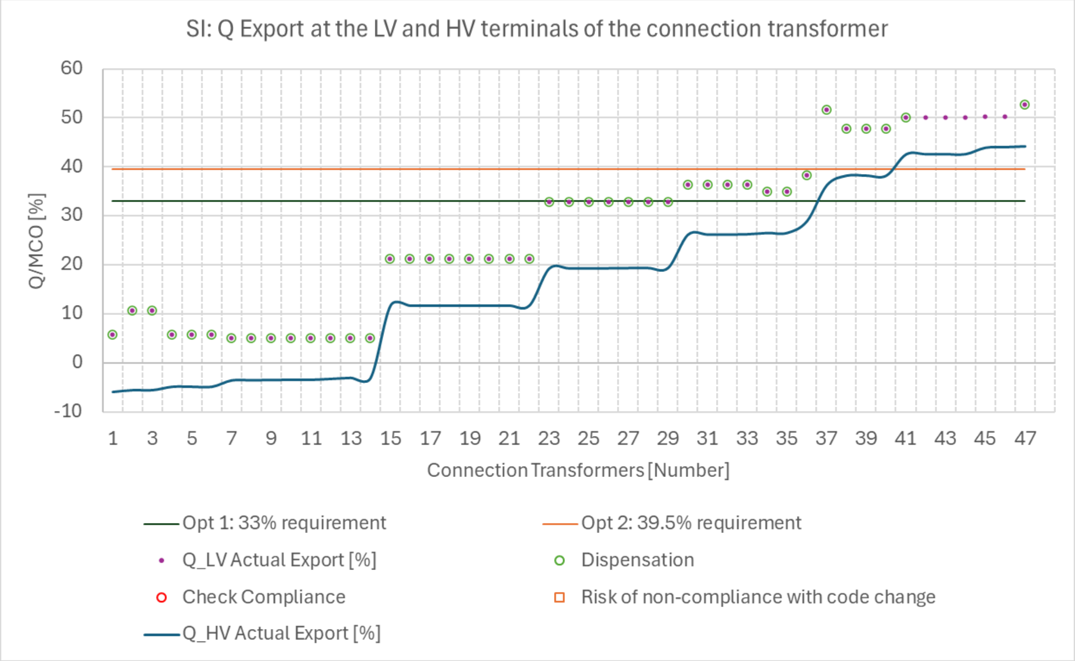

Figure 10: **South Island**, export case: Reactive power at the LV and HV terminals of the connection transformer.

As illustrated in Figure 9 and Figure 10, the reactive power on the LV side of the connection transformer (purple markers) is higher than the reactive power on the HV side (navy blue line) due to the reactive losses across the connection transformer. In these figures, the horizontal black line indicates a 33% export requirement, and the horizontal orange line indicates a 39.5% export requirement at the HV terminals. With reference to these requirements and existing dispensations, the plot indicates that a number of generating units that currently meet the 50% export requirement at the LV terminals will not meet the 39.5% export requirement at the point of connection. However, most of these generating units will meet the 33% requirement[6]. Find the study results below:

a. **North Island**: 70[7] and 36[8] installations may not meet, respectively, the proposed 39.5% and 33% export requirements at the point of connection. There are 58 existing dispensations in the generation set (87 installations) considered in the North Island study.
b. **South Island**: 40 and 36 installations may not meet, respectively, the proposed 39.5% and 33% export requirements at the point of connection. [9] There are 45 existing dispensations in the generation set (47 installations) considered in the South Island study.

