Promoting reliable electricity supply – a Code amendment proposal on common quality-related information

Consultation paper

1 July 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the security and resilience of New Zealand's power system to ensure that it delivers the best possible outcomes for consumers. To help achieve this, we are refining industry rules to accommodate new and emerging technologies and changing system dynamics while maintaining a stable and reliable power system for consumers.

A key part of this is the Future Security and Resilience (FSR) work programme—a multi-year initiative focused on preparing the power system for the challenges and opportunities of electrification. A crucial part of this programme is a review of the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code).

Through targeted engagement and consultation, the Authority identified seven key issues[1] with these requirements. One of these key issues is a lack of sufficient information provided to network operators and owners about assets connected or connecting to the power system. This limits the ability of network operators and owners to plan and operate the system safely, reliably and efficiently.

This consultation paper sets out the Authority's proposal to amend the Code to clarify and update the Part 8 common quality information requirements and to separately incorporate technical specifications in a new system operation document.

The proposed changes will ensure the system operator has timely access to accurate information it needs to operate the power system in accordance with its principal performance obligations under the Code. Among other things, this would reduce the risk of consumers facing economic costs associated with:

- the imposition of overly conservative constraints that may suppress generation or increase electricity market inefficiencies
- unforeseen power system behaviours during disturbances or high-stress events
- major electricity outages.

We sought feedback on three high-level options

In October 2024, we sought feedback on three options to improve the provision of common quality-related information to network owners and operators.[2] We also sought views on placing various common quality-related information requirements in a separate system operation document incorporated by reference in the Code.

We are addressing the information-related issue in two stages

After considering submitter feedback, the Authority proposes to proceed with the third short-listed option to:

- update and clarify the common quality-related information requirements in the Code

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1 Review of common quality requirements in Part 8 of the Code

2 Electricity Authority, Addressing common quality information requirements - Consultation paper, October 2024.

- enable the system operator to share common quality-related information with distribution network operators
- enable the system operator to share common quality-related information with Transpower, as a transmission network owner.

The Authority intends to implement this proposal in two stages:

Stage one involves updating the Code so that the system operator receives necessary common quality-related information from asset owners. This includes incorporating in the Code a new system operation document containing technical specifications for the common quality-related information requirements.

Stage two will consider the broader framework for the sharing of common quality-related information between the system operator, Transpower as a transmission network owner, and distributors.

This staged approach allows us to first address immediate concerns, before turning our attention to developing solutions to the more complex challenge of enabling the sharing of common quality-related information between the system operator and Transpower, as a transmission network owner, and with distributors.

The Connected Asset Commissioning, Testing and Information Standard

The Authority proposes a number of technical requirements for common quality information obligations, including some that are currently in the Code, be put in a new system operation document called the Connected Asset Commissioning, Testing and Information Standard (CACTIS) that would be incorporated by reference in the Code. It would detail information about assets, commissioning, testing and operational communications that the system operator needs to meet its principal performance obligations under the Code.

Due to the technical nature of common quality information requirements, the Authority considers that it is more practical for the system operator to author and maintain the CACTIS. The Authority would retain final approval over its incorporation into the Code and any future amendments.

A first draft of the proposed CACTIS is included as Appendix B. The system operator will consult separately on its content in September 2025. In the meantime, the Authority invites feedback on the attached draft, which we will share with the system operator to help inform the final drafting of the document.

We welcome your feedback

The Authority welcomes feedback on the Code amendment proposal in this paper and on the draft CACTIS. During the consultation period, Authority staff will be available upon request for individual and group briefings with interested stakeholders.

Next steps

We will make our final decisions on the Code amendment proposal after considering all submissions received. We will share our decisions and supporting rationale in a decision paper, which we anticipate will be published towards the end of 2025.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. This paper seeks feedback on a proposal to improve the provision of common quality-related information to the system operator for use in operating New Zealand's power system.

1.2. The Electricity Authority (Authority) proposes to amend the Electricity Industry Participation Code 2010 (Code) to incorporate by reference in the Code a 'Connected Asset Commissioning, Testing and Information Standard' (CACTIS) prepared by the system operator.

1.3. The CACTIS will include the technical specifications relating to:

(a) the information, including modelling information, provided to the system operator in an asset capability statement (ACS)

(b) the information provided to the system operator as part of commissioning assets connected to the power system

(c) standards for periodically testing an asset or configuration of assets

(d) the minimum requirements for operational communications between asset owners and the system operator

(e) the minimum requirements for high-speed monitors that asset owners must install

(f) the timeframes in which asset owners must provide the system operator with the documentation and information required by the CACTIS.

1.4. We have built on the thinking set out in our 2023 common quality issues paper[3] and 2024 consultation paper on short-listed options.[4] We discuss the options considered for addressing these issues and the rationale for our preferred approach.

1.5. Section 5 of this paper outlines the Code amendment proposal, while Section 6 presents a regulatory statement for the proposal. The regulatory statement assesses the proposal against the requirements in section 32(1) of the Electricity Industry Act 2010 (Act).[5] The regulatory statement includes the proposal's objectives, an evaluation of its costs and benefits, and an assessment of alternative ways to achieve its objectives.

1.6. We have assessed the proposal against the Authority's main objective under section 15(1) of the Act, which is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act does not apply to

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3 Electricity Authority, Future Security and Resilience Issues paper - Part 8 common quality requirements, April 2023.

4 Electricity Authority, Addressing common quality information requirements - Consultation paper, October 2024.

5 This enables the Code to include provisions consistent with the Authority's objectives that are necessary or desirable to promote the matters listed in section 32(1).

the proposal as the proposal does not involve dealings between electricity industry participants and domestic and small business consumers.

How to make a submission

1.7. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to fsr@ea.govt.nz with '*Consultation Paper—Promoting reliable electricity supply – a common quality-related information Code amendment proposal*' in the subject line.

1.8. If you cannot send your submission electronically, please contact the Authority (fsr@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions we receive. If you consider that the Authority 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 received by the Authority, including any parts the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12. Please deliver your submission by 5pm on Tuesday 12 August 2025.

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

Next steps following our consultation

1.14. Following our consultation on this paper, the Authority will consider submissions received and decide whether to proceed with the Code amendment proposal, and if so, whether to proceed with it as proposed or in a varied form. Our indicative timing for this decision is the end of 2025.

1.15. If, after considering submissions, the Authority were to proceed with Code amendments based on the proposal in this paper, we propose these amendments would come into effect on 1 July 2026. This would provide a period of approximately six months from our anticipated decision to when the proposal, or some form of it, was effective.

2. Introduction

2.1. New Zealand's power system is being transformed from one dominated by large synchronous power stations to a diverse mix of generation resources and technologies of various sizes. At the same time, consumers are engaging with their electricity supply in new and innovative ways.[6]

2.2. Operating a power system is highly complex and dynamic. The system operator must continuously balance the supply and demand for electricity, manage voltage and frequency, and maintain sufficient reserves to handle unexpected events while keeping the system within its operational design limits. This is to ensure a secure and reliable power system that continuously meets consumers' demand for electricity.

2.3. To help achieve this outcome, the system operator must have access to certain information about assets connected to the power system. As New Zealand's economy becomes more electrified, it will become more difficult to manage fluctuations in peak electricity demand, increasing variability and intermittency of electricity supply, and the resilience of the power system.

2.4. The Authority's Future Security and Resilience (FSR) work programme is one of several Authority initiatives supporting New Zealand's transition to a more electrified economy. Other such Authority initiatives include:

(a) Improving the visibility of distribution networks.

(b) Developing solutions for issues with the power system's peak capacity.

(c) More efficient prices and processes for connecting to distribution networks.

(d) Reviewing the customer switching process and enabling multiple electricity retailers/traders to offer services to a consumer.

(e) A programme to encourage innovation in the electricity industry (the *Power Innovation Pathway (PIP)* programme).

The Future Security and Resilience programme

2.5. The Authority's Future Security and Resilience (FSR) programme is a multi-year work programme that seeks to ensure New Zealand's power system remains secure and resilient as the country transitions towards a more electrified economy.

2.6. The FSR programme is focused on how New Zealand's power system operates in real time, or close to real time, to continuously balance electricity supply and demand and to supply consumers with electricity that is of an appropriate quality.

2.7. One of the most critical parts of this programme is a review of the common quality requirements in Part 8 of the Code.

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6 By 'power system' we mean all the components of New Zealand's electricity system, such as generation, transmission, distribution, and consumption (load) assets.

Reviewing the common quality requirements in Part 8 of the Code

2.8. The aim of the review of common quality requirements in Part 8 of the Code is to ensure these requirements enable new and evolving technologies, particularly inverter-based resources (IBRs), in a manner that is consistent with the Authority's statutory objectives. This includes:

(a) ensuring the common quality requirements in Part 8 of the Code accommodate and facilitate opportunities offered by new and evolving technologies, particularly IBRs

(b) addressing the increasing risk to the power system's security and resilience from more distributed generation being installed and bi-directional electricity flows becoming more prevalent

(c) mitigating the increasing risk of investments in new and evolving technologies bringing about outcomes that are not for the long-term benefit of consumers.

2.9. For the review, the Authority defines 'common quality' to cover all connected transmission and distribution networks in New Zealand. This definition is broader than the Code's definition, which defines 'common quality' as relating only to the transmission network. The broader definition reflects the shared security and resilience challenges across both the transmission network and distribution networks.

What is 'Common Quality'?

'Common quality' refers to those elements of the quality of electricity conveyed across New Zealand's power system that cannot be isolated to an identifiable person or group of persons.

An example is the frequency of electricity, which is the rate (measured in Hertz) at which electrical current alternates between having a positive voltage and a negative voltage. Voltage is the force or pressure that pushes electrical charges along an electrical conductor, such as a power line or a power cord. New Zealand's power system operates at a standard frequency of 50 Hertz, which means electrical current is switching between positive and negative voltage 50 times a second.

If this frequency becomes too high or too low, electrical equipment can be damaged. At the extreme it could cause power outages, adversely affecting large numbers of consumers.

2.10. Although the review's primary focus is the common quality requirements in Part 8 of the Code, the review is considering linkages between these common quality requirements and requirements in other parts of the Code.

Information provision is a key issue for common quality

2.11. In April 2023, the Authority published an issues paper identifying seven key issues with the common quality requirements in Part 8 of the Code.[7]

[7] Electricity Authority, Future Security and Resilience Issues paper - Part 8 common quality requirements, April 2023.

2.12. One of these issues concerns the provision of common quality-related information to network owners and operators. We summarised this issue as follows:

> *Network owners and operators lack sufficient information about assets seeking to connect or already connected to the power system. This limits their ability to plan and operate the system safely, reliably, and efficiently.*

2.13. Following the 2023 consultation, we considered ways to enhance the availability of information for network operators and owners, so they can better support common quality across New Zealand's power system.

2.14. The Authority has engaged with various stakeholders through formal meetings and informal discussions, including:

(a) the Common Quality Technical Group – which is providing technical advice to the Authority on the Part 8 common quality review

(b) Transpower, as the system operator

(c) distribution network owners and operators

(d) Transpower, as a transmission network owner.

2.15. Our discussions with stakeholders have highlighted challenges in obtaining asset information, particularly modelling data for IBRs like wind generation, solar photovoltaic generation, and battery energy storage systems (BESSs).

Three options were shortlisted to address the information-related issue

2.16. In October 2024, the Authority published a consultation paper seeking feedback on three options to improve the provision of common quality-related information to network owners and operators.

Short-listed options to help address the common quality-related information issue	
Option 1	Update and clarify common quality-related information requirements in the Code
Option 2	Update and clarify common quality-related information requirements in the Code, <u>and</u> enable the system operator and distribution network operators to share common quality-related information
Option 3	Update and clarify common quality-related information requirements in the Code, <u>and</u> enable the system operator and distribution network operators to share common quality-related information, <u>and</u> enable the system operator to share common quality-related information with Transpower as a transmission network owner.

2.17. The consultation also sought feedback on placing various common quality-related information requirements in a system operation document incorporated by reference in the Code.

2.18. We received 12 submissions on the consultation paper, which are available on the Authority's website.[8] **Appendix F** of this paper includes a summary of submitters' feedback.

2.19. After considering submitter feedback, the Authority proposes to amend the Code to implement Option 3 and to put a number of technical requirements for common quality information obligations in a new system operation document incorporated by reference in the Code.

The Authority will address the information-related issue in two stages

2.20. The Authority has decided to address the common quality-related information issue in two stages. This approach is consistent with feedback received in submissions. By building on existing Code obligations, the Authority can efficiently address what stakeholders have identified as the most pressing concerns.

2.21. Stage one comprises updating and clarifying the Code's common quality information requirements to better enable the system operator to support common quality. This includes the proposal to incorporate by reference in the Code a new system operation document containing a number of technical requirements for common quality information obligations.

2.22. The Code amendment proposal in this paper relates solely to stage one.

Stage two will consider common quality information shared between the system operator, distributors and Transpower, as a network owner

2.23. The second stage will comprise updating and clarifying the Code's common quality information requirements to better enable distributors and Transpower, as a transmission network owner, to support common quality. This work will consider what common quality-related information should be shared between these parties and the system operator, how this information should be shared, and the extent to which information transparency can be promoted.

2.24. This stage will involve significant engagement with distributors, Transpower, and other affected parties. This is to ensure solutions developed are feasible and practical, align with industry needs, and deliver outcomes that are for the long-term benefit of consumers.

2.25. Effective power system planning and reliability depend on the exchange of asset-related information. The Authority recognises the Part 8 common quality requirements are interrelated with other parts of the Code. In particular, there are existing provisions in Parts 6 and 12 of the Code that enable, respectively, distributors and Transpower as a transmission network owner to obtain relevant information from asset owners.[9]

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8 See Electricity Authority I Future security and resilience I October 2024 common quality Code amendment proposals I Submissions.

9 An asset owner means a participant who owns an asset used for the generation or conveyance of electricity and a person who operates such asset and, in the case of Part 8, includes a consumer with a point of connection to the transmission network.

2.26. Stage two will consider the common quality-related information requirements in Parts 6 and 12 of the Code, to address these interdependencies. This will help ensure a more integrated and effective regulatory framework that supports both the security and operational efficiency of the power system.

2.27. International experience shows that effective regulatory frameworks for information sharing can enhance the security and resilience of the power system. The Authority is incorporating lessons from overseas jurisdictions in our work on common quality information requirements.

The Authority has used a technical group to help develop the proposal

2.28. The Authority established the Common Quality Technical Group in June 2023 to provide technical advice during our review of the common quality requirements in Part 8 of the Code.[10] The Common Quality Technical Group has 11 members drawn from the electricity industry. Their knowledge and experience collectively range from power system operation, both at the transmission and distribution levels, to generation and demand-side management technologies.

2.29. Their operational and technical perspectives have been especially beneficial to the Authority in developing the Code amendment proposal in this consultation paper.

The Authority has engaged with the system operator

2.30. The Authority has also engaged with the system operator in developing more efficient solutions for managing common quality-related information.

2.31. The system operator has the technical expertise and system knowledge to author the document that is proposed to be incorporated by reference in the Code. Given its role in managing real-time system operations and ensuring power system security, the system operator is uniquely positioned to define the technical specifications required for common quality-related information.

2.32. Through this engagement, the Authority has worked to refine the information-sharing framework to ensure it is both practical and aligned with industry needs, such as appropriate confidentiality arrangements and compliance costs are proportionate to factors such as risk and size of asset.

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10 Further information on the Common Quality Technical Group is available on the Authority's website at Common Quality Technical Group | Electricity Authority (ea.govt.nz).

3. The existing arrangements

3.1. The system operator is responsible for planning and operating the power system in a safe, reliable and economically efficient manner. To fulfil this role, the system operator requires information about assets that are connected, or intend to connect, to the power system.

3.2. This section summarises the current requirements for asset owners to share common quality-related information with the system operator under Part 8 of the Code.

The system operator requires information about assets to meet the principal performance obligations

3.3. The system operator is responsible for the scheduling and dispatch of electricity in real time in a manner that keeps the frequency and voltage of electricity supply within acceptable limits and avoids the disruption of electricity supply. In addition to its real-time co-ordination activities, the system operator assesses planned maintenance outage information and publishes these assessments where there is a potential failure to meet the system operator's principal performance obligations (PPOs).

3.4. Under the Code the system operator has high level, output-focused PPOs in relation to common quality and electricity dispatch. These PPOs may be summarised as operating the power system to maintain frequency and voltage in real time, to avoid a 'cascade failure' of New Zealand's power system.

3.5. To enable the system operator to meet the PPOs, the Code places some mandatory performance obligations on asset owners. These obligations are known as asset owner performance obligations (AOPOs).

3.6. To enable the modelling, monitoring and management of power system reliability and security, the system operator requires information to:

(a) enable the connection of new assets and the upgrade of existing assets

(b) conduct power system studies for planning purposes

(c) investigate power system common quality issues

(d) assess compliance with AOPOs

(e) undertake system studies not specific to a connected asset, and

(f) support the real-time operation of the power system and on-going protection co-ordination.

Asset capability statement information

3.7. Part 8 of the Code requires each asset owner to provide the system operator with an asset capability statement for each asset connected to or forming part of the transmission network, or which the asset owner proposes be connected to the transmission network.

3.8. The asset capability statement must, amongst other things, include:

(a) all information reasonably requested by the system operator so as to allow the system operator to determine the limitations in the operation of the asset that the system operator needs to know for the safe and efficient operation of the transmission network

(b) any modelling data for the planning studies, as reasonably requested by the system operator.[11]

3.9. Supporting these Code obligations are the system operator's companion guides for the commissioning of generation. For example, the system operator's guide *Connection Study Requirements for Connecting a New Generating Station* is intended to provide direction to an asset owner needing to submit connection studies to the system operator. This document is intended to provide clear and complete technical requirements, a study methodology, and acceptance criteria for performing connection studies.[12]

Commissioning and test planning

3.10. The Code places obligations on asset owners in relation to commissioning plans and test plans for:

(a) assets to be connected to the transmission network or which form part of the transmission network

(b) changes made to assets (eg, certain changes to protection or control systems)

(c) ascertaining or confirming asset capabilities.[13]

3.11. The Code also places obligations on owners of embedded generation to provide information to the system operator regarding the intended output of each embedded generating station greater than 10MW. This applies if the system operator reasonably considers it necessary to assist in planning to comply, and complying, with the PPOs and achieving the dispatch objective.[14]

Periodic testing

3.12. The periodic testing requirements cover a range of assets, including generating units, transmission network infrastructure, and protection systems. These tests verify the correct operation of frequency response mechanisms, voltage control systems, and protection functions. Regular testing ensures that system components respond appropriately to disturbances and comply with operational performance expectations.

3.13. Clause 8(2) of Technical Code A of Schedule 8.3 of the Code requires asset owners to carry out periodic testing of their assets in accordance with Appendix B of Technical Code A. This ensures that assets remain compliant with AOPOs and

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11 See clause 2(5) of Technical Code A of Schedule 8.3 of the Code.

12 Transpower, *Connection Study Requirements for Connecting a New Generating Station*, May 2023.

13 See clause 2(6)-(8) of Technical Code A of Schedule 8.3 of the Code.

14 See clause 8.25(5)(a) of the Code.

technical codes, contributing to the stability, reliability, and efficiency of the power system.

3.14. Following the relevant tests, asset owners must submit information to the system operator. This information enables the system operator to evaluate system performance, identify potential risks, and implement necessary adjustments to maintain power system security and reliability.

3.15. For generators that are connected to the transmission network, this includes:

(a) a verified set of control parameters for their generating unit transformers' on-load tap changer control systems, including voltage set points, operating dead bands and response times

(b) a verified set of modelling parameters and voltage response data for their generating units' voltage control system.

3.16. For all generators, except owners of excluded generating stations, this includes:

(a) a verified set of under-frequency and over-frequency trip settings and time delays for their generating units' under- / over-frequency relays / protection settings

(b) a verified set of modelling parameters and governor or frequency control system response data for their generating units' speed governors and/or frequency control system.

3.17. For transmission network owners, this includes:

(a) a verified set of control parameters for their transformers' on-load tap change control systems, including voltage set points, operating dead bands, and response times

(b) a verified set of modelling parameters, transient response parameters, steady state response parameters, and alternating current disturbance response data for their dynamic reactive power compensation devices

(c) a verified set of control system test results for their reactive power control assets, including voltage set points, operating dead bands, and time delays

(d) a verified set of modelling parameters and voltage response data for their synchronous compensators.

3.18. South Island transmission network owners must also provide to the system operator a verified set of trip settings and time delays of their automatic under-frequency load shedding systems. In the North Island, this obligation rests with distributors and consumers directly connected to the transmission network.

3.19. The owner of the high voltage direct current (HVDC) link between the North and South Island must provide the system operator with:

(a) a set of control system test results for the HVDC link

(b) a set of protection system test results for the HVDC link.

3.20. All asset owners must verify that their alternating current protection systems comply with the relevant AOPOs and technical codes. Additionally, asset owners that own a dynamic reactive power compensation device must provide the system operator with a verified set of modelling parameters, transient response parameters, steady state response parameters, and alternating current disturbance response data for this device.

Operational communications

3.21. The Code mandates that communication systems must be capable of transmitting critical operational data and that asset owners must always maintain reliable communication channels to support system operations. Effective communication between asset owners and the system operator is essential for real-time system monitoring, co-ordination of network responses, and the efficient dispatch of generation and load.

3.22. Technical Code C of Schedule 8.3 of the Code establishes the minimum communication requirements between asset owners (except owners of excluded generating stations) and the system operator. These requirements are designed to ensure efficient, reliable, and accurate communication, supporting the system operator in meeting the PPOs.

3.23. As part of these operational communication requirements, asset owners must provide the system operator with real-time indications and measurements regarding the performance and status of their assets. These include generator output levels, voltage data, transformer tap positions, circuit breaker statuses, and other telemetry necessary for power system operation. The system operator relies on this information to ensure compliance with dispatch instructions and make informed operational decisions, including in managing contingencies on the power system.

3.24. Asset communication systems must meet specified performance standards, including latency, redundancy, and security measures to prevent data loss or delays. Asset owners must also have contingency measures in place to restore communication in case of failure, ensuring uninterrupted data exchange with the system operator. Compliance with these communication requirements is monitored and enforced by the system operator. Asset owners are required to promptly rectify any deficiencies that could compromise power system security or operational effectiveness.

4. Issues the Authority would like to address

4.1. A core function of the system operator is to plan and operate the power system in a safe, reliable and economically efficient manner. To fulfil this role, the system operator requires detailed technical and modelling information about assets that are connected, or intend to connect, to the power system.

4.2. However, the Authority considers that the system operator is not currently receiving sufficient or consistent information to support effective system planning and operation. In the absence of detailed information, the system operator will operate the transmission network more conservatively than if the system operator had better information. This cautious approach is necessary to avoid potential economic losses for consumers and industry participants that could arise from power system disturbances caused or exacerbated by assets.

4.3. This section summarises the key issues that underpin this concern. For a more detailed discussion, we encourage you to read the October 2024 consultation paper on options to improve the provision of common quality-related information to network owners and operators.[15]

Some Part 8 information requirements are ambiguous

4.4. The Code does not prescribe in detail the specific asset-related information that asset owners must provide to the system operator. For example, while the Code requires asset owners to provide any modelling data for planning studies, as 'reasonably requested' by the system operator, it does not define what constitutes a reasonable request.[16] There are further ambiguities in the Code, including around the requirements for:

(a) timeframes for submitting information

(b) commissioning and test plans

(c) model types (for example, RMS, EMT)

(d) model compatibility with software platforms (for example, PowerFactory, TSAT, PSCAD)

(e) use of model encryption

(f) validation, documentation and maintenance of models

(g) connection studies

(h) periodic testing obligations

4.5. These ambiguities have led to inconsistent interpretations between asset owners and the system operator. In practice, this results in delays, inefficiencies, and in some cases, disputes about what must be provided. Although the system operator

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15 Electricity Authority, Addressing common quality information requirements - Consultation paper, October 2024.

16 Clause 2(5)(b) of Technical Code A of Schedule 8.3 of the Code.

has published guidelines to help clarify expectations, these are not enforceable, and compliance remains an issue.

Some Part 8 information requirements are outdated

4.6. As technologies evolve, the common quality information requirements must keep pace to remain effective. The Code amendment process, while transparent and robust, is not well suited to updating technical specifications quickly. This can result in delays that leave the system operator without the information needed to manage new or emerging technologies.

4.7. Some of the existing information requirements in the Code no longer reflect current operational practices or technological capabilities. These lags in updating requirements contribute to information gaps, limiting the system operator's ability to plan for contingencies, assess system behaviour, and maintain secure and efficient operation of the power system.

Modelling information is changing

4.8. As more IBRs connect to the power system, the modelling requirements for planning and operation are more complex. IBRs behave differently from traditional synchronous generators and require more sophisticated modelling to understand how they affect power system behaviour. While root mean square (RMS) models were historically sufficient, electromagnetic transient (EMT) models are now also needed to accurately capture the fast-switching, software-driven controls of IBRs.

4.9. These models are critical for identifying risks such as voltage and frequency instability, unintended control interactions, or protection issues, particularly during system disturbances. Without access to appropriate models, the system operator may underestimate these risks, potentially compromising system security.

Information provided to the system operator is sometimes incomplete or sub-standard

4.10. Models submitted to the system operator are sometimes incomplete, inaccurate, or do not meet the required technical standards for accuracy and engineering best practice. Several factors contribute to this issue:

(a) IBRs require more detailed and precise modelling than traditional generators, and their dynamic behaviour is not always accurately captured.

(b) Some asset owners dispute what qualifies as a 'reasonable request,' and manufacturers may withhold model details due to intellectual property concerns.

(c) Asset owners use different modelling tools, and converting models between platforms (e.g. PowerFactory, TSATools, PSCAD) is increasingly difficult, error-prone, and can result in data loss.

4.11. Incomplete information imposes a cost on the system operator, who must either correct sub-standard models or request resubmissions. While one poor-quality model may have limited impact, multiple low-quality models increase the risk of unforeseen power system behaviours during disturbances or high-stress events.

This can undermine the operator's ability to carry out reliable planning, compliance assessments, and real-time operations.

Confidentiality concerns create barriers to sharing information

4.12. A further challenge is the reluctance of equipment manufacturers to share detailed models due to concerns about protecting intellectual property. This is particularly the case for EMT models, which often contain proprietary software-based control systems. These systems, which vary between manufacturers, are implemented in software and define the key performance characteristics of the IBR.

4.13. While the system operator can sometimes access models by engaging directly with equipment manufacturers, this process is informal, time-consuming, and not always successful. In many cases, the system operator must sign a non-disclosure agreement (NDA), which introduces additional delays, legal complexity, and administrative burden. Moreover, some manufacturers still choose not to provide the requested information.

4.14. These confidentiality concerns create a bottleneck in the system operator's ability to obtain accurate and detailed data for planning, analysis, and compliance assessment. Other jurisdictions, such as Australia, have introduced formal frameworks that allow model encryption and establish enforceable confidentiality protections (see the Australian case study below for an example).

