Addressing common quality information requirements

Consultation paper

1 October 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is reviewing the common quality requirements in Part 8 of the Electricity Industry Participation Code 2010 (Code). The Authority is undertaking this review as part of our Future Security and Resilience (FSR) programme.

'Common quality' means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons. The common quality requirements in the Code are foundational to the safe and reliable supply of electricity to consumers.

The Authority wants the Code's common quality requirements to enable evolving technologies, particularly inverter-based resources (IBRs). Examples of IBRs include wind generation, solar photovoltaic generation, and battery energy storage systems.

We see these technologies as a key enabler of:

- consumers having more choice and flexibility around their electricity use and supply
- the electrification of parts of New Zealand's economy, such as transportation and heating.

In addition to providing opportunities, these technologies do, however, pose some challenges. In particular, we expect that co-ordinating the real-time operation of New Zealand's power system to supply electricity to consumers at the level of reliability they want will become more complex over the coming years. This increased complexity will be the result of evolving technologies enabling a significant increase in variable and intermittent generation and an increase in bi-directional electricity flows.

Through a combination of one-on-one engagement and formal consultation with interested parties, the Authority has identified seven key issues with the common quality requirements in Part 8 of the Code. In April 2023 we published a consultation paper on these seven key issues.[1] In June 2024, we published a suite of consultation papers on matters relating to five of these seven key issues.[2]

This paper contains short-listed options to help address the sixth key common quality issue identified, which relates to the provision of common quality-related information to network operators and network owners.

We have summarised this information issue 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 Electricity Authority, Future Security and Resilience Issues paper - Part 8 common quality requirements, April 2023.

2 Electricity Authority, Future Security and Resilience - Review of common quality requirements in the Code, June 2024.

The Authority is proposing we investigate the following options to help address this issue:

(a) **Option 1**: Update and clarify common quality-related information requirements in the Code.

(b) **Option 2**: Update and clarify common quality-related information requirements in the Code and enable the system operator and distribution network operators to share common quality-related information.

(c) **Option 3**: Update and clarify common quality-related information requirements in the Code, enable the system operator and distribution network operators to share common quality-related information, and enable the system operator to share common quality-related information with Transpower as a transmission network owner.

We have not yet formed a view on any preferred option(s) to address the common quality-related information issue. While we have identified three options, we are open to feedback on other viable options to address the issue.

The Authority has benefitted greatly from input we have received from the Common Quality Technical Group (CQTG), the system operator, distributors and Transpower, as a transmission network owner. The CQTG is supporting our evaluation of options to help address the seven identified key common quality issues. The knowledge and experience of its members collectively ranges from the operation of the power system at both the transmission and distribution levels to the operation of generation and demand-side management technologies.

Your feedback is welcomed

The Authority welcomes feedback from interested parties on the options described in this paper.

The Authority acknowledges the content of this consultation paper is technical. During the consultation period the Authority will be available to hold individual and group briefings with interested stakeholders.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on options to improve common quality-related information provided to network operators and owners for use in planning and operating New Zealand's power system.

> **What is 'Common Quality'?**
>
> **'Common quality' means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons. An example is the frequency of electricity.**

1.2. The options in this paper aim to help address the following key common quality issue identified by the Authority following a combination of one-on-one engagement and formal consultation with interested parties:

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.

How to make a submission

1.3. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to fsr@ea.govt.nz with 'Consultation Paper— Addressing common quality information requirements' in the subject line.

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

1.5. 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).

1.6. If you indicate part of your submission should not be published, the Authority typically will discuss this with you before deciding whether to not publish that part of your submission.

1.7. However, please note that all submissions received by the Authority, including any parts that 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

1.8. Please deliver your submission by 5pm on Tuesday 12 November 2024.

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

2. Introduction

The Future Security and Resilience programme

2.1. This paper is part of a multi-year work programme being undertaken by the Authority, called the Future Security and Resilience (FSR) programme. The FSR programme is seeking to ensure New Zealand's power system (at both the transmission and distribution levels) remains secure and resilient as the country transitions towards a lower emissions economy.

2.2. By 'power system' we mean all components of the New Zealand electricity system underpinning the New Zealand electricity market, including generation, transmission, distribution, and consumption (load) assets.

2.3. The FSR programme is focussed 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.

Reviewing the common quality requirements in Part 8 of the Code

2.4. The highest priority activity in the FSR programme is a review of the common quality requirements in Part 8 of the Code. The review's purpose is to ensure these requirements enable evolving technologies, particularly inverter-based resources, in a manner that is consistent with the Authority's statutory objectives.

2.5. This review is the highest priority activity on the FSR programme because of:

(a) the need to ensure the common quality requirements accommodate and facilitate the opportunities offered by evolving technologies, particularly inverter-based resources (IBRs)

(b) the increasing risk to security and resilience as more distributed generation is installed and bi-directional electricity flows become more prevalent

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

2.6. As Figure 1 and Figure 2 show, the power system is changing. We need to ensure the common quality requirements in Part 8 of the Code are fit-for-purpose now and in the future.

Figure 1: The power system of the past

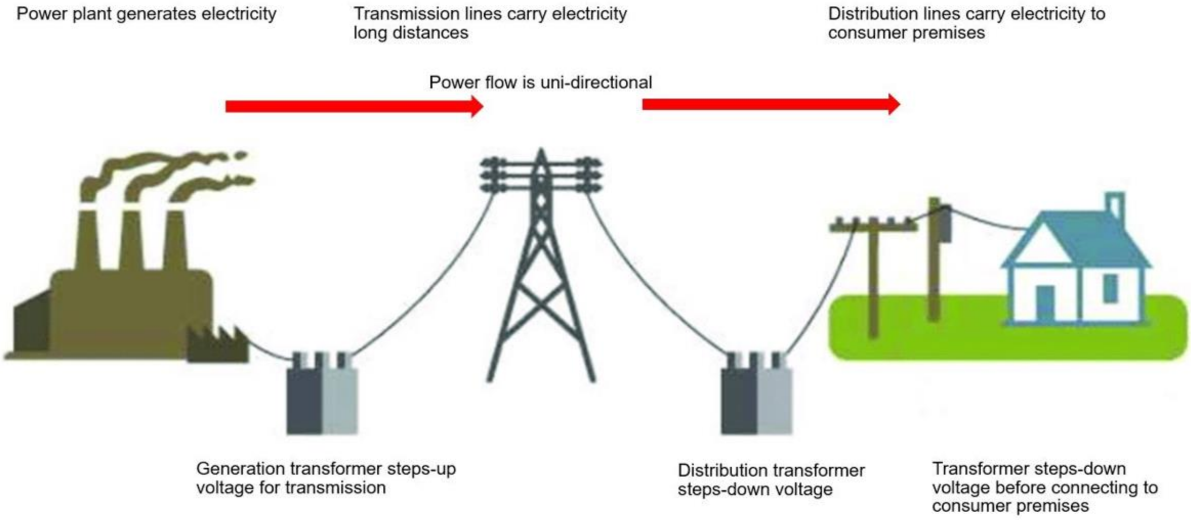
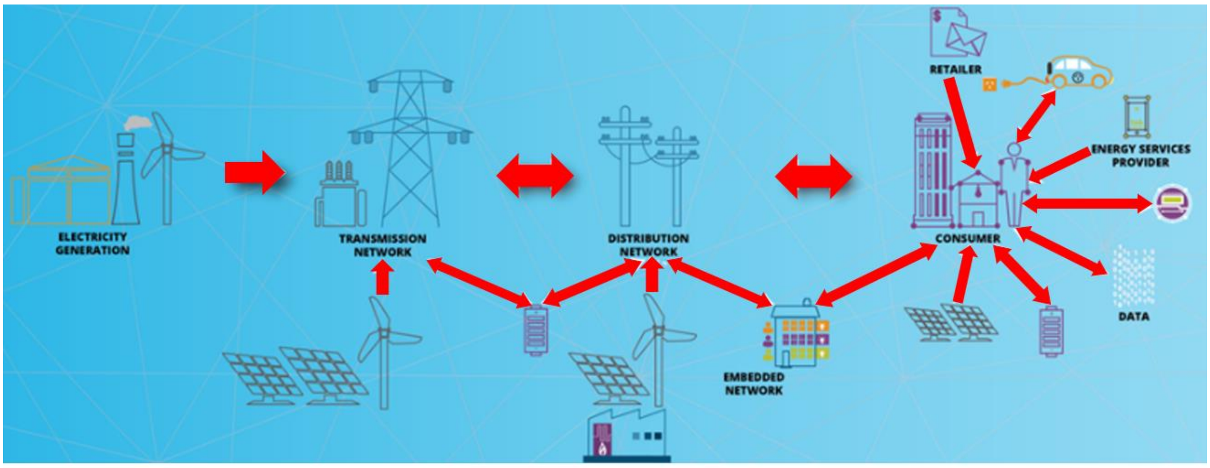


Figure 2: The power system today



Power flows have become bi-directional with distributed energy resources (DER) connecting to the distribution network

2.7. These changes to the power system are also an important driver of the 'Future System Operation' workstream within the FSR programme. This workstream is looking at the potential challenges and opportunities with operating the power system as New Zealand transitions to a low-emissions economy.[3]

2.8. For the purposes of our review of common quality requirements in the Code, the Authority is defining common quality to apply across all of New Zealand's connected transmission and distribution networks. This is broader than the Code's definition, which defines 'common quality' as relating only to the transmission network. The broader definition being used in the FSR programme acknowledges that various security and resilience challenges and opportunities will be common to the transmission network and distribution networks.