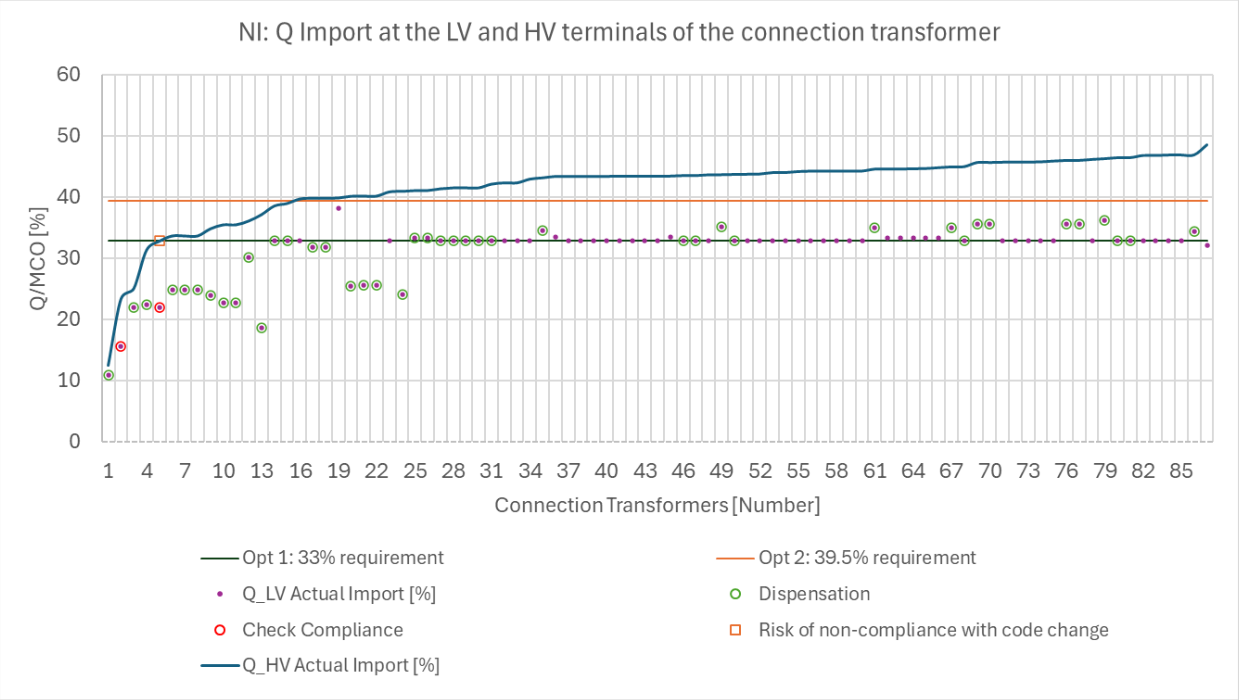

Figure 11: **North Island**, import case: Reactive power at the LV and HV terminals of the connection transformer.

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[6] It is to be expected that, should the Authority change the Code as proposed in this report, existing dispensations would have to be reassessed and new dispensations issued.

[7] 49 of these installations have dispensations.

[8] 28 of these installations have dispensations.

[9] All of these installations have existing dispensations.

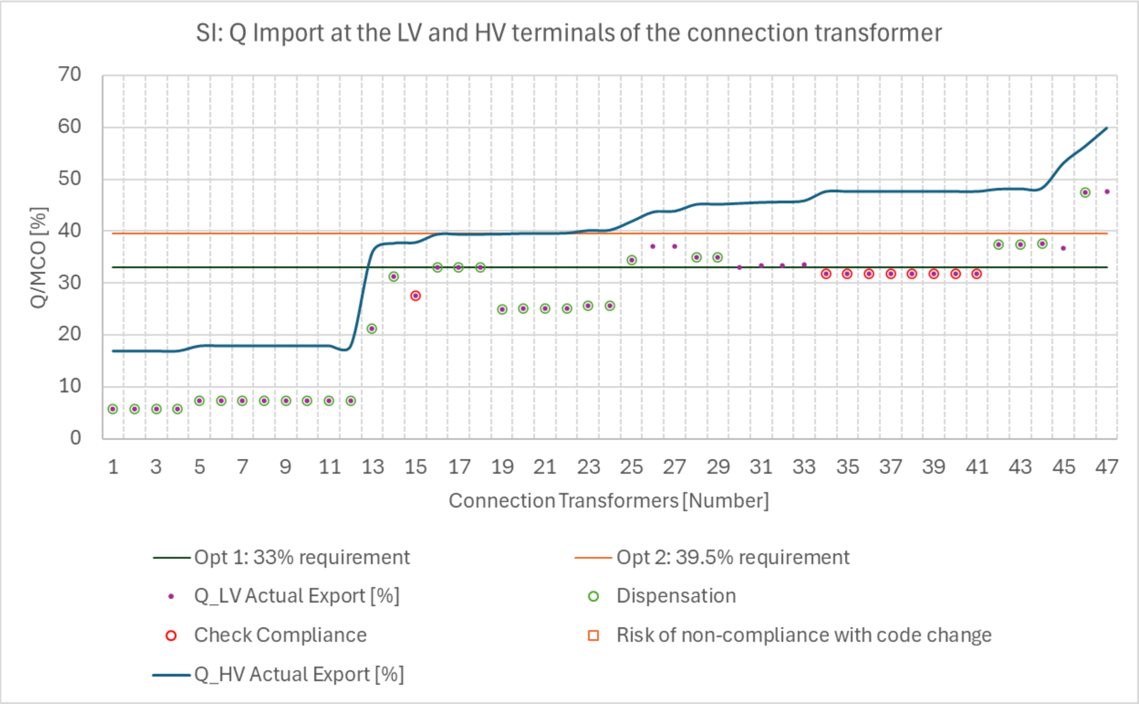


Figure 12: **South Island**, import case: Reactive power at the LV and HV terminals of the connection transformer.

Figure 11 and Figure 12 illustrate the import capability, where the reactive power at the HV terminals is higher than the reactive power at the LV terminals. Note that the connection transformer reactive power losses contribute to this additional import support. This plot shows that most generating units in the North Island that currently meet the 33% import requirement at the LV terminals will be able to meet the 39.5% import requirements at the HV terminals. Note that the sign of reactive power in PowerFactory is negative for import at the generating unit terminals. These signs were inverted to positive for direct comparison in all plots.