Case study: Australian approach to modelling information and intellectual property

An independent study commissioned by the Australian Energy Market Commission found that equipment manufacturers generally were willing to share detailed EMT models with the Australian Energy Market Operator (AEMO) and network service providers (including distributors) but were reluctant to share these models with third parties, such as the owners of other generating assets or loads.[17]

AEMO developed a structured framework that allows equipment manufacturers to protect their IP while still meeting modelling obligations. AEMO allows model providers to black-box, compile, or encrypt portions of EMT models, as long as the model still meets usability requirements and can be used for system studies. Furthermore, any third party that receives modelling information is required to treat it as confidential.

4.15. These international approaches suggest that an enforceable framework that permits model encryption and sets clear confidentiality obligations can protect manufacturers' intellectual property while ensuring the system operator has access to accurate, detailed models needed for secure and efficient system operation.

Declining visibility of smaller generators

4.16. IBRs are expected to make up a larger share of New Zealand's generation capacity over the coming years. As these technologies become more prevalent and cost-

[17] AECOM Australia, EMT and RMS Model Requirements, June 2017

effective, they will be accessible to a wider range of commercial, industrial, and residential users.

4.17. A growing share of new generation is expected to operate below the current 10 MW threshold that requires asset owners to provide information to the system operator. For example, solar PV systems and BESS installations on commercial and industrial sites often operate at capacities below this threshold. Because the Code does not mandate detailed data provision from these generators, they can connect to the power system with limited visibility to the system operator.

4.18. As more generating stations below the 10 MW threshold connect to the power system, the system operator will have less information about their output and behaviour. This reduces the system operator's visibility of the power system in real time, making it more difficult for the system operator to forecast electricity demand and supply, plan for contingencies, and efficiently operate the parts of the power system it is responsible for.

5. Proposal

5.1. The Authority proposes to amend Part 8 of the Code to update the framework under which asset owners provide common quality-related information to the system operator. This is to better enable the system operator to plan to comply, and comply, with the PPOs. We note this is expected to also assist the system operator in achieving the dispatch objective in Part 13 of the Code.[18] This will benefit consumers by ensuring a secure and reliable power system that continuously meets consumers' demand for electricity.

Clarify common quality information requirements

5.2. The Code amendment proposal would require asset owners to provide common quality-related information to the system operator that meets the technical specifications set out in a new system operation document. System operation documents are documents developed by the system operator, that are incorporated by reference in the Code. The proposed system operation document, the CACTIS, would specify:

(a) the information, including any modelling information, that asset owners must provide the system operator in an asset capability statement

(b) the information asset owners must provide the system operator relating to commissioning a new or existing asset or configuration of assets

(c) standards for periodically testing an asset or configuration of assets

(d) minimum requirements for operational communications between asset owners and the system operator

(e) minimum requirements for high-speed monitors that asset owners must install

(f) the timeframes in which asset owners must provide the system operator with the documentation and information required by the CACTIS.

5.3. Existing technical specifications in Part 8 of the Code relating to these matters would be removed from the main body of the Code and added to the new system operation document. These technical specifications are:

(a) certain technical specifications in the main body of Technical Code A of Schedule 8.3

(b) Appendix B of Technical Code A of Schedule 8.3: Routine testing of assets and automatic under frequency load shedding systems

(c) Technical Code C of Schedule 8.3 – Operational communications.

5.4. **Appendix A** contains a draft of the proposed amendments to the Code.

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18 See clause 13.57 of the Code.

The proposed Connected Asset Commissioning, Testing and Information Standard

5.5. The proposed new system operation document would be called the Connected Asset Commissioning, Testing and Information Standard (CACTIS).

5.6. Section 64 of the Legislation Act 2019 empowers the Authority to incorporate by reference a wide range of material, including a standard, framework, code of practice, recommended practice, or requirement of an international organisation or a national organisation, or any other written material that deals with technical matters if it is reasonable to consider that it is impracticable to include the material in the Code or the material is so large that including it in the Code will prevent persons to whom the law applies from using or understanding the Code with reasonable ease.

5.7. While the power to incorporate material by reference has the potential to give material legislative effect, even where material is not authored by the Authority itself, the decision to exercise the power ultimately lies with the Authority, as the entity that has been given the delegated authority to make and administer the Code.

5.8. The content of the CACTIS meets the requirements for the kinds of materials that can be incorporated by reference in the Code. This is due to the specialist technical nature of the CACTIS in specifying the information that the system operator requires about assets, commissioning, testing, and operational communications to meet the PPOs.

5.9. Further, the system operator has the requisite technical expertise and power system knowledge to author the CACTIS. On that basis, it is more practical for the system operator to author and maintain the CACTIS, with the Authority's ultimate approval being required for its incorporation in the Code.

5.10. As a system operation document, the process for amending the document and consulting on those amendments is specified in Part 7 of the Code, which applies to other (existing) system operation documents.

5.11. The Authority proposes the system operator be required to review the CACTIS at least once every two years. This helps ensure the CACTIS continues to improve and adapt to an evolving power system. Additionally, the system operator may, at any time outside these two-yearly reviews, propose a change to the CACTIS.

5.12. In accordance with the current requirements in the Code, proposed changes to the document would generally require the system operator (after obtaining the Authority's consent) to consult with parties the system operator considers to be affected by the proposed changes prior to seeking approval from the Authority. Notwithstanding the consultation undertaken by the system operator, the Authority may undertake a wider consultation on the proposed changes prior to making a final decision as to whether to accept the system operator's proposed changes.

5.13. An early draft of the proposed CACTIS is attached as **Appendix C** to help readers understand how it fits with the proposed amendments to the main body of the Code.

5.14. The draft CACTIS introduces new minimum technical requirements for operational communication between asset owners and the system operator (Table 1). These requirements ensure that the operator receives timely and accurate operational data, which is critical for real-time decision-making and maintaining system security.

Table 1: New minimum technical requirements for operational communications

Indication or measurement	Purpose of collecting information
Specific Requirements for Generators	
Frequency Control Operation Mode	Modelling.
Voltage Control Operation Mode	Modelling.
Power System Stabiliser or Power Oscillation Damper Status	Modelling.
Station HV Bus Voltage (if HV bus is not owned by a grid owner)	Real-time operations - management of voltage.
Specific Requirements for synchronous Generating Units	
Generating unit Terminal Voltage kV	Event investigation and modelling.
Specific Requirements for Battery Energy Storage Systems	
Station state of charge (SOC) (%)	Modelling.
Specific Requirements for PV assets	
Solar irradiance horizontal (W/m^2)	Forecasting.
Specific Requirements for Wind Turbine Assets	
Wind speed at nacelle height (km/h)	Forecasting.
Specific Requirements for Hybrid Plant	
Station intermittent generation MW	Modelling.
Station BESS Injection / Load MW	Modelling.
Grid-Owner Specific Requirements	
Reactive Power Controller status	Real-time operations - management of voltage.
Reactive Power Controller Setpoint kV or Mvar	Real-time operations - management of voltage.

5.15. The draft CACTIS also mandates that asset owners provide real-time indications of controllable load. This change addresses the current challenge where connected parties must relay controllable load data via phone or submit difference bids during grid emergencies, a process that can add operational pressure. By using real-time

SCADA indications, the system operator's situational awareness will improve, reducing operational risk and ensuring more effective and equitable shortfall responses.

5.16. Submitters are welcome to provide feedback on the draft CACTIS. Although the Authority is not formally consulting on this draft, we will share any feedback received with the system operator to support their development process.

5.17. The draft CACTIS included in this consultation reflects the current version prepared by the system operator. It is presented here in its current form to support transparency and alignment with the proposed Code amendments. However, this draft may be subject to further changes before the system operator's formal consultation.

5.18. The system operator intends to consult on an updated version of the CACTIS in September 2025. That consultation will provide an opportunity for stakeholders to engage directly with the system operator on the detailed content of the CACTIS.

Confidentiality protections

5.19. In response to the October 2024 consultation, three submitters raised concerns about protecting intellectual property and maintaining confidentiality when sharing models and related information.

5.20. The Authority acknowledges that some common quality-related information is currently subject to non-disclosure agreements between the system operator and asset owners or original equipment manufacturers, and some information being requested (particularly modelling information) may be commercially sensitive.

5.21. Clause 3(2) of Technical Code A, Schedule 8.3 of the Code provides a foundation for protecting sensitive information. Under this clause, the system operator may only disclose information about an asset, or the supply or demand of other asset owners:

(a) as expressly provided for in the Code, or

(b) as reasonably required in a transmission network emergency or to ensure the security of the transmission network, or

(c) as required by law, or

(d) otherwise as may be agreed with the relevant asset owners.

5.22. This Code provision serves to limit the disclosure of information and provide a baseline level of protection for commercially sensitive data. However, feedback in response to our October 2024 consultation indicates a strong desire from some industry participants, for more certainty that intellectual property will be safeguarded.

5.23. To support the sharing of information while maintaining strong protections around commercially sensitive information, the Authority proposes to require the system operator to store unencrypted models securely and to restrict access to authorised personnel. We also propose to prohibit the system operator from sharing these models with any third parties unless the asset owner has given prior written consent or as required by law.

Clarifying the information provision threshold in clause 8.21

5.24. Clause 8.21 of the Code currently requires generators to advise the system operator of their intention to connect to the transmission network or to a local distribution network, a generating unit with a capacity of 1MW or more. These generators must also provide the system operator with certain information about the generating unit.

5.25. There is a regulatory gap in relation to these obligations in clause 8.21. Generators face no obligation under the clause for any of their larger generating stations with generating units below the 1MW threshold.

5.26. The Authority proposes to amend clause 8.21 so that it also applies to any generating station with a total capacity of 10MW (a.c.) or more.

5.27. This change ensures the system operator has visibility of larger generating stations connecting to the power system, and information about these generating stations that supports the system operator to meet its PPOs.

Q1. Do you support the Authority's proposal to clarify the Code's common quality information requirements and describe the technical specifications in a document incorporated by reference in the Code?

Q2. Do you have any comments on the drafting of the proposed amendment?

Q3. Do you see any unintended consequences in making such an amendment?

Please explain your answers.

6. Regulatory Statement

Objectives of the proposed amendment

6.1. The proposed amendment's objective is to better enable the system operator to plan to comply, and comply, with the PPOs and achieve the dispatch objective, by:

(a) improving the accuracy and clarity of asset owners' obligations to provide common quality-related information to the system operator

(b) enabling the system operator to develop, and update in a timely manner, technical specifications for common quality information requirements.

Evaluation of the costs and benefits of the proposed amendment

6.2. The proposed amendment delivers a material net benefit by enabling better informed development of common quality-related information requirements, by improving the security and reliability of New Zealand's power system, and by reducing transaction costs. While some asset owners may incur reasonably material compliance costs, these are proportionate to corresponding but larger operational benefits, and are aligned with international practice. Table 2 provides a summary of the costs and benefits of the proposed amendment.

Table 2: Summary of the costs and benefits of the proposed Code amendment

Benefit / Cost	Magnitude of benefit / cost
The benefit from improving the security and reliability of the power system	Expected to be material
The benefit from better informed development of, and more timely updates to, technical specifications for the Code's common quality-related information requirements	Expected to be material
The benefit of more timely updates to common quality-related information requirements.	Expected to be modest
The benefit from reducing transaction costs currently incurred through negotiating information collection	Expected to be modest
Implementation costs faced by the system operator	Expected to be negligible
The ongoing cost for the system operator to operate under the proposed amendment	Expected to be negligible
Implementation costs faced by industry participants	Expected to be material
The ongoing cost for industry participants to operate under the proposed amendment	Expected to be modest
Expected net benefit	**Expected to be modest**

6.3. The proposed Code amendment's primary benefit is promoting the security and resilience of the power system. This is achieved in a couple of ways.

6.4. First, the system operator relies on detailed asset information for network studies, stability assessments, real-time operation, and contingency planning. As New Zealand's electricity generation mix becomes increasingly dominated by IBRs, the complexity and risk associated with inaccurate models grows.

6.5. The amendment clarifies and strengthens asset owners' obligations to provide the system operator with accurate and validated asset information, supporting the system operator to plan to comply, and to comply, with the PPOs. Accurate modelling of both synchronous and inverter-based generation improves the system operator's ability to proactively manage power system risks, prevent power system instability, and avoid the imposition of overly conservative constraints that may suppress generation or increase electricity market inefficiencies.

6.6. Second, the proposed amendment supports better informed development of, and more timely updates to, technical specifications for the Code's common quality-related information requirements. The proposed amendment does this by relocating these technical specifications from the main body of the Code to the proposed CACTIS. This change provides for the Code to evolve more quickly to new and emerging technologies and evolving industry needs.

6.7. Third, the proposed amendment is expected to reduce transaction and compliance costs in aggregate across asset owners affected by the amendment. At present, the system operator must negotiate bespoke information-sharing arrangements with asset owners and translate or adapt modelling formats (particularly TSAT models) from limited or incomplete sources. The proposed CACTIS removes ambiguity by standardising expectations and responsibilities across asset owners (and through them across original equipment manufacturers).[19] This improves efficiency, reduces duplication, and limits the administrative burden on all parties in relation to common quality information obligations under the Code.

6.8. We expect the cost of implementing the proposed Code amendment to be modest relative to the expected benefit. This is on the basis that asset owners are already required to provide the system operator with most of the information set out in the proposed CACTIS. The proposed amendment primarily clarifies existing obligations and streamlines information-sharing processes, rather than introducing significant new obligations.

6.9. There are two main exceptions to this:

(a) the proposed increase in the number of models for IBRs that an asset owner must provide to the system operator

(b) the proposed new requirement for distributors to provide the system operator with controllable load indications.

[19] Noting that original equipment manufacturers have no Code obligations, with asset owners responsible for meeting any Code obligations that require the involvement of original equipment manufacturers.

6.10. Under the draft proposed CACTIS, owners of IBR generation must provide four distinct model types to the system operator for this generation. Most original equipment manufacturers already have PowerFactory and PSCAD models available for new assets. The validation of PowerFactory models is already required by the system operator and therefore does not represent an incremental cost of the proposal. PSCAD models require validation, at an estimated cost of $15,000 to $20,000, though this can vary significantly.

6.11. These models can typically be translated into the required TSAT format by the original equipment manufacturers or third-party providers at a cost of about $50,000 to $100,000, with an additional $10,000 to $15,000 cost for validation. As industry standards for Dynamic Link Library (DLL) models advance, these costs are expected to decrease.

6.12. There are expected to be no incremental costs associated with translating synchronous generation models under the proposal. The translation costs for these models remain minimal because the models are standardised and less complex. The system operator will continue to provide translation services for these models. However, IBR technology is evolving continuously. Due to the unpredictable, confidential and complex nature of IBR models, the system operator does not have the resources to provide translation services for these models.

6.13. The draft proposed CACTIS introduces new minimum technical requirements for operational communication between asset owners and the system operator. This is expected to impose additional compliance costs on some asset owners. For synchronous generation, we estimate an additional fixed cost of approximately $500 per generating station, along with a variable cost of $2,000 per generating unit. For IBRs, the estimated additional fixed cost ranges from $2,500 to $5,000 per generating station, depending on the type of generation (eg, wind, solar photovoltaic) and the complexity of the generating station. However, no additional variable costs are expected for IBRs beyond what is already required under current arrangements.

6.14. In addition, asset owners will need to install high-speed monitors at each generating station, at an estimated cost of between $20,000 and $30,000 per station.

6.15. The draft proposed CACTIS contains an obligation on distributors to provide real-time indications of controllable load to the system operator. Implementing these controllable load indications nationwide is estimated to cost approximately $2.3 million—primarily due to the need for some distributors to establish Inter-Control Centre Communication Protocol (ICCP) links or upgrade their existing ICCP links. The system operator’s implementation costs are expected to be minimal, with negligible ongoing cost implications.

6.16. Despite the upfront expenditure, the benefits are projected to exceed the costs. These benefits are expected to be in the form of avoided costs associated with delayed investigations of power system events, constrained generation, and major electricity outages. Quantified estimated benefits are approximately $16,500 per year in operational efficiencies, $175,000 per year in avoided costs from reduced loss of load during emergencies, and $500,000 per year in avoided investigation costs. Additional long-term benefits include enhanced emergency response, the potential for automated load control and restoration, and the establishment of a data-sharing infrastructure that will support future interactions between the system operator and distributors.

Evaluation of alternative means of achieving the objectives of the proposed amendment

6.17. The Authority considered four alternative means of achieving the objectives of the proposal. However, we considered they did not achieve the proposal's objectives to the same extent as the preferred proposal, as summarised in Table 3 below:

Table 3: Evaluation of alternative options

Alternative option	Reasons not favoured
Update the Code's common quality-related information requirements by inserting technical specifications in the main body of the Code, rather than in a system operation document.	The system operator holds the required expertise to maintain technical specifications for the Code's common quality-related information requirements. Maintaining these technical specifications in the main body of the Code would be less efficient as it would involve a less streamlined process of engagement by the Authority with the system operator and other interested parties.
Increased investment in protection equipment to compensate for uncertainty about asset performance.	This would impose significant costs on asset owners and the electricity industry, leading to higher electricity prices for consumers.
Form an industry working group to define clear expectations between asset owners and the system operator on the standard of "reasonableness" for information requirements.	Relying solely on working groups to define and update common quality-related information requirements would lack enforceability and lead to inconsistency in compliance.
Update the system operator's guideline for the submission of modelling information.[20]	Voluntary guidelines lack enforceability and would maintain the existing problems with compliance.

The proposed amendment complies with section 32(1) of the Act

6.18. The Authority considers that the proposed Code amendment is consistent with the Authority's main statutory objective, and with section 32(1) of the Act, because it promotes the reliable supply of electricity to consumers and the efficient operation of the electricity industry. The proposed amendment does this by enhancing the accuracy and clarity of asset owners' obligations to provide common quality-related information to the system operator. This improves the system operator's ability to plan to comply, and comply, with the PPOs and achieve the dispatch objective.

20 Transpower, GL-EA-716 Power Plant Dynamic Model Validation and Submission Prerequisites, May 2023.

The Authority has complied with section 17(1) of the Act

6.19. Under section 17(1) of the Act, the Authority, in performing its functions, must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister for Energy. Table 4 below sets out our consideration of the Government Policy Statement on Electricity.[21]

Table 4: Consideration of the proposed amendments against the Government Policy

Clause	Consideration
2. The Government therefore expects the electricity system to deliver reliable electricity at lowest possible cost to consumers. It should serve the interests of all electricity consumers, including through the provision of sufficient electricity infrastructure to ensure security of supply and avoid excessive prices.	The proposal aligns with the Government Policy Statement as it strengthens the reliability and resilience of the power system. It achieves this by ensuring the system operator has accurate information about connected and connecting assets. This improves the system operator's ability to operate the transmission network securely and efficiently.
8. The Government's role is to ensure clear and consistent regulatory settings, reflected in market rules with robust compliance monitoring and enforcement, that enable an efficient market anchored by accurate price signals, and effective risk management tools and competition.	The proposal aligns with the Government Policy Statement by promoting clear and consistent obligations for asset owners to provide common quality-related information.
23. In accordance with market rules and arrangements, the System Operator is responsible for efficiently co-ordinating the utilisation of electricity generation and demand-side offers that have been made available in the wholesale market by market participants in response to spot price signals.	The proposal aligns with the Government Policy Statement as it enhances the system operator's ability to comply with the PPOs by ensuring it has timely access to accurate and standardised information about connected and connecting assets. This supports more effective and efficient power system operation, including improved co-ordination and reduced risk of power system instability or outages.

The Authority has given regard to the Code amendment principles

6.20. When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to Code amendment principles, to the extent that the Authority considers they are applicable. Table 5 describes the Authority's regard for the Code amendment principles in the preparation of the Code amendment proposal.

[21] New Zealand Government, Government Policy Statement on Electricity, October 2024.

Table 5: Regard for Code amendment principles

Principle	Consideration
1. Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	Part 4 of this paper sets out the case for regulation. In summary, the system operator is not consistently receiving the information it needs to operate the power system securely and efficiently—due to ambiguous, outdated, and unenforceable Code requirements, confidentiality barriers, and limited visibility of smaller generators. Regulatory reform is needed to ensure timely access to accurate, standardised, and enforceable modelling information, especially as IBRs become more prevalent.
2. Costs and benefits are summarised	The costs and benefits of the Code amendment proposal are set out in the evaluation of the costs and benefits in this part 6. The Authority considers key benefits of the Code amendment proposal include: • a more secure and reliable power system • better informed development of, and more timely updates to, technical specifications for the Code's common quality-related information requirements • reduced transaction costs • supporting the quality of electricity supply to consumers. The Authority considers key costs of the Code amendment proposal include: • compliance costs.

Q4. Do you agree with the objective of the proposed amendment? If not, why not?

Q5. Do you agree the benefits of the proposed amendment outweigh its costs? Please provide evidence to support your view. This may include incremental benefits and costs associated with the draft CACTIS.

Q6. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objectives in section 15 of the Electricity Industry Act 2010.

Q7. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

Appendix A Proposed amendment

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

…

asset capability statement means a statement of capability and operational limitations that applies to specific **assets** during the normal and abnormal conditions that may arise on the **grid**, provided to the **system operator** in accordance with clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3

…

connected asset commissioning, testing and information standard means the connected asset commissioning, testing and information standard that is incorporated by reference in this Code under clause 8.73

…

high-speed monitor means a device capable of capturing and storing high-resolution waveform data of voltage and current signals during power system events or disturbances, with sufficient sampling frequency and accuracy to support detailed analysis of power system behaviour

…

~~**scaling factor**, for the purpose of Appendix A of Technical Code C of Schedule 8.3, means a factor applied to a measurement at 1 point to calculate a corresponding measurement at another point~~

…

~~**S**~~**system operation document** means any of the following documents:

(a) the **security of supply forecasting and information policy**:

(b) the **emergency management policy**:

(c) the **policy statement**:

(d) the **procurement plan**:

(e) the **AUFLS technical requirements report**:

(f) the **system operator rolling outage plan**~~.~~:

(g) the **connected asset commissioning, testing and information standard**

…

7.15 Review of system operation documents ~~policy statement and procurement plan~~

(1) The **system operator** must review the following **system operation documents** ~~**policy statement** and the **procurement plan**~~ at least once every 2 years to identify whether the document should be amended:

(a) the **connected asset commissioning, testing and information standard**:

(b) the **policy statement**:

(c) the **procurement plan**.

(1A) The **system operator** may review a **system operation document** not referred to in subclause (1) at any time.

(2) For the purposes of subclause (1), any 2 year period commences on either—

(a) if the previous review does not result in an amendment being made, the date the **system operator** advised the **Authority** under clause 7.15(3)(b) ~~the date the last review of the document was completed if that review did not result in an amendment being made~~; or

(a) if ~~a~~ the previous review results in an amendment being made, the date the amendment takes legal effect.

(3) At the conclusion of a review the **system operator** must either—

(a) propose an amendment to the **Authority**, following consultation where required by clause 7.20, after obtaining consent as required by clause 7.16; or

(b) advise the **Authority** that the **system operator** does not consider that an amendment is required and provide the **Authority** with a written report describing the process carried out for the review, the **system operator's** decision, and the reasons for the decision.

…

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in **Technical Code** A of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** that exports less than 30 **MW** to a **local network** or the **grid**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in **Technical Code** A of Schedule 8.3.

(2) Whether likely to be **an excluded** ~~**generation**~~ **generating station** or not, a **generator** ~~who is planning to connect to the **grid** or a **local network** a **generating unit** with rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.) capacity)~~ must provide the **system operator** with written advice of its intention to connect a **generating unit** or **generating station** to the **grid** or directly or indirectly to a **local network**, together with other information relating to that **generating unit** or **generating station** in accordance with clause 8.25(4) where:

(a) the **generating unit** has a rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.)) capacity at the **point of connection** to the **network**; or

(b) the **generating station** has a capacity equal to or greater than 10 **MW** at the **point of connection** to the **network**.

…

8.25 Other asset owner performance obligations and technical standards

…

(3) Each **asset owner** and each **purchaser** must provide communication facilities that comply with the ~~**technical codes**~~ **connected asset commissioning, testing and information standard** ~~or otherwise, as the **system operator** reasonably requires, which must assist the **system operator** in planning to comply, and complying, with its **principal performance obligations** and achieving the **dispatch objective**~~.

(4) Each **asset owner** and each **purchaser** must provide information to the **system operator** that complies with the **technical codes** and the **connected asset commissioning, testing and information standard** ~~or otherwise as the **system operator** reasonably requests, to assist the **system operator** in planning to comply, and complying, with its **principal performance obligations** and achieving the **dispatch objective**~~.

(5) If the **system operator** reasonably considers it necessary to assist the **system operator** in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**, the **system operator—**

(a) may require that an **embedded generator** provide information regarding the intended output of each **embedded generating station** greater than 10 **MW** in capacity, that must be either—

(i) submitted as an **offer** in accordance with subpart 1 of Part 13; or

(ii) provided in a form and manner specified in the **connected asset commissioning, testing and information standard** ~~agreed between the **system operator** and the **embedded generator**~~; and

(b) must advise the **embedded generator** of its requirement at least 20 **business days** in advance of the requirement coming into effect.

(6) If the **system operator** reasonably considers it necessary to assist it in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**, the **system operator** may apply to the **Authority** to require an **embedded generator** to provide information regarding the intended output of a group of **embedded generating stations** that total greater than 10 **MW** in capacity and that are connected to the same **grid exit point**.

(7) If the **Authority** approves the **system operator's** request under subclause (6), the **embedded generator** must provide the information in accordance with the **connected asset commissioning, testing and information standard** ~~must be provided to the **system operator** by the relevant **embedded generator** in a form and manner determined by the **Authority**~~.

…

Subpart 7—Connected asset commissioning, testing and information standard

8.71 Contents of this subpart

This subpart contains provisions relating to the **connected asset commissioning, testing and information standard**.

Connected asset commissioning, testing and information standard

8.72 System operator to comply with connected asset commissioning, testing and information standard

The **system operator** must comply with the **connected asset commissioning, testing and information standard**.

8.73 Incorporation of connected asset commissioning, testing and information standard by reference

(1) The **connected asset commissioning, testing and information standard** is incorporated by reference in this Code.

(2) Clauses 7.13 to 7.22 apply to any amendment or replacement of the **connected asset commissioning, testing and information standard**.

8.74 Content of connected asset commissioning, testing and information standard

A **connected asset commissioning, testing and information standard** must set out the following requirements on **asset owners** which are to assist the **system operator** in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**:

(a) the information that an **asset owner** must provide to the system operator relating to **commissioning** a new or existing **asset** or configuration of **assets** or **decommissioning assets**; and

(b) the information, including any modelling information, that an **asset owner** must provide to the **system operator** in an **asset capability statement**; and

(c) requirements for carrying out connection studies for an **asset** or configuration of **assets**; and

(d) requirements for periodically testing an **asset** or configuration of **assets**; and

(e) minimum requirements for operational communications between **asset owners** and the **system operator**; and

(f) requirements for **high-speed monitors**; and

(g) requirements for **asset owners** to provide information to the **system operator** to enable the **system operator** to assess the **grid interface**;

(h) requirements for an **asset owner** to provide information to the **system operator** if an **asset owner** reasonably believes that an **asset** may not comply with an **asset owner performance obligation** or with **Technical Code A** of Schedule 8.3;

(i) requirements on an **asset owner** to undertake remedial action or testing of its **assets** if the situation described in paragraph (h) arises;

(j) time frames that an **asset owner** must meet in relation to any of the matters in paragraphs (a) to (i) or within which information must be provided under the Code; and

(k) the manner and form in which information must be provided to the **system operator**.