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3 See Electricity Authority I Future operation of New Zealand's power system.

2.9. While the focus of this work is on the common quality requirements in Part 8 of the Code, the Authority is aware that a review of these requirements has linkages to one or more other parts of the Code. The Authority is carefully considering these linkages as part of the review of common quality requirements in Part 8.

Common quality-related information provision is a key issue

2.10. In April 2023 the Authority published a consultation paper on seven key issues with the common quality requirements in Part 8 of the Code.[4]

2.11. One of these issues was the provision of common quality-related information to network owners and operators. We have summarised this issue 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.*

2.12. Since the close of consultation on our 2023 Issues paper, the Authority has considered improvements that would ensure network operators and network owners have sufficient information to support the common quality aspects of electricity conveyed across New Zealand's power system.

2.13. The Authority has engaged with several stakeholders through formal meetings and informal one-on-one discussions. These stakeholders have included:

(a) the Common Quality Technical Group (CQTG)

(b) Transpower, as the system operator

(c) distributors

(d) Transpower, as a transmission network owner.

2.14. The CQTG is supporting our evaluation of options to help address the seven common quality issues identified. The knowledge and experience of its members collectively ranges from the operation of the power system at both the transmission and distribution levels to the operation of generation and demand-side management technologies.[5] The insights provided by people with day-to-day operational involvement in common quality matters and/or who bring a range of relevant commercial and technical experience has been most valuable to us.

2.15. Our discussions with the stakeholders listed above have provided us with valuable insights into challenges faced by network operators and owners in obtaining information on assets wanting to connect, or which are connected to the power system. A particular challenge is obtaining modelling information for IBRs like wind generation, solar photovoltaic generation, and battery energy storage systems (BESSs).

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

5 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).

2.16. As part of our consideration of options to address the common quality-related information issue, the Authority has also reviewed approaches adopted in overseas jurisdictions. Over the past 15 years Australia, Great Britain, and North America have enhanced their regulatory requirements for the provision of common quality-related information to network operators and owners. A key focus of the regulatory changes has been enabling network operators and owners to undertake power system analysis to maintain power system security and facilitate new connections.

Other Authority work on improving information availability for distributors

2.17. In addition to the work being undertaken as part of our review of the Part 8 common quality requirements, the Authority has two other workstreams looking at the provision of information to distributors.

Updating Regulatory Settings for Distribution Networks work programme

2.18. The 'Updating Regulatory Settings for Distribution Networks' work programme is the Authority's main distribution sector workstream.[6] We published an indicative work programme in October 2023.[7] Current and recent work includes:

(a) improvements to the Default Distributor Agreement (DDA)[8]

(b) improving access to smart metering data (eg, for distributors and flexibility providers) to increase the understanding of how electricity is being used on low voltage networks and to encourage more flexible electricity use

(c) improving the granularity of data in the registry of installation control points (ICP registry), and the functionality of the ICP registry (or an alternative), to encourage more flexible electricity use

(d) bringing flexibility providers into the Code so they can support a more competitive, reliable and efficient power system for the long-term benefit of consumers

(e) providing guidance on how to apply for Code exemptions

(f) providing guidance on the 'arm's length' rules for distributors.

The Network Connections Project

2.19. The Network Connections Project is part of the Updating Regulatory Settings for Distribution Networks work programme. This project's core focus is Part 6 of the Code (*Connection of distributed generation*). The project is considering:

(a) the processes for connection to a distribution network

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6 For details of this work programme, including feedback on Authority consultations, see our website: Updating regulatory settings for distribution networks.

7 Electricity Authority, *Delivering key distribution sector reform - Work programme*, October 2023.

8 The DDA sets out the default terms for distributors and retailers to work together to provide electricity to consumers effectively, efficiently and reliably. The DDA simplifies negotiations and clarifies requirements, enabling more competition between retailers, and reducing compliance costs, both of which can result in relatively lower electricity prices for consumers.

(b) the processes for amending existing connections to distribution networks

(c) the operation of distribution networks (eg, power quality and congestion).

2.20. The project's intended outcome is for distributors to provide efficient, standardised processes for load and generation to connect and operate efficiently. It responds to issues raised during Authority consultations in 2021 and 2022, and from ongoing conversations the Authority is having with stakeholders.

2.21. The project is being undertaken in two stages so the Authority can more quickly address issues stakeholders tell us are most important. In response to stakeholder feedback, the main objective for the project's first stage is to make the process of connecting to networks easier, faster, more consistent, and more equitable.

3. Drivers of change in common quality information requirements

3.1. New Zealand’s power system is undergoing a period of transformation. Within New Zealand’s electricity sector significant changes are occurring in the generation supply mix and in electricity usage / demand. Driving these changes are the development of new technologies, the reduced cost of some technologies, and climate change policies.

3.2. These changes are impacting the power system and will continue to do so into the future. While this transformation creates investment opportunities and helps the progress towards a lower emissions economy, it also presents significant operational challenges for the power system.

3.3. Transitioning toward a power system with a higher share of IBRs creates potential power quality issues, as power electronic devices are used at the interface between IBRs and electricity networks. If not addressed in a timely manner, the increasing use of power electronic devices has the potential to adversely impact power quality and compromise the power system’s reliability.

3.4. Network operators and owners need information on assets wanting to connect, or which are connected, to the power system to provide for the safe, reliable and economically efficient operation of the power system.

3.5. There are many modes of failure for the power system, and each individual asset that is connected to, or forms part of the power system, cannot be considered independently. As such, studying interdependencies within the power system requires mathematical models for such assets, for use in computer software simulations.

3.6. A power system model is a set of mathematical equations, typically a combination of algebraic and differential equations, used to simulate the behaviour of the physical power system.

3.7. Power system models are used for many purposes. They help in evaluating whether proposed generating stations meet performance standards. They help in managing power system security. These models enable various stakeholders to examine how the power system will operate under different conditions.

3.8. The section summarises the following key drivers of change in common quality-related information requirements:

(a) the changing nature of New Zealand’s power system

(b) emerging power system issues due to new and evolving technologies

(c) the modelling requirements for IBR-based generation and load differ from traditional technologies

(d) learnings from overseas jurisdictions on the need for accurate and up-to-date models.

The changing nature of New Zealand's power system

3.9. The New Zealand power system is evolving from a system dominated by large synchronous power stations to a system that includes a multitude of power generation resources and technologies of various sizes. At the same time, consumers are engaging with their electricity supply in new ways.

3.10. As the power system evolves, so do the modes of failure of the power system. In the last several years, overseas jurisdictions have observed new phenomena (such as sub-synchronous control interactions[9]) that have not been observed previously.

Changes to generation technologies

3.11. Historically, all electricity generation was machine-based synchronous generation, regardless of the energy source it was fuelled by (eg, water (hydro), gas, coal, geothermal, oil). As such, the operation of the power system was designed around this generation technology.

3.12. Wind turbines, solar photovoltaics and BESSs interface with electricity networks via inverters, which operate based on fast-switching power electronics devices. As New Zealand's economy electrifies, there is expected to be a significant increase over the coming years in the number of IBRs connected to the power system – particularly in distribution networks.

3.13. The way in which IBR-based generation interacts with the power system is significantly different from synchronous machine-based generation. Power electronic interfaces have no electro-mechanical coupling between the energy source and the electricity network. This can be detrimental to the power system, for example, where the IBR generation is unable to provide inertia and fault current, which act to help stabilise the power system after a disturbance on the system.

3.14. Additionally, IBR-based generation is connected to the power system using control systems implemented in the form of computer software. As a result, many new power system phenomena are the result of how the control systems of IBR-based generation have been programmed.