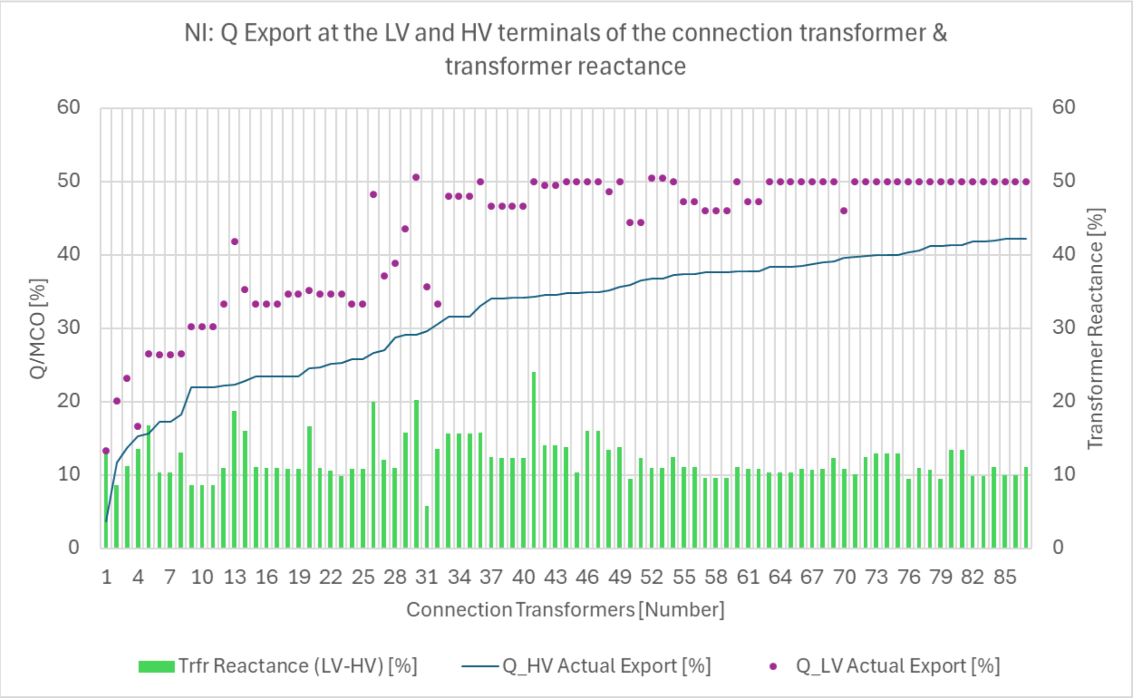


Figure 13: **North Island**, export case: Reactive power at the LV and HV terminals of the connection transformer and transformer reactance.

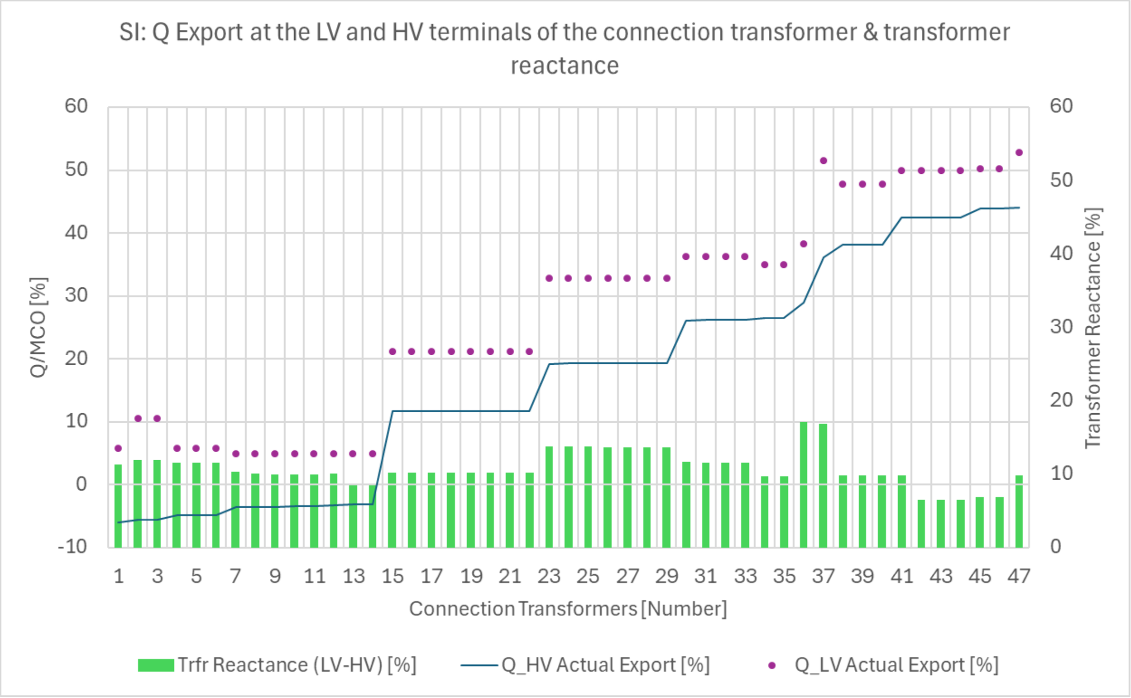


Figure 14: **South Island**, export case: Reactive power at the LV and HV terminals of the connection transformer and transformer reactance.