…

Schedule 8.3

Technical Codes

Technical Code A – Assets

…

2 General requirements

(1) Each **asset owner** must ensure that—

(a) its **assets** at **grid exit points** and at grid injection points, and, in the case of **connected asset owners**, the **assets** of any **embedded generator** connected to it, are identified and referred to by a **system number**; and

(b) its **assets**, both in the manner in which they are designed and operated, are capable of being operated, and operate, within the limits stated in the **asset capability statement** provided by the **asset owner** for that **asset**~~; and~~

(c) it meets any ~~other reasonable~~ requirements of the **system operator**, identified in the **connected asset commissioning, testing and information standard**~~during planning studies, which are required for the **system operator** to plan to comply, or to comply, with its **principal performance obligations**~~.

~~(2) Each **asset owner** must provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, to allow the **system operator** to assess compliance of its **asset** or any configuration of **assets** with the requirements of the **asset owner performance obligations** and **technical codes** at each of the following times :~~

~~(a) before the completion of planning for the construction of that **asset** or configuration of **assets**:~~

(b) ~~at, or before, the completion of construction but before the **commissioning** of that **asset** or configuration of **assets**, except that the **asset owner** must put in place a **commissioning** plan in accordance with subclauses (6) to (8) to minimise the impact of **commissioning** tests on the **system operator's** ability to comply with its **principal performance obligations**, and adhere to this plan during **commissioning**, unless otherwise agreed to by the **system operator**~~.

~~(2A) For **asset owners** that are **generators**, the obligation to provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, applies only to **generators** with a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2).~~

(3) On, or before, completion of **commissioning** of an **asset** or configuration of assets, the **asset owner** must obtain a final assessment of the **asset** or configuration of **assets** in writing from the **system operator** in accordance with the requirements set out in the **connected asset commissioning, testing and information standard**~~that the **asset** or configuration of **assets** meets the requirements of the **asset owner performance obligations** and **technical codes**~~. ~~This final assessment must be based on the information supplied by the **asset owner** and, if necessary, the result of **system tests** at **commissioning**~~.

(4) ~~The **system operator** must give the assessment referred to in subclause (2)(b) within a reasonable time frame and supply the **asset owner** with all information that supports its assessment.~~ Any permission granted by the **system operator** to an **asset owner** to conduct **commissioning** of any **asset** or configuration of **assets** must permit connection of the **asset** (or configuration of **assets**) solely for the purposes of **commissioning**.

(5) Each **asset owner** must provide the **system operator** with an **asset capability statement** in accordance with the **connected asset commissioning, testing and information standard**~~in the form from time to time published by the **system operator** for each **asset** that~~—

(a) for each **asset** that is—

(i) proposed to be connected, or is connected to, or forms part of the **grid**; or

(ii) proposed to be connected, or is connected directly or indirectly to a **local network**; and

(b) where the **asset owner** is a **generator**, for each **asset** that—

(i) forms part or all of a **generating unit** with a rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2)(a) at the **point of connection** to the **network**; or

(ii) forms part or all of a **generating station** with a capacity equal to or greater than the threshold specified in clause 8.21(2)(b) at the **point of connection** to the **network**.

~~(5A) The **asset capability statement** must—~~

~~(a) include all information reasonably requested by the **system operator** so as to allow the **system operator** to determine the limitations in the operation of the **asset** that the **system operator** needs to know for the safe and efficient operation of the **grid**; and~~

~~(b) include any modelling data for the planning studies, as reasonably requested by the **system operator**; and~~

~~(c) be updated and reissued to the **system operator** as information and design development progresses through the study, design, manufacture, testing and **commissioning** phases; and~~

~~(d) be complete and up to date before the **commissioning** of the **asset**; and~~

~~(e) be complete and up to date at all times while the **asset** is—~~

~~(i) connected to, or forms part of, the **grid**.; or~~

~~(ii) connected directly or indirectly to a **local network**.~~

(6) Each **asset owner** must provide a **commissioning** plan or test plan ~~in accordance with~~ to the **system operator** in compliance with the **connected asset commissioning, testing and information standard**. ~~subclauses (7) or (8) (as the case may be) in the following situations:~~

~~(a) when changes are made to **assets** that alter any of the following at the **grid interface**:~~

~~(i) the **single-line diagram**:~~

~~(ii) a protection system, other than a change to a protection system setting:~~

~~(iii) a **control system**, including a change to a **control system** setting:~~

~~(iv) any rating of **assets**:~~

~~(b) when **assets** are to be connected to, or are to form part of, the **grid**:~~

(c) ~~if it is necessary for an **asset owner** to perform a **system test** or other test to ascertain or confirm **asset** capabilities, and if the **commissioning** or testing or connection of those **assets** may affect the **system operator's** ability to plan to comply, or to comply with, its **principal performance obligations**. If an **asset owner** is unsure whether the **commissioning** or connection of an **asset** may impact on the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations** it must contact the **system operator** for advice.~~

~~(7) The **commissioning** plan prepared by an asset owner and agreed by the **system operator** must—~~

~~(a) include a timetable containing the sequence of events necessary to connect the **assets** to the **grid** and conduct any proposed **system test**; and~~

~~(b) contain the protection and control settings to be applied before the assets are made live (where live has the meaning given to it in the Electricity (Safety) Regulations 2010); and~~

~~(c) contain the procedures for **commissioning** the plant with minimum risk to personnel and plant and to the ability of the **system operator** to plan to comply and to comply with its **principal performance obligations**.~~

~~(8) If a test plan is required under subclause (6), it must be prepared by the **asset owner** in consultation with the **system operator**. The test plan must contain sufficient information to enable the **system operator** to plan to comply, and to comply, with the **principal performance obligations**.~~

(9) Once assessed by the **system operator** acting reasonably, the **asset owner** must follow the **commissioning** plan or test plan at all times, unless otherwise agreed with the **system operator** (such agreement must not be unreasonably withheld if compliance with the **commissioning** plan or testing plan is not practicable and non-compliance does not impact on the **system operator's** ability to comply with its **principal performance obligations** or on other **asset owners**).

(10) Each **asset owner** must—

(a) carry out connection studies for each **asset**, in accordance with the **connected asset commissioning, testing and information standard;**

(b) provide connection study reports, including modelling information, to the **system operator** in compliance with the **connected asset commissioning, testing and information standard**.

3 Requirements for asset information

~~(1) In accordance with clause 8.25(4), the following information is required by the **system operator** to assist it to plan to comply, and to comply, with its **principal performance obligations**:~~

~~(a) sufficient information must be exchanged between the **system operator** and the **asset owner** to ensure that both fully understand the implications of any changes to the **asset capability statement** or of any proposed connection of the relevant **assets** to the **grid** or to the **local network**. This information must be exchanged in accordance with a timetable agreed to by the **system operator** and the **asset owner**:~~

~~(b) if reasonably requested by the **system operator**, the **asset owner** must provide sufficient information to the **system operator** to demonstrate the compliance~~

~~of the **asset owner's assets** with the **asset owner performance obligations** and the **technical codes.**~~

(2) Information about an **asset**, **supply** or **demand** of other **asset owners** must only be disclosed by the **system operator—**

(a) as expressly provided for in this Code; or

(b) as reasonably required in a **grid emergency** or to ensure the security of the **grid**; or

(c) as required by law; or

(d) otherwise as may be agreed with the relevant asset owners.

(2A) The **system operator** must—

(a) store unencrypted models in a secure server that is accessible only to **system operator** employees, contractors or advisers that require access to the unencrypted models to perform their roles; and

(b) not disclose unencrypted models to third parties, except as provided in subclause (a), including a **grid owner** or **distributor**, without the prior written consent of the **asset owner** that provided the model or as required by law.

~~(3) Each **asset owner** must provide the **system operator** with—~~

~~(a) all information reasonably requested by the **system operator** so as to ensure compliance with clause 8.25(4) and to enable the **system operator** to assess the **grid interface**; and~~

~~(b) details of protection systems, including settings, to ensure that the requirements of clause 8.25(4) are met.~~

(4) Each **asset owner** must ensure that all supporting information for the operational control of **assets** is kept up to date.

…

7 Modifications and changes to assets

(1) **Assets** that are modified, or are proposed to be modified, are—

(a) to be treated as~~deemed to be~~ new **assets** for the purposes of theis Code, and ~~this **Technical Code**~~ the **connected asset commissioning, testing and information standard;** and

(b) are subject to the requirements for connection to the **grid** and the requirements for **commissioning assets** in the **Code** and the **connected asset commissioning, testing and information standard**.

(1A) ~~For the purposes of this Schedule, the following are considered to be modifications to **assets**, if the~~A new connection or alteration that may affect the capacity of the **assets** or may affect **asset owner performance obligations**,~~ or~~ **technical code** requirements or requirements in the **connected asset commissioning, testing and information**

standard is to be treated as a modification to the relevant **assets** for the purposes of this Schedule if it is one of the following:

(c) a new connection of **assets** to the **grid** or a **local network**:

(d) a new connection of **assets** to form part of the **grid**:

(e) a new connection of an **embedded generator** to a **local network** other than an **excluded generator** as defined in clause 8.21(1):

(f) an alteration to **assets** already connected to the **grid** or, in the case of **embedded generator**, already connected to a **local network**.

(2) If an **asset owner** proposes or intends to decommission any **assets**, ~~T~~the **asset owner** must provide a **decommissioning** plan and give written notice to the **system operator** ~~in a timely manner of any **assets** that have been **decommissioned**~~ in accordance with the **connected asset commissioning, testing and information standard** ~~if the assets affect or could affect the system operator's ability to comply with its principal performance obligations~~.

8 Records, tests and inspections

(1) Each **asset owner** must arrange for, and retain, records for each of its **assets** to demonstrate that the **assets** comply with the **asset owner performance obligations**, ~~and~~ this **technical code** and the **connected asset commissioning, testing and information standard**.

(2) In addition to the requirements for **commissioning** or testing in clause 2(6), ~~to~~ 2(8), and 2(10) each **asset owner** must ~~carry out periodic testing—~~

(a) carry out periodic testing of its **assets**, including **automatic under-frequency load shedding** systems, in accordance with ~~Appendix B~~ the **connected asset commissioning, testing and information standard**; and

(b) [Revoked]

(c) provide **high-speed monitors** that comply with the requirements specified in the **connected asset commissioning, testing and information standard**.

(3) If the **system operator** advises an **asset owner** that it reasonably believes that an **asset** may not comply with an **asset owner performance obligation** or this **technical code**, the **asset owner** must advise the **system operator** and undertake remedial action or testing of its **assets** in accordance with the **connected asset commissioning, testing and information standard**.~~—~~

~~(a) as soon as practicable, but no later than 30 days after receiving a written request, advise the **system operator** of its remedial or test plan for the **assets**; and~~

~~(b) as soon as reasonably practicable undertake any remedial action or testing of its **assets** in accordance with its plan advised to the **system operator** in~~

~~paragraph (a). The **system operator** may require such testing or remedial action to be undertaken in the presence of a **system operator** representative~~.

…

~~*Appendix B: Routine testing of assets and automatic under-frequency load shedding systems*~~

~~**1 Periodic tests to be carried out**~~

~~(1) This Appendix sets out periodic tests required for the purposes of clause 8(2) of **Technical Code** A.~~

~~(2) Each **asset owner** may be legally required, other than under this Code, to carry out additional tests to ensure that their **assets**, including **automatic under-frequency load shedding** systems, are safe and reliable.~~

~~(3) *[Revoked]*~~

~~(4) Each **asset owner** with one or more **generating units** commissioned before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.~~

~~**2 Generating unit frequency response**~~

~~Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38, must—~~

~~(a) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** analogue over-frequency relays and analogue under-frequency relays at least once every 4 years; and~~

~~(b) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** non-self monitoring digital over-frequency relays and non-self monitoring digital under-frequency relays at least once every 4 years; and~~

~~(ba) for **generating units** with an inverter, test the trip frequencies and trip time delays of non-self monitoring digital over-frequency protection settings and non-self monitoring digital under-frequency protection settings for the **generating units** at least once every 4 years; and~~

~~(c) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and~~

~~(ca) for **generating units** with an inverter, test the trip frequencies and trip time delays of self monitoring digital over-frequency protection settings and self monitoring digital under-frequency protection settings for the **generating units** at least once every 10 years; and~~

~~(d) based on the tests carried out in accordance with paragraphs (a), (b), (ba), (c) or (ca), provide a verified set of under-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and~~

~~(e) based on the tests carried out in accordance with paragraphs (a), (b), (ba), (c) or (ca), provide a verified set of over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.~~

~~**3 Generating unit governor and speed control**~~

~~Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 must—~~

~~(a) for each of its **generating units** with no inverter, test the governor response of the **generating unit's** mechanical or analogue speed governor and/or mechanical or analogue frequency **control system** at least once every 5 years; and~~

~~(b) for each of its **generating units** with no inverter, test the response of the **generating units'** digital or electro-hydraulic frequency **control system** at least once every 10 years; and~~

~~(ba) for its **generating units** with an inverter, test the response of each frequency **control system** used for those **generating units** at least once every 10 years; and~~

~~(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter test the response of each frequency **control system** used for those **generating units** within 3 months of a change to the control settings and/or firmware of the frequency **control system** (where the change to the firmware has the potential to materially affect the performance of the frequency response of the **generating units** or **generating station** that the **generating units** are part of); and~~

~~(c) based on the tests carried out in accordance with paragraphs (a), (b), (ba) or (bb), provide a verified set of modelling parameters and governor or frequency **control system** response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—~~

~~(i) a block diagram showing the mathematical representation of the frequency **control system**; and~~

~~(ii) for **generating units** with a turbine, a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and~~

~~(iia) for **generating units** with a power converter, a block diagram showing the mathematical representation of the power converter and its electrical control; and~~

~~(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and~~

~~(iv) for **generating units** with an inverter, a verified set of control settings and relevant firmware version identifiers for the frequency **control system** used for each **generating unit**.~~

~~4 Generating unit transformer voltage control~~

~~Each **generator** with a **point of connection** to the **grid** must—~~

~~(a) test the operation of each of its **generating unit** transformers' on-load tap changer analogue **control systems** at least once every 4 years; and~~

~~(b) test the operation of each of its **generating unit** transformers' on-load tap changer digital **control systems** at least once every 10 years; and~~

~~(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters including voltage set points, operating dead bands and response times to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.~~

~~5 Generating unit voltage response and control~~

~~Each **generator** with a **point of connection** to the **grid** must—~~

~~(a) test for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the **generating unit's** analogue voltage **control system** at least once every 5 years; and~~

~~(b) for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the **generating unit's** digital voltage **control system** at least once every 10 years; and~~

~~(ba) for its **generating units** with an inverter, test the response of each voltage **control system** used for those **generating units** at least once every 10 years; and~~

~~(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter test the response of each voltage **control system** used for those **generating units** within 3 months of a change to the control settings and/or firmware of the voltage **control system** (where the change to the firmware has the potential to materially affect the performance of the voltage response of the **generating units** or **generating station** that the **generating units** are part of); and~~

~~(c) based on the tests carried out in accordance with paragraphs (a), (b), (ba) or (bb), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—~~

~~(i) a block diagram showing the mathematical representation of the voltage **control system**; and~~

~~(ii) *[Revoked]*~~

~~(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and~~

~~(iv) for **generating units** with an inverter, a verified set of control settings and relevant firmware version identifiers for the voltage **control system** used for each **generating unit**.~~

~~**6 North Island connected asset owner automatic under-frequency load shedding systems profiles and trip settings**~~

~~Each North Island **connected asset owner** must—~~

~~(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and~~

~~(b) test the operation of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and~~

~~(c) test the operation of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and~~

~~(d) test the operation of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and~~

~~(e) based on the relevant test carried out in accordance with paragraphs (b), (c) or (d), provide a verified set of trip settings and time delays to **the system operator** in an updated **asset capability statement** within 3 months of the completion date of the relevant test.~~

~~**7 South Island grid owner automatic under-frequency load shedding systems profiles and trip settings**~~

~~Each South Island **grid owner** must—~~

~~(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and~~

~~(b) test the operation of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and~~

~~(c) test the operation of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and~~

~~(d) test the operation of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and~~

~~(e) based on the relevant test carried out in accordance with paragraphs (b), (c) or (d), provide a verified set of trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of the relevant test.~~

~~8 Grid owner transformer voltage range~~

~~Each **grid owner** must—~~

~~(a) test the operation of each of its transformers' on-load tap changer analogue **control systems** at least once every 4 years; and~~

~~(b) test the operation of each of its transformers' on-load tap changer digital **control systems** at least once every 10 years; and~~

~~(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including voltage set points, operating dead bands and response times.~~

~~9 Asset owner dynamic reactive power compensation device transient response and control~~

~~Each **asset owner** with a **dynamic reactive power compensation device** directly connected to the **grid** must—~~

~~(a) test the transient response, steady state response and a.c. disturbance response of each of its **dynamic reactive power compensation devices** at least once every 10 years; and~~

~~(b) test the operation of each of its **dynamic reactive power compensation devices'** analogue **control systems** at least once every 4 years; and~~

~~(c) test the operation of each of its **dynamic reactive power compensation devices'** digital **control systems** at least once every 10 years; and~~

~~(d) based on the test carried out in accordance with paragraph (a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and a.c. disturbance response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—~~

~~(i) a block diagram showing the mathematical representation of the **dynamic reactive power compensation device**; and~~

~~(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and~~

~~(iii) a detailed functional description of all of the components of the **dynamic reactive power compensation device** and how they interact in each mode of control; and~~

~~(iv) step response test results; and~~

~~(v) a.c. fault recovery disturbance test results; and~~

~~(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a set of **control system** test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.~~

~~10 Grid owner capacitors and reactive power control systems~~

~~Each **grid owner** must—~~

~~(a) test the capacitance of each of its capacitors at least once every 8 years; and~~

~~(b) test the operation of each of its reactive power control assets' analogue **control systems** at least once every 4 years; and~~

~~(c) test the operation of each of its reactive power control assets' digital **control systems** at least once every 10 years; and~~

~~(d) based on the test carried out in accordance with paragraph (a), provide a set of test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and~~

~~(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a verified set of **control system** test results including voltage set points, operating dead bands and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.~~

~~11 Grid owner synchronous compensators~~

~~Each **grid owner** must—~~

~~(a) test each of its synchronous compensators' analogue and electromechanical voltage **control systems** at least once every 5 years; and~~

~~(b) test each of its synchronous compensators' digital voltage **control systems** at least once every 10 years; and~~

~~(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—~~

~~(i) a block diagram showing the mathematical representation of the voltage **control system**; and~~

~~(ii) *[Revoked]*~~

~~(iii) a detailed functional description of the voltage **control system** in all modes of control; and~~

~~(iv) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.~~

~~12 HVDC link frequency control and protection~~

~~The **HVDC owner** must—~~

~~(a) test the operation of each of its **HVDC link's** analogue **control systems** at least once every 4 years; and~~

~~(b) test the operation of each of its **HVDC link's** digital **control systems** at least once every 10 years; and~~

~~(c) test the operation of each of its **HVDC link's** analogue protection systems at least once every 4 years; and~~

~~(d) test the operation of each of its **HVDC link's** digital protection systems at least once every 10 years; and~~

~~(e) test the modulation functions on its **HVDC link** at least once every 10 years; and~~

~~(f) based on the tests carried out in accordance with paragraphs (a) or (b), provide a set of **control system** test results and verified modelling parameters to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and~~

~~(g) based on the tests carried out in accordance with paragraphs (c) or (d), provide a set of protection system test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and~~

~~(h) based on the tests carried out in accordance with paragraph (e), provide a set of modulation function test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—~~

~~(i) a block diagram showing the mathematical representation of the **HVDC link**; and~~

~~(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagram; and~~

~~(iii) a detailed functional description of all of the components of the **HVDC link** and how they interact in each mode of control.~~

~~13 Asset owner a.c. protection systems~~

~~Each asset owner must—~~

~~(a) test the operation of the analogue protection systems on its a.c. **assets** at least once every 4 years; and~~

~~(b) test the operation of the non-self monitoring digital protection systems on its a.c **assets** at least once every 4 years; and~~

~~(c) test the operation of the self monitoring digital protection systems on its a.c. **assets** at least once every 10 years; and~~

~~(d) test the operation of the protection system measuring circuits on its a.c. **assets** by secondary injection at least once every 4 years; and~~

~~(e) test the operation of the protection system trip circuits, including circuit breaker trips, on its a.c. **assets** at least once every 4 years; and~~

~~(f) confirm at least once every 4 years that its protection settings are identified, co-ordinated, applied correctly and meet the requirements of the **AOPOs** and the **technical codes**; and~~

~~(g) based on tests carried out in accordance with paragraphs (a) to (e), provide a verification to the **system operator** in an updated **asset capability statement** that the protection systems meet the requirements of the **AOPOs** and **technical codes** within 3 months of the completion date of each such test; and~~

~~(h) based on the confirmation carried out in accordance with paragraph (f), provide an updated **asset capability statement** to the **system operator** within 3 months of the completion date of each such confirmation.~~

~~14 Representative testing~~

~~(1) Subject to clause 8(3) of **Technical Code** A, each **asset owner** may provide the information required under clauses 3(c), 5(c), and 11(c) to the **system operator**, based on representative modelling parameters and response data instead of based on the tests required under clauses 3(a) and (b), 5(a) and (b), and 11(a) and (b), for any group of identical **assets**, if each of those **assets**—~~

~~(a) was manufactured to the same specification; and~~

~~(b) is installed at the same location; and~~

~~(c) is controlled in the same way; and~~

~~(d) has a similar maintenance history.~~

~~(2) Each **asset owner** providing representative modelling parameters and response data to the **system operator** in accordance with subclause (1) for a group of identical **assets** must—~~

~~(a) complete a full set of tests in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as applicable, on an **asset** that is representative of that group to derive a verified set of modelling parameters and response data; and~~

~~(b) complete sufficient testing on the remaining **assets** in that group of identical **assets** in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as~~

~~applicable, to verify that the performance of the remaining **assets** in that group is fully consistent with the modelling parameters and response data derived from the tests carried out on the representative **asset**; and~~

~~(c) certify to the **system operator**, that to the best of the **asset owner's** information, knowledge and belief, the performance of that group of **assets** is fully consistent with the representative modelling parameters and response data provided to the **system operator** for that group of **assets**.~~

~~**15 Transitional provisions**~~

~~(1) Unless a test interval of less than 60 months is specified in this Appendix, each **asset owner** must complete the first of each test required in this Appendix no later than 5 June 2013.~~

~~(2) A test that is required to be carried out in accordance with this Appendix, but that an **asset owner** carried out before 5 June 2008, is deemed to be the first test of that type required in this Appendix, if—~~

~~(a) the **asset owner** has submitted the relevant written test results to the **system operator**; and~~

~~(b) the **system operator** has advised the **asset owner** that the specification of the test is acceptable; and~~

~~(c) the interval between the actual date of the test and the date on which this Code came into force is less than the maximum test interval specified for the corresponding test in this Appendix.~~

~~(3) If a test has been deemed to be the first test in accordance with subclause (2), the date by which the next such test must be carried out must be calculated using the actual date upon which the first test was carried out, not the date upon which it was deemed to have been carried out.~~

…

Technical Code B – Emergencies

…

7 Load shedding systems

…

(9) In addition to their obligations to provide information under the **connected asset commissioning, testing and information standard** ~~clauses 6 and 7 of Appendix B of **Technical Code** A~~, each North Island **connected asset owner** and each South Island **grid owner** must provide **automatic under-frequency load shedding** block **demand** profile information to the **system operator** if reasonably requested by the **system operator**. For each North Island **connected asset owner** that information must be in the form, and supplied by the date, specified by the **system operator** in the **AUFLS technical requirements report**. For each South Island **grid owner** that information

must be in the form specified by the **system operator** in the relevant **asset capability statement**.

(9A) If requested by the **Authority**, the **system operator** must provide information it obtains under the **connected asset commissioning, testing and information standard** ~~clauses 6 and 7 of Appendix B of **Technical Code** A~~ and subclause (9) of this clause to the **Authority**, supplemented by the **system operator's** assessment, based on its analysis of that information, as to whether the **automatic under-frequency load shedding** scheme is secure.