Changes to load profiles

3.15. Currently, electricity demand-side behaviour is relatively passive and predictable. While electricity demand has remained relatively constant in recent years, scenarios indicate it could increase by up to 68% by 2050.[10]

3.16. Empowered by evolving technologies, controllable loads are also expected to significantly increase over the coming years. Examples of these loads include controllable hot water, electric vehicle chargers, energy storage systems, and smart appliances.

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9 "Control interactions" refers to a situation where a generating unit is oscillating or interacting with another generation unit (or units), leading to undamped voltage, active and/or reactive power oscillations at the point of connection with the electricity network.

10 Transpower, Whakamana i Te Mauri Hiko - Empowering our Energy Future, March 2020.

3.17. Controllable loads can provide flexibility by modifying consumption patterns and profiles in response to an external signal (eg a change in price) to provide a service within the power system. For example, water heating or electric vehicle charging could adjust or turn on and off in response to signals based on electricity prices. Soon consumers (households and businesses) are expected to have increasing amounts of controllable load with the potential to provide a range of flexibility services.

3.18. Like IBR-based generation, modern controllable loads typically interface with the power system via power electronic converters. Therefore, modern controllable loads may cause the same power system phenomena as IBR-based generation.

Increased penetration of embedded generation and distributed energy resources

3.19. One of the major issues related to traditional transmission planning simulation tools is their use of 'lumped' models to represent entire distribution networks connected to the transmission network.

3.20. As an entire distribution network is represented through a single model, the parameterisation of the model is important in adequately capturing the voltage diversity throughout the distribution network. Accurately reflecting power system behaviour in power system modelling will become increasingly challenging with increased amounts of distributed energy resources (DERs) connected to distribution networks. This is because some assumptions made during the parameterisation process may not hold true under certain scenarios.

3.21. Another modelling issue associated with the increased penetration of DERs is the ability of some modelling tools to accurately estimate the amount of DERs that will disconnect from the network when a fault occurs on the power system. Existing simulation tools tend to underestimate the amount of DERs tripping in response to a fault on the power system.[11]

Emerging power system issues due to new and evolving technologies

3.22. As the penetration of IBRs and DERs increases, new and different challenges to power system operation will emerge.

3.23. One of the operational challenges for the system operator is oscillation in the power system, especially sub-synchronous system oscillations.[12] Sub-synchronous oscillations are power system oscillations occurring at less than the fundamental (50Hz) frequency. If left unmanaged, a sub-synchronous oscillation in the power system may cause damage to transmission and generation assets, and system security issues.

3.24. In the past, sub-synchronous oscillations in a power system were of a low magnitude and were adequately damped with inherent network controls. However,

11 Specifically, 'positive sequence' simulation tools struggle to demonstrate how multiple DERs co-ordinate and impact transmission operational stability, because positive sequence voltages are higher than the lowest individual phase during unbalanced faults.

12 Energy System Operator, System oscillation assessment of Inverter Based Resources (IBR), January 2024.

increased penetration of IBRs has resulted in sub-synchronous oscillations being observed by the operators of several overseas power systems.

3.25. In 2022 the Institute of Electrical and Electronics Engineers published 19 examples of sub-synchronous oscillations in power systems around the world over the period 2009–2021.[13] Similarly, in 2023, Great Britain's power system operator, National Grid, observed several sub-synchronous oscillations in the British power system.[14]

3.26. The Australian Energy Market Operator has identified oscillatory instability as one of the major concerns in Australia's National Electricity Market region (comprising Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania).[15] The recent uptake of large-scale IBRs in this region has the potential to worsen this instability.

The modelling requirements for IBR-based generation and load differ from traditional technologies

3.27. The modelling requirements for IBR-based generation and load differ from the modelling requirements for traditional technologies. Please see Appendix C of this paper for some background information on power system modelling.

Modelling requirements for IBR generation

3.28. Traditionally, root mean square (RMS) models have been adequate for power system analysis and studies, due to the predominance of machine-based synchronous electricity generation. However, these mathematical models are not accurate enough (for both power system analysis and investigation) in an evolving power system with IBRs.

3.29. To accurately capture the detailed behaviour of IBR control systems, more detailed electro-magnetic transient (EMT) models are needed. The current modelling methods and tools, such as conventional phasor-based modelling software, fall short in assessing the impact of large-scale IBRs on small-signal stability.[14] These tools provide overly optimistic and inaccurate IBR responses for sub-synchronous events.[16]

3.30. To address these limitations, overseas regulators such as Ofgem in the United Kingdom and the Australian Energy Regulator have initiated work programmes that include EMT-based simulation studies. These studies require control models (EMT models) to evaluate IBR control interactions.

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13 IEEE PES IBR SSO Task Force, "Real-world subsynchronous oscillation events in power grids with high penetrations of inverter-based resources," *IEEE Transactions on Power Systems* 38, no. 1 (2022): 316-330.

14 Energy System Operator, *ESO Operational Transparency Forum*, November 2023.

15 Farahani, E., P. F. Mayer, J. Tan, F. Spescha, and M. Gordon, "Oscillatory interaction between large scale IBR and synchronous generators in the NEM," *CIGRE Science & Engineering,* no. 28 (2023): 170-183.

16 Alberta Electric System Operator (AESO), *EMT modelling requirement update*, December 2023.

3.31. However, offline EMT simulations, which run on a computer or offline server, generally take longer to compute compared to RMS models.[17] The high computational burden and inefficiency of running numerous simulations make EMT models less practical for routine power system operations and planning.

3.32. To address these challenges, advanced real-time digital simulators have been developed. Unlike personal computer-based EMT software, real-time digital simulators use dedicated parallel processing hardware to perform simulations in real time. This real-time capability allows for hardware-in-the-loop testing, where external equipment can be connected to the simulated network.

3.33. Hardware-in-the-loop testing facilitates the simultaneous testing of multiple power electronics devices, provides detailed insights into their behaviour and interaction with protection and control systems, and offers a controlled laboratory setting. Testing real equipment rather than just a model increases confidence in equipment behaviour and helps minimise issues during commissioning and field operation.

3.34. Real-time digital simulators are widely used by system operators overseas to improve the accuracy of power system models, especially in systems with high penetration of power electronics devices such as IBRs, electric vehicle chargers, and data centres.

3.35. In New Zealand, the system operator owns and maintains a real-time digital simulator, using it to verify code and setting changes in assets connected to the power system, conduct modelling and simulation studies, answer questions raised by the system operator, and to validate models.

Modelling requirements for controllable load technologies

3.36. As noted above, new controllable load technologies connect to transmission and distribution networks through inverters, posing similar modelling challenges to those posed by IBR-based generation.

3.37. Currently, network operators use simple static load models, which are insufficient for capturing the full dynamic behaviour of aggregated loads. Dynamic load modelling is critical for studies that involve voltage stability and control and can also be important for power oscillation studies.

3.38. Although there is a need for load models that accurately represent dynamic behaviour, more detailed region-specific studies are required, which introduces complexity into the modelling. This is due to the diversity of the load components in different distribution networks, variable operating envelopes (daily and annually), and the emergence of new power electronics-based load types such as electric vehicle chargers and data centres.

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17 Kati Sidwall and Paul Forsyth, "A Review of Recent Best Practices in the Development of Real-Time Power System Simulators from a Simulator Manufacturer's Perspective," *Energies 15*, no. 3 (2022):1111, https://doi.org/10.3390/en15031111.

International insights on the need for accurate and up-to-date models

3.39. Overseas, regulators and system operators have changed common quality-related information requirements following large scale blackouts and outages caused by instances of unreliable performance by IBRs.

3.40. With the anticipated increase in IBRs in New Zealand's power system, the Authority is proactively monitoring developments abroad and assessing the solutions that have been deployed.

North America

3.41. In January 2023, the North American Electric Reliability Corporation (NERC) established an EMT task force to improve the modelling requirements and quality verification process for transmission-connected IBRs.[18]

3.42. The main reasons for NERC initiating this workstream were as follows:

(a) models provided by developers and inverter manufacturers do not accurately reflect actual site conditions

(b) models supplied by developers / inverter manufacturers do not reproduce issues related to unreliable performance by IBR-based generation (eg, nuisance tripping), or reductions in output in the normal operation of IBRs

(c) most faults are unbalanced faults, and existing RMS-based power system studies do not capture the control and protection instabilities of IBRs

(d) system studies using RMS models provided by inverter manufacturers do not detect control interactions between IBRs, which can lead to issues like sub-synchronous oscillations.

3.43. Other NERC workstreams also identified issues with the power system models provided by equipment manufacturers. Key findings from one report included:[19]

(a) Some North American transmission system operators have noted that the current process for asset owners to submit updated dynamic models may lead to systematic modelling issues for verifying the accuracy of these models in relation to IBR behaviour during large power system disturbances.