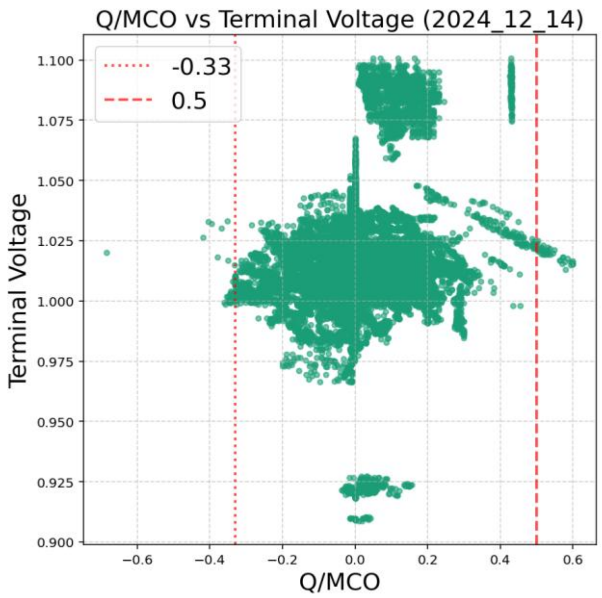
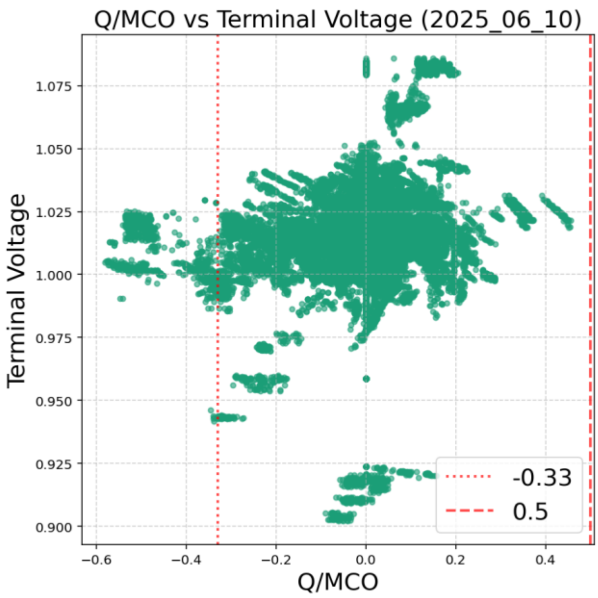
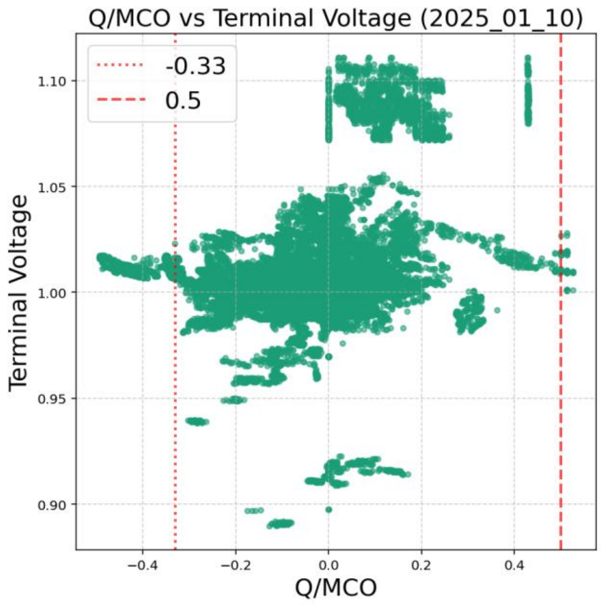
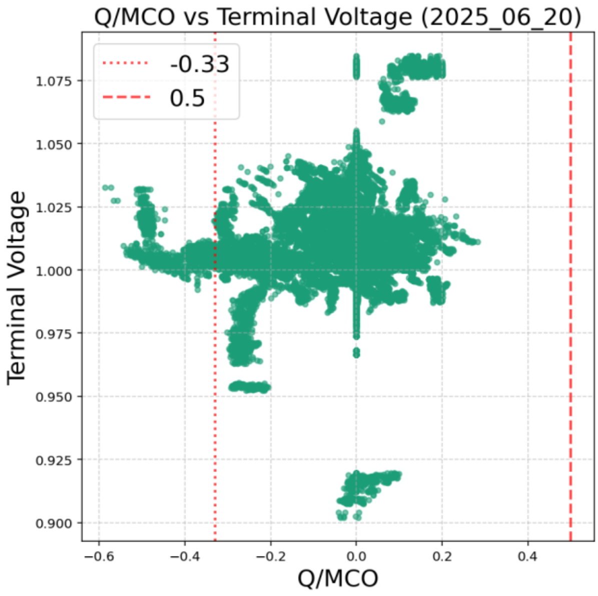
As seen in Figure 13 and Figure 14, the reduction in the reactive power on the HV side of the connection transformer is proportional to transformer reactance, noting that losses would be affected by transformer loading as well. These figures also show there are a number of high impedance transformers across both islands.

Historical Terminal Voltage Data vs Q/MCO Analysis

For generating units in the North Island and South Island, Figure 15 through Figure 22 below display historical generating unit terminal voltages versus Q/MCO for four representative days in summer and winter. These figures illustrate the actual voltage range at which reactive power was delivered at the generating unit terminals for voltage support to the grid across a 24-hour period and calculated from .raw files extracted from real-time cases.

While this data is not necessarily indicative of future trends, it highlights multiple occasions where significant reactive power import (absorption) was required in specific regions of the network. This demonstrates that the system currently relies on the aggregate import capability of these stations, including the inherent reactance of the connection transformers, to maintain stable operating voltages during high-voltage periods.

The existing additional import reactive power support is beneficial to manage the power system at high voltages. Applying a requirement at the HV terminals may not fully utilise a generating unit’s reactive power capability as the connection transformer reactance may be used to meet the reactive power capability obligation, which could adversely impact the System Operator’s ability to manage high voltages on the grid. We currently rely on the inherent capability of generating stations for system operation, as shown by the plots in Figure 15 through to Figure 22. Hence, it is important to retain this capability.