…

~~*Technical Code C – Operational communications*~~

~~**1 Purpose**~~

~~The purpose of this technical code is to state the minimum requirements for the communications required under this Code between asset owners, except owners of excluded generating stations, and the system operator, in order to assist the system operator to plan to comply, and to comply, with the principal performance obligations. Additional requirements may be set out in other clauses. This technical code does not deal with the content of communications, which is dealt with in each technical code and in Part 13 where relevant.~~

~~**2 Application**~~

~~This technical code applies to the system operator and to all asset owners except owners of excluded generating stations. If the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with the principal performance obligations, the system operator may require that an excluded generating station comply with some or all of the requirements of this technical code.~~

~~**3 General requirements for operational communications**~~

~~(1) Each voice or electronic communication between the **system operator** and an **asset owner** must be logged by the **system operator** and the **asset owner**. Unless otherwise agreed between the **system operator** and the **asset owner**, every voice instruction must be repeated back by the person receiving the instruction and confirmed by the person giving the instruction before the instruction is actioned.~~

~~(2) The **system operator** and each **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **system operator** and the **asset owner**. Each **asset owner** must also nominate and advise the **system operator** of the person to receive instructions and **formal notices** as set out in **Technical Code** B. The preferred points of contact must include those to be used when the **system operator** instructs the **asset owner**, when the **system operator** sends **formal notices** to the **asset owner** and when the **asset owner** contacts the **system operator**. The alternative points of contact must be used only if the preferred points of contact are not available.~~

~~(3) The **grid owner** and each other **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **grid owner** and the other **asset owner** for the purpose of communications regarding the availability of the **grid owner's** data transmission communications. The alternative points of contact must only be used if the preferred points of contact are not available.~~

~~4 Specific requirements for voice communication~~

~~(1) Each **asset owner** must have in place a primary means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The primary means of voice communication must use either—~~

~~(a) the **grid owner's** speech network; or~~

~~(b) a widely available public switched telephone network that operates in real time and in full duplex mode.~~

~~(2) Each **asset owner** must have in place a backup means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The backup means of voice communication—~~

~~(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and~~

~~(b) may include, but is not limited to, satellite phone or cellular phone; and~~

~~(c) may be used only if the primary means of voice communication described in subclause (1) is unavailable or otherwise with the agreement of the **system operator**.~~

~~(3) An **asset owner** who has a **control room** with, at any time, operational control of more than 299 **MW** of **injection**, **offtake**, or power flow must have 2 or more back up means of voice communication between the **control room** of the **asset owner** and the **system operator**, each of which must meet the requirements of subclause (2).~~

~~5 Specific requirements for transmitting information~~

~~(1) Each **asset owner** must transmit information between its **control room** and the **system operator** in writing.~~

~~(2) Despite subclause (1), an **asset owner** may request the **system operator** to approve an alternative means of transmitting information (such approval not to be unreasonably withheld).~~

~~(3) Each **asset owner** must have in place a backup means of transmitting information. The backup means of transmitting information—~~

~~(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and~~

~~(b) may include, but is not limited to, voice communication or email; and~~

~~(c) may only be used if the primary means of transmitting information described in subclause (1) or (2) is unavailable or otherwise with the agreement of the **system operator**.~~

~~**6 Specific requirements for data transmission communication**~~

~~(1) Each **asset owner** (other than a **grid owner**) must have in place—~~

~~(a) a primary means of transmitting data between the **assets** of the **asset owner** and a **SCADA** remote terminal unit of a **grid owner**; or~~

~~(b) if approved by the **system operator** (such approval not to be unreasonably withheld), a primary means of transmitting data between the **assets** of the **asset owner** and the **system operator**.~~

~~(2) A **grid owner** must have in place a primary means of transmitting data between the **assets** of the **grid owner** and the **system operator**.~~

~~(3) Each **asset owner** must have in place a backup means of transmitting data for each type of indication and measurement specified in Appendix A of this **technical code**. The backup means of data transmission communication—~~

~~(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and~~

~~(b) may include, but is not limited to, use of voice communication or document transmission communication; and~~

~~(c) may only be used if the primary means of data transmission communication described in subclause (1) or (2) is unavailable or otherwise with the agreement of the **system operator**.~~

~~**7 Availability of primary means of communication**~~

~~(1) Each **asset owner** must use reasonable endeavours to ensure that the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is available continuously.~~

~~(2) If the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is unavailable, an **asset owner** must use reasonable endeavours to restore availability of the primary means of communication as soon as practicable.~~

~~**8 Notice of planned outages of primary means of communication**~~

~~Each **asset owner** must give written notice to the **system operator** of any planned outage of a primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2).~~

~~**9 Performance requirements for indications and measurements**~~

~~(1) Each **asset owner** must provide the relevant indications and measurements shown in Appendix A to the **system operator**, in accordance with clause 6. The **system operator** may require the **asset owner** to provide additional information if, in the reasonable opinion of the **system operator**, such information is required for the~~

~~**system operator** to plan to comply, and to comply, with its **principal performance obligations**.~~

~~(2) The **asset owner** must use reasonable endeavours to ensure that the accuracy of the measurements it provides to the **system operator** in accordance with subclause (1) complies with Appendix A.~~

~~(3) Each indication and measurement provided in accordance with subclause (1) must be updated at the **grid owner's SCADA** remote terminal or the **system operator's** interface unit at least once every 8 seconds when provided by the primary means of data transmission communications.~~

~~*Appendix A: Indications and Measurements*~~

~~*(Clause 9(1)-(3) of Technical Code C)*~~

~~**Table A1: Requirements of generators**~~

~~Each **generator** must provide the indications and measurements in Table A1. If net (or gross) measurements are required in Table A1, the use of **scaling factors** together with the provision of the relevant gross (or net) values is acceptable with the **system operator's** approval. Each **generator** must provide **scaling factors** to the **grid owner** so that the **grid owner** can apply the adjustment at the **SCADA** server.~~

~~**Indication or measurement**~~	~~**Values required**~~	~~**Accuracy**[3]~~
~~**Station net MW**~~	~~Import and export~~	~~±2%~~
~~**Generating unit gross MW**[1]~~	~~Import and export, for each **generating unit**~~	~~±2%~~
~~**Station net** Mvar~~	~~Import and export~~	~~±2%~~
~~**Generating unit gross** Mvar[1]~~	~~Import and export, for each **generating unit**~~	~~±2%~~
~~**Generating unit circuit breaker** status[1]~~	~~Open /closed /in transition/ indication error[2]~~	~~N/A~~
~~**Grid interface circuit breaker** status~~	~~Open /closed /in transition/ indication error[2]~~	~~N/A~~
~~**Grid interface** disconnector status~~	~~Open /closed /in transition/ indication error~~	~~N/A~~
~~**Special protection scheme** status~~	~~Enabled/disabled/summer/winter~~	~~N/A~~
~~Maximum output capacity of **generating station** (for **intermittent generators** only)~~	~~Number of connected **generating units** × **MW** capability of each **generating unit**~~	~~N/A~~

~~**Table A2: Requirements of grid owners:**~~

~~Each **grid owner** must provide the indications and measurements shown in Table A2 in respect of assets connected to, or forming part of, the **grid**.~~

~~**Indication or measurement**~~	~~**Values required**~~	~~**Accuracy**[3]~~

~~**Grid interface circuit breaker** status~~	~~Open /closed /in transition/ indication error[2]~~	~~N/A~~
~~**Grid interface** disconnector status~~	~~Open/ closed/ in transition/ closed to earth/ indication error~~	~~N/A~~
~~**Grid interface** auto reclose status~~	~~Enabled/disabled/ operated/locked out~~	~~N/A~~
~~**Grid interface MW**~~	~~**Import and export**~~	~~±2%~~
~~**Grid interface** Mvar~~	~~Import and export~~	~~±2%~~
~~Circuit Amps~~	~~Current at each termination point of a circuit~~	~~N/A~~
~~Circuit **MW**~~	~~**MW** at each termination point of a circuit~~	~~N/A~~
~~Circuit Mvar~~	~~Mvar at each termination point of a circuit~~	~~N/A~~
~~Tap positions for **interconnecting transformers** and supply transformers with on-load tap changers~~	~~Tap position for all windings including tapped tertiaries~~	~~N/A~~
~~Tap positions for **interconnecting transformers** and supply transformers with off-load tap changers[4]~~	~~Tap position for all windings including tapped tertiaries~~	~~N/A~~
~~Reactive plant (eg RPC equipment, capacitor, reactor, condenser) Mvar~~	~~Import and export~~	~~±2%~~
~~Bus voltage~~	~~kV~~	~~±2%~~
~~**Special protection scheme** status~~	~~Enabled/disabled/summer/winter~~	~~N/A~~
~~**HVDC** modulation status~~	~~Frequency stabiliser/ spinning reserve sharing/ Haywards frequency control/ AC transient voltage support~~	~~N/A~~

~~**Table A3: Requirements of connected asset owners**~~

~~Each **connected asset owner** must provide the indications and measurements shown in Table A3 in respect of **assets** connected to, or forming part of, the **grid**~~

~~**Indication or measurement**~~	~~**Values required**~~	~~**Accuracy**~~
~~**Grid interface circuit breaker** status~~	~~Open/ closed/ in transition/ indication error[2]~~	~~N/A~~
~~**Grid interface** disconnector status~~	~~Open/ closed/ in transition/ indication error~~	~~N/A~~
~~**Grid interface** auto reclose status~~	~~Enabled/disabled/operated/locked out~~	~~N/A~~
~~**Special protection scheme** status~~	~~Enabled/disabled/summer/winter~~	~~N/A~~

~~Reactive plant 5 (eg RPC equipment, capacitor, reactor, condenser) Mvar~~	~~Import and export~~	~~±2%~~

~~[1] Required only if a **generating unit** has a maximum continuous rating of greater than 5 **MW**.~~

~~[2] No intentional time delays should be included for **circuit breaker** indications as these are time tagged by the **system operator** to less than 10 ms.~~

~~[3] If accuracy is measured at the input terminal of the RTU of the **grid owner**, under normal operating conditions at full scale.~~

~~[4] Indication required within 5 minutes of status change.~~

~~[5] Required only if reactive plant has a maximum continuous rating of greater than 5 Mvar.~~

…

Part 12
Transport

…

12.10 Default transmission agreements

…

(3) The service levels set out in Schedule 5 of a **default transmission agreement** must be determined on the following basis:

(a) the capacity service levels for each **branch** must be consistent with—

(i) the capacities of the **branch** or component **assets** in the most recent **asset capability statement** provided by **Transpower** under clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3; or

…

12.107 Transpower to identify interconnection branches, and propose service measures and levels

…

(5) The information provided under subclause (4) must,—

(a) in the case of information provided under subclause (4)(a), (c) and (d), be consistent with the information disclosed by **Transpower** in the most recent **asset capability statement** provided by **Transpower** under clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3; and

(b) in the case of information provided under subclause (4)(b), be consistent with the **manufacturer's specification** for the component **assets** and the information disclosed by **Transpower** in the most recent **asset capability statement** provided under clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specifications**;

…

12.112 Exceptions to clause 12.111

(1) **Transpower** is not required to comply with clause 12.111(1)(a) or (2) if—

…

(ea) in relation to the **HVDC link**—

(i) the **HVDC owner** is operating the **HVDC link** in accordance with—

(A) a **commissioning** plan agreed with the **system operator** under clause 2(6) ~~to~~and (9) of **Technical Code** A of Schedule 8.3; or

(B) a test plan provided to the **system operator** under clause 2(6) ~~to~~ and (9) of **Technical Code** A of Schedule 8.3; and

…

12.116 Information on capacities of individual interconnection assets

…

(2) The information required under subclause (1)—

(a) must be consistent with the **manufacturer's specification** for the **asset** or with the most recent **asset capability statement** provided by **Transpower** under clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specification**; and

…

Schedule 12.4
Transmission Pricing Methodology

…

10 Calculations and Estimations

…

(4) Except as otherwise stated in this Code, **Transpower** may use the following information to calculate **allocation data** and is not required to (but may) use any other information:

…

(e) indications and measurements required to be provided by a **participant** to the **system operator** under this Code, including under the **connected asset**

commissioning, testing and information standard ~~Technical Code C of Schedule 8.3 of this Code~~, that are published or made available to **Transpower**.

…

Schedule 12.6

Default transmission agreement template

…

37.3 Information on capacities of individual Connection Assets

…

(b) The information required under paragraph (a) above:

(1) must be consistent with the **manufacturer's specification** of the Connection Asset or with the most recent Asset Capability Statement provided by Transpower under clause 2(5~~f~~) of Technical Code A of Schedule 8.3 of the Code, if this differs from the **manufacturer's specification**;

…

Part 13

Trading arrangements

…

13.29 Standing data on grid capability to be provided to system operator

In addition to the **asset owner** obligations to provide information under ~~clauses 2(5) and (6) and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, each **grid owner** must provide standing data on the capability of the transmission system to the **system operator** that is consistent with the configuration of the transmission system in the algorithms described in Schedule 13.3. The transmission data must include—

(a) AC system configuration, including the transmission **lines**; and

(b) AC system capacity including the limits of each transmission line of the transmission system; and

(c) AC system loss characteristics including transmission loss functions for each transmission line of the transmission system.

…

13.30 Standing data on HVDC capability to be provided to system operator

(1) In addition to the **asset owner** obligations to provide information under ~~clauses 2(5) and (6), and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset**

commissioning, testing and information standard, the **HVDC owner** must provide standing data on the capability of the **HVDC link** to the **system operator** consistent with the **HVDC link configuration**.

…

(3) Subclause (2)(d) applies only if—

(a) the **HVDC owner** is operating the **HVDC link** in accordance with—

(i) a **commissioning** plan agreed with the **system operator** under clause 2(6) ~~to~~and (9) of **Technical Code** A of Schedule 8.3; or

(ii) a test plan provided to the **system operator** under clause 2(6) ~~to~~and (9) of **Technical Code** A of Schedule 8.3; and

…

13.31 Standing data on transformer capability to be provided to system operator

In addition to the **asset owner** obligations to provide information under ~~clauses 2(5) and (6), and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, each **grid owner** must provide standing data on the capability of transformers to the **system operator** consistent with the configuration of those transformers. The data must include—

(a) the transformer capacity of each transformer; and

(b) the transformer loss characteristics, including transformer loss functions, for each transformer.

…

13.32 Transmission grid capability information to be updated

In addition to the **asset owner** obligations to provide information under ~~clauses 2(5) and (6) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, and subject to that standard, ~~any timetable agreed with the **system operator** under clause 3(1) of **Technical Code** A of Schedule 8.3,~~ each **grid owner** must submit to the **system operator** for each **trading period** of a **schedule period**, or for such longer period of time as agreed between the **system operator** and each **grid owner**, any updates to the information described in clauses 13.29 to 13.31 and 13.33(d).

…

13.33 Grid owners must submit revised information to system operator

Up to 1 hour before the beginning of the relevant **trading period**, but subject to any requirements in the **connected asset commissioning, testing and information standard** ~~any timetable agreed with the **system operator** under clause 3(1) of **Technical Code** A of Schedule 8.3~~, each **grid owner** must immediately submit revised information to the **system operator** if there has been or is likely to be—

(a) a change to the information described in clauses 13.29 or 13.30; or

(b) a change of 5% or more in the capacity limit of any transmission line of the transmission system, of the **HVDC link**, or of any transformer, represented in the algorithms described in Schedule 13.3; or

(c) a change to loss characteristics, including loss functions, for any transmission line of the transmission system or of the **HVDC link**, or for any transformer, represented in the algorithms described in Schedule 13.3 that causes any **losses** or marginal **losses** to change by 5% or more; or

(d) a change in the availability of **assets** forming part of the **grid**.

…

…

Part 17
Transitional provisions

…

17.47 Specific requirements for document transmission communication

(1) *[Revoked]*

~~(2) An approval of primary or backup means of document transmission communication under clauses 4.1 or 4.2 of technical code C of schedule C3 of part C of the **rules** that was in force immediately before this Code came into force, is deemed to be an approval under clause 5(2) or (3), as the case may be, of **Technical Code** C of Schedule 8.3.~~

Q8. Do you have any comments on the drafting of the proposed amendment?

Appendix B Cover Note for the proposed Connected Asset Commissioning, Testing and Information Standard (CACTIS)

Cover Note for the proposed Connected Asset Commissioning, Testing and Information Standard (CACTIS)

1 July 2025

1) Introduction

The Connected Asset Commissioning, Testing and Information Standard (CACTIS) is a system operator-owned document proposed for incorporation by reference into the Electricity Industry Participation Code 2010 (the Code). It contains technical requirements for the provision of asset capability information, asset commissioning (including timing requirements), modelling, testing, and operational communications.

2) Background

2.1 Review of common quality information requirements in Part 8 of the Code

The Electricity Authority Te Mana Hiko (the Authority) is reviewing the common quality requirements in Part 8 of the Code, as part of its Future Security and Resilience (FSR) programme.

In April 2023, the Authority published a consultation paper outlining seven common quality issues. These were identified through Authority stakeholder engagement over:

a) The implications for the Code's common quality requirements of increasing amounts of variable and intermittent generation, primarily in the form of inverter-based resources; and
b) The extent to which the Code's common quality requirements enable new and evolving technologies, in particular inverter-based resources.

One of these issues concerns the provision of common quality-related information to network owners and operators (issue six). The Authority summarised issue six as follows:

"Network owners and operators have insufficient information on assets wanting to connect, or which are connected, to the power system to provide for the planning and operation of the power system in a safe, reliable and economically efficient manner."[1]

In its October 2024 consultation paper, the Authority proposed to update and clarify common quality-related information requirements in the Code relating to:

a) Testing and commissioning of new assets and upgrades to existing assets, including the timing of the provision of information; and
b) Undertaking system studies and investigating transmission and distribution system common quality issues.

The Authority added that it may be desirable to move these common quality requirements into a document incorporated by reference in the Code – the proposed CACTIS. This would give the system operator the responsibility of using its subject matter expertise to manage and develop the common quality-related asset information requirements necessary for the system operator to meet its common quality Code obligations.

After considering submissions on the consultation paper, the Authority requested the system operator to proceed with the drafting of a proposed CACTIS (appended to this cover note) for initial consultation by the Authority.

2.2 Why the proposed CACTIS is needed

As they stand, certain common quality information requirements in the Code are unclear, leaving some of the current phrasing subject to varying interpretations. Additionally, the Code does not specify the timing of commissioning process activities that both asset owners and the system operator must adhere to, making it difficult to plan and coordinate these activities. Current common quality information requirements also do not accurately reflect recent technological changes and industry trends, such as the increase of inverter-based resource generation.

2.3 Purpose of the proposed CACTIS

The proposed CACTIS contains clearer technical requirements to address the above needs in relation to asset capability information, asset commissioning (including timing requirements),

[1] Part 8 Common Quality Requirements Issues Paper, p7.

modelling, testing, and operational communications. The document aims to support the system operator's ability to plan to comply, and comply, with its principal performance obligations (PPOs) under the Code. This includes providing more clarity on requirements which are currently set out in 'guidelines' and making them more clearly consistent and enforceable.

The proposed CACTIS allows for a more responsive Code, as the system operator can develop changes to the technical requirements in the CACTIS that align with industry and technological evolution. This will help enable new and evolving technologies to smoothly integrate into the power system as New Zealand's electricity industry transitions to providing more renewable energy.

2.4 The Scope of the proposed CACTIS

The proposed CACTIS is organised into the following chapters:

Chapter Title	Content Summary
1. Time Frame Requirements	...indicates the expected timings for required commissioning activities related to new assets and making changes to existing assets, as well as decommissioning.
2. Commissioning Plan Requirements	...outlines the technical specifications related to the creation of a commissioning plan.
3. Asset Capability Statement Requirements	...details the technical requirements for asset capability statement information provided by an asset owner.
4. Modelling Requirements	...specifies the technical modelling requirements that asset owners must adhere to, including model formats, software, and documentation.
5. Connection Study requirements	...outlines the technical requirements for performing and documenting connection studies.
6. Test Plan Requirements	...focuses on the details that asset owners must include in test plans for commissioning and modifications of assets.
7. Testing Requirements	...describes the technical testing requirements for asset owners, including commissioning tests, routine testing, and the general and specific technical requirements for different asset types.

Chapter Title	Content Summary
8. Operational Communication Requirements	...covers the minimum technical requirements for operational communication between asset owners and the system operator.
9. High Speed Data Requirements	...details the technical requirements for high-speed data that generators must provide to the system operator for post-event analysis and routine testing.
Appendix A	...provides visual representations of common generating plant topologies.

3) Code changes associated with the proposed CACTIS

The scope of the proposed CACTIS means some provisions in Part 8 of the Code that relate to common quality information requirements can be moved from the main body of the Code to the CACTIS. These include:

- Technical Code A – some clauses relating to technical requirements for asset capability statements, commissioning, modelling, and testing.
- Technical Code A – Appendix B (routine testing of assets and automatic under-frequency load shedding systems).
- Technical Code C (operational communications).

The proposed CACTIS would contain only technical specifications. The main body of the Code (Part 8) would continue to contain significant policy matters relating to common quality information requirements, and empowering provisions for obligations in the proposed CACTIS.

4) Proposed requirement changes

The proposed CACTIS contains several clarifications of existing technical requirements in Part 8 of the Code. These include:

- More detailed asset testing parameters, for example, for routine testing.
- Defining different stages of asset capability statement information provision.
- Indications and measurements for new asset technologies such as battery energy storage systems and hybrid plants.

The proposed CACTIS also includes some new specifications:

- High-speed data recording requirements to enhance real-time monitoring and responsiveness.
- Controllable load indications for connected asset owners to improve the system operator's ability to manage shortfall events and reduce the risk of supply disruption to consumers.

Lastly, the proposed CACTIS incorporates information requirements that are currently referenced in system operator guideline documents, such as:

- Timeframes for commissioning process activities.
- Modelling data specifications to enable integration of new technologies.
- Connection study requirements.

The system operator requests most of these regularly from asset owners as part of current practice. Formalising these requirements through the proposed CACTIS provides clarity of expectations for the industry and facilitates all parties fulfilling their performance obligations. Any further changes to the proposed CACTIS will be governed by the existing formal consultation processes under Part 7 of the Code.

5) Benefits of the proposed CACTIS

The proposed CACTIS provides clearer common quality information requirements, supporting both asset owners and the system operator to fulfil their respective performance obligations under Part 8 of the Code.

The system operator strives to study, monitor and coordinate all equipment on New Zealand's transmission system. The proposed CACTIS would allow the system operator to be more responsive to changes in the energy landscape, facilitating the integration of new and evolving technologies and the uptake of inverter-based resources. This is especially important as the size of the power system grows and the composition of demand and supply of connecting assets becomes more complex. Through the proposed CACTIS, the system operator would be better empowered to plan to comply, and comply, with its PPOs under the Code, ultimately bolstering system security. The formal consultation process would also ensure that others can provide valuable input to arrive at a document that serves industry needs.

More information about the benefits is available in the questions and answers document

6) Next steps

The system operator will undertake its own consultation on the technical specifications within the proposed CACTIS. However, stakeholders are invited to provide early feedback during the Authority's Common Quality Information Requirements Code amendment consultation.

The system operator notes the Authority holds the ultimate decision-making power regarding whether the proposed CACTIS is incorporated by reference in the Code.

Appendix C Draft of the proposed Connected Asset Commissioning, Testing and Information Standard (CACTIS)

Connected Asset Commissioning, Testing and Information Standard

Contents

Introduction

PURPOSE

1. This is the **connected asset commissioning, testing and information standard** (**CACTIS**) referred to in Part 8 of the Electricity Industry Participation Code 2010 (**Code**).

2. This **CACTIS** takes effect from [1 July 2026].

3. The purpose of this **CACTIS** is to specify requirements relating to:

   3.1 the information, including modelling information, that **asset owners** must provide the **system operator**; and

   3.2 the commissioning and testing of **assets**; and

   3.3 other operational matters,

   to enable the **system operator** to plan to comply, and comply, with the **principal performance obligations**.

INTERPRETATION

4. This **CACTIS** must be read in conjunction with the relevant guidance and forms from time to time **published** by the **system operator**.

5. Any bolded terms in this **CACTIS** that are defined in the **Act** or in Part 1 of the **Code** and that are not defined in the Definitions section of this **CACTIS**, have the same meaning as given to them in the **Act** or Part 1 of the **Code** (as applicable).

6. In this **CACTIS**, unless the context otherwise requires, references to paragraphs and Chapters are to paragraphs and Chapters of this **CACTIS**.

7. In this **CACTIS** and the Code, unless the context otherwise requires, a reference to an **asset capability statement** for an **asset** means the most recent **asset capability statement** for the **asset** provided to the **system operator** (which may be a **planning stage asset capability statement**, **pre-commissioning stage asset capability statement** or a **final asset capability statement**).

8. In the event of any inconsistency between the provisions of this **CACTIS** and the provisions of the rest of the **Code** (excluding other material incorporated by reference into the Code), the provisions of the rest of the **Code** will prevail to the extent of the inconsistency.

DEFINITIONS

In this **CACTIS**, unless the context otherwise requires:

as-left means the final set of **control system** parameters, settings and configurations applied to a **control system** after **commissioning**.

battery energy storage system or **BESS** means an **energy storage system** with an electro-chemical storage component.

commissioning plan means a plan for the **commissioning** of an **asset** that complies with the specifications in Chapter 2.

connection study report means a report on connection study cases for an **asset** that complies with the specifications in Chapter 5.

decommissioning plan means a plan for the **decommissioning** of an **asset** that complies with the specifications in paragraphs 1.18, 1.19, and 1.20.

encrypted means a control system model in which the control block(s) and signal flow are accessible, but the logic, mathematical equations, and programming code are not accessible to the **system operator.**

end of commissioning period means the point at which all testing of an **asset** has been completed in accordance with the **commissioning plan** for the **asset**.

engineering methodology means a document that includes a full description of all tests to be performed on an **asset** including the methodology for each test, the signals to be recorded, the sampling rates to be used, and the format for submitting test results to the **system operator**.

final asset capability statement means an asset capability statement prepared at the completion of **commissioning** of an **asset** that complies with the requirements in Chapter 3.

final compliance assessment means a compliance assessment for an **asset** provided by the **system operator** to the **asset owner** under paragraphs 1.16 and 1.17.

final copy means the final version of a document or model that is complete, takes into account all feedback from relevant parties' and is ready for sign-off.

final decommissioning plan means a plan submitted to the system operator under paragraph 1.18.

generating system means a group of **generating units electrically connected** to a **network** through a common circuit breaker, excluding a **grid interface** circuit breaker.[1]

m1 model means a model for an **asset** that complies with the m1 specifications in Chapter 4.

m2 model means a model for an **asset** that complies with the m2 specifications in Chapter 4.

planning stage asset capability statement means an asset capability statement prepared prior to the completion of planning for the

1 Refer to the single line diagrams in Appendix A for further guidance.

construction or modification of an **asset** that complies with the specifications in Chapter 3.

pre-commissioning stage asset capability statement means an asset capability statement prepared at the completion of construction or modification of an **asset** that complies with the specifications in Chapter 3.

start of commissioning period means the first time a new or modified **asset** is **electrically connected** to a **network**.

state of charge means the amount of energy stored in a **BESS**, expressed as a percentage of its nameplate energy rating.

test plan means an operational test plan for an **asset** to inform the **system operator** of the timing and details of testing during which the **asset** is **electrically connected** to a **network**.

unencrypted means a control system model in which all the control blocks, logic, mathematical equations, signal flows, and programming code are accessible to the **system operator**.

Chapter 1: Time Frame Requirements

1.1 This Chapter specifies the time frames in which an **asset owner** must provide the **system operator** with the documentation and information required by this **CACTIS** and the Code before and after **commissioning** an **asset** and when an **asset** is **decommissioned**.

1.2 This Chapter also specifies the time frames in which the **system operator** must review (which includes providing written feedback on) the documentation and information provided to it by an **asset owner** in accordance with this **CACTIS** and the Code before and after **commissioning** an **asset** and when an **asset** is **decommissioned**.

1.3 If, following review by the **system operator** of any documentation or information provided by an **asset owner** under this **CACTIS**, the **system operator** requires further information from the **asset owner** or the **system operator** is otherwise not satisfied that the documentation or information provided by the **asset owner** meets the relevant requirements set out in this **CACTIS**:

(a) the **system operator** may request that the **asset owner** provide additional information as necessary or amend and resubmit the relevant documentation or information to the **system operator** for further review; and

(b) the **asset owner** must comply with the **system operator's** request within a time frame agreed between the **system operator** and **asset owner** or, failing agreement, within a time frame determined by the **system operator** (acting reasonably); and

(c) for the purposes of assessing the **asset owner's** compliance with the time frame in this **CACTIS** for providing the relevant documentation or information, the **asset owner** will be deemed not to have provided the **system operator** with the documentation or information until the **asset owner** complies with the **system operator's** request.

1.4 Where the time frames in this Chapter for providing the **system operator** with documentation and information are not adhered to, the **asset owner** must not first **electrically connect** an **asset** to a **network**, without prior written approval from the **system operator**.

BEFORE COMMISSIONING

1.5 A **planning stage asset capability statement** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 12 months prior to when the **asset** is **electrically connected** to a **network**; and

(b) reviewed by the **system operator** within 20 **business days** of receiving the **planning stage asset capability statement**.

1.6 A **pre-commissioning stage asset capability statement** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 2 months prior to when the **asset** is **electrically connected** to a **network**; and

(b) reviewed by the **system operator** within 20 **business days** of receiving the **pre-commissioning stage asset capability statement**.

1.7 The **asset owner** must establish communication paths for data transmission and agree on datasets for the provision of **SCADA** and **dispatch** signals with the **system operator** at least 3 months prior to when an **asset** is **electrically connected**.

1.8 A **final copy** of a **commissioning plan** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 2 months prior to when the **asset** is **electrically connected** to a **network**; and

(b) agreed by the **system operator** within 20 **business days** of receiving the **commissioning plan**.

1.9 A **final copy** of the **m1 model** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 2 months prior to when the **asset** is **electrically connected** to a **network**; and

(b) reviewed by the **system operator** within 20 **business days** of receiving the **m1 model**.