(b) Several transmission system operators reported that the dynamic models provided by equipment manufacturers either had incorrect parameterisation or were not a reasonable representation of the asset.

(c) Most of the transmission system operators received little or no updated dynamic models for existing solar photovoltaic generating stations.

(d) There were ambiguities in the existing data provision requirements. For example, the requirement to provide data for the excitation control system of aggregate IBR-based generating plant (such as wind and solar photovoltaic)

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18 NERC, *Reliability Guideline Electromagnetic Transient Modeling for BPS - Connected Inverter-Based Resources —Recommended Model Requirements and Verification Practices*, March 2023.

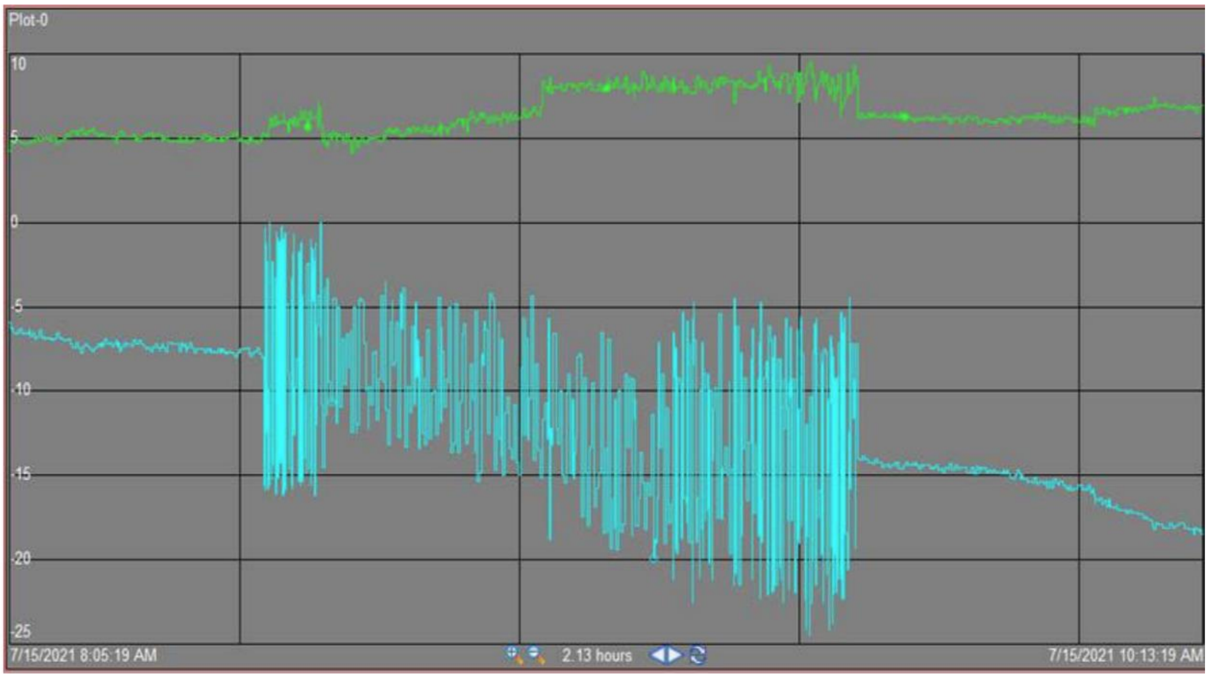
19 NERC, *Technical report BPS-connected Inverter Based Resource Modelling and Studies*, May 2020.

was unclear. It was uncertain whether verification activities included inverter-level parameter values for the dynamic models. Testing engineers and other entities expressed confusion about whether the standard applied to plant-level parameters or to the aggregate representation of inverter-level settings.

3.44. The Alberta Electric System Operator (AESO), a North American transmission system operator regulated by NERC, reported that the RMS models provided by equipment manufacturers were overly optimistic in relation to transient responses. In December 2023, AESO updated its EMT modelling requirements to address this issue. The update was based on operational experience with low system strength and the need for more accurate models in power system software.

3.45. One North American power system incident comprised network asset outages caused by unstable interactions between voltage controllers at wind generation facilities and significant voltage fluctuations at a solar photovoltaic facility following the planned outage of a nearby transmission line. The primary cause of these oscillations was that the plant controller and inverters at the photovoltaic generating station were not tuned for short circuit conditions (Figure 3).

Figure 3: Oscillations observed at an Alberta solar photovoltaic generating station following a planned transmission circuit outage



Great Britain

3.46. In 2019, the British government and Ofgem investigated an electricity outage that affected around one million electricity consumers. The incident was caused by unexpected generation losses following a correctly cleared fault on the British transmission network.

3.47. A key reason for the power system models failing to detect the occurrence of the outage was a lack of clarity in Great Britain's grid code around the format and requirements for generation control system modelling. Following its investigation, Ofgem introduced new compliance processes, control system modelling requirements, and requirements around sharing data to facilitate sub-synchronous interaction studies.[20]

Q1. Do you agree with the key drivers of change in power system modelling requirements identified in this section? If you disagree, please explain why.

Q2. Are there any other drivers of change in power system modelling requirements which are not covered in this section? If so, please elaborate.

[20] Ofgem, *Grid Code (GC) GC0141: Compliance Processes and Modelling amendments following 9th August Power Disruption (GC0141)*, December 2022.

4. Elaborating on the common quality-related information issue

4.1. As noted in the preceding section, transitioning toward a power system with a higher share of IBRs creates potential power quality issues, as power electronic devices are used to interface IBRs with the power system.

4.2. Network operators and owners need adequate models and tools to simulate the performance of the power system under future conditions, in order to have confidence in how the power system will perform under these conditions.

4.3. Using accurate and up-to-date models can benefit participants and consumers. Power system studies allow network operators and owners to define power system limits mathematically and to then use advanced methods to optimise the use of the power system.

4.4. The format, accuracy and level of detail required of power system models depends on the failure mode or phenomena being studied. By foregoing detailed models, there is a risk that power system studies may not identify modes of failure which, if they occurred in real life, could risk the security and reliability of the power system, and cause damage to assets forming part of, or connected to, the power system.

4.5. The Authority considers the system operator, distributors and Transpower, as a transmission network owner, 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. We elaborate on this below.

The system operator has insufficient information to manage emerging power system issues

Information is sometimes incomplete or sub-standard

4.6. Models provided to the system operator are sometimes incomplete or do not meet the required technical standards for accuracy and engineering best practice.

4.7. This results in higher transaction costs as the system operator must either fix sub-standard models or request that asset owners submit improved versions. Although a single inaccurate model may not impact system security, the cumulative effect of multiple sub-standard models poses an unacceptable risk.

4.8. The system operator requires models to be provided in all currently used software platforms, including Digsilent's PowerFactory, PowerTech's DSATools, and MHI's PSCAD (for EMT models). Historically, models were only provided in the PowerFactory format, and the system operator would convert them to other formats as required. However, this approach is no longer practical due to:

(a) the increased complexity of IBR models, and

(b) the increased number of new connections, which is straining the system operator's resources.

4.9. Conversion of modelling data from one software platform to other platform often leads to loss of data. Not all network operators and owners (ie, the system operator, transmission network owners and distributors) use the same software for network connection and/or planning studies. Hence, the developer / equipment manufacturer sometimes develops a model using a particular software platform for a distributor and then converts it to meet Transpower's requirements.

4.10. This leads to inaccurate modelling data when the information provided needs to be converted between different software formats.

Some equipment manufacturers are reluctant to share information due to confidentiality concerns

4.11. Both EMT-type and RMS-type models contain proprietary information about an asset. Manufacturers of IBR equipment are concerned that third parties might be able to reverse-engineer information contained in encrypted models, potentially compromising the manufacturer's intellectual property. As a result, such manufacturers are often reluctant to share detailed modelling information directly with asset owners, even when this information is required by the system operator.

4.12. The sensitivity around intellectual property associated with EMT models primarily relates to an IBR's control and protection systems, particularly for IBR-based generation. These systems vary between manufacturers and dictate the IBR's major performance characteristics.

4.13. An independent study commissioned by the Australian Energy Market Commission found that original equipment manufacturers generally were willing to supply detailed EMT models to the Australian Energy Market Operator 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.[21]

4.14. Currently, the system operator here in New Zealand addresses the challenge of acquiring proprietary modelling information by directly engaging with equipment manufacturers. However, this process is often encumbered by manufacturers' requirements for the system operator to sign non-disclosure agreements, which can introduce significant delays and administrative burdens and costs. Furthermore, this is a voluntary process on the part of the equipment manufacturers, and some manufacturers do not provide the requested information to the system operator.