Summer	**Winter**
 Figure 15: Reactive power support vs voltage.	 Figure 16: Reactive power support vs voltage.
 Figure 17: Reactive power support vs voltage.	 Figure 18: Reactive power support vs voltage.

Summer	**Winter**

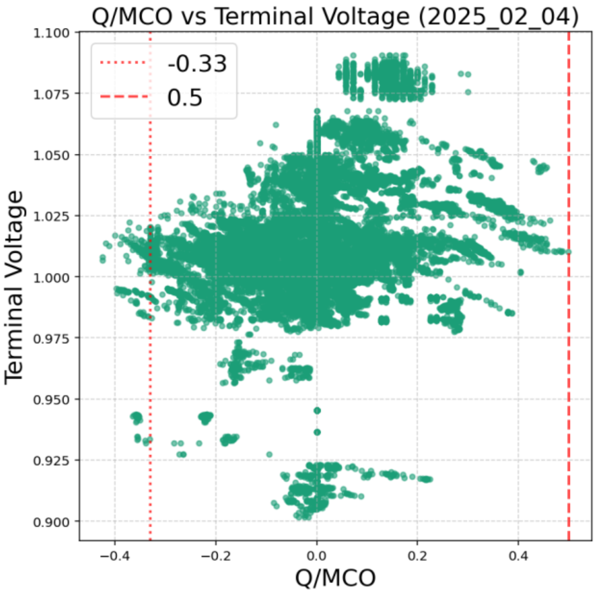


Figure 19: Reactive power support vs voltage.

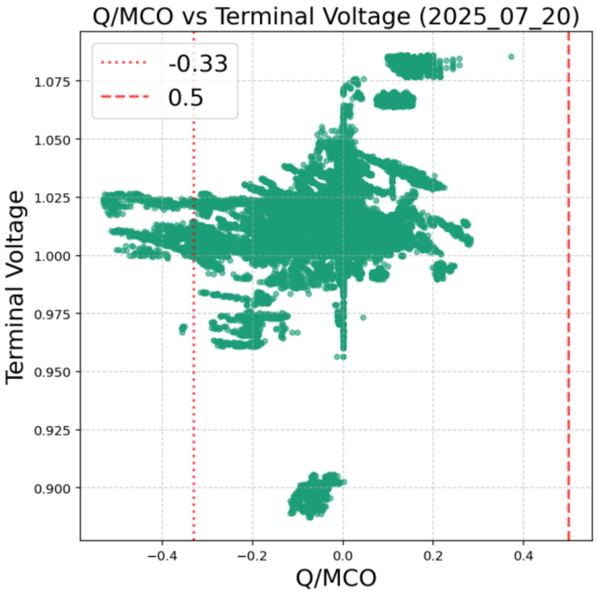


Figure 20: Reactive power support vs voltage.

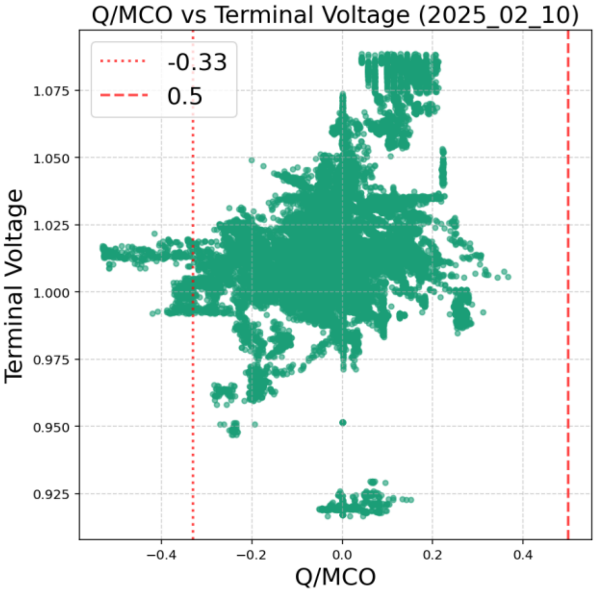


Figure 21: Reactive power support vs voltage.

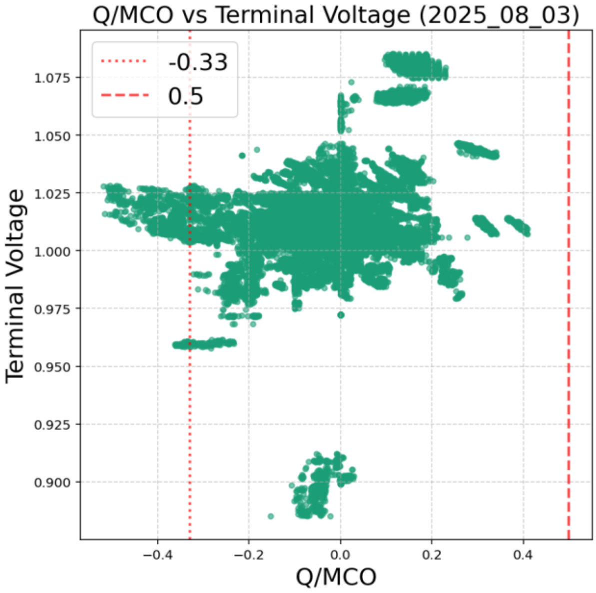


Figure 22: Reactive power support vs voltage.