1.10 A **final copy** of a **connection study report** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 2 months prior to when the **asset** is **electrically connected** to a **network**; and

(b) agreed by the **system operator** within 20 **business days** of receiving the **connection study report**.

1.11 A **final copy** of an **engineering methodology** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 30 **business days** prior to when the **asset** is **electrically connected** to a **network**; and

(b) agreed by the **system operator** within 20 **business days** of receiving the **engineering methodology**.

1.12 The **asset owner** must provide a **test plan** for an **asset** to the **system operator** at least 15 **business days** prior to when the **asset** is **electrically connected** to a **network**.

1.13 The following requirements in relation to an **asset** must be demonstrated to the **system operator** at least 10 **business days** prior to when the **asset** is **electrically connected** to a **network**:

(a) **SCADA** for the **asset** is fully modelled and operational in the **system operator's** production server.

(b) **Dispatch** communications for the **asset** are operational.

(c) Protection coordination for the **asset** at the **grid interface** is confirmed in writing by each **participant electrically connected** to a **network** at the relevant **point of connection** in the format agreed by the **grid owner**.

(d) If required, the **system operator's** Reserves Management Tool (RMT) is updated for the **asset**.

AFTER COMMISSIONING

1.14 A **final asset capability statement** and a full set of test results for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** within 20 **business days** of the **end of commissioning period**; and

(b) reviewed by the **system operator** within 20 **business days** of receiving the **final asset capability statement**.

1.15 A **final copy** of a **m2 model** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** within 3 months of the **end of commissioning period** for the **asset**; and

(b) reviewed by the **system operator** within 20 **business days** of receiving the **m2 model**.

1.16 The **system operator** must provide the **asset owner** with a **final compliance assessment** for an **asset** within 4 months of the **end of commissioning period** for the **asset**, subject to the **asset owner:**

(a) meeting the requirements of paragraphs 1.14 and 1.15; and

(b) providing the **system operator** with any additional documentation or information reasonably requested by the **system operator** for the purpose of issuing the **final compliance assessment**.

1.17 The **final compliance assessment** for an **asset** must:

(a) confirm that the **asset** meets the requirements of the **asset owner performance obligations** and **technical codes**; and

(b) be based on the documentation and information supplied by the **asset owner**, including (where applicable):

(i) the **final asset capability statement**; and

(ii) all modelling information; and

(iii) the results of **system tests** undertaken during **commissioning**.

DECOMMISSIONING

1.18 A **final copy** of a **decommissioning plan** for an **asset** must be:

(a) provided by the **asset owner** to the **system operator** at least 2 months prior to permanently **electrically disconnecting** the **asset** from a **network**.

(b) agreed by the **system operator** within 20 **business days** of receiving the **decommissioning plan**.

1.19 The **final copy** of the **decommissioning plan** for an **asset** must confirm:

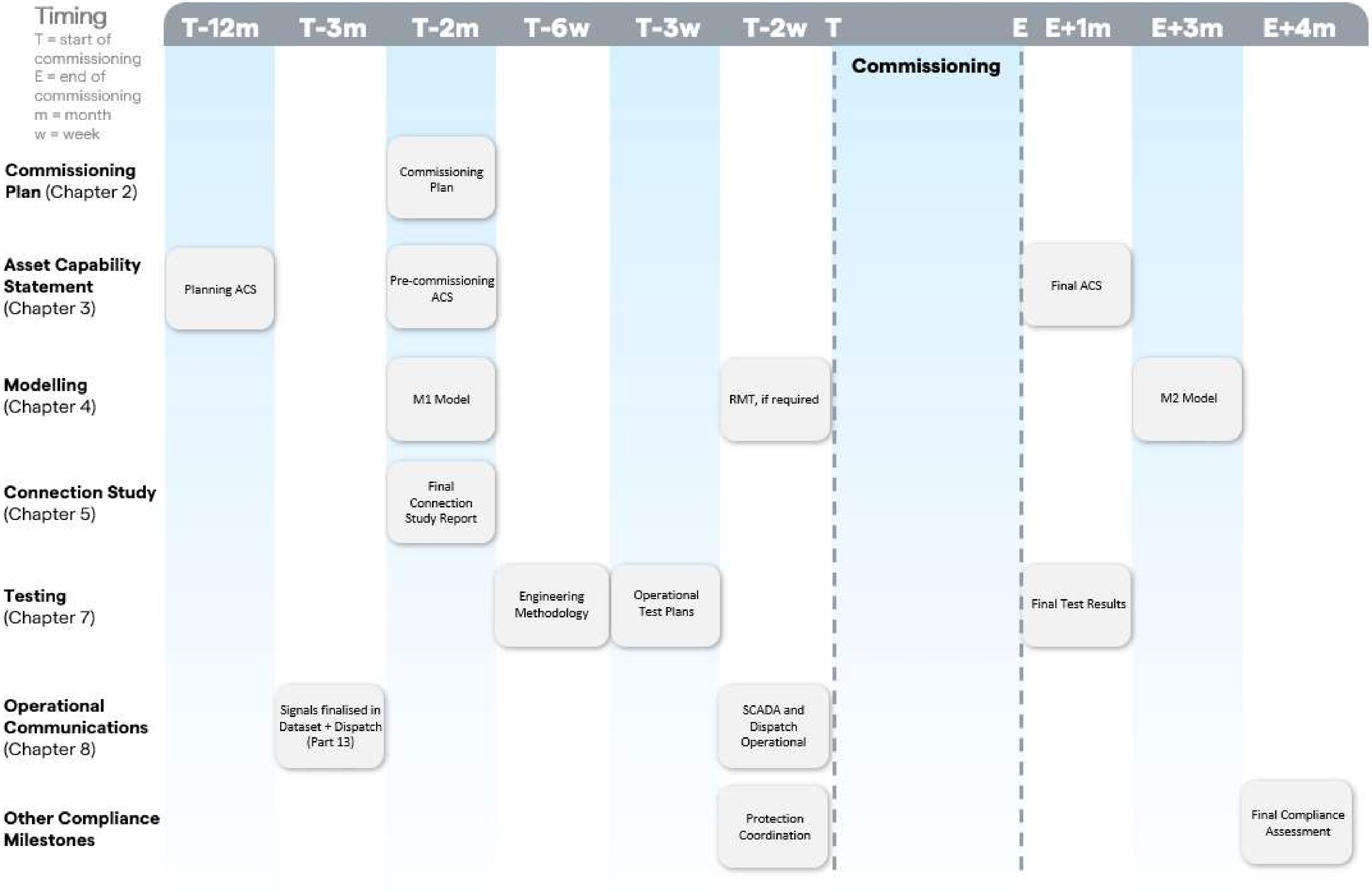
(a) the date the asset was, or will be, **decommissioned**; and

(b) the date the **asset** will be permanently **electrically disconnected** from a **network**; and

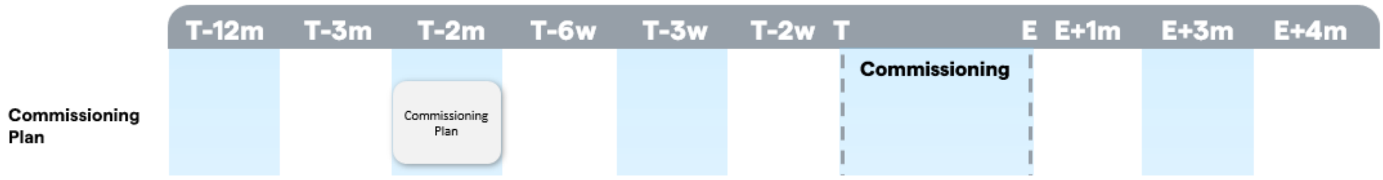
(c) the date that all the **system operator's** tools should be updated to record the **decommissioning** and permanent **electrical disconnection** of the **asset**.

1.20 The **asset owner** must provide the **system operator** with an update to the **asset capability statement** for a **decommissioned asset** within 2 weeks of **decommissioning** the **asset**.

Figure 1: Timeline of Commissioning Requirements



Chapter 2: Commissioning Plan Requirements



2.1 This Chapter specifies the requirements for **commissioning plans** that must be provided by an **asset owner** to the **system operator** under clause 2(6) of **Technical Code** A of Schedule 8.3 of the Code.

2.2 The **asset owner** must provide a **commissioning plan** for an **asset**:

(a) in the form from time to time **published** by the **system operator**; and

(b) in accordance with the time frame in Chapter 1.

2.3 The **asset owner** must provide a **commissioning plan** for an **asset** in the following situations:

(a) when the **asset** is to be **electrically connected** to a **network**; and

(b) when changes are made to the **asset** that alter any of the following at the **grid interface**:

(i) the **single-line diagram**; or

(ii) a protection system, other than a change to a protection system setting; or

(iii) a **control system**, including a change to a **control system** setting or firmware; or

(iv) any capability or rating of the **asset**.

2.4 The **asset owner** must contact the **system operator** for advice if:

(a) the **commissioning** or **electrical connection** of an **asset** may affect the **system operator's** ability to plan to comply, or to comply, with the **principal performance obligations**; or

(b) the **asset owner** is unsure whether the **commissioning** or **electrical connection** of the **asset** may affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations**.

2.5 A **commissioning plan** for an **asset** must:

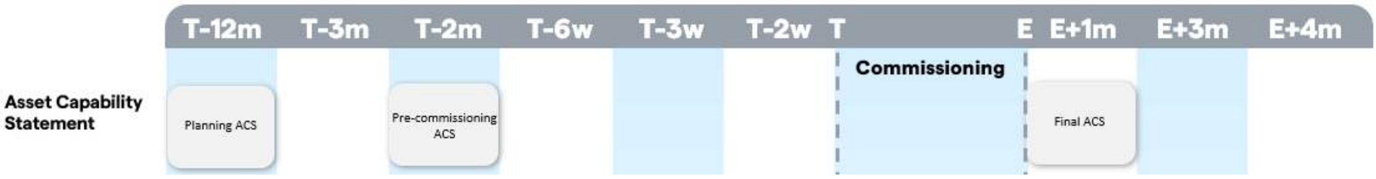
(a) include a timetable containing the sequence of events necessary to **electrically connect** the **asset** to**,** or make the **asset** part of**,** a **network** and undertake any proposed test; and

(b) contain the protection and control settings to be applied before the **asset** is **electrically connected** to, or becomes part of, a **network**; and

(c) contain the procedures for **commissioning** the **asset** with minimum risk to personnel and plant and to the ability of the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; and

(d) contain all other information required by the form for the **commissioning plan** from time to time **published** by the **system operator**.

Chapter 3: Asset Capability Statement Requirements



3.1 This Chapter specifies the requirements for **asset capability statements** that must be provided by an **asset owner** to the **system operator** under clause 2(2) of **Technical Code** A of Schedule 8.3 of the Code.

3.2 The **asset owner** must provide each **asset capability statement** for an **asset**:

(a) in the form from time to time published by the **system operator**; and

(b) in accordance with the relevant time frame in Chapter 1.

3.3 For the purpose of clause 2(5) of **Technical Code** A of Schedule 8.3 of the Code, the **asset owner** must provide **asset capability statements** for:

(a) each **asset** that is, or is proposed to be, **electrically connected** to, or part of, a **network**; and

(b) each of its **generating stations** with a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21 (2).

3.4 For the purpose of clause 2(5A) of **Technical Code** A of Schedule 8.3 of the Code, an **asset capability statement** for an **asset** must:

(a) include the following information:

(i) if the **asset capability statement** is a **planning stage asset capability statement**:

(A) if the **asset** is a **generating station**, information relating to **generating station** capability and connection topology; and

(B) any modelling data required by and prepared in accordance with Chapter 4; and

(C) any connection studies required by and prepared in accordance with Chapter 5; or

(ii) if the **asset capability statement** is a **pre-commissioning stage asset capability statement**:

(A) all information contained in the **planning stage asset capability statement** (updated as necessary to reflect changes to the **asset** at the pre-**commissioning** stage); and

(B) “as designed” or “site specific” data relating to the **asset**; and

(C) (as applicable) details of transmission line, **generating unit**, transformer, **battery energy storage system**, and **reactive power** device capabilities; or

(iii) If the **asset capability statement** is a **final asset capability statement**:

(A) all information contained in the **pre-commissioning stage asset capability statement** (updated as necessary to reflect changes to the **asset** at the post-commissioning stage); and

(B) “tuned” or **as-left** data relating to the **asset**; and

(b) be updated as information and design development progresses through the study, design, manufacture, testing and **commissioning** phases for the **asset**; and

(c) always be complete and up to date while the **asset** is **electrically connected** to a **network**.

3.5 If there is any change to the capability of an **asset** that may affect either the **asset owner's** ability to meet its **asset owner performance obligations** or the **system operator's** ability to meet the **principal performance obligations**, the **asset owner** must:

(a) notify the **system operator** immediately and update the **asset's asset capability statement** within 2 **business days** of the change; or

(b) where the change is urgent or temporary (less than 4 weeks), promptly notify the **system operator** in writing of the change using the form from time to time **published** by the **system operator**. For the purposes of this paragraph, an urgent or temporary change in **asset** capability is a change where the **asset owner**:

(i) unexpectedly becomes aware the capability of the **asset** may differ from the capability described in the **asset's asset capability statement** and there is no practicable opportunity to update the **asset capability statement** in accordance with this **CACTIS**; and

(ii) the **asset owner** needs to perform further investigations to determine or confirm the capability of the **asset** after the change.

3.6 When the **asset owner** updates an **asset capability statement** for an **asset**:

(a) the **system operator** must assess, based on the information in the updated **asset capability statement**, whether the **asset** is consistent with the **asset owner's asset owner performance obligations** and provide written feedback to the **asset owner** within 20 **business days** of receiving the update; and

(b) if required by the **system operator**, the **asset owner** must provide the **system operator** with a further updated **asset capability statement** for the **asset** addressing the **system operator's** feedback in a time frame agreed between the **system operator** and **asset owner** or, failing agreement, determined by the **system operator** (acting reasonably).

Chapter 4: Modelling Requirements

4.1 This Chapter specifies the requirements for modelling data that must be provided by **asset owners** to the **system operator** and under clauses 2(5A) and 2(5B) of **Technical Code** A of Schedule 8.3 of the Code and in connection with other requirements in this **CACTIS**.

M1 AND M2 MODELS

4.2 An **asset owner** must provide an **m1 model** and **m2 model** at the times specified in Chapter 1:

4.3 An **m1 model** is a connection study model where all the site-specific parameters and control modes are modelled with the control and protection system with appropriate settings. The protection system must include, at a minimum, frequency and voltage protection functions.

4.4 An **m2 model** is a final validated model where all the as-built parameters with the intended control mode and transition between controls are included. All the control and protection system must be in the model with **as-left** settings. The protection system must include, at a minimum, frequency and voltage protection functions.

SOFTWARE PACKAGES, FORMATS, AND CONFIDENTIALITY

4.5 All **m1 models** and **m2 models** must be provided in software packages currently used by the **system operator**. The currently used software package and model formats for **m1 models** and **m2 models** are as follows, depending on the type of **asset**:

(a) For a synchronous **generating unit**, both the **m1 model** and **m2 model** must use PowerFactory.

(b) For a **generating unit** producing power from wind or solar or **BESS**:

(i) the **m1 model** must use:

(A) PowerFactory, and must be **unencrypted**; and

(B) Power System Computer Aided Design (**PSCAD**); and

(C) Western Electricity Coordinating Council (**WECC**) generic model; and

(ii) the **m2 model** must use:

(A) PowerFactory, and must be **unencrypted**; and

(B) Powertech’s Transient Security Assessment Tool (**TSAT**); and

(C) PSCAD; and

(D) WECC generic model.

4.6 If an **asset owner** provides an **unencrypted** model to the **system operator**, the model must be in one of the following formats:

(a) a model block diagram format, where the model is prepared with basic control blocks and graphical representation of control system components. PowerFactory, PSCAD, TSAT and WECC generic models must have the control blocks, logic and signal flow accessible to the **system operator**.

(b) a model source code format, where the model is prepared with programming codes written and organised to implement control system functions. The programming code in PowerFactory and TSAT models must be accessible to the **system operator**.

4.7 If an **asset owner** provides an **encrypted** PSCAD and TSAT model (or **encrypted** parts of a PSCAD and TSAT model) to the **system operator**, the **asset owner** must make the outputs and inputs of the **encrypted** model (or part thereof) accessible to the **system operator**, and the function of the **encrypted** model (or part thereof) must be explained in the supporting documentation.

4.8 If an original equipment manufacturer deems a model is not to be shared publicly, then in addition to the **m1 model** and **m2 model,** the **asset owner** must also provide the **system operator** with an **encrypted** PowerFactory or a WECC generic model, which can be shared publicly by the **system operator**.

GENERAL MODEL CONFIGURATION REQUIREMENTS

4.9 An **asset owner** must provide the **m1 model** and **m2 model** suitable for root mean square (RMS), positive phase-sequence, time domain and electromagnetic transient (EMT) studies. The **system operator** must use these to:

(a) assess the **asset**’s capability to meet the corresponding Code obligations; and

(b) carry out other power system studies such as system security, short-term operation planning, stability, and post-event investigation assessments.

4.10 All models an **asset owner** provides to the **system operator** must:

(a) have a degree of adequacy and accuracy that allows the **system operator** to make informed decisions based on simulation results; and

(b) be site-specific; and

(c) represent the dynamic behaviour of the **asset**, including all elements and control systems that affect the **active power** and **reactive power** output of the **asset** in response to frequency and voltage changes at the **point of connection**. The **asset** must be modelled according to its type, as follows:

(i) a synchronous **generating unit** must be modelled as a full **generating station**, including individual **generating units**, **generating unit** transformers and **generating station** auxiliary loads; and

(ii) a **generating unit** producing power from wind or solar or **BESS** can be aggregated with **generating units** of the same design into a single **generating unit** to accurately represent the overall performance of the **generating units** at a common **point of connection**. A representation of the collector system, inverter transformer, grid tie transformer and any additional **dynamic reactive power compensation devices** must be included in the aggregated model; and

(d) represent all control modes within the frequency and voltage control system, ensuring they can be used in real-time operation and can accept external signals to trigger changes; and

(e) not contain any unused control blocks or programme codes; and

(f) allow the **system operator** access to, and visibility of, all control signals and equations used to initialise the model; and

(g) be compatible with the modelling software package versions from time to time **published** by the **system operator**.

POWERFACTORY AND TSAT MODEL REQUIREMENTS

4.11 A PowerFactory and TSAT model submitted by an **asset owner** to the **system operator** must:

(a) be numerically stable for the full operating range, which must be at least a frequency range of 45 to 55 Hz and at least a voltage range of 0 to 1.3 pu; and

(b) be numerically stable for a simulation time of at least 120 seconds, with voltage, frequency, **active power** and **reactive power** remaining constant with no disturbance; and

(c) be numerically stable for a minimum of 60 seconds following any set point changes or contingency; and

(d) be operationally stable with an integration time step that is a minimum of 5 milliseconds; and

(e) have key parameters such as droop setting, ramp rate and state of charge for **BESS** and hybrid plants available for the **system operator** to change.

PSCAD MODEL REQUIREMENTS

4.12 A PSCAD model submitted by an **asset owner** to the **system operator** must:

(a) be developed with adequate details to represent the complete behaviour of the control system; and

(b) include suitable phase-locked loop (PLL), inner current controls and protection settings; and

(c) have key parameters including droop setting, deadband and ramp rate available for users to change; and

(d) initialise correctly and match closely the desired power flow solution; and

(e) initialise within 3 seconds of the start of a simulation and have snapshot capability; and

(f) support a 10 microsecond or greater simulation time step and be stable for at least 30 seconds of simulation time under no disturbance conditions.

MODEL VALIDATION

4.13 The **asset owner** must validate PowerFactory and PSCAD models against test results recorded during **commissioning** of the **asset** to confirm accuracy and reliability of the final **control system** parameters.

4.14 The **asset owner** must benchmark a WECC generic and TSAT model against a PSCAD validated model of the **asset**.

MODEL DOCUMENTATION

4.15 The **asset owner** must supplement each models provided to the **system operator** with documentation that includes the following:

(a) a full description of the model and its functionality, including transfer function block diagram, signal description, mapping, and calculations; and

(b) instructions on the use and operation of the models including operational limitations; and

(c) descriptions of the parameters available for the **system operator** to monitor; and

(d) details of the aggregation method and functional block diagrams; and

(e) descriptions of the control functions and any specific features of the models like fault-ride through control or phase-locked loop (PLL) operation; and

(f) values and ranges of all configurable parameters, and their impact on the control system performance; and

(g) cross-referencing between the PowerFactory and TSAT model control blocks and the PSCAD model control blocks; and

(h) limitations of the models and dependencies on compiler or software operating environments; and

(i) instructions to re-compile the model for when the **system operator** migrates to new software package versions.

MODEL MAINTENANCE AND UPDATE

4.16 For the purpose of clause 2(5B) of **Technical Code** A of Schedule 8.3 of the **Code**, the **asset owner** must:

(a) following notification by the **system operator** of an upgrade to its software package version, provide (as necessary) updated models to the **system operator** compatible with the updated software package version; and

(b) following an event investigation by the **system operator** that identifies any shortfall in models, provide (as necessary and if requested by the **system operator**) updated models to the **system operator** to address the shortfall.

4.17 If an **asset owner** receives a notification or request from the **system operator** under paragraph 4.16, the **asset owner** must provide the necessary updated models to the **system operator** within 1 month of receiving the notification or request, or within a different time frame agreed to with the **system operator**.

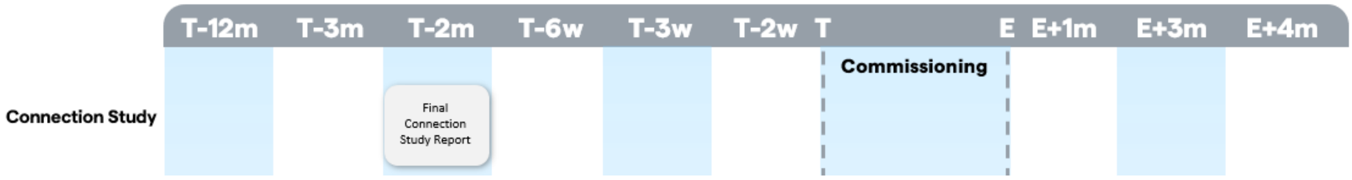
4.18 The **asset owner** must validate and submit to the **system operator** a new model for an **asset** in the following situations:

(a) when any change in the **asset** alters its performance; and

(b) after the completion of routine testing of the **asset** where the **asset's** performance has changed.

4.19 If, after the completion of routine testing of the **asset**, the performance of the **asset** has not changed, the **asset owner** must submit to the **system operator** an updated validation report incorporating the existing model and most recent routine test results.

Chapter 5: Connection Study Requirements



GENERAL CONNECTION STUDY REQUIREMENTS

5.1 This Chapter specifies the requirements for connection study cases that must be undertaken by **asset owners** and **connection study reports** that **asset owners** must submit to the **system operator** under clause 2(10) of **Technical Code** A of Schedule 8.3 of the **Code**.

5.2 **Asset owners** must submit **connection study reports** to the **system operator**:

(a) in accordance with the time frames in Chapter 1; and

(b) together with the **m1 model** and supporting documents for the **asset**.

5.3 The **asset owner** must comply with the following requirements for connection studies for an **asset**:

(a) The **asset owner** must undertake (and include in the **connection study report** the results of) a power-flow study.

(b) If the **asset owner** has or will have frequency support obligations in respect of the **asset**, the **asset owner** must undertake (and include in the **connection study report** the results of) the following connection studies:

(i) Frequency regulation and tuning study; and

(ii) Short circuit study; and

(iii) Transient stability study.

(c) If the **asset owner** has or will have voltage support obligations in respect of the **asset**, the **asset owner** must undertake (and include in their **connection study report** the results of) the following connection studies:

(i) **Reactive power** capability study; and

(ii) Voltage regulation and tuning study; and

(iii) Short circuit study; and

(iv) Transient stability study.

(d) If an **asset owner** has or will have fault ride through obligations in respect of the **asset**, the asset owner must undertake (and include in their **connection study report** the results of) the following connection studies:

(i) Short circuit study; and

(ii) Fault ride through study; and

(iii) Transient stability study.

5.4 The **asset owner** must identify and explain in the **connection study report** for an **asset** any non-compliant or potentially non-compliant behaviour observed for the **asset** in any connection study.

POWER-FLOW STUDY

5.5 A power-flow study must be undertaken to ensure the **asset** does not overload existing power system equipment or impose operational constraints under normal conditions and outage conditions.

5.6 A power-flow study must cover a minimum 3-year horizon.

REACTIVE POWER CAPABILITY STUDY

5.7 A **reactive power** capability study must be undertaken while the **asset** is generating at 100%, 50%, and 30% **active power** levels.

5.8 If the **asset** is a **BESS**, the **reactive power** capability study must also be undertaken while the **asset** is charging at 100%, 50%, and 30% **active power** level.

FREQUENCY REGULATION AND TUNING STUDY

5.9 A frequency regulation and tuning study must be undertaken to assess the frequency regulation performance of the **asset** in the context of major power system disturbances, including the disconnection of major **generating units** and the **HVDC link** bipole.

5.10 The stability of the **asset's** frequency **control system** and suitability of that system's settings must be assessed during the frequency regulation and tuning study.

VOLTAGE REGULATION AND TUNING STUDY

5.11 A voltage regulation and tuning study must be undertaken to assess the voltage regulation performance of the **asset** in the context of voltage disturbances caused by factors such as tripping of other **assets** that are electrically close to the **asset**.

5.12 The stability of the **asset's** voltage **control system** and suitability of that system's settings must be assessed in conjunction with other **assets**, including **dynamic reactive power compensation devices**.

5.13 The voltage regulation and tuning study must include:

(a) Power System Stabiliser (**PSS**) or Power Oscillation Damper (**POD**), as applicable; and

(b) over- and under-excitation limiters; and

(c) over-voltage and under-voltage protection.

SHORT CIRCUIT STUDY

5.14 A short circuit study must be undertaken to determine the Effective Short Circuit Ratio (**ESCR**) at the **asset's point of connection** under the following operating conditions:

(a) Covering a minimum 3-year horizon; and

(b) Full intact power system and n-1-1 outage scenarios; and

(c) Maximum and minimum short circuit levels at the **point of connection** and nearby buses under various power system conditions, including relevant power system reconfiguration.

TRANSIENT STABILITY STUDY

5.15 For a synchronous **generating unit**, a transient stability study must be undertaken to determine the Critical Fault Clearing Time (**CFCT**) by applying a three phase-to-ground fault at the **generating unit's point of connection**.

5.16 For a **generating unit** producing power from wind or solar or **BESS**, a transient stability study must be undertaken by applying an unbalanced fault to assess the ability of the inverter to recover and remain stable after the fault has been removed.

FAULT RIDE THROUGH STUDY

5.17 The **asset owner** must finalise all the **control system** parameters for an **asset** before undertaking fault ride through studies for the **asset**.

5.18 If the **asset owner** modifies any of the **control system** parameters for the **asset** during the fault ride through studies, the **asset owner** must notify the **system operator** and the fault ride through studies must be repeated with the new **control system** parameters.