Some Part 8 information requirements are ambiguous

4.15. Currently there is some uncertainty about the obligations on asset owners under Part 8 of the Code to share specific information about their assets with the system operator.

4.16. In the absence of detailed information on the performance of assets, 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.

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21 AECOM Australia, EMT and RMS Model requirements, June 2017.

4.17. The Code does not prescribe in detail the asset-related information that asset owners must provide to the system operator. For example, clauses 2(5)(b) and 3 of Technical Code A of Schedule 8.3 of the Code do not mandate the disclosure of modelling information compatible with different software platforms used by the system operator, such as PowerFactory, TSAT, and PSCAD. A lack of compatible modelling data affects the system operator's ability to efficiently manage the power system.

4.18. The Code requires asset owners to provide any modelling data for planning studies, as reasonably requested by the system operator.[22] However, the Code does not specify what constitutes 'reasonably requested', which can lead to disputes and operational inefficiencies.

4.19. To address this, the system operator has developed a guideline for the submission of modelling information by asset owners. This guideline details the models that the system operator requires, along with the required format, technical standards for accuracy, and engineering best practice.[23]

4.20. However, a lack of prescription in the Code regarding common quality-related information requirements results in additional effort, time, and costs for both the asset owner and the system operator in negotiating what information can be reasonably requested by the system operator and when this information must be provided.

The share of generating stations that meet the threshold for providing information to the system operator is expected to decrease

4.21. There is expected to be a percentage decrease in generating stations for which the system operator receives information regarding intended output.

4.22. IBR-based variable and intermittent generation resources are expected to comprise a larger share of New Zealand's generation capacity over the coming years. The fall in the relative cost of these technologies, coupled with New Zealand moving towards a highly renewable electricity generation, means a larger share of generation in New Zealand is expected to be less than 10MW (eg, solar photovoltaic generation and energy storage systems installed by commercial and industrial consumers).

4.23. This will reduce the percentage of embedded generation for which the system operator has information regarding intended output, which in turn is expected to impair the system operator's ability to operate the transmission network securely and efficiently.

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

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

Distribution network operators have insufficient information to manage the changing portfolio of assets connecting to distribution networks

Distribution network operators lack the necessary information about DERs to assess network impacts

4.24. Distributors play a critical role in maintaining the integrity, stability and safety of their distribution networks, particularly as DERs become more prevalent. These assets directly influence the operational capabilities of distributors, impacting network capacity, stability, security, and compliance with regulatory standards, including the Electricity (Safety) Regulations 2010.

4.25. Currently, the information provided to distributors by asset owners as part of the distributed generation connection process under Part 6 of the Code only confirms compliance with the distributor's connection and operation standards. Distributors do not have access to more detailed RMS/EMT modelling information.

4.26. As electricity generation and load assets change in distribution networks, distributors will need more detailed information about these connected assets. This is to better enable distributors to manage their networks during routine operation (eg, managing voltage) and in response to contingencies on the network. This will require improved co-ordination between distributors and the system operator in relation to the real-time operation of the power system.

4.27. Future distribution network operation in New Zealand may also require:

(a) more complex tools and processes to handle increasingly complex operating scenarios and to improve visibility of distribution network operating conditions (particularly the low voltage sections of distribution networks) and assets connected to them (ie, DERs)

(b) more sophisticated distribution outage planning, extending 'deeper' into distribution networks (ie, to increasingly lower distribution network voltages).

4.28. These will require distributors to have good quality information about DER assets and DER operating statuses.

4.29. Currently, for DERs that do not participate in the wholesale electricity market, distributors typically have little or no access to power quality data from the DERs' electricity meters. Consequently, distributors typically have little or no visibility of the operating status of many DERs.

4.30. At present, distributors can host DERs on their respective distribution networks with minimal active management. This is because fluctuations in output and demand are not significant enough to affect distribution network operation, violate distribution network constraints, or adversely affect the supply of electricity to consumers.

4.31. If the sharing of information about DER assets does not improve, some distributors report that the uncertainty regarding their performance, availability and intended use will lead to distributors adopting greater operational risk mitigation measures. In turn, this may result in the inefficient use of power system resources and additional costs to consumers (eg, higher-than-necessary instantaneous reserve costs, or additional costs that arise due to measures imposed by the system operator to mitigate increased voltage or frequency instability and/or more automatic under-frequency load shedding (AUFLS) events).

Transpower, as a transmission network owner, has insufficient information for network planning and management

Transpower, as a transmission network owner, lacks the necessary information about IBRs to assess transmission network impacts

4.32. The power system models created by Transpower, as a transmission network owner, help to reliably, securely and safely extend transmission transfer limits and maximise transmission network utilisation, thereby helping to minimise costs to consumers. In addition, the models are used to conduct various power system studies that benefit connected assets (eg, distributed networks, generators, and large consumers directly connected to the transmission network).

4.33. In transmission planning, studies undertaken by Transpower, as a transmission network owner, support thermal capacity analysis of transmission components, the investigation of new generation and load connections, proposals for major transmission network capital investments, and the deployment of new technologies that affect dynamic performance of the transmission network.

4.34. In the design, build, and maintenance of the transmission network, these models assist in fault level calculations for equipment ratings, in the design of special protection schemes, and in ensuring compliance with transmission agreements. The models are also crucial for protection design, harmonic allocation, the management of AUFLS in the South Island, equipment specifications, and high voltage direct current (HVDC) system design and tuning. Additionally, the models support transmission network control system design and tuning to manage voltage profiles and dynamic reserves.

4.35. In operational support, the models are used for geomagnetically induced current analysis to assess solar weather impacts, financial transmission rights modelling, power quality monitoring, and validating transmission network models to meet regulatory obligations. The models are also used for studies on controller interactions with transmission network equipment.

4.36. Currently, the asset capability statement information that transmission-connected parties must provide to Transpower, as a transmission network owner, does not include the detailed modelling information that manufacturers provide to the system operator. This reduces the ability of Transpower, as a transmission network owner, to efficiently design, build and maintain the transmission network.

The process for sharing asset capability statement information is inefficient

4.37. Under the Code, Transpower, as the system operator, is not authorised to share asset capability statement information with the transmission network owner side of Transpower. Therefore Transpower, as a transmission network owner, must independently source the same asset capability statement information provided to the system operator. This duplicative process is inefficient.

4.38. Transpower, as a transmission network owner, has sought authorisation from each transmission-connected customer to access the asset capability statement information those customers have provided to the system operator. While Transpower's customers often give their authorisation, some do not respond. This process is inefficient, creates incomplete authorisations and can create confusion for asset owners.

Q3. Do you agree with the Authority's elaboration on the common quality-related information issue set out in this section? If you disagree, please explain why.

Q4. Do you agree that the current provisions in the Code are insufficient to address the common quality-related information issue described in this section? If you disagree, please explain why.

Q5. Do you consider there to be any other aspects of the common quality-related asset information issue that are not covered in this section? If so, please elaborate.

5. Short-listed options to help address the common quality-related information issue

5.1. The Authority has considered a range of options to help address the common quality-related information issue discussed in this paper.

5.2. We have concluded that the issue will not be addressed by the existing regulatory arrangements. These arrangements were developed at a time when machine-based synchronous generation technology dominated the electricity sector. The existing regulatory arrangements are also premised inherently on electricity demand being relatively passive and predictable.

5.3. In the absence of regulatory intervention to address the common quality-related information issue, the Authority expects there to be an increased probability of frequency and voltage instability on New Zealand's power system, and possibly more AUFLS events. Network operators, in particular, need better information on assets connected to New Zealand's transmission network and distribution networks, to better ensure the safe, reliable and economically efficient operation of the power system.

5.4. The Code can be improved by more clearly specifying information, including proprietary information, that asset owners must share with the system operator, distributors and Transpower, in its role of a transmission network owner, to better enable these parties to meet their common quality-related Code obligations.

5.5. The Authority has not yet formed a view on a preferred option to address the common quality-related information issue.

5.6. We have shortlisted three options and welcome feedback from interested parties on these and other viable options.

Option 1: Update and clarify common quality-related information requirements in the Code

5.7. Under option 1, the Code would be amended to update common quality-related information requirements relating to:

(a) Testing and commissioning of new assets and upgrades to existing assets, including the timing of the provision of information

(b) Undertaking transmission and distribution system studies and investigating transmission and distribution system common quality issues.

5.8. The updated information requirements would be those necessary to enable the system operator, distributors, and Transpower, as a transmission network owner, to meet their common quality obligations under the Code. This would include placing responsibility with asset owners to ensure the system operator receives sufficiently detailed information so that there is no 'black box' when the system operator uses the information for equipment performance assessment and checking compliance with technical requirements on the asset owner set out in Part 8 of the Code.