6 Conclusion and Recommendations

6.1 Conclusion

With emerging technology types and potential varying plant configurations, reactive power export capability is expected to be lower at a generating station's point of connection than at the generating unit terminals. This is due to reactive power losses between generating unit terminals and the point of connection. The System Operator would have a better knowledge of a generating station's reactive power capability if the point of compliance for reactive power were moved from generating unit terminals to a station's point of connection to the grid. When moving the point of compliance to the point of connection, the percentage requirements for export in the Code must be reduced to maintain consistency with existing requirements. However, care must be taken to avoid unintentionally reducing effective import support currently used for high-voltage management.

Implementing these changes with immediate effect would place a human resource constraint on the electricity industry and the System Operator, as all existing dispensations would need to be reassessed and new dispensations assessed and issued. Hence, transitional arrangements need to be considered.

While the point of compliance should be moved to the point of connection, reactive power capability curves should continue to represent the plant's reactive power capability at the LV side of the connection transformer. This is because connection transformers and any transmission lines from a connection transformer to the point of connection are modelled in the System Operator's real-time tools and in the EMI casefile. PowerFactory models a generating unit's reactive power capability in the generator model. Maintaining LV-side curves aligns with the System Operator's current modelling practices and ensures the inherent capability of the plant is accurately represented within the dispatch tools.

6.2 Recommendations

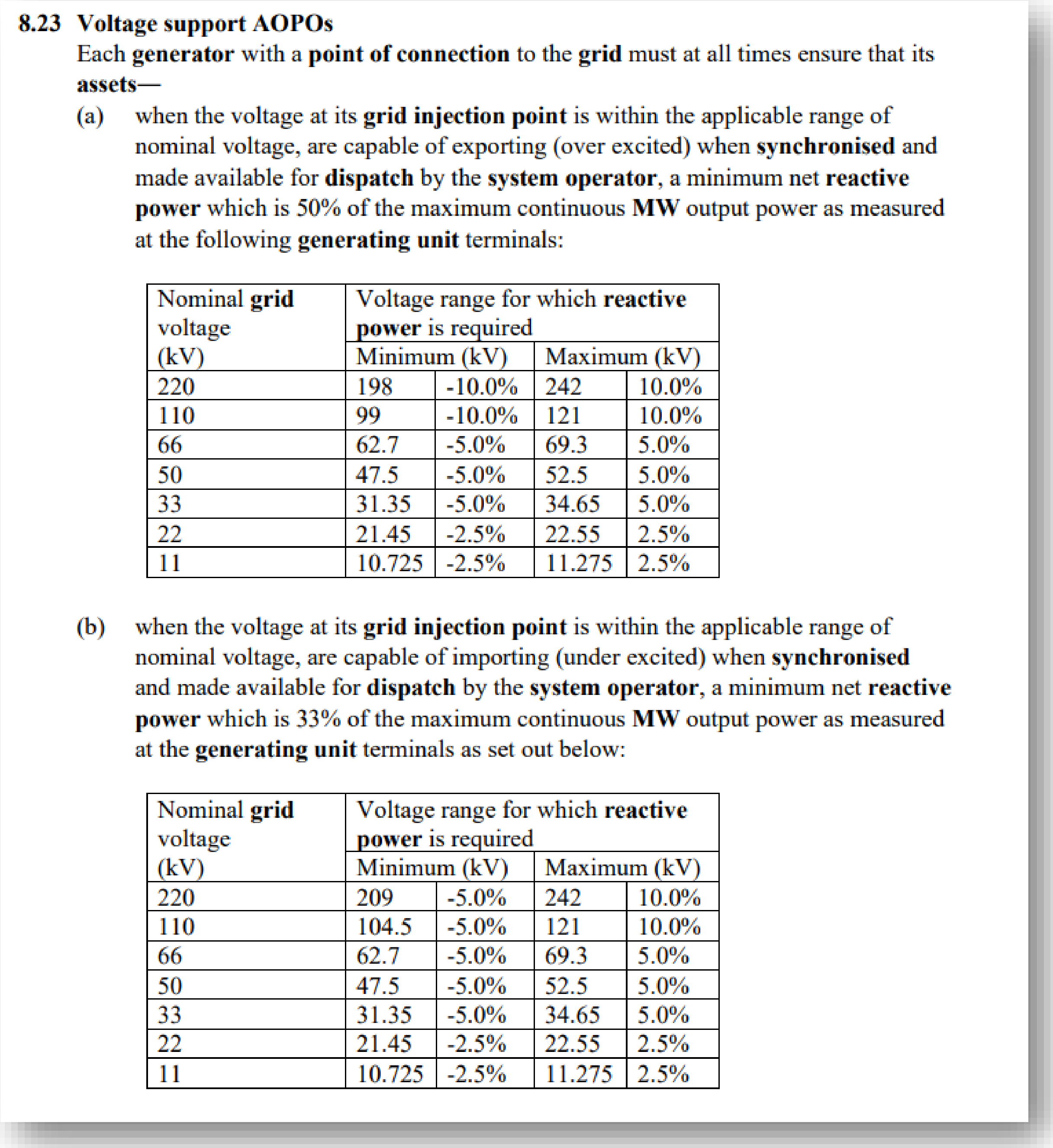
1. Move the point of compliance in clause 8.23 of the Code to be at a generating station's point of connection to the transmission grid.
2. Set the percentage value of the new limits to either ±39.5% or ±33%. Our study results do not indicate that one is better than the other. However, prescribing 33% may cause Asset Owner to design or operate their plant to the lower limit. While moving the point of compliance might improve visibility of export capability, care must be taken to avoid unintentionally reducing effective import support currently used for high-voltage management.
3. Retain clause 8.23 as a "minimum" reactive power obligation so that generating stations are expected to utilise, where practicable, the inherent reactive power capability to support grid voltage. By moving the point of compliance, this inherent capability would include the tap changing capability of the connection transformer.
4. Changes should be implemented with a grandfathering clause to mitigate human resource constraints, with the option to impose the new obligations after routine testing or when major investment/refurbishment of plant occurs (e.g. a transformer replacement or generator rewind).
5. The existing voltage range requirements should be retained.