5.19 For a synchronous **generating unit**, the **asset owner** must undertake fault ride through studies with PowerFactory RMS simulations.

5.20 For a **generating unit** producing power from wind or solar or **BESS**, the **asset owner** must undertake fault ride through studies as follows:

(a) undertake a PowerFactory RMS simulation as an initial screening to cover all possible generation scenarios, fault types and **asset** operation conditions; and

(b) undertake a PSCAD study to assess a selection of study cases identified in the PowerFactory RMS simulation, as agreed with the **system operator**.

5.21 If the **asset owner** modifies any of the **control system** parameters for the asset during or after **commissioning**, the **asset owner** must notify the **system operator** and the fault ride through studies must be repeated with the new **control system** parameters.

SHARING OF ENCRYPTED MODELS FROM OTHER ASSET OWNERS

5.22 If a fault ride through study for an **asset** requires the **asset owner** to assess how other **assets** impact the **asset's** fault ride through capabilities, the **asset owner** must either:

(a) seek consent directly from the other **asset owners** to obtain **encrypted** models of the relevant **assets**; or

(b) request the **system operator** seek consent from the other **asset owners** to share their **encrypted** models held by the **system operator** with the **asset owner**.

5.23 The **asset owner** must use the models solely for the purpose of fault ride through studies for the **asset**.

Chapter 6: Test Plan Requirements

6.1 This Chapter specifies the requirements for **test plans** that must be provided by **asset owners** to the **system operator** under clause 2(6) of **Technical Code** A, Schedule 8.3 of the **Code**.

6.2 **Asset owners** must submit **test plans** to the **system operator** in accordance with the time frames in Part 1.

WHEN A TEST PLAN MUST BE PROVIDED

6.3 The **asset owner** must provide a **test plan** to the **system operator** in the following situations:

(a) when the **asset** is either to be **electrically connected** to, or is to form part of, a **network**, and

(b) when a change is made to an **asset** that alters any of the following at the **grid interface**:

(i) the **single-line diagram**; or

(ii) a protection system, other than a change to a protection system setting; or

(iii) a **control system**, including a change to a **control system** setting or firmware; or

(iv) any rating of **assets**; and

(c) if it is necessary for the **asset owner** to perform a **system test** or other test to ascertain or confirm **asset** capabilities, and

(d) if the testing or connection of an **asset** may affect the **system operator's** ability to plan to comply, or to comply with, the **principal performance obligations**; and

(e) when planned work is to be carried out on an **asset** that affects either the **system operator's** ability to achieve the **dispatch objective** or the accuracy of any operational communications described in Chapter 8.

6.4 For the purposes of clause 2(6) of **Technical Code** A of Schedule 8.3 of the Code, a **test plan** must contain:

(a) the **asset owner's** contact information, including contact person, phone number, email address, and point of contact for the test plan; and

(b) **asset** and test details, including **asset** name, type of test, test date, test time and test duration; and

(c) description and expected impact of test, including change in **asset** capability, potential risk to the **grid** and expected impact on **asset owner performance obligations**; and

(d) any other information that the **asset owner** considers could assist the **system operator** to assess the test plan or assist the **system operator** in planning to comply, and complying, with the **principal performance obligations**.

Chapter 7: Testing Requirements

7.1 This Chapter specifies the requirements for testing that must be undertaken by **asset owners** and communicated to the **system operator** under clauses 8(2)(a) and 8(3) of **Technical Code** A of Schedule 8.3 of the **Code**.

7.2 **Asset owners** must undertake testing in accordance with the time frames in this Chapter and in Chapter 1.

7.3 **Asset owners** must submit all test results required in this Chapter, including for routine testing, and:

(a) update the **asset capability statement** within 1 month of the completion of testing; and

(b) provide the **system operator** with a validated **m2 model** within 3 months of the completion of testing.

GENERAL REQUIREMENTS

7.4 **Asset owners** must fulfil the requirements in this Chapter when undertaking testing for new or modified **assets** that are being **commissioned**, and for routine and remedial testing.

7.5 An **asset owner** with one or more **generating units commissioned** before 1 January 2016 for which wind is the primary power source must complete the first of each routine test required in this Chapter for those **generating units** no later than 31 December 2028.

7.6 If the **system operator** advises an **asset owner** under clause 8(3) of **Technical Code** A, Schedule 8.3 of the Code, the **asset owner** must:

(a) as soon as practicable, but no later than 30 days after receiving a written request, advise the **system operator** of its remedial or **test plan** for the **asset**; and

(b) as soon as reasonably practicable, undertake any remedial action or testing of the **asset** in accordance with its plan advised to the **system operator** under paragraph 7.6(a). The **system operator** may require such testing or remedial action to be undertaken in the presence of a **system operator** representative.

ENGINEERING METHODOLOGY

7.7 An **asset owner** must submit an **engineering methodology** to the **system operator** for review if:

(a) the **asset owner** intends to **electrically connect** a new **asset** to a **network**; or

(b) the **asset owner** intends to modify an existing **asset** that is connected to a **network**; or

(c) the **asset owner** is carrying out routine testing of an **asset** and is unsure if its proposed testing will meet the requirements in this Chapter.

7.8 The **asset owner** must provide a **final copy** of the **engineering methodology** to the **system operator** in accordance with the time frames in Chapter 1.

REPRESENTATIVE TESTING

7.9 Subject to paragraph 7.6, an **asset owner** may provide the information required under paragraphs 7.16(c), 7.18(c), 7.21(c), 7.23(c), and 7.27(c) to the **system operator**, based on representative modelling parameters and response data, instead of based on the tests required under paragraphs 7.16(a) and 7.16(b), 7.18(a) and 7.18(b), 7.21(a) and 7.21(b), 7.23(a) and 7.23(b), and 7.27(a) and 7.27(b) for any group of identical **assets**, if each of those **assets**:

(a) was manufactured to the same specification; and

(b) is installed at the same location; and

(c) is controlled in the same way; and

(d) has a similar maintenance history.

7.10 An **asset owner** providing representative modelling parameters and response data to the **system operator** in accordance with paragraph 7.9 for a group of identical **assets** must:

(a) complete a full set of tests in accordance with paragraphs 7.16(a) and 7.16(b), 7.18(a) and 7.18(b), 7.21(a) and 7.21(b), 7.23(a) and 7.23(b), and 7.27(a) and 7.27(b), as applicable, on an **asset** that is representative of that group to derive a verified set of modelling parameters and response data; and

(b) complete sufficient testing on the remaining **assets** in that group of identical **assets** in accordance with paragraphs 7.16(a) and 7.16(b), 7.18(a) and 7.18(b), 7.21(a) and 7.21(b), 7.23(a) and 7.23(b), and 7.27(a) and 7.27(b), as applicable, to verify that the performance of the remaining **assets** in that group is fully consistent with the modelling parameters and response data derived from the tests carried out on the representative **asset**; and

(c) certify to the **system operator** that, to the best of the **asset owner's** information, knowledge and belief, the performance of that group of **assets** is fully consistent with the representative modelling parameters and response data provided to the **system operator** for that group of **assets**.

EVENT DATA IN LIEU OF TESTING

7.11 The owner of a **generating station** that exports 10 **MW** or more but less than and 30 **MW** to a **network** may update its **asset capability statement** to verify to the **system operator** that the **control system** for the **generating station** meets the requirements of the **asset owner performance obligations** and **technical codes** based upon event data instead of carrying out testing, subject to the following conditions being met:

(a) Data recorded must have accuracy and refresh rates that match or are better than the test data requirements in Chapter 9; and

(b) Data must be provided within 10 **business days** of the event; and

(c) The event must have occurred within the required testing interval in this Chapter.

SPECIFIC TESTING REQUIREMENTS

SHUNT CAPACITORS AND REACTIVE POWER CONTROL SYSTEMS

7.12 An **asset owner** with a **shunt** capacitor directly connected to a **network** must:

(a) test the capacitance of each **shunt** capacitor at least once every 8 years; and

(b) test the operation of each of its reactive power control **asset's** analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its **reactive power** control **asset's** digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph 7.12(a), provide a set of test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(e) based on the tests carried out in accordance with paragraphs 7.12(b) or (c), provide a verified set of **control system** test results including voltage set points, operating dead bands and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

DYNAMIC REACTIVE POWER COMPENSATION DEVICE TRANSIENT RESPONSE AND CONTROL

7.13 An **asset owner** with a **dynamic reactive power compensation device** directly connected to a **network** must:

(a) test the transient response, steady state response and alternating current (a.c.) disturbance response of each of its **dynamic reactive power compensation devices** at least once every 10 years; and

(b) test the operation of each of its **dynamic reactive power compensation devices'** analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its **dynamic reactive power compensation devices'** digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph 7.13(a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and alternating current (a.c.) disturbance response data to the **system operator** in an updated **asset capability statement,** including**:**

(i) a block diagram showing the mathematical representation of the **dynamic reactive power compensation device**; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and

(iii) a detailed functional description of all of the components of the **dynamic reactive power compensation device** and how they interact in each mode of control; and

(iv) step response test results; and

(v) alternating current (a.c.) fault recovery disturbance test results; and

(e) based on the tests carried out in accordance with paragraphs 7.15(b) or 7.15(c), provide a set of **control system** test results to the **system operator** in an updated **asset capability statement**.

ALTERNATING CURRENT (A.C.) PROTECTION SYSTEMS

7.14 An **asset owner** must:

(a) test the operation of the analogue protection systems on its alternating current (a.c.) **assets** at least once every 4 years; and

(b) test the operation of the non-self monitoring digital protection systems on its alternating current (a.c.) **assets** at least once every 4 years; and

(c) test the operation of the self monitoring digital protection systems on its alternating current (a.c.) **assets** at least once every 10 years; and

(d) test the operation of the protection system measuring circuits on its alternating current (a.c.) **assets** by secondary injection at least once every 4 years; and

(e) test the operation of the protection system trip circuits, including circuit breaker trips, on its alternating current (a.c.) **assets** at least once every 4 years; and

(f) confirm at least once every 4 years that its protection settings are identified, co-ordinated, applied correctly and meet the requirements of the **asset owner performance obligations** and the **technical codes**; and

(g) based on tests carried out in accordance with paragraphs 7.14(a) to (e), provide an updated **asset capability statement** to verify to the **system operator** the protection systems meet the requirements of the **asset owner performance obligations** and **technical codes**; and

(h) based on the confirmation carried out in accordance with paragraph 7.14(f), provide an updated **asset capability statement** to the **system operator.**

SYNCHRONOUS GENERATING UNITS

GENERATING UNIT FREQUENCY RESPONSE

7.15 A **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 of the **Code**, must, for each of its **generating units**:

(a) test the trip frequencies and trip time delays of the **generating unit's** analogue over-frequency functions and analogue under-frequency relays at least once every 4 years; and

(b) test the trip frequencies and trip time delays of the **generating unit's** non-self monitoring digital over-frequency relays and non-self monitoring digital under-frequency relays at least once every 4 years; and

(c) test the trip frequencies and trip time delays of the **generating unit's** self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and

(d) based on the tests carried out in accordance with paragraphs 7.15(a), (b) or (c) provide a verified set of under-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement**; and

(e) based on the tests carried out in accordance with paragraphs 7.15(a), (b) or (c), provide a verified set of over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement**.

GENERATING UNIT FREQUENCY CONTROL SYSTEM

7.16 A **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 of the **Code**, must, for each of its **generating units**:

(a) test the response of the **generating unit's** mechanical or analogue speed governor and/or mechanical or analogue frequency **control system** at least once every 5 years; and

(b) test the response of the **generating unit's** digital or electro-hydraulic frequency **control system** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraph 7.16(a) or (b), provide a verified set of modelling parameters and governor or frequency **control system** response data to the **system operator** in an updated **asset capability statement**, including:

(i) a block diagram showing the mathematical representation of the frequency **control system**; and

(ii) a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams.

GENERATING UNIT TRANSFORMER VOLTAGE CONTROL

7.17 A **generator** with a **point of connection** to the **grid** must, for each of its **generating units**:

(a) test the operation of the **generating unit** transformer's on-load tap changer analogue **control systems** at least once every 4 years; and

(b) test the operation of the **generating unit** transformer's on-load tap changer digital **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs 7.17(a) or (b), provide a verified set of control parameters including voltage set points, operating dead bands and response times to the **system operator** in an updated **asset capability statement**.

GENERATING UNIT VOLTAGE RESPONSE AND CONTROL

7.18 A **generator** with a **point of connection** to the **grid** or must, for each of its **generating units**:

(a) test the modelling parameters and voltage response of the **generating unit's** analogue voltage **control system** at least once every 5 years; and

(b) test the modelling parameters and voltage response of the **generating unit's** digital voltage **control system** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs 7.18(a) and (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement**, including:

(i) a block diagram showing the mathematical representation of the voltage **control system**; and

(ii) a parameter list showing gains, time constants and other settings applicable to the block diagrams.

GENERATING UNIT PRODUCING POWER FROM WIND OR SOLAR OR BESS

GENERATING UNIT FREQUENCY RESPONSE

7.19 A **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 of the **Code**, must, for each of its **generating units**:

(a) confirm the trip frequencies and trip time delays of non-self monitoring digital over-frequency protection functions and non-self monitoring digital under-frequency protection functions for the **generating units** at least once every 4 years; and

(b) confirm the trip frequencies and trip time delays of self monitoring digital over-frequency protection functions and self monitoring digital under-frequency protection functions for the **generating units** at least once every 10 years; and

(c) based on confirmation of settings in accordance with paragraphs 7.19(a) or (b), provide a set of under-frequency and over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement**.

GENERATING STATION FREQUENCY RESPONSE

7.20 A **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 of the **Code**, must, for each of its **generating stations** that has frequency protection relays installed at the station level:

(a) test the trip frequencies and trip time delays of the **generating station's** analogue over-frequency relays and analogue under-frequency relays at least once every 4 years; and

(b) test the trip frequencies and trip time delays of the **generating station's** non-self monitoring digital over-frequency relays and non-self monitoring digital under-frequency relays at least once every 4 years; and

(c) test the trip frequencies and trip time delays of the **generating station's** self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and

(d) based on the tests carried out in accordance with paragraph 7.20(a), 7.15(b) or (c) provide a verified set of under-frequency and over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement**.

GENERATING STATION FREQUENCY CONTROL SYSTEM

7.21 A **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 of the **Code** must, for each of its **generating stations**:

(a) test the response of each frequency **control system** used for the **generating station** at least once every 10 years; and

(b) unless agreed otherwise with the **system operator**, immediately following a change to the control settings or firmware for the frequency **control system** used for the **generating station**, test the response of each frequency **control system** used for the **generating station** where the change to the control settings or firmware has the potential to materially affect the performance of the frequency response of the **generating station**; and

(c) based on the tests carried out in accordance with paragraphs 7.21(a) or (b), provide a verified set of modelling parameters and frequency **control system** response data to the **system operator** in an updated **asset capability statement**, including:

(i) a block diagram showing the mathematical representation of the frequency **control system**; and

(ii) a block diagram showing the mathematical representation of the power converter and its electrical control; and

(iii) a verified set of control settings and relevant firmware version identifiers for the frequency **control system** used for the **generating station**.

GENERATING STATION TRANSFORMER VOLTAGE CONTROL

7.22 A **generator** with one or more **generating stations** directly connected to the **grid** must, for each such **generating station**:

(a) test the operation of the **generating station** transformers' on-load tap changer analogue **control systems** at least once every 4 years; and

(b) test the operation of each the **generating station** transformers' on-load tap changer digital **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs 7.22(a) or (b), provide a verified set of control parameters including voltage set points, operating dead bands and response times to the **system operator** in an updated **asset capability statement**.

GENERATING STATION VOLTAGE RESPONSE AND CONTROL

7.23 A **generator** with one or more **generating stations** directly connected to the **grid** must, for each such **generating station**:

(a) test the response of each voltage **control system** used for the **generating station** at least once every 10 years; and

(b) unless agreed otherwise with the **system operator**, immediately following a change to the control settings or firmware of the **control system** used for the **generating station**, test the response of each voltage **control system** used for the **generating station** where the change to the control settings or firmware has the potential to materially affect the performance of the voltage response of the **generating station**; and

(c) based on the tests carried out in accordance with paragraphs 7.23(a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement**, including:

(i) a block diagram showing the mathematical representation of the voltage **control system**; and

(ii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iii) a verified set of control settings and relevant firmware version identifiers for the voltage **control system**.

NORTH ISLAND CONNECTED ASSET OWNER AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING SYSTEM PROFILES AND TRIP SETTINGS

7.24 A North Island **connected asset owner** must:

(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 of the **Code** to the **system operator** in an updated **asset capability statement** at least once every year; and

(b) test the operation of each of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and

(c) test the operation of each of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and

(d) test the operation of each of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and

(e) based on the tests carried out in accordance with paragraph 7.24(b), (c), or (d), provide a verified set of trip settings and time delays to the **system operator** in an updated **asset capability statement**.

SOUTH ISLAND GRID OWNER AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING SYSTEMS PROFILES AND TRIP SETTINGS

7.25 A South Island **grid owner** must:

(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 of the **Code** to the **system operator** in an updated **asset capability statement** at least once every year; and

(b) test the operation of each of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and

(c) test the operation of each of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and

(d) test the operation of each of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and

(e) based on the tests carried out in accordance with paragraphs 7.25(b), (c), or (d), provide a verified set of trip settings and time delays to the **system operator** in an updated **asset capability statement**.

GRID OWNER TRANSFORMER VOLTAGE RANGE

7.26 A **grid owner** must:

(a) test the operation of each of its transformers' on-load tap changer analogue **control systems** at least once every 4 years; and

(b) test the operation of each of its transformers' on-load tap changer digital **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs 7.26(a) or (b), provide a verified set of control parameters to the **system operator** in an updated **asset capability statement**, including voltage set points, operating dead bands and response times.

GRID OWNER SYNCHRONOUS COMPENSATORS

7.27 A **grid owner** must:

(a) test each of its synchronous compensators' analogue and electromechanical voltage **control systems** at least once every 5 years; and

(b) test each of its synchronous compensators' digital voltage **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs 7.27(a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement**, including:

(i) a block diagram showing the mathematical representation of the voltage **control system**; and

(ii) a detailed functional description of the voltage **control system** in all modes of control; and

(iii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.

HVDC LINK FREQUENCY CONTROL AND PROTECTION

7.28 The **HVDC owner** must:

(a) test the operation of each of its **HVDC link's** analogue **control systems** at least once every 4 years; and

(b) test the operation of each of its **HVDC link's** digital **control systems** at least once every 10 years; and

(c) test the operation of each of its **HVDC link's** analogue protection systems at least once every 4 years; and

(d) test the operation of each of its **HVDC link's** digital protection systems at least once every 10 years; and

(e) test the modulation functions on each **HVDC link** at least once every 10 years; and

(f) based on the tests carried out in accordance with paragraphs 7.28(a) or (b), provide a set of **control system** test results and verified modelling parameters to the **system operator** in an updated **asset capability statement**; and

(g) based on the tests carried out in accordance with paragraphs 7.28(c) or (d), provide a set of protection system test results to the **system operator** in an updated **asset capability statement**; and

(h) based on the tests carried out in accordance with paragraph 7.28(e), provide a set of modulation function test results to the **system operator** in an updated **asset capability statement** including:

(i) a block diagram showing the mathematical representation of the **HVDC link**; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagram; and

(iii) a detailed functional description of the components of the **HVDC link** and how they interact in each mode of control.

Chapter 8: Operational Communication Requirements

8.1 This Chapter specifies the minimum requirements for operational communications for the purposes of clause 8.25(3) of the Code.

8.2 **Asset owners**, except owners of **excluded generating stations**, must comply with the minimum requirements described in this Chapter, to assist the **system operator** to plan to comply, and to comply, with the **principal performance obligations**.

8.3 The **system operator** may require that a generator comply with some or all the requirements of this Chapter in respect of an **excluded generating station** if the **system operator** reasonably considers it necessary to assist the **system operator** to plan to comply, and to comply, with the **principal performance obligations**.

GENERAL REQUIREMENTS FOR OPERATIONAL COMMUNICATIONS

8.4 Each voice or electronic communication between the **system operator** and an **asset owner** must be logged by the **system operator** and the **asset owner**. Unless agreed otherwise between the **system operator** and the **asset owner**, every voice instruction must be repeated back by the person receiving the instruction and confirmed by the person giving the instruction before the instruction is actioned.

8.5 The **system operator** and each **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **system operator** and the **asset owner**. Each **asset owner** must also nominate and advise the **system operator** of the person to receive instructions and **formal notices** as set out in **Technical Code** B of Schedule 8.3 of the **Code**. The preferred points of contact must include those to be used when the **system operator** instructs the **asset owner**, when the **system operator** sends **formal notices** to the **asset owner** and when the **asset owner** contacts the **system operator**. The alternative points of contact must be used only if the preferred points of contact are not available.

8.6 The **grid owner** and each other **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **grid owner** and the other **asset owner** for the purpose of communications regarding the availability of the **grid owner's** data transmission communications. The alternative points of contact must only be used if the preferred points of contact are not available.

SPECIFIC REQUIREMENTS FOR VOICE COMMUNICATIONS

8.7 Each **asset owner** must have in place a primary means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The primary means of voice communication must use either:

(a) the **grid owner's** speech network; or

(b) a widely available public switched telephone network that operates in real time and in full duplex mode.

8.8 An **asset owner** must have in place a backup means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The backup means of voice communication:

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, satellite phone or cellular phone; and

(c) may be used only if the primary means of voice communication described in paragraph 8.7 is unavailable or otherwise with the agreement of the **system operator**.

8.9 An **asset owner** who has a **control room** with, at any time, operational control of more than 299 **MW** of **injection**, **offtake**, or power flow must have two or more backup means of voice communication between the **control room** of the **asset owner** and the **system operator**, each of which must meet the requirements of paragraph 8.8.

SPECIFIC REQUIREMENTS FOR TRANSMITTING INFORMATION

8.10 An **asset owner** must transmit information between its **control room** and the **system operator** in writing.

8.11 Despite paragraph 8.10, an **asset owner** may request the **system operator** to approve an alternative means of transmitting information (such approval not to be unreasonably withheld).

8.12 An **asset owner** must have in place a backup means of transmitting information. The backup means of transmitting information:

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, voice communication or email; and

(c) may be used only if the primary means of transmitting information described in paragraph 8.10 or 8.11 is unavailable or otherwise with the agreement of the **system operator**.

SPECIFIC REQUIREMENTS FOR DATA TRANSMISSION COMMUNICATION

8.13 An **asset owner** (other than a **grid owner**) must have in place either:

(a) a primary means of transmitting data between the **assets** of the **asset owner** and a **SCADA** remote terminal unit of a **grid owner**; or

(b) if approved by the **system operator** (such approval not to be unreasonably withheld), a primary means of transmitting data between the **assets** of the **asset owner** and the **system operator**.

8.14 A **grid owner** must have in place a primary means of transmitting data between the **assets** of the **grid owner** and the **system operator**.

8.15 An **asset owner** must have in place a backup means of transmitting data for each type of applicable indication and measurement specified in paragraph 8.22. The backup means of data transmission communication:

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, use of voice communication or document transmission communication; and

(c) may only be used if the primary means of data transmission communication described in paragraph 8.13 or 8.14 is unavailable or otherwise with the agreement of the **system operator**.

AVAILABILITY OF PRIMARY MEANS OF COMMUNICATION

8.16 An **asset owner** must use reasonable endeavours to ensure that the primary means of communication described in paragraphs 8.7, 8.10, 8.11, 8.13 and 8.14 is available continuously.

8.17 If the primary means of communication described in paragraphs 8.7, 8.10, 8.11, 8.13 and 8.14 is unavailable, the **asset owner** must use reasonable endeavours to restore availability of the primary means of communication as soon as practicable.

NOTIFICATION OF PLANNED OUTAGES OF PRIMARY MEANS OF COMMUNICATION

8.18 An **asset owner** must give written notice to the **system operator** of any planned outage of a primary means of communication described in paragraphs 8.7, 8.10, 8.11, 8.13, 8.14.

PERFORMANCE REQUIREMENTS FOR INDICATIONS AND MEASUREMENTS

8.19 An **asset owner** must provide the relevant indications and measurements shown in the *Required Indications and Measurements* section below (starting at paragraph 8.22) to the **system operator** in accordance with paragraphs 8.13 to 8.15. The **system operator** may require the **asset owner** to provide additional information if, in the reasonable opinion of the **system operator**, such information is required for the **system operator** to plan to comply, and to comply, with the **principal performance obligations**.

8.20 An **asset owner** must use reasonable endeavours to ensure that the accuracy of the measurements it provides to the **system operator** in accordance with paragraph 8.19 complies with the *Required Indications and Measurements* section below (starting at paragraph 8.22).

8.21 Each indication and measurement provided in accordance with paragraph 8.19 must be updated at the **grid owner's SCADA** remote terminal or the **system operator**'s interface unit at least once every 8 seconds when provided by the primary means of data transmission communications.

REQUIRED INDICATIONS AND MEASUREMENTS

GENERAL REQUIREMENTS

8.22 A **generator**, **grid owner**, and **connected asset owner** must provide the indications and measurements listed in Table A below and to the extent applicable, provide the indications and measurements listed in Tables B-J below.

8.23 If net (or gross) measurements are required in any of Tables A-J below, the use of **scaling factors** together with the provision of the relevant gross (or net) values is acceptable with the **system operator's** approval (such approval not to be unreasonably withheld). Each **generator** and **connected asset owner** must provide **scaling factors** to the **grid owner** so that the **grid owner** can apply the adjustment at the **SCADA** server.

8.24 If numerical values are required in any of Tables A-J below, the accuracy of numerical values must be measured at the input terminal of the RTU of the **grid owner**, under normal operating conditions at full scale.

Table A: General Requirements, Applicable to all Assets

Indication or measurement	**Values required**
Grid interface circuit breaker status	Open/closed/in transition/indication error (exclude time delays for circuit breaker indications, as they are time tagged by the **system operator** to less than 10ms)
Grid interface disconnector status	Open/closed/in transition/indication error
Special protection scheme status	Enabled/disabled/summer/winter
Dynamic reactive power compensation devices Mvar	Import and export (±2% accuracy; required only if **dynamic reactive power compensation device** has a maximum continuous rating of greater than 5 Mvar)
Shunt capacitors Mvar	Import and export (±2% accuracy; required only if **shunt** capacitor bank has a maximum continuous rating of greater than 5 Mvar)
Grid interface auto reclose status	Enabled/disabled/operated/locked out

GENERATOR-SPECIFIC REQUIREMENTS

8.25 A **generator** must provide the indications and measurements listed in Table B below.

Table B: Specific Requirements for Generators

Indication or measurement	**Values required**
Station net **MW**	Import and export (±2% accuracy)
Station net Mvar	Import and export (±2% accuracy)
Frequency Control Operation Mode	Enabled / Disabled
Voltage Control Operation Mode	Enabled / Disabled
Power System Stabiliser or Power Oscillation Damper Status	Enabled / Disabled
Station HV Bus Voltage (if HV bus is not owned by a **grid owner**)	kV (±2% accuracy)
Circuit Amps (if circuit is not owned by a **grid owner**)	Current at each termination point of a circuit
Circuit **MW** (if circuit is not owned by a **grid owner**)	**MW** at each termination point of a circuit
Circuit Mvar (if circuit is not owned by a **grid owner**)	Mvar at each termination point of a circuit

8.26 If the **asset** is a synchronous **generating unit**, the **asset owner** must provide the indications and measurements listed in Table C below.