A document incorporated by reference in the Code may be desirable

5.9. It may be desirable to move various common quality-related information requirements in Part 8 of the Code into a document incorporated by reference into the Code.

5.10. The Legislation Act 2019 permits the Authority to incorporate documents into the Code by reference where the requirements of section 64(1) of that Act are met.[24] The Authority currently has nine documents incorporated by reference into the Code.[25] This document could be incorporated by reference into the Code if the requirements of the Legislation Act were met.

5.11. The system operator could be given responsibility for preparing a document that specifies the common quality-related asset information requirements necessary for the system operator to meet its common quality Code obligations. The system operator would be required to do this in a manner consistent with the preparation of other system operation documents under Part 7 of the Code.[26]

5.12. The Authority considers the system operator, rather than the Authority, is best placed to develop the common quality-related asset information requirements necessary for the system operator to meet its common quality Code obligations. The system operator has better subject matter expertise, knowledge and understanding of the information it needs than does the Authority.

5.13. The Authority considers our role is more appropriately that of an independent approver, ensuring the system operator has followed proper process, including ensuring asset owners' input into the document is appropriate.

5.14. We welcome feedback from submitters on the desirability of such a document.

5.15. The Authority is unsure of the necessity and practicalities of adopting a similar approach in relation to distributors and Transpower, as a transmission network owner. We welcome feedback on this point too.

Summary of the key pros and cons of option 1

5.16. Key pros for option 1 include:

(a) Increased clarity for asset owners regarding their obligations to provide common quality-related information to the system operator.

(b) Decreased transaction costs related to the provision of common quality-related information to the system operator, distributors and Transpower, as a transmission network owner, which should ultimately result in relatively lower costs for consumers.

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24 Section 64(1) of the Legislation Act 2019 permits the incorporation by reference into the Code of materials such as certain standards, frameworks, and codes of practice, and other materials that are impractical to include in secondary legislation.

25 These nine documents are available on the Authority's website at Electricity Authority I Documents incorporated into the Code.

26 See clauses 7.13 – 7.22 of the Code.

(c) Surety that network operators and owners have sufficient information to meet their common quality-related Code obligations.

(d) A document incorporated by reference into the Code that specified the common quality-related asset information requirements necessary for the system operator to meet its common quality Code obligations would:

   (i) enable some of the common quality-related information requirements to be developed by the system operator, who has specialist knowledge and expertise in this area

   (ii) facilitate more timely updates to the common quality-related information requirements, through the system operator being able to update drafts of the document itself rather than via the Authority

   (iii) enable the main body of Part 8 of the Code to be shorter, simpler, and clearer.

5.17. Key cons for option 1 include:

(a) Ensuring the system operator receives sufficiently detailed information to avoid there being a 'black box' when the system operator uses the information may cause original equipment manufacturers to threaten to discontinue, or indeed discontinue, the provision of their equipment to the New Zealand market if they do not want to provide the system operator with proprietary asset-related information.

(b) There is a risk that material incorporated by reference is not appropriate for legislation because the material was developed for another purpose (eg, for a guideline).

Option 2: Enable the system operator and distribution network operators to share common quality-related information

5.18. Option 2 extends the scope of option 1 to allow the system operator and distribution network operators to share common quality-related asset information with each other, to enable the respective parties to meet their common quality obligations under the Code.

5.19. Distributors would need to have in place satisfactory arrangements to ensure that proprietary information provided to them by the system operator was able to be accessed by only persons in the network operation side of the distribution business.

Summary of the key pros and cons of option 2

5.20. Key pros for option 2 that are additional to those for option 1 include:

(a) Reduced transaction costs to the extent that there is duplication in the provision of common quality-related information to the system operator and to distributors, in their role of network operators.

(b) Improved efficiencies in the overall operation of the power system.

(c) Reduced potential for distributors to invest in assets to compensate for inadequate information, with this reduced potential expected to place downward pressure on distribution costs passed on to consumers.

5.21. Key cons for option 2 that are additional to those for option 1 include:

(a) In contrast with New Zealand's electricity transmission arrangements, where the system operator and transmission network owner functions are separately defined in the Code, a distributor's asset ownership and network operations roles are more integrated. This could potentially lead to perceived or actual conflicts of interest in relation to common quality-related asset information provided to the distributor (eg, the network owner side of the distribution business obtains information that gives it an unfair advantage in respect of asset investment decisions).

(b) There is the risk that original equipment manufacturers may threaten to discontinue, or indeed discontinue, the provision of their equipment to the New Zealand market if they do not want to provide distributors with proprietary asset-related information required under the Code.

Option 3: Enable the system operator to share common quality-related information with Transpower as a transmission network owner

5.22. Option 3 extends the scope of option 2 to allow the system operator to share common quality-related asset information with Transpower, as a transmission network owner, to enable Transpower to meet its common quality obligations under the Code.

Summary of the key pros and cons of option 3

5.23. Key pros for option 3 that are additional to those for options 1 and 2 include:

(a) Reduced transaction costs since parties do not have to provide the same information to Transpower, as a transmission network owner, twice.

(b) Improved efficiency for the processing of transmission network connections, as models are collected, processed and validated only once, by the system operator.

(c) Improved power system reliability from better co-ordination of protection systems, due to the availability of detailed models.

(d) Better investment decision making in relation to transmission network assets, including reduced over-capacity in network assets.

(e) A reduced mismatch between the assessment of transmission capacity or power system stability limits undertaken by the system operator and Transpower, as a transmission network owner, thus avoiding costs to resolve discrepancies relating to unexpected operational constraints.

(f) Avoided duplication and costs associated with a repository of common quality-related asset information.

(g) Enabling the removal of the requirement, in transmission agreements, for distributors to ensure that embedded generators provide asset capability statement information to Transpower, as a transmission network owner.

5.24. Key cons for option 3 that are additional to those for options 1 and 2 include:

(a) The potential for perceived conflicts of interest for Transpower, since this option reduces information barriers between Transpower's asset owner and system operator roles. The risks are the same as those discussed in respect of distributors under the option 2 cons.

(b) There is the risk that original equipment manufacturers may threaten to discontinue, or indeed discontinue, the provision of their equipment to the New Zealand market if they do not want to provide Transpower, as a transmission network owner, with proprietary asset-related information required under the Code.

Q6. Do you agree with the short-listed options presented by the Authority? If you disagree, please explain why.

Q7. Do you have any feedback on the desirability of a document incorporated by reference in the Code specifying various common quality-related information requirements?

Q8. Do you agree with the pros and cons associated with each option? What costs are likely to arise for affected parties (eg, asset owners, network operators and network owners) under each of the options?

Q9. Do you consider any perceived conflicts of interest arising under the second and third short-listed options to be material in nature? If so, please elaborate.

Q10. Do you propose any alternative options to address the common quality-related information issue? If so, please elaborate.

5.25. The table below contains the Authority's high-level evaluation of the short-listed options to help address the common quality-related information issue.

Table 1: High level evaluation of short-listed options

	Evaluation criteria	Option 1 assessment	Option 2 assessment	Option 3 assessment
1.	*The option is feasible / implementable with little or no risk of unintended consequences*	The option is moderately feasible with uncertain risk of unintended consequences. The risk includes that equipment manufacturers may be reluctant to participate in the New Zealand market as they may consider that the Code undermines their intellectual property rights.	The option is feasible with uncertain risk of unintended consequences. The system operator may not have the capability to be the guardian of the detailed RMS/EMT models of generating assets to be accessed by network operators.	The option is feasible with uncertain risk of unintended consequences. The system operator may not have the capability to be the guardian of the detailed RMS/EMT models of generating assets to be accessed by network operators and Transpower, as a transmission network owner.
2.	*The option is consistent with the Authority's statutory objectives*	The option promotes one or more limbs of the Authority's main statutory objective (competition, reliability and efficiency).	The option promotes one or more limbs of the Authority's main statutory objective (competition, reliability and efficiency).	The option promotes one or more limbs of the Authority's main statutory objective (competition, reliability and efficiency).
3.	*The option promotes competitive neutrality amongst technologies / fuels*	Yes. The option is neutral as to which technology (synchronous / inverter-based) and fuel type can provide the required service / output.	Yes. The option is neutral as to which technology (synchronous / inverter-based) and fuel type can provide the required service / output.	Yes. The option is neutral as to which technology (synchronous / inverter-based) and fuel type can provide the required service / output.
4.	*The option signals full costs and benefits*	Somewhat. Marginal cost pricing and costs not allocated solely to beneficiaries or causers.	Somewhat. Marginal cost pricing and costs not allocated solely to beneficiaries or causers.	Somewhat. Marginal cost pricing and costs not allocated solely to beneficiaries or causers.
5.	*The option is a market-based approach*	No. The option is not a market-based / tender-based approach to providing the required service / output.	No. The option is not a market-based / tender-based approach to providing the required service / output.	No. The option is not a market-based / tender-based approach to providing the required service / output.
6.	*The option is output-based rather than prescriptive*	No. The option is prescriptive as to what a participant must do / provide to achieve the common quality outcome.	No. The option is prescriptive as to what a participant must do / provide to achieve the common quality outcome.	No. The option is prescriptive as to what a participant must do / provide to achieve the common quality outcome.