Abbreviations

Abbreviation	Definition
Code	Electricity Industry Participation Code made under the Electricity Industry Act 2010
EMI	Energy Market Information
HV	High Voltage
IBR	Inverter-Based Resource
LV	Low Voltage
MCO	Maximum Continuous Output
MVAr	Megavolt-ampere reactive
MW	Megawatt
NI	North Island
POC	Point of Connection
Q	Reactive power
SCADA	Supervisory Control and Data Acquisition
SI	South Island
STATCOM	Static Synchronous Compensator

Appendix

Excerpt from the Code:



8.23 Voltage support AOPOs

Each **generator** with a **point of connection** to the **grid** must at all times ensure that its **assets**—

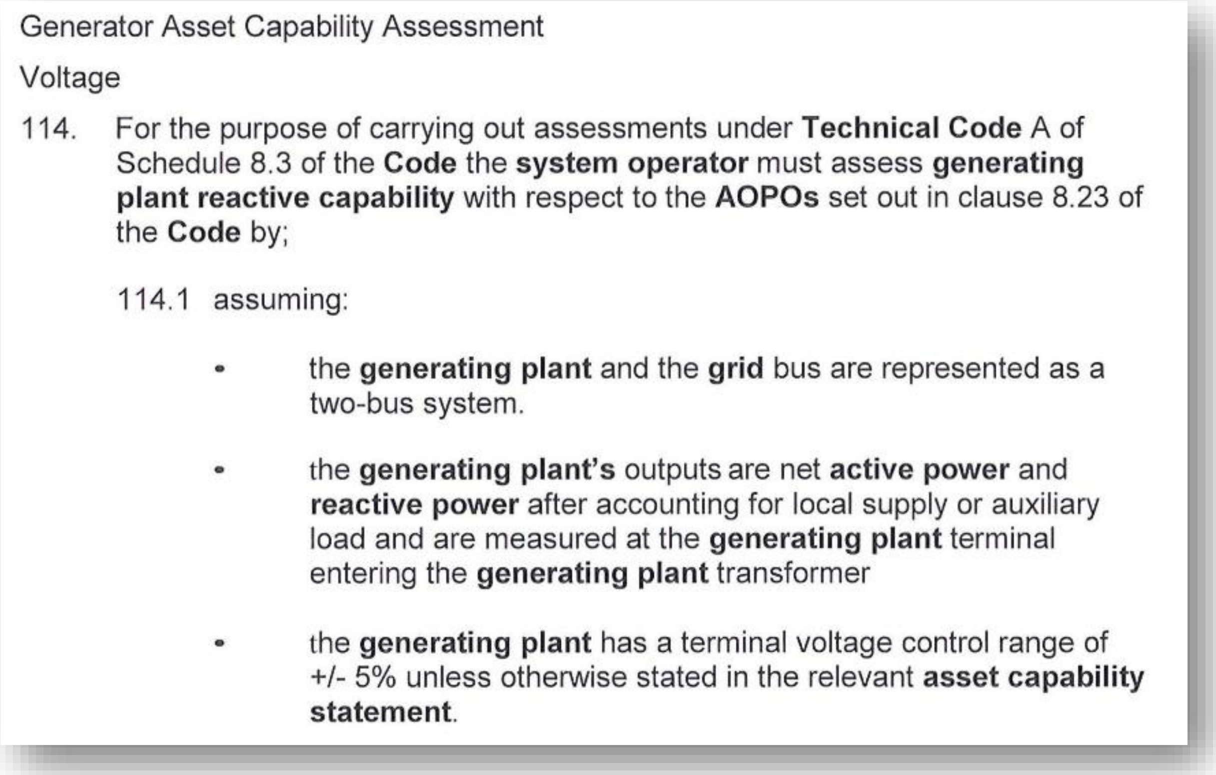
(a) when the voltage at its **grid injection point** is within the applicable range of nominal voltage, are capable of exporting (over excited) when **synchronised** and made available for **dispatch** by the **system operator**, a minimum net **reactive power** which is 50% of the maximum continuous **MW** output power as measured at the following **generating unit** terminals:

Nominal **grid** voltage (kV)	Voltage range for which **reactive power** is required			
	Minimum (kV)		Maximum (kV)	
220	198	-10.0%	242	10.0%
110	99	-10.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

(b) when the voltage at its **grid injection point** is within the applicable range of nominal voltage, are capable of importing (under excited) when **synchronised** and made available for **dispatch** by the **system operator**, a minimum net **reactive power** which is 33% of the maximum continuous **MW** output power as measured at the **generating unit** terminals as set out below:

Nominal **grid** voltage (kV)	Voltage range for which **reactive power** is required			
	Minimum (kV)		Maximum (kV)	
220	209	-5.0%	242	10.0%
110	104.5	-5.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

Excerpt from the Policy Statement:



Generator Asset Capability Assessment

Voltage

114. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant reactive capability** with respect to the **AOPOs** set out in clause 8.23 of the **Code** by;

114.1 assuming:

- the **generating plant** and the **grid** bus are represented as a two-bus system.
- the **generating plant's** outputs are net **active power** and **reactive power** after accounting for local supply or auxiliary load and are measured at the **generating plant** terminal entering the **generating plant** transformer
- the **generating plant** has a terminal voltage control range of +/- 5% unless otherwise stated in the relevant **asset capability statement**.