Table C: Specific Requirements for synchronous Generating Units

Indication or measurement	**Values required**
Generating unit gross **MW**	Import and export (±2% accuracy)
Generating unit gross Mvar	Import and export (±2% accuracy)
Generating unit circuit breaker status	Open/closed/in transition/indication error
Generating unit Terminal Voltage kV	kV (±2% accuracy)

8.27 If the **asset** is one or more **generating units** producing power from wind or solar or **BESS**, the **asset owner** must provide the indications and measurements listed in Table D below.

Table D: Specific Requirements for generating units *producing power from wind or solar or* ***BESS***

Indication or measurement	**Values required**
Generating system net **MW**	Import and export (±2% accuracy)
Generating system net Mvar	Import and export (±2% accuracy)
Generating system circuit breaker status	Open/closed/in transition/indication error

Number of **active** inverters or wind turbines in the **generating station**	
Station available **MW**	the available active power if generating the maximum the resource allows.
Station MV bus voltage (kV) (only if applicable; see Appendix A for further guidance)	

8.28 If the **asset** is a **BESS**, the **asset owner** must provide the indications and measurements listed in Table E below.

Table E: Specific Requirements for Battery Energy Storage Systems

Indication or measurement	Values required
Station state of charge (SOC) (%)	Must be the energy stored in the **BESS** as a percentage of nameplate rated capacity, irrespective of any S.O.C limits.

8.29 If the **asset** is one or more photovoltaic **generating units**, the **asset owner** must provide the indications and measurements listed in Table F below.

Table F: Specific Requirements for Photovoltaic Generation Assets

Indication or measurement	Values required
Solar irradiance horizontal (W/m^2)	Must be the average of all sensors on the site.

8.30 If the **asset** is one or more wind turbines, the **asset owner** must provide the indications and measurements listed in Table G below.

Table G: Specific Requirements for Wind Turbine Assets

Indication or measurement	Values required
Wind speed at nacelle height (km/h)	Must be an average of every nacelle or group of nacelles.

8.31 If the **asset** is hybrid plant, the **asset owner** must provide the indications and measurements listed in Table H below.

Table H: Specific Requirements for Hybrid Plant

Indication or measurement	Values required
Station intermittent generation **MW**	Import and export (±2% accuracy)
Station **BESS** Injection / Load **MW**	Import and export (±2% accuracy)

GRID OWNER-SPECIFIC REQUIREMENTS

8.32 A **grid owner** must provide the indications and measurements listed in Table I below in respect of **assets** connected to, or forming part of, the **grid**.

Table I: Grid-Owner Specific Requirements

Indication or measurement	**Values required**
Grid interface auto reclose status	Enabled/disabled/operated/locked out
Grid interface MW	Import and export (±2% accuracy)
Grid interface Mvar	Import and export (±2% accuracy)
Circuit Amps	Current at each termination point of a circuit
Circuit **MW**	**MW** at each termination point of a circuit
Circuit Mvar	Mvar at each termination point of a circuit
Tap positions for **interconnecting transformers** and supply transformers with on-load tap changers	Tap position for all windings including tapped tertiaries
Tap positions for **interconnecting transformers** and supply transformers with off-load tap changers	Tap position for all windings including tapped tertiaries (indication required within 5 minutes of status change)
Bus voltage	kV (±2% accuracy)
HVDC modulation status	Frequency stabiliser/spinning reserve sharing/Haywards frequency control/AC transient voltage support
Reactive Power Controller status	Enabled / Disabled
Reactive Power Controller Setpoint kV or Mvar	kV or Mvar

CONNECTED ASSET OWNER-SPECIFIC REQUIREMENTS

8.33 A **connected asset owner** must provide the indications and measurements listed in Table J below.

Table J: Connected Asset Owner-Specific Requirements

Indication or measurement	**Values required**
Controllable load available **MW**	Any **controllable load** that is not currently off or armed for **interruptible load** Actual or calculated (±5% accuracy) Per GXP unless agreed otherwise
Controllable load currently off **MW**	Actual or calculated (±5% accuracy) Per GXP unless agreed otherwise
Controllable load armed for **interruptible load MW**	Actual (±2% accuracy) Per GXP unless agreed otherwise

Chapter 9: High Speed Data Requirements

9.1 This Chapter specifies the minimum requirements for **high-speed monitors** that **asset owners** must install for the purposes of clause 8(2)(c) of **Technical Code** A of Schedule 8.3 of the Code.

9.2 An **asset owner** must install a **high-speed monitor** at each of its **generating stations** and provide event data from the **high-speed monitor** to the **system operator** for post-event analysis and routine testing requirements in accordance with Chapter 7.

9.3 The **asset owner** must submit **high-speed monitor** data to the **system operator** in either a csv, ascii, or COMTRADE format.

9.4 **High-speed monitor** data must include the values listed in Table K below.

Table K: High-Speed Monitor Data Requirements

Indication and Measurements	**Notes**
Station **Active Power** (**MW**)	Must provide all values other than frequency per-phase.
Station **Reactive Power** (Mvar)	
Station Frequency (Hz)	
Station Transformer HV Voltage (kV)	
Station Transformer HV Current (A)	

9.5 **High-speed monitor** data recording must be triggered according to Table L below and must be GPS-time stamped and recorded as follows:

(a) pre-trigger, 10 seconds;

(b) post-trigger, 120 seconds;

(c) at a resolution of 20 milliseconds or better.

Table L: High-Speed Monitor Data Triggers

Trigger Type	**Setting**
Under-voltage	90% Nominal Voltage
Over-voltage	110% Nominal Voltage
Under-frequency	49.5 Hz
Over-frequency	50.5 Hz

Appendix A : Single Line Diagrams

This Appendix A shows the common topologies for different **generating plant**, and the **system operator's** interpretation of how the terms **generating station**, **generating unit** (each with their meanings as defined in the Code), and **generating system** (as defined in this **CACTIS**) apply to these topologies.

Not all **generating stations** will use one of these topologies. Specific cases can be discussed with the **system operator** during the **commissioning** process.

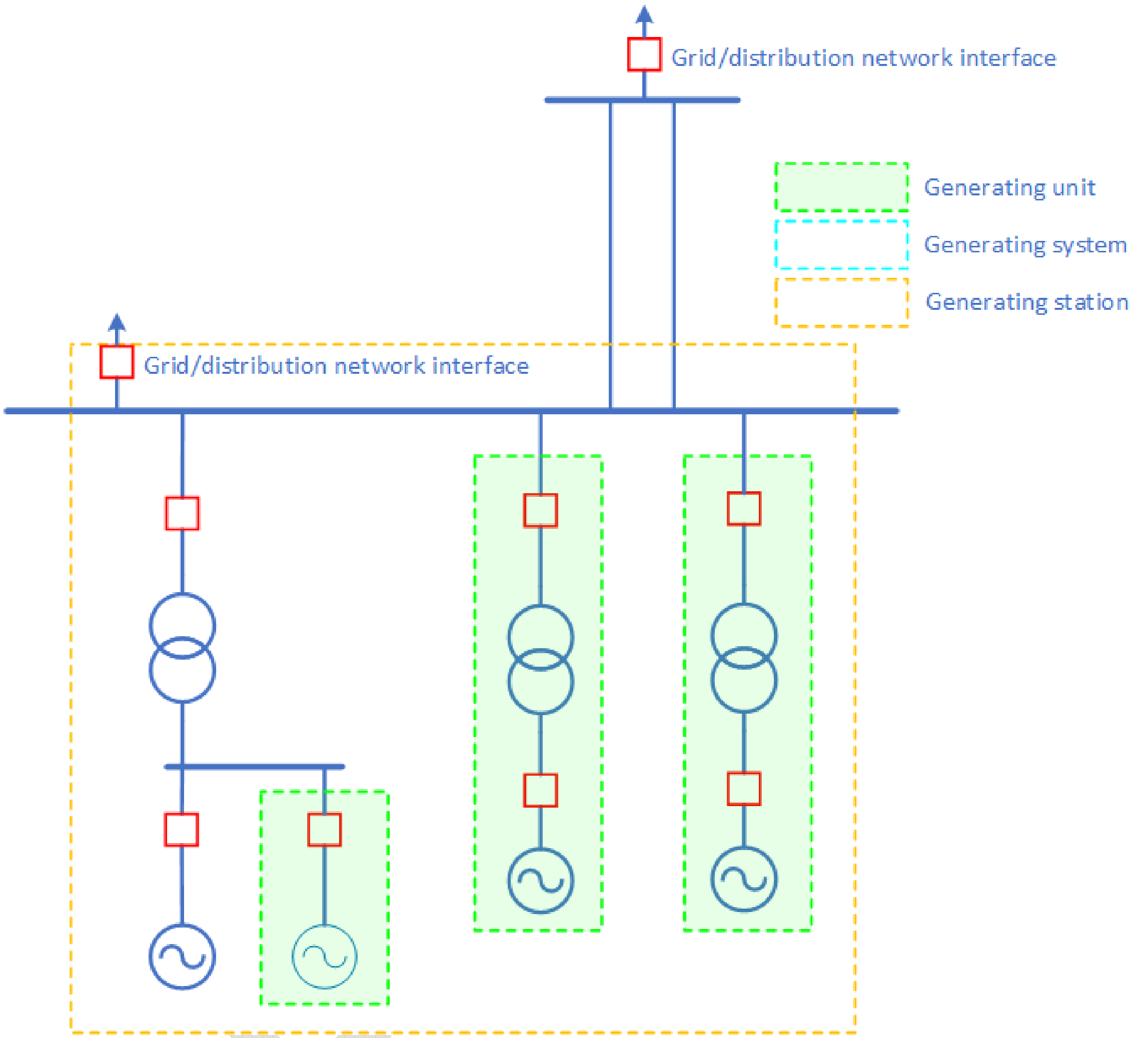


Figure A1: Typical Configuration of a Synchronous Generating Station.

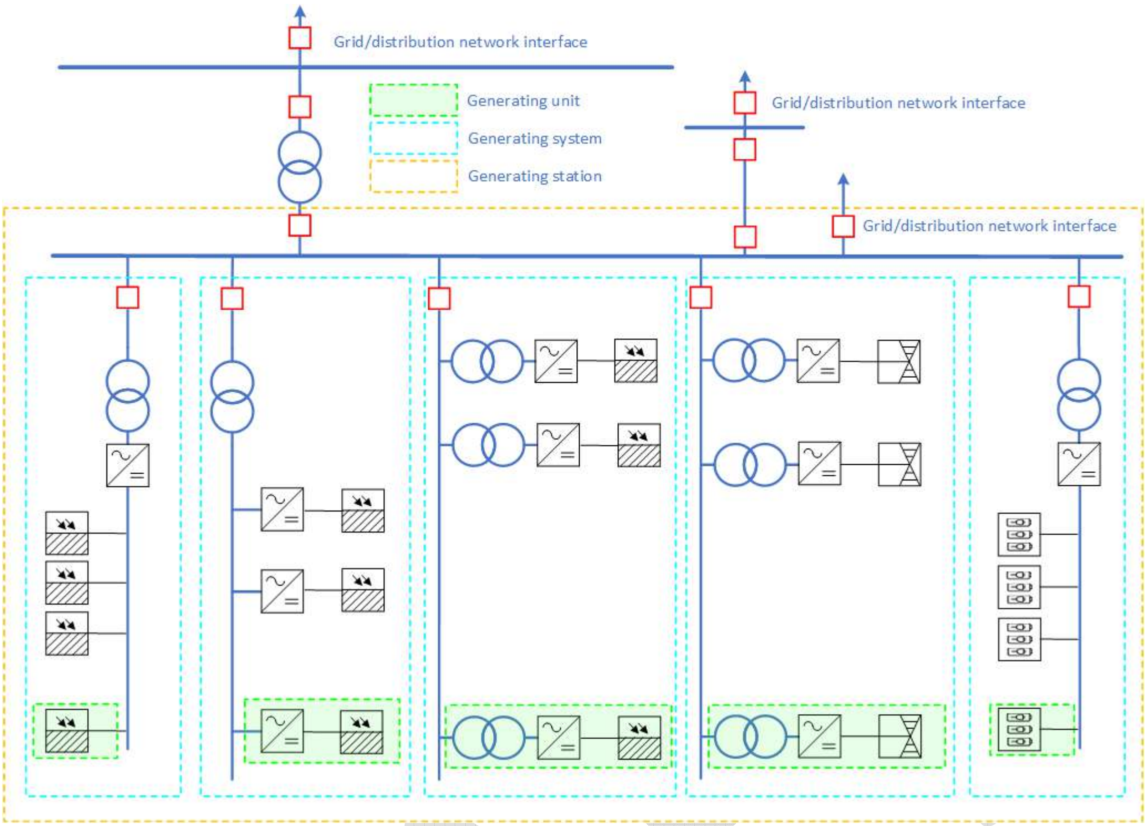


Figure A2: Typical configuration of generating units** producing power from wind or solar or **BESS. Note that although this diagram shows multiple generation types and topologies, typically only one would apply for a given generating station. See Figure A3 below for hybrid plant topologies.

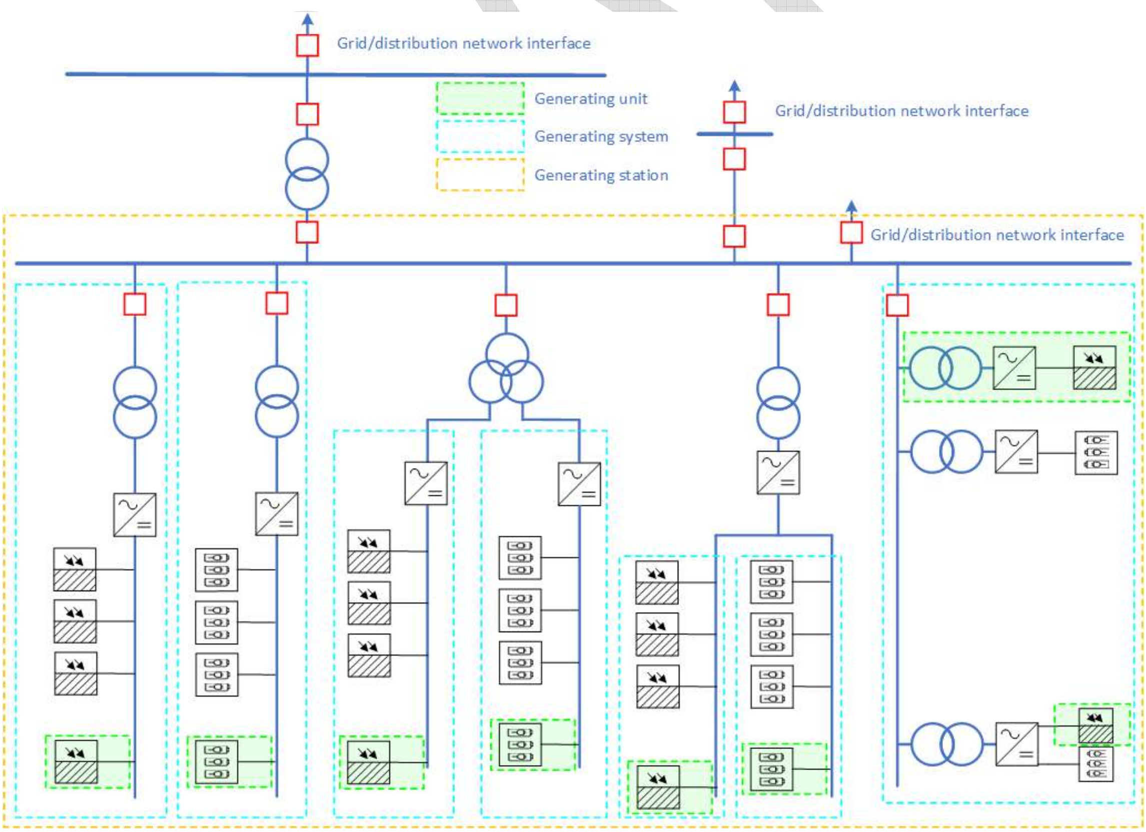


Figure A2: Typical hybrid plant topologies. Note that only the photovoltaic generation-BESS hybrid plant is shown in this diagram. Other types of hybrid plants (e.g. wind generating-BESS) are possible.

Appendix D Questions and Answers for the Proposed Connected Asset Commissioning, Testing Information Standard (CACTIS)

Q9. Do you have any comments on the draft Connected Asset Commissioning, Testing and Information Standard?

Questions and Answers for the Proposed Connected Asset Commissioning, Testing and Information Standard (CACTIS)

1 July 2025

Questions Answered

1. What are the model requirements under the proposed CACTIS?
2. What are the software formats used by the system operator and are they used for?
3. Why does the system operator require each of the models mentioned above?
4. Why does the system operator request one model type for synchronous generating units, and four different model types for generators with an inverter?
5. Do asset owners have to validate all the models?
6. Do asset owners have to conduct connection studies using all models?
7. How much will it cost to produce TSAT models?
8. What benefits do accurate models provide?
9. Do asset owners have to meet modelling requirements regardless of plant size?
10. Why is the system operator introducing controllable load requirements for connected asset owners?

1) What are the model requirements under the proposed CACTIS?

Type of Asset	Models Required under the Proposed CACTIS
Synchronous Generator	• DIgSILENT PowerFactory
Inverter-based Resource	• DIgSILENT PowerFactory • Power System Computer Aided Design (PSCAD) • Powertech Transient Security Assessment Tool (TSAT) • Western Electricity Coordinating Council (WECC) generic model

2) What are the software formats used by the system operator and what are they used for?

Software Format	Purpose
DIgSILENT PowerFactory	To model New Zealand's power system and enable detailed studies and stability analysis, particularly for: • Connection studies • Fault ride through studies • Planning studies • Event investigations • Other general frequency and voltage studies
PSCAD	To simulate various power system scenarios with precision, particularly for: • Fault ride through studies • Control interaction studies • Event investigations
TSAT	To analyse off-line and on-line transient stability, especially for: • Rotor angle stability studies (TRAS) • Frequency stability analysis • Event investigations • Real-time operation support • Running simulations using exact system conditions like frequency studies

The system operator also uses WECC models in DIgSILENT PowerFactory and TSAT formats for real-time studies and for published EMI cases, where disclosure of models to the wider public is not permitted under Technical Code A Clause 3(2) or the terms of non-disclosure agreements entered into by the system operator.

3) Why does the system operator require each of the models mentioned above?

All power system simulation tools have their strengths and weaknesses. For example, if a simulation needs to focus on electromagnetic transients (EMT), PSCAD would be a suitable tool to use. The system operator uses PSCAD for studies on fault ride through performance and inverter stability.

For general power system analysis, including load flow, fault analysis and RMS (frequency and voltage) stability studies, the system operator uses PowerFactory and TSAT. PowerFactory offers advantages such as an informative graphical user interface, the ability to integrate models, and ease of use. However, PowerFactory is not designed for online (real-time) applications.

TSAT, on the other hand, is the tool that the system operator uses for some offline applications and real-time applications. Offline uses include real-time support, event investigation or frequency studies that require accurate modelling of frequency reserve. For real-time applications, TSAT is used for voltage, frequency and transient stability analysis. The system operator runs voltage stability analysis in real-time every 2-4 minutes, and frequency analysis every 7-9 minutes to check power system security.

All power system simulation tools rely on models to produce results that the system operator uses to make key operational decisions. Currently, simulation tools can only 'read' models that are built for that particular tool; for instance, a PSCAD model can be read by PSCAD software, but not by PowerFactory or TSAT software. As a result, the system operator requires asset owners to submit three different types of models to match the three different types of software in use.

The system operator is not unique in requiring multiple models from asset owners. As outlined in the table below, system operators overseas also require asset owners to submit multiple model formats for their operational tools.

System Operator	Modelling Requirements
AEMO	PSSE, PSCAD, SSAT
ERCOT	PSSE, PSCAD, TSAT
National Grid	PSCAD, PowerFactory or generic WECC/IEC/IEEE
Eirgrid	PSSE and WECC. WECC models are used in real-time TSAT, but asset owners (or their consultants) do not submit TSAT cases; instead they validate WECC models in software of their preference, then submit parameters in a spreadsheet template.

In the future, once the IEEE/CIGRE power system Dynamic Linked Library (DLL) model standard becomes widely accepted, it will be possible to share models across simulation tools that support this standard.

Instability arising from inverter controls is an emerging risk faced by many system operators[1]. The power system stability classification (see Figure 1 below) includes new stability concerns arising from the increased penetration of inverter-based resources (IBRs) in the power system. The stability classes shown in the blue box are the phenomena that are well understood. The system operator is confident that it has the knowledge, the tools and the mitigation measures to manage these instabilities. However, the stability classes within the green box are newer. Research is underway worldwide across academic institutions and utilities to understand these instability phenomena and find ways to monitor and contain them. At the same time, IBR technology is evolving, which may introduce further stability classes that require careful responses from system operators.

To analyse how close the power system is operating to stability limits, the system operator requires detailed, site-specific models. Studying some of the stability issues, like converter-driven instability, requires the use of EMT software like PSCAD. The system operator is also investigating using TSAT models in Powertech's Small Signal Assessment Tool (SSAT) package to study small signal or inverter control interaction phenomena in the future.

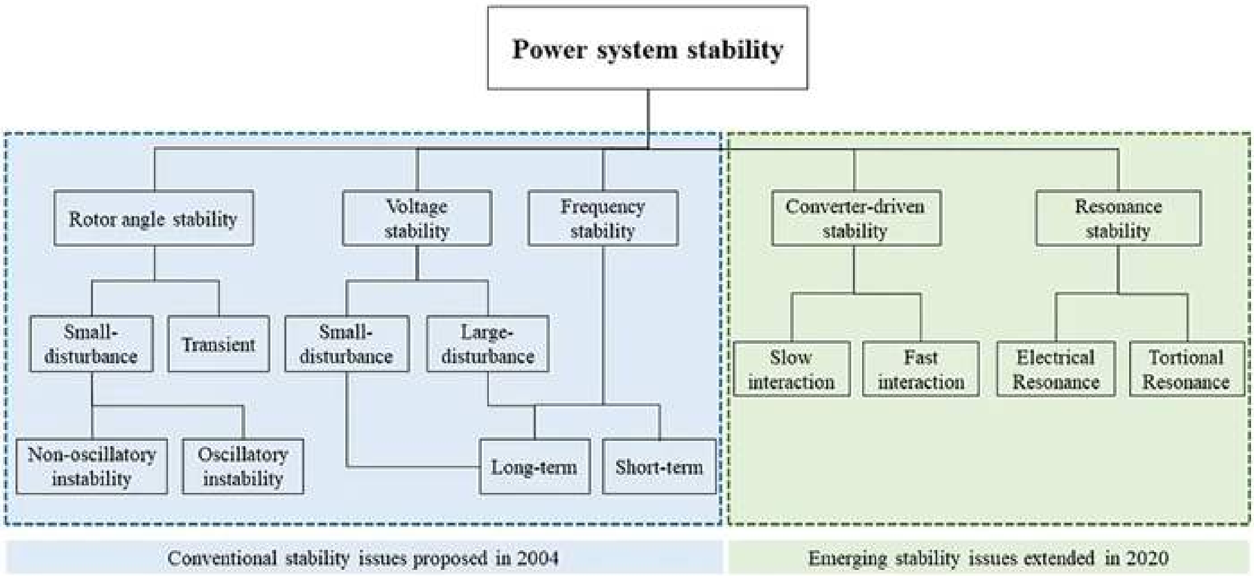


Figure 1: Power system stability classification and definitions (IEEE Transactions on power systems, Vol. 36, No. 4, July 2021, "Definition and classification of power system stability – Revisited and extended")

[1] Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources.

4) Why does the system operator request one model type for synchronous generating units, and four different model types for generators with an inverter?

Synchronous generating units use common and well-researched technology, making their behaviour reasonably easy to predict across different manufacturers. Standard models like GENSAE and GENROU are widely available, and many speed governor and AVR control system models have become standard over time. Hence, PowerFactory software is sufficient for representing generating units with no inverters. If models need to be translated to TSAT or PSCAD, the relatively low complexity of synchronous generating units (by comparison to IBRs) means that the system operator can resource the translation at relatively low cost.

In contrast, IBRs are continuously evolving. Equipment manufacturers differ in how they configure control system architecture, which are often encrypted. This makes the behaviour of IBRs less predictable and more complex and also makes model translation more difficult for the system operator. In addition, the system operator requires RMS and EMT models for IBRs to accurately capture high-frequency components and holistically assess IBR performance. Given the increased complexity and preponderance of IBRs, the system operator does not have the resources to translate these models. Instead, it is more appropriate for original equipment manufacturers to undertake the translation, as they can access the model without encryption and understand the model's control philosophy.

5) Do asset owners have to validate all the models?

The system operator requires asset owners to validate PowerFactory and PSCAD models because accurate modelling enables the system operator to forecast real-time and future system behaviour accurately. Other model types provided to the system operator (e.g., WECC models) simply need to be benchmarked against those two models using sample test cases.

This approach ensures consistency and accuracy across the different software platforms used by the system operator and accounts for differences in simulation performance. It supports the system operator in maintaining accurate models for all software packages, that can reliably represent dynamic behaviour with sufficient precision. Detailed requirements will appear in the next release of the system operator's GL-EA-716 Power Plant Dynamic Model Validation and Submission Prerequisites guideline, should the proposed CACTIS be incorporated by reference in the Code.

6) Do asset owners have to conduct connection studies using all models?

Asset owners do not have to conduct connection studies using all models. Requirements vary depending on the type of generation technology and the study:

- For synchronous generation, the required model is PowerFactory RMS.
- For IBR-based generation, both PowerFactory RMS and PSCAD EMT models are needed.

Asset owners and their consultants need to understand the limitations of each model and choose the appropriate software to carry out each connection study. PowerFactory models are adequate for frequency controller tuning studies and voltage controller tuning studies. However, an IBR generator's fault ride through study requires a PSCAD model, since PowerFactory models may not produce the behaviours needed to assess the generating station's performance. To give an example, through the use of a PSCAD model, the system operator observed that the fault ride through studies for a recent commissioning project revealed instabilities. This would not have been identified using a PowerFactory model.

7) How much will it cost to produce TSAT models?

The system operator foresees two pathways for handling the costs of producing the required models.

Pathway 1 (the status quo): The system operator continues performing the service of translating PowerFactory or PSCAD to TSAT, as needed.

- For synchronous generating units, simple models require 2-3 weeks of input from the system operator's modelling team, whereas complex models require 3-6 weeks.
- For IBR-based generating units, the system operator's modelling team can translate PowerFactory or PSCAD models to WECC generic models at a cost of 2-3 weeks of effort per case. However, these generic models suffer some inaccuracies. It is impossible for the system operator's modelling team to translate site-specific PowerFactory or PSCAD models to TSAT user-defined models, due to their complexity, encryption and confidentiality concerns.