7.	*The option is durable*	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years. This option may not be durable if modelling technologies or generation / load technologies cause significant changes to power system modelling in the coming years.	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years. This option may not be durable if modelling technologies or generation / load technologies cause significant changes to power system modelling in the coming years.	Yes. The option is durable across a wide (>3) range of uncertain future scenarios that may happen in the next 15 years. This option may not be durable if modelling technologies or generation / load technologies cause significant changes to power system modelling in the coming years.

Q11. Do you agree with the Authority’s high-level evaluation of the short-listed options to help address the common quality-related information issue? If you disagree, please explain why.

Appendix A Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree with the key drivers of change in power system modelling requirements identified in this section? If you disagree, please explain why.	
Q2. Are there any other drivers of change in power system modelling requirements which are not covered in this section? If so, please elaborate.	
Q3. Do you agree with the Authority's elaboration on the common quality-related information issue set out in this section? If you disagree, please explain why.	
Q4. Do you agree that the current provisions in the Code are insufficient to address the common quality-related information issue described in this section? If you disagree, please explain why.	
Q5. Do you consider there to be any other aspects of the common quality-related asset information issue that are not covered in this section? If so, please elaborate.	
Q6. Do you agree with the short-listed options presented by the Authority? If you disagree, please explain why.	
Q7. Do you have any feedback on the desirability of a document	

incorporated by reference in the Code specifying various common quality-related information requirements?	
Q8. Do you agree with the pros and cons associated with each option? What costs are likely to arise for affected parties (eg, asset owners, network operators and network owners) under each of the options?	
Q9. Do you consider any perceived conflicts of interest under the second and third short-listed options to be material in nature? If so, please elaborate	
Q10. Do you propose any alternative options to address the common quality-related information issue? If so, please elaborate.	
Q11. Do you agree with the Authority's high-level evaluation of the short-listed options to help address the common quality-related information issue? If you disagree, please explain why.	

Appendix B Existing Code requirements for common quality-related information

B.1. As noted in section 3 of this paper, network operators and owners need information on assets wanting to connect, or which are connected, to the power system.[27] This is to provide for the safe, reliable and economically efficient operation of the power system.

B.2. This appendix summarises the existing requirements for asset owners to share common quality-related information with:

(a) Transpower, as the system operator

(b) distributors, as distribution network owners and operators

(c) Transpower, as a transmission network owner.

Provision of asset information to the system operator

B.3. The system operator is responsible for the scheduling and dispatch of electricity in real time in a manner that avoids fluctuations in the frequency and voltage of electricity supply, or 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 PPOs.

B.4. Under the Code the system operator has high level, output-focussed PPOs in relation to the real-time delivery of common quality and dispatch. PPOs also include a 'plan to meet' obligation. 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.

B.5. The Code places certain mandatory performance obligations on asset owners (AOPOs) to enable the system operator to meet its PPOs.

B.6. To enable the modelling, monitoring and management of 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) undertake system studies not specific to a connected asset, and

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

Asset capability statements

B.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

[27] For the purposes of this paper, an 'asset' is any equipment or plant that is connected to or forms part of the transmission network or a distribution network.

transmission network, or which the asset owner proposes be connected to the transmission network.

B.8. The asset capability statement must, amongst other things:

(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 transmission network

(b) include any modelling data for the planning studies, as reasonably requested by the system operator.[28]

B.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.[29]

Asset test planning

B.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.[30]

B.11. Additionally, under the Code, the system operator may require an embedded generator to provide information regarding the intended output of each embedded generating station greater than 10MW if the system operator reasonably considers it necessary to assist in planning to comply, and complying, with the PPOs and achieving the dispatch objective.[31]

Provision of asset information to distributors

B.12. Distribution network operators also play a critical role in managing the reliability and security of electricity delivered to consumers. To enable the modelling, monitoring and management of distribution network reliability and security, distributors require information to:

(a) connect distributed generation to the distributor's network

(b) manage network capacity, stability, safety, and quality.

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

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

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

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

Connection of distributed generation

B.13. Part 6 of the Code permits distributors to require distributed generators applying to connect distributed generation to the distributor's network to provide information showing how the distributed generation complies with the distributor's connection and operation standards.[32]

B.14. Part 6 of the Code also permits distributors to require distributed generators applying to connect distributed generation with a nameplate capacity of more than 10kW in total to provide any information required by the system operator.[33]

Information to manage network capacity, stability, safety, and quality

B.15. Distributors need to capture DER asset information to assess how the DER affects network capacity, stability, security, safety and quality. It is important for short- and long-term planning to understand how DERs react under a full range of operational network scenarios.

B.16. There are certain obligations to keep the ICP registry updated under Part 11 of the Code, which enables distributors to see certain DER asset information. However, any changes to DER software / control modes that are not required to be captured in the ICP registry may not be visible to the distributor.

B.17. One way that some distributors are accessing DER information from asset owners is through new tariff offerings for retailers. Consumers' DERs (eg, electric vehicle chargers, BESSs) can be connected directly to a DER Management System platform, or indirectly via a third party's platform (eg, via an electricity retailer or a DER manager). A consumer connected to a DER Management System (directly, or indirectly via a third party) may provide distributors with additional information on the consumer's DER(s).

Provision of asset capability statement information to Transpower as a transmission network owner

B.18. Transpower owns almost all of New Zealand's transmission network (termed the 'grid' in the Code). In its role of a transmission network owner, Transpower is responsible for planning, building, maintaining, and making available for use its transmission network.

B.19. Under the Code, every entity connected to Transpower's transmission network must have a transmission agreement with Transpower, in its role of a transmission network owner. The transmission agreement covers (amongst other things) connection conditions, ongoing operations post-commissioning of the asset connecting, and payment of transmission charges.

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32 See clauses 2(3)(f) and 11(3)(f) of Schedule 6.1 of the Code.

33 See clause 11(3)(p) of Schedule 6.1 of the Code.

Asset capability statement

B.20. Under transmission agreement terms prescribed by the Code,[34] when someone who is connected to New Zealand's transmission network provides an asset capability statement to the system operator, that person must also provide the same asset capability statement to Transpower, in its role as a transmission network owner. The information must include all modelling data relating to equipment capability that Transpower, as a transmission network owner, requires (acting reasonably) for planning purposes.

B.21. Anyone connected to New Zealand's transmission network must also ensure that any third party who has equipment directly connected to that person's equipment, but not to the transmission network, that may adversely affect the reliability, availability or integrity of the transmission network complies with the obligations on the connected party as set out in the Connection Code.[35]

B.22. The Connection Code also includes requirements to provide Transpower, as a transmission network owner, with certain information before and during the commissioning and testing of transmission-connected equipment.[36]

B.23. Currently, the asset capability statement information that transmission-connected parties are required to provide to Transpower, as a transmission network owner, does not include the detailed modelling information that manufacturers provide to the system operator.

34 See clause 2.1 – 2.2 of the Connection Code, which is in Schedule 8 of Schedule 12.6 of the Code (the default transmission agreement template, previously the benchmark agreement, which transmission agreements must generally be consistent with (clause 12.14 of the Code)).

35 Under clause 1.5 of the Connection Code, any generating units with a combined installed capacity of greater than 1MW, or motors with a combined installed capacity of greater than 1MW capacity are treated as having the potential to adversely affect the reliability, availability or integrity of the grid, unless Transpower and the connected party agree that a higher capacity is more appropriate.

36 See clauses 2.4 – 2.6 of the Connection Code.

Appendix C Some background on power system modelling

Overview of power system models

C.1. A power system model is a set of mathematical equations, typically a combination of algebraic and differential equations, used to simulate the behaviour of the physical power system.

C.2. Power system models serve various purposes, including:

(a) the assessment of new generating stations against performance standards

(b) helping to manage power system security

(c) enabling stakeholders to examine power system performance under different conditions.