TRANSPOWER

Appendix D International experience with BESS-hybrid stations

New Zealand can fully enable the use of BESS and BESS-hybrid stations while the use of these technologies is in its early stages

D.1. BESS and BESS-hybrid station uptake remains limited in New Zealand compared with overseas jurisdictions. New Zealand's high penetration of renewable electricity generation, and evolving market and regulatory settings provide a context where BESSs and BESS-hybrid stations could be incorporated in a more coordinated way.

D.2. International experience shows the growing use of these technologies to support the integration of renewable electricity generation into the power system, along with power system flexibility and security of supply.

International experience using BESS and BESS-hybrid stations

Europe

D.3. Europe currently has around 5GW of utility-scale BESSs and 1.75GW of BESSs co-located with variable and/or intermittent renewable electricity generation.[37] The uptake of BESSs and BESS-hybrid stations has been uneven across the European Union, with BESSs and BESS-hybrid stations more concentrated in Germany and Italy. A reason for the uneven distribution in BESS uptake is that deployment of such technologies is more closely linked to national regulatory frameworks than technology maturity.[38]

D.4. In many European countries, notably Germany, France and the United Kingdom, BESSs have already become key providers of frequency response and reserves, helped by reforms that have enabled BESSs to access the markets for these services.[39] For example, Germany has actively promoted solar PV BESS-hybrid stations and renewable BESS-hybrid stations through its EEG Innovation Tenders, which require projects to combine generation with flexibility.[40]

D.5. In 2024, German network operators received almost 10,000 connection requests for BESSs at the medium voltage level, with a planned capacity of approximately 400GW. The currently installed capacity of medium-voltage storage systems totals around 2.3GW. Therefore, the biggest obstacle facing the connection of BESSs in Germany is the sheer volume of network connection requests for medium-to-large BESSs.

Australia

D.6. While there are not yet any operational BESS-hybrid assets in the Australian National Electricity Market (NEM), one solar PV BESS-hybrid station project has entered commissioning testing and is expected to be fully operational in the last

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[37] Hybrid Storage Assets Briefing.pdf

[38] Hybrid Storage Assets Briefing.pdf

[39] Batteries and Secure Energy Transitions

[40] Germany Seeking Bidders For Over 583 MW Renewable Energy Capacity

quarter of 2026.[41] Several other projects have reached financial close and are under construction. Network-connected utility-scale BESSs in Australia are increasing in size and duration, with major 4-hour batteries expected to come online between 2024 and 2028.

D.7. The BESS market is on track to commission approximately 21GW of storage by 2030.[42] By 2050, the NEM is expected to require 42GW of dispatchable BESS storage, with the majority of this expected to come from utility-scale BESSs.

D.8. It has been noted that existing grid infrastructure in Australia may be a potential obstacle to the uptake of BESSs, potentially complicating deployment and operational efficiency.[43]

United States of America

D.9. In the United States of America there are currently 543 BESS-hybrid stations in operation, with generation capacity of 57GW and BESS capacity of 14GW. The most common hybrid station configuration is solar PV-BESS, representing approximately 22GW of generation capacity and 12GW of BESS capacity. This reflects that solar PV-BESS uptake was higher than the uptake of other BESS-hybrid stations between 2020 and 2024. The total capacity of BESSs in hybrid stations grew by approximately 70% in 2024.[44]

D.10. BESSs in hybrid stations have been used for network services as much as, and in some cases more than, for pure energy arbitrage. These network services include:

- frequency regulation
- load following
- ramping and reserve
- voltage and reactive power support.

D.11. About 23% of all active projects awaiting connection to the United States power system are BESS-hybrid stations. Of this, nearly 87% of BESS-hybrid station generation capacity is solar PV.[45]

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[41] Quorn Park Solar Hybrid - Potentia Energy

[42] BESS Opportunities Article Report

[43] BESS Opportunities Article Report

[44] Hybrid Plant Tracking 2025

[45] Hybrid Plant Tracking 2025

Appendix E Format for submissions

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

Submitter	

Section 3: Terminology

Questions	Comments
Q3.1. Do you support the proposed 5-level structure for generating asset definitions?	
Q3.2. Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?	
Q3.3. Do you have any feedback on the System Operator's recommendations in its *Hybrid Plant Integration* report?	

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.	
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.	
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.	
Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?	
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.	

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.	
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.	
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?	
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.	
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.	
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.	
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?	
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.	
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.	
Q5.10. Do you consider there to be an alternative that is preferrable 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.	
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?	
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.	
Q5.13. Do you consider that legacy arrangements would be needed for existing generation? Please give reasons for your answer.	

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 circumstances, over the alternative option of creating new obligations for BESS-hybrid stations? If not, why not?	
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?	
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?	
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?	
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?	