Ultimately, Pathway 1 would result in increasing delays for asset owners wanting to connect new or upgraded assets to the power system, as well as increasing system security risks due to model inaccuracies. Given the increased penetration of IBRs into the power system, the system operator does not have the resources or capability to manage the volume and complexity of incoming model translations, particularly given the concerns about sensitivity.

Pathway 2: Asset owners translate and validate their models.

- For synchronous generating units, the system operator continues to translate models at no additional cost to the asset owner.
- For IBR-based generating units, asset owners would obtain PSCAD models from the original equipment manufacturers, who generally use PSCAD software to design controllers. The system operator understands that the cost of obtaining the PSCAD models would be relatively low. The more significant cost would be associated with validating these models. However, the system operator considers the increased accuracy of the validated models would justify the cost, by better enabling the system operator to manage the security of the power system. Equipment manufacturers also have the capability to translate PSCAD models to other model types. If a manufacturer is unable to do so, PowerTech Lab Inc. offers TSAT translation services for NZ$50-100k, with an additional estimated validation cost of $NZ10-15k.

The system operator considers Pathway 2 more sustainable than Pathway 1 from a resourcing standpoint. Pathway 2 also supports both asset owners and the system operator in being able to accurately model the power system.

In addition, as mentioned in the proposed CACTIS, the system operator will accept source code DLL models. Once the IEEE/CIGRE DLL model format matures, model sharing should become easier.

8) What benefits do accurate models provide?

Accurate models are essential for managing power system security. The system operator performs various system studies to determine the operational boundaries in which the power system can operate safely and securely. Accurate validated models are necessary for the system operator to perform network simulations to monitor and coordinate all equipment in the power system. Accurate models also provide the system operator with simulation results that are much closer to the actual equipment performance, allowing for more accurate key operational decisions.

As the power system grows, the system operator needs to adapt its systems to handle new information from the transmission system. Inaccurate modelling risks jeopardising system security, thus preventing the system operator from planning for and meeting its *principal performance obligations* under the Electricity Industry Participation Code 2010 (Code).

Accurate models are vital for event investigation. While it is possible to procure models while investigating power system events and once an asset is operational, doing so is significantly more expensive than obtaining them during the asset's commissioning. Asset owners must request a model from their original equipment manufacturer, which often requires additional contracts and incurs further cost. In addition, asset owners must arrange testing to validate the new model.

A recent grid event illustrates why the system operator needs accurate models for event investigation. Despite a strong grid connection point, the asset has failed to ride through faults over the years. Multiple generating units tripped and failed to recover after transmission faults were cleared, significantly reducing the MW generation of the asset. In September 2024, the asset failed to ride through another fault and its output dropped from 96MW to 36MW. Due to inadequate modelling, neither the system operator nor the asset owner was able to recreate the scenario for investigation. A new agreement between the asset owner and the equipment manufacturer had to be negotiated and drawn up, and as of April 2025, the cause of the asset failure remains undetermined.

Such scenarios put the entire power system at risk, especially if other assets exhibit similar behaviour. A lack of accurate validated models can prolong investigations, which not only draws out the risk to the power system but also reduces the efficiency of the electricity market's operation in instances where the system operator applies constraints to assets.

Accurate models reduce the risks of events. The system operator needs accurate validated models in studies to manage the risk of blackouts. A power system event can result in power quality issues and/or disconnection of generation or load, which carry significant costs.

According to the system operator's 2024 Credible Event Review,[2] a blackout costs $32,700/MWh (calculated by inflating the Code value of lost load of $20,000/MWh from 2004). The system operator's Risk Matrix indicates blackouts could cost between $3,000,000 (for a small regional blackout) to $300,000,000 (for a single island blackout). International event investigations support these estimates. For example:

- Oscillation in West Murray, Australia cost an estimated $17M AUD[3] in 2019-2020, primarily due constraints imposed on generation by the system operator, to reduce the impact of the oscillation on the power system.
- The cost of the 2011 Southwest blackout in Arizona was estimated at between $12M USD and $100M USD[4]. In this case, dynamic models used in planning or real-time studies were not able to accurately predict the control system response for tripping of critical generators in the region.

Other international cases underscore the need for accurate models to conduct system studies that help mitigate security risks and reduce the occurrence of power system events. For example, the blackouts in Turkey in 2015[5] and the blackout in India in 2012 [6] were both attributed, in part, to the absence of adequate dynamic models in real-time.

Accurate models reduce the likelihood of constraints being imposed on assets, and the associated costs. In scenarios where model accuracy is of concern, the system operator may impose constraints to minimise system security risks. This imposes opportunity costs for asset owners, who are unable to sell their full output to the electricity market. This could amount to hundreds of thousands of dollars in lost revenue while an asset is constrained. Investigations into events such as oscillations can take months, and inaccurate models can exacerbate the length of time an asset is constrained.

Constraints imposed on assets also place pressure on the electricity market. Supply shortages can drive up energy prices, and to resolve these, the system operator may be forced to dispatch a constrained asset, putting the power system at risk of further instability.

[2] https://www.transpower.co.nz/system-operator/information-industry/operational-information-system/event-categorisation.

[3] Transgrid - AEMO - PMU Cost Benefit Analysis for NSW region - 2 Aug 2022 - PUBLIC.pdf

[4] Southwest Power Outage Economic Cost Put At $100M , 2011 Southwest blackout - Wikipedia , eLibrary

[5] 20150921_Black_Out_Report_v10_Clean.docx

[6] REPORT OF THE INQUIRY COMMITTEE

Accurate models are vital for future system operation. As the uptake of IBRs continues to grow, the system operator must exercise due diligence to avoid instability events due to new generation technologies.

The IEEE PES IBR SSO task force report[7] stresses the importance of accurate site-specific models to study sub-synchronous control interactions (SSCI). In the future, advancements in software technology may enable the system operator to use small signal analysis or other impedance scanning techniques in real-time applications to protect the power system from SSCI.

For these real-time tools to be effective and reliable, they must be underpinned by accurate site-specific models. This will help the system operator to avoid taking either overly conservative actions that reduce the efficiency of the power system or electricity market, or overly optimistic actions that compromise system security.

9) Do asset owners have to meet modelling requirements regardless of plant size?

Asset owners must submit models based on their obligations in the Code. For example, a validated frequency controller model must be provided to the system operator if the asset has frequency obligations. The Code specifies that some smaller generating plants do not have such obligations.

All asset owners that have common quality obligations must provide the system operator with validated models. The system operator uses these to analyse instability phenomena and to conduct traditional power system studies like frequency and voltage studies.

On the one hand, individual smaller generating units/stations will have little impact on system frequency or voltage and can be adequately studied with generic or unvalidated models. On the other hand, instability can be caused by small MW or Mvar oscillations, as demonstrated by events in Australia between 2018 and 2023[8]. Investigations into these events indicated that affected solar farms oscillated between 3-6 MW and 2-5 Mvar, thereby causing issues with power quality across the system.

[7] Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources.

[8] Identifying Potential Sub-synchronous Oscillations Using Impedance Scan Approach.

In a separate event in China, several series compensated capacitors were put into operation and all the connected wind power stations were operated normally[9], resulting in sub-synchronous oscillation (SSO). A divergence oscillation was observed with peak-to-peak MW of about 100 MW. If the magnitude of oscillation is large, as it was in this case, it could potentially cause system-wide disturbances like tripping of other assets.

10) Why is the system operator introducing controllable load requirements for connected asset owners?

Since the generation shortfall event of 9 August 2021, the system operator and Electricity Authority have agreed that controllable load plays a crucial role in managing shortfall events. To support this, permanent Code changes were introduced (see *Clause 5A of Schedule 8.3, Technical Code B*) requiring connected parties to provide controllable load information as difference bids via WITS when requested by the system operator. However, during fast moving grid emergencies phone calls are often used to convey controllable load information and this practice places undue pressure on system operator and connected parties' operational teams.

To remove this operational risk, the proposed CACTIS requires connected asset owners to submit real-time controllable load SCADA indications or estimates, improving the system operator's situational awareness and therefore its ability to manage shortfall events. Additionally, this requirement ensures that the system operator treats connected parties equitably.

While this requirement isn't explicitly stated in the Code today, the system operator is able to request these indications in order to plan to comply, and to comply with its PPOs (refer Clause 9 of Schedule 8.3, Technical Code C). Adding this requirement explicitly into the CACTIS removes any ambiguity on the need for real-time controllable load indications.

[9] Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources.

Appendix E Format for submissions

Appendix E Format for submissions

Submitter	

Questions	Comments
Q1. Do you support the Authority's proposal to clarify the Code's common quality information requirements and describe the technical specifications in a document incorporated by reference in the Code?	
Q2. Do you have any comments on the drafting of the proposed amendment?	
Q3. Do you see any unintended consequences in making such an amendment?	
Q4. Do you agree with the objective of the proposed amendment? If not, why not?	
Q5. Do you agree the benefits of the proposed amendment outweigh its costs? Please provide evidence to support your view. This may include incremental benefits and costs associated with the draft CACTIS.	
Q6. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q7. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Q8. Do you have any comments on the drafting of the proposed amendment?	
Q9. Do you have any comments on the draft Connected Asset Commissioning, Testing and Information Standard?	

Appendix F Summary of submissions

F1. We received 12 submissions on our October 2024 consultation paper from parties listed in Table 6. This section summarises the submissions on the drivers, issues and options. However, the summaries are not exhaustive, and we encourage you to review individual submissions for a comprehensive account of submitters' views.

Table 6: List of submitters

Submitter	Category
Electricity Engineers' Association of New Zealand (EEA)	Representative body for electrical engineers
Electricity Networks Aotearoa (ENA)	Representative body for distributors
Manawa Energy	Generator
Mercury	Generator–retailer
Meridian	Generator–retailer
NewPower Energy	Owner/operator of solar photovoltaic generation and battery energy storage systems
Orion	Distributor
Powerco	Distributor
SolarZero	Flexibility provider
Transpower (as a grid owner and the system operator)	Transmission grid owner and system operator
Vector	Distributor
WEL Networks	Distributor

Submitters broadly agreed with the key drivers of change

F2. Most submitters agreed with the Authority's assessment of the key drivers. The EEA, ENA, Manawa Energy, Mercury, Meridian, NewPower, Orion, Transpower, and Vector expressed broad agreement that the increasing penetration of inverter-based resources (IBRs) and the evolving complexity of New Zealand's power system necessitate more sophisticated modelling approaches.

F3. Transpower highlighted the potential IBR interactions that can only be assessed using EMT models. They noted that the system operator and grid owner will require EMT models to effectively undertake a range of studies, compliance assessments, monitoring and investigations.

F4. NewPower and WEL Networks submitted an additional driver are the developments in approaches to modelling, such as AI-driven modelling, parameter-less modelling, and immittance-based frequency domain models. NewPower suggested that, over time, better modelling techniques and the development of generic models for IBRs could reduce the reliance on detailed, unencrypted electromagnetic transient (EMT) models.

F5. NewPower noted that while enhanced modelling is essential for managing the power system effectively, the level of accuracy required must be weighed against practical limitations and cost implications. Powerco emphasised that while modelling is critical for the system operator to manage complex dynamic interactions, distributors have a more limited role in frequency management. NewPower and Powerco submitted that while distributors will need access to certain modelling information in the future—particularly as the prevalence of DERs and BESS increases—the modelling responsibilities of distributors, the system operator, and Transpower as a grid owner must remain clearly delineated.

F6. SolarZero stated that while the power system is undergoing a period of rapid transformation, the full scope of necessary modelling refinements may not become clear until further real-world data is available. SolarZero suggested the Authority examine overseas experiences in depth before making decisions about modelling requirements. Mercury further noted that while the transition towards a higher share of IBRs is a global phenomenon, the extent of change in New Zealand may be less pronounced than in other jurisdictions due to the continued dominance of hydro and geothermal synchronous generation.

Submitters emphasised the importance of balancing information provision, costs, and intellectual property

F7. Submitters provided a range of views on the common quality-related information issues. The EEA, ENA, Manawa Energy, Mercury, Orion, Transpower and Vector agreed that network operators and owners lack sufficient information to plan and operate the power system effectively. Meridian, NewPower and WEL Networks did not agree with the Authority's position and raised some concerns regarding feasibility, cost, and the differing needs of industry participants.

F8. Mercury and NewPower raised concerns about the potential impact of requiring asset owners to provide non-black-box EMT models. They noted the reluctance of equipment manufacturers to share these models due to intellectual property concerns and were concerned that manufacturers may refuse to supply them, potentially leading to supply chain disruptions. Transpower suggested partial encryption as a compromise, allowing access to some adjustable parameters while safeguarding sensitive elements.

F9. Mercury noted that only the system operator can effectively study how different plants interact, which could result in a bottleneck for system studies. To help streamline new connections, they proposed that the Authority publish EMT models on the EMI database, with appropriate measures to protect intellectual property.

F10. Another recurring theme was the differing information needs of the system operator, Transpower as grid owner, and distributors. The ENA, NewPower and Powerco pointed out that while the system operator requires detailed dynamic models to ensure overall grid stability, distributors often rely on a mix of performance standards and real-time monitoring rather than extensive modelling. Powerco also noted that the ability of distribution networks to regulate frequency is limited compared to the broader role of the system operator.

F11. Orion and the EEA emphasised the growing role of aggregators in managing DERs and the challenges distributors face due to limited visibility of these assets, which could pose risks to grid stability. The EEA, ENA, and Vector recommended improving distributor access to smart meter data to mitigate this issue and improve voltage and reactive power management.

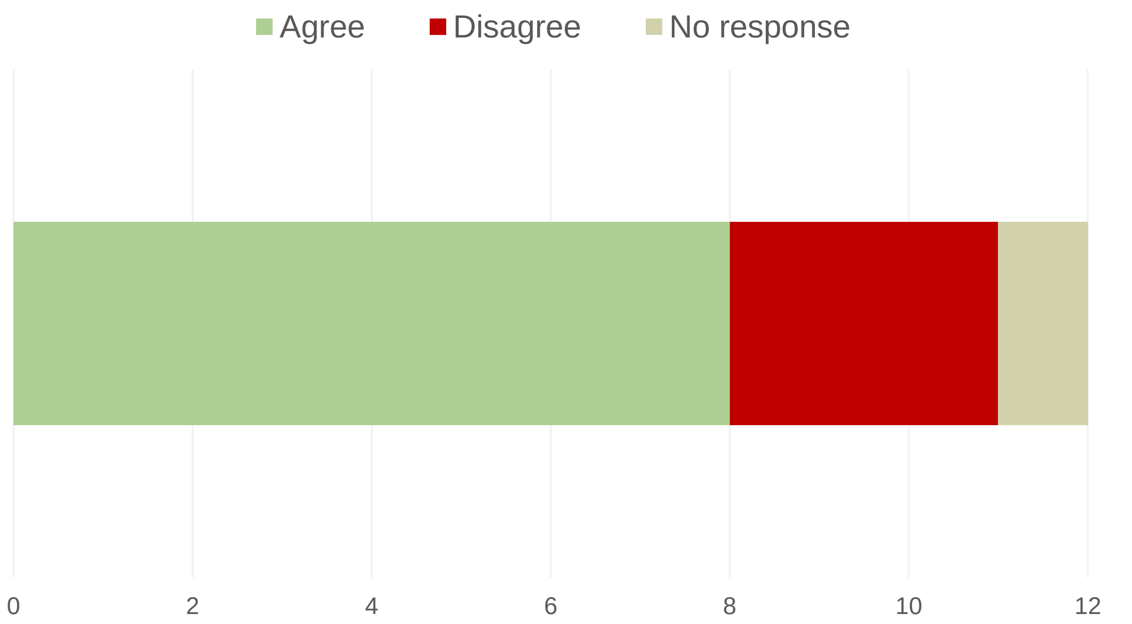
F12. Meridian, NewPower and WEL Networks considered the issue is more economic than technical. Meridian and WEL Networks supported retaining the existing Code framework and negotiation-based mechanisms for providing information to the system operator to ensure information requests are proportionate and necessary.

F13. NewPower and WEL Networks stated that the system operator and grid owner can connect new generation with limited asset information if risks are managed through operational constraints, increased ancillary services, additional asset testing, or potential over-investment in transmission. They emphasised the need to balance the costs of obtaining, processing, and storing asset information against its benefits. NewPower also questioned whether the system operator's current modelling tools are adequate for future needs.

Most submitters agreed that the existing Code provisions are insufficient

F14. Most submitters agreed that the existing Code provisions are insufficient to address the common quality-related information issue, while others argued that existing frameworks already provide adequate mechanisms (Figure 1).

Figure 1: Do you agree that the current provisions in the Code are insufficient to address the common quality-related information issue?



F15. The EEA, ENA, Manawa Energy, Mercury, Orion, Powerco, Transpower and Vector agreed that the existing Code provisions are insufficient or could be improved, while Meridian, NewPower and WEL Networks considered them adequate. SolarZero suggested a thorough review of overseas approaches.

F16. Submitters that agreed the current Code is insufficient highlighted challenges such as a lack of clear standards, insufficient access to distributed energy resources data, and the need for better visibility into network performance.

F17. Transpower noted that asset owners are already required to supply certain information under the Code but suggested the Code could be clarified and enhanced through a consultation process with industry.

F18. Manawa Energy acknowledged limitations in the Code but attributed the issue more to a lack of common standards and clarity in information management. They suggested clearer guidelines may be more effective than Code changes in addressing common quality-related information challenges.

F19. Meridian, NewPower and WEL Networks supported retaining the current regulatory framework, structured around negotiation. They raised concerns that requiring additional data could create economic burdens, particularly for new asset owners. NewPower and WEL Networks noted that the system operator and grid owner should only request information that is "reasonably required" and suggested clearer definitions could prevent disputes and inefficiencies.

Most submitters supported the proposed options with refinements for data-sharing protocols and confidentiality protections

F20. The EEA, ENA, Manawa Energy, Orion, Transpower, and Vector agreed with the three shortlisted options, while Powerco supported options 2 and 3. Meridian and NewPower did not agree with the shortlisted options, while Mercury and SolarZero provided general comments.

F21. EEA and Orion agreed with all the short-listed options. Orion preferred options 2 or 3, while Powerco and Transpower favoured option 3, emphasising the potential to enhance information-sharing between distributors and Transpower while improving system planning.

F22. Transpower suggested additional refinements to clarify what constitutes asset information and how the system operator, Transpower as a grid owner, and distributors should handle confidentiality to protect proprietary data.

F23. NewPower and Meridian did not support the short-listed options. NewPower argued that common quality-related obligations should be applied at grid exit and injection points rather than at the distribution level. NewPower also questioned the necessity of requiring non-black-box EMT models and suggested that validated test results should be sufficient for compliance assessments. Meridian expressed concerns that the options did not sufficiently account for the standard of reasonableness in determining information-sharing requirements.

F24. Mercury and SolarZero highlighted the importance of aligning New Zealand's approach with international best practices. Mercury suggested replicating Australia's

National Electricity Market (NEM) framework. Similarly, SolarZero called for a more thorough review of international standards.

Most submitters supported a document incorporated by reference in the Code developed in collaboration with industry stakeholders

F25. Submitters provided a range of views on using a system operation document incorporated by reference in the Code. The EEA, ENA, Orion, SolarZero, Transpower and Vector supported the proposal as it would improve clarity and standardisation, while NewPower, WEL Networks, and Meridian raised concerns about flexibility, legal compliance, and consultation processes.

F26. The EEA, Transpower, Vector and WEL Networks emphasised the importance of stakeholder collaboration in developing the document. Transpower suggested that the objective of the document should be to ensure the information it contains is "reasonably required." They noted that the consultation process could help develop a shared understanding of what is considered "reasonable to request." The EEA stated that industry collaboration was important to make the document practical and adaptable to evolving standards, and Vector reiterated the need to involve distributors to support planning and co-ordination of distributed energy resources. Manawa Energy remained neutral but indicated willingness to contribute to the document's development.

F27. NewPower and WEL Networks emphasised the need for consultation and compliance with the Legislation Act 2019. Meridian considered the existing system operator-developed guidelines provide sufficient industry guidance and stated the proposed approach was unnecessarily rigid.

Submitters expressed mixed views on the evaluation of each option and suggested further industry engagement

F28. Submitters expressed mixed views on the Authority's high-level evaluation of the shortlisted options. Some agreed with the Authority's evaluation, while others challenged specific points, particularly around cost implications, data-sharing concerns, and potential conflicts of interest.

F29. The EEA, ENA, Manawa Energy and Orion generally supported the Authority's evaluation. The EEA emphasised the need for standardized data formats and interoperability to facilitate better information exchange across stakeholders. They also suggested that the evaluation should explicitly consider the long-term adaptability of each option to account for evolving technologies and data needs.

F30. The EEA, Powerco and Transpower agreed that the outlined pros and cons provided a reasonable foundation for evaluating the options. Transpower considered that concerns raised in the consultation, particularly around intellectual property protection for IBR models, can be managed rather than serving as a barrier to accessing necessary system performance data. Manawa Energy also agreed with the general assessment but highlighted the challenge of managing the costs of data-sharing.

F31. The EEA, Orion, and Transpower recommended refining the assessment and engaging with industry before finalising any approach. The EEA called for a more nuanced evaluation that considers regional network conditions, asset ownership structures, and operational realities. Orion suggested that if a centralized data-sharing platform were to be introduced, a neutral entity should manage it to ensure fair access and accountability.

F32. Other submitters disagreed with key elements of the Authority's assessment. NewPower and WEL Networks disagreed with the evaluation, citing gaps in cost-benefit analysis and economic impact assessment. NewPower stated that the Authority did not sufficiently evaluate alternative approaches, such as using generic IBR models that could be tuned to match system needs. Similarly, WEL Networks stated that the evaluation did not adequately address costs and benefits.

F33. NewPower and Powerco questioned whether requiring asset owners to provide unencrypted EMT models would deter international manufacturers from supplying equipment to New Zealand. NewPower suggested that the Authority conduct a formal analysis of manufacturers' willingness to comply. Meridian submitted that the stated transaction cost benefits were overstated, as obtaining unencrypted models would likely increase costs for asset owners.

F34. NewPower and WEL Networks raised concerns about the cost burden placed on asset owners and the lack of clarity around how shared data would be managed. NewPower argued that the Authority had not demonstrated a clear benefit to distributors in accessing common quality-related asset data, given that distributors already have access to relevant models. WEL Networks questioned whether distributors and network owners truly needed asset capability data to meet their common quality obligations.

F35. Meridian provided partial agreement with the Authority's evaluation, noting that the proposed approach could lead to more compliance breaches and exemption applications. They also expressed concern that the evaluation prioritises reliability over efficiency, potentially resulting in an oversupply of information that imposes unnecessary costs on industry participants.

F36. Meridian also raised concerns that unencrypted models are difficult and costly to obtain from manufacturers and that the Authority's assessment overstates the benefits of additional data-sharing requirements.

Most submitters were not concerned about conflicts of interest

F37. Most submitters did not see a material conflict of interest arising under options 2 and 3. The EEA, ENA, Orion, Powerco, and Vector did not agree that distributors would gain a competitive advantage if they had access to detailed performance models about distributed energy resources and other assets connected to their networks. They stated that many distributors are community-owned and pointed to existing competition laws and regulatory oversight as safeguards.

F38. Manawa Energy and Transpower acknowledged concerns over sharing proprietary data, particularly around unencrypted models. Manawa Energy emphasised that while non-proprietary data-sharing was acceptable, manufacturers remained highly protective of their intellectual property.

F39. Transpower noted that allowing distributors access to unencrypted EMT models could create a perceived conflict of interest but stated that it does not own generation assets so does not have conflicting interests. However, Manawa Energy stated that the perception of a conflict of interest already discourages equipment manufacturers from sharing proprietary models with Transpower.

F40. NewPower and WEL Networks raised concerns that Transpower could gain a competitive advantage over other grid owners if it has access to exclusive asset information. They recommended that the system operator publish encrypted models, ensuring that all grid owners and relevant parties have equal access to the same data.

Submitters proposed alternative approaches focused on data governance, international best practices and providing encrypted models

F41. Several submitters proposed alternative approaches to managing common quality-related information, focused on data governance, international best practices, and refining the role of the system operator in managing information access.

F42. Transpower proposed an alternative option in which the system operator could share information and models with grid owners but not with distributors, to manage confidentiality concerns while minimising duplication in the connection process.

F43. The EEA recommended enhancing existing options by improving data quality and governance. They proposed a standardised data quality framework for consistency, automated quality assurance tools for real-time error detection, and training programs to strengthen data integrity. Additionally, they emphasised the need for formal data governance structures continuous improvement mechanisms to improve accountability and drive ongoing improvements.

F44. Meridian suggested industry-wide discussions or a working group to define what common quality information is "reasonably required" in different scenarios. They favoured guidelines over prescriptive regulations, advocating for a collaborative process to align asset owner and system operator expectations. SolarZero recommended a comprehensive review of international best practices, citing the Wind Grid Integration Project as an example.

F45. NewPower suggested three alternative approaches:

a. The system operator should manage asset capability information and provide suitable models for different stakeholders to use, such as distributors conducting power system studies or investigating non-transmission alternatives.

b. Generators should be allowed to provide black-box EMT models, with the system operator responsible for managing associated risks. NewPower stated that the risk remains low as long as the black-box model closely reflects generator behaviour.

c. The system operator should develop generic IBR models that can be tuned to match black-box models, ensuring full understanding of system behaviour while safeguarding intellectual property.

Additional feedback

F46. Submitters provided additional feedback on various aspects of the consultation, including international best practices, the applicability of the existing approach and cost-benefit considerations.

F47. SolarZero emphasized the importance of learning from overseas jurisdictions, particularly Australia, where IBRs play a significant role in electricity production. They recommended establishing a comprehensive study similar to New Zealand’s Wind Grid Integration Project.

F48. WEL Networks questioned whether the current modelling approach for the transmission system is suitable for distribution networks, given the increasing complexity of small-scale DERs and controllable loads. Additionally, they emphasised the need for a detailed cost-benefit analysis before making regulatory changes, warning that more detailed modelling requirements could introduce unnecessary costs without delivering proportionate benefits.

F49. The ENA expressed concerns that distributors might be burdened with obligations to collect and transmit information without directly benefiting from it. They called for greater clarity on the scope of proposed changes to ensure practicality.

F50. Mercury and Meridian stressed that clear, transparent, and easily understandable modelling requirements are essential to avoid unnecessary delays in the validation process and to streamline interactions between vendors and the system operator.

Glossary of abbreviations and terms

a.c.	Alternating current
ACS	Asset capability statement
AEMO	Australian Energy Market Operator
AOPOs	Asset owner performance obligations
Act	Electricity Industry Act 2010
Authority	Electricity Authority Te Mana Hiko
BESS	Battery energy storage system
CACTIS	Connected Asset Commissioning, Testing and Information Standard
Code	Electricity Industry Participation Code 2010
DLL	Dynamic Link Library
EEA	Electricity Engineers' Association of New Zealand
EMT	Electromagnetic transient
ENA	Electricity Networks Aotearoa
FSR	Future Security and Resilience
HVDC	High voltage direct current
IBRs	Inverter-based resources
ICCP	Inter-Control Centre Communication Protocol
MW	Megawatt
NDA	Non-disclosure agreement
NEM	(Australian) National Electricity Market
PIP	Power Innovation Pathway programme
PPOs	Principal performance obligations
RMS	Root mean square
SOC	State of charge