Different types of power system models

Vendor-specific electro-magnetic transient (EMT) models: These are detailed three-phase vendor-specific models, which include proprietary information used by original equipment manufacturers for the design of internal control systems and other applications associated with the generating station or composite dynamic load (consumer) installation. They can be implemented using various software platforms, such as PSCAD, MATLAB® Simulink®, and EMTP-RV.

Vendor-specific root mean square (RMS) models: These models are typically benchmarked by the original equipment manufacturer against the higher-level models described above, within the bandwidth of stability analysis tools (typically 0.1Hz to 10Hz or so). These models are typically developed in native programming code associated with commercially available software platforms such as Siemens PTI PSS®E, DigSILENT PowerFactory, GE PSLF, PowerWorld Simulator, PowerTech Labs TSAT. These models also include proprietary information. As they are owned and maintained by the original equipment manufacturer, they are typically shared under non-disclosure agreements.

Generic RMS/EMT models: These are open source, publicly available model structures, developed through broad industry efforts (e.g. the North American second generation generic renewable energy system models or the International Electrotechnical Commission standard models for wind turbine generators). These models have the benefit of being public, open source, and readily transferable across most major commercial software platforms. However, their main drawback is that they have the most limited range of applicability, and they provide a generic approximation of an asset's behaviour.

C.3. Power system modelling information enables the system operator to undertake power system analysis, which is crucial for planning to comply, and complying, with the PPOs set out in the Code.[37]

C.4. Network owners, including Transpower and distributors, use these power system models to assess how new assets, such as a generating stations, impact their

[37] See clause 7.2 of the Code.

networks. They also use these models to assess network adequacy for expected future demand and to investigate potential solutions to network issues.

C.5. Developers of generating stations and large loads use power system models for investment planning and connection arrangements. In New Zealand, developers typically use models provided by the system operator and larger distributors.

C.6. Engineering judgment is crucial when selecting a modelling approach, conducting simulations, and interpreting results. No single model is suitable for all power system conditions and analyses. For example, using detailed EMT-type models for a system-wide small-signal stability analysis to determine the damping of oscillations would be impractical. The computational load, data management, and post-processing required would far exceed any potential benefits.

Confidentiality of IBR modelling information

C.7. Both EMT-type and RMS-type models can contain proprietary information about manufacturers' equipment. In Australia, RMS-type models provided to the Australian Energy Market Operator and to network service providers under the National Electricity Rules are governed by strict confidentiality requirements. This same process is expected to be applied to EMT-type models.

C.8. Equipment manufacturers utilise encryption to protect proprietary information in models – a process referred to as 'black boxing'. In a complete black box, users of a model only see the inputs and outputs, with no visibility of internal model parameters. For the purpose of tuning models, equipment manufacturers may offer slightly more flexible black box models that provide access to the internal model parameters.

Background on dynamic load modelling

C.9. Early digital simulations of power systems focused primarily on generation, with simplistic load representations. This was due to technological limitations and the absence of a need for detailed load models.

C.10. Static load models have traditionally been used to simulate events like voltage collapse.

C.11. While the need for accurate dynamic load models is recognised, creating them is complex. This is due to diverse load components, varying operating envelopes (daily and annually), and new power electronics-based loads. Detailed studies are required to develop these dynamic load models.

C.12. Network operators and owners use two approaches to obtain load data – field-based measurements and component-based methods. Each has its advantages and disadvantages.

C.13. From the late 1980s and early 1990s, incidents like voltage recovery delays and inter-area power oscillations led organisations such as the Institute of Electrical and Electronics Engineers, the Electric Power Research Institute, and the United States Department of Energy to develop widely accepted dynamic load models.

C.14. A key challenge in dynamic load modelling is validating models and understanding their penetration at consumer levels (eg, distribution factors and types of dynamic loads in lower voltage networks).

C.15. There is an absence of a universal standard for dynamic load modelling, requiring each jurisdiction's system operator to develop its own framework.

International dynamic load modelling experience: Australia

C.16. In June 2024, the Australian Energy Market Operator released new industry guidelines for dynamic load modelling using ‘PSS/E’ and ‘PSCAD’ formats.

C.17. The Australian Energy Market Operator, in collaboration with network service providers, developed PSS/E dynamic models to represent the aggregate behaviour of distributed photovoltaic generation and composite load during power system disturbances. For PSCAD, Manitoba Hydro International was commissioned to develop and validate dynamic models for bulk aggregate changes in active and reactive power at transmission buses.

C.18. The Australian Energy Market Operator continues to refine its guidelines for the dynamic load models in co-operation with transmission system operators.

Appendix D Australia case study: Sharing asset modelling information

D.1. In 2017, the Australian Energy Market Commission consulted on a rule change requiring the submission of EMT-type models to the Australian Energy Market Operator.[38]

D.2. As part of the rule change process, the Australian Energy Market Commission engaged AECOM to advise on the cost of developing EMT-type models, confidentiality issues associated with sharing EMT-type models with certain parties other than the system operator, and the Australian experience with projects requiring EMT-type models.[39]

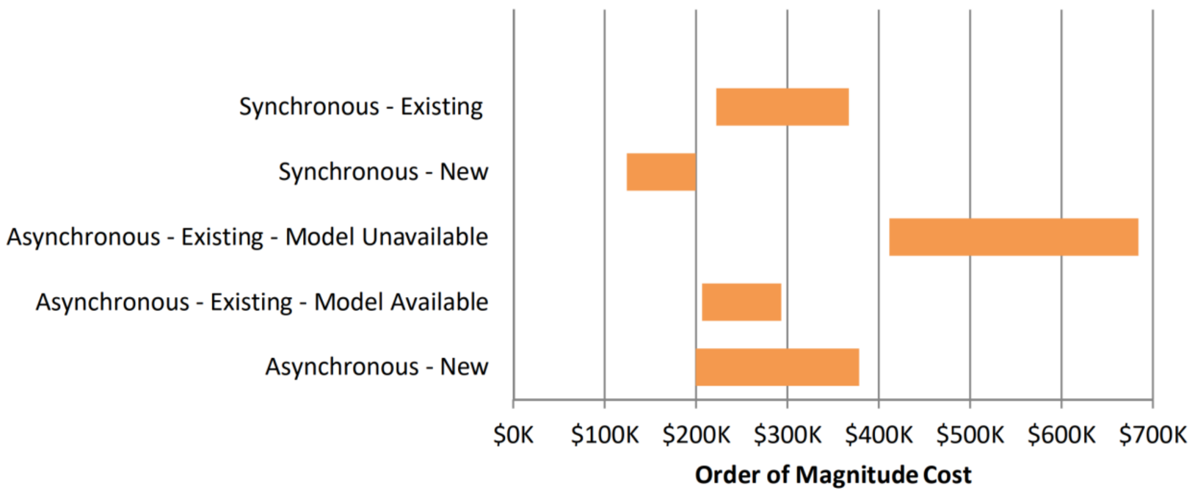
D.3. The findings of this report provide useful insights to the options being considered by the Authority to address the common quality-related information issue.

D.4. AECOM's report stated that the development cost of EMT-type models depended on several factors, including technology type and whether the generating system is either new or existing.

D.5. The order-of-magnitude cost estimated (in Australian dollars) in the report is shown in the figure below.

Figure 4: Order of magnitude cost for EMT type model development

D.6.



D.7. The estimates give an indication of the cost of developing similar EMT-type models for the New Zealand' market. Given the significant uptake of IBRs since this report was published in 2017, the Authority expects these figures may, if anything, have fallen or at least remained relatively static. Nevertheless, preparing these models has a material cost. This places significant importance on network operators/owners

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38 AEMC, Consultation Paper: National Electricity Amendment (Generating System Model Guidelines) Rule 2017, March 2017.

39 AECOM Australia, EMT and RMS Model requirements, June 2017.

providing clarity and guidance regarding the requirement for, and use of, these models.

D.8. Regarding the confidentiality related to EMT-type models, the Australian Energy Market Commission raised key questions in its consultation with stakeholders, which are highly relevant to the options set out in this paper:

(a) Should third parties have access to EMT-type models?

(b) What information should be made available to third parties?

(c) Would encryption of this data provide sufficient protection to address issues related to commercial sensitivity of the data?

D.9. Through informal engagements with asset owners and original equipment manufacturers, the Australian Energy Market Commission found that the EMT-type model preserves the same degree of detail as the actual controller. The Australian Energy Market Commission noted that this is one of the key reasons why the manufacturers of IBRs are reluctant to distribute EMT-type models to third parties, even in encrypted format.

D.10. After duly considering this matter, the Australian Energy Market Commission decided that asset owners must provide RMS information to the registered participants in the National Electricity Market in compiled, encrypted and secured form. The registered participants in the National Electricity Market include the developers (generation owners), transmission system network operators, and distribution network system operators.