GL-EA-789 Interim Requirements for Connection of New Generation Technology

Requirements to support participation of Battery Energy Storage Systems (BESS), inverter connected solar farms and Dispatch Notified Generation (DNG) in the wholesale energy market.

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3	30th Nov 2021	Operational Requirements clarified
4	3rd June 2022	Major amendment to reflect Code and Procurement Plan changes to enable inverter connected generation technology, such as Battery Energy Storage Systems (BESS) and solar farms
5	4th October 2022	Change in assessment of where a Point of Connection to the Grid exists
6	27/4/2023	Updated for Dispatch Notified Generation (DNG)
7	17/5/2023	Additional links updated due to document renamings.

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IMPORTANT

Disclaimer

This document is developed within the current regulatory framework and is accurate as at the published date. Subsequent changes to the Code or other regulations and policies may result in inaccuracies. Please contact Transpower to discuss current requirements.

This document does not relieve asset owners from identifying and meeting their obligations set out in the Code. Where there is conflict between this document and the Code, the Code takes precedence. Asset owners are strongly advised to seek expert advice to understand their full obligations under the Code.

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1 Introduction

1.1 Purpose of this document

This document provides guidance to expedite the entry of grid and distribution network connected new generating technologies into the power system and the wholesale market. These requirements apply to inverter connected Battery Energy Storage Systems (BESS), solar farms and Dispatch Notified Generation (DNG). While DNG permits participation of aggregated assets at individual GXPs, this document does not cover multiple generation technologies at one site, or aggregated assets across distributed sites, or residential solar and/or battery installations.

This document is prepared based on the current arrangements and obligations set out in the Electricity Industry Participation Code (the Code) including the Ancillary Services Procurement Plan and those regulations are subject to review by the Electricity Authority (the Authority).

This document sets out key areas for consideration including Code obligations such as registration as a participant, metering, operational communication requirements, and engagement with the Grid Owner.

1.2 Background information to support these requirements

In reading this document, asset owners may familiaise themselves with supporting documentation and requirements as set out below for more detail on various aspects of the connection process.

Generation Connection Guide – this document helps asset owners understand their obligations when connecting to the New Zealand power system.

Generator Commissioning and Decommissioning Requirements – this document provides an overview of the typical activities that need to be considered when connecting and testing new generation, or when decommissioning generation.

Connection Study Requirements for Connecting New Generating Station – this document has been prepared to assist Asset Owners in understanding the requirements to be met when requesting connection to the New Zealand power system.

Generator Testing Requirements – this document provides Asset Owners an overview of testing processes and procedures in order to demonstrate asset performance and limitations during operation.

Power Plant Dynamic Model Validation and Submission Prerequisites – this document has been prepared to assist Asset Owners in understanding the requirements for developing mathematical models of equipment and their supporting information when required to be submitted to the System Operator.

These documents and more can be found on Transpower's website.

1.3 Terminology

The Code details obligations for **generating units** (an asset which generates electricity) and **generators** (a person who owns a generating unit). These requirements provide advice for owners of Battery Energy Storage Systems (BESS) and solar farms, both of which are considered generating units; therefore, their asset owners are considered generators.

Dispatch Notified Generation (DNG) is a lower-compliance form of market participation. Particularly, DNG asset owner are not required to provide real-time indications. Information about DNG classification and approval conditions is found in Part 13 the Code and the Policy Statement.

Solar farms can be considered intermittent generators under the Code. Owners of intermittent generation seeking to install a hybrid generating station, such as solar+BESS or wind+BESS, should contact the System Operator to discuss any queries they may have regarding the proposed generating station. For clarity, purely intermittent generation may not also be DNG, as intermittent generation requires real-time indications for dispatch.

Collectively, BESS and solar farms are referred to as “inverter-connected assets” in this document. DNG assets may or may not also be inverter-connected assets.

1.4 Connection to the power system

Inverter-connected assets may be connected to either Transmission or Distribution assets.

Transmission-connected installations are subject to contractually agreeing to terms and conditions with Transpower (as Grid Owner) in what is called a Benchmark Agreement. A robust process to connect to Transpower assets is described in the Generation Connection Guide. These installations are all assessed as having a point of connection to the grid.

Distribution connected installations are subject to contractually agreeing to the distributor’s published “use of system agreement”, which is available on any distributor’s website. An overview of the distribution companies and contact details can be found on the Electricity Network Association (ENA) website.

1.4.1 Technical considerations for connection

Considerations when connecting to the Transpower assets are based on topology of connection and is considered on a case-by-case basis, which may include:

- thermal constraints on equipment
- voltage and stability constraints on where they are connected (steady-state, step, and transient)

If there are constraints, they may be mitigated by installing (or modifying):

- replacement of existing plant and equipment
- special protection schemes
- co-ordination of the automatic voltage controls of the supply transformers and the inverter-connected asset system. This may require the addition of (usually simple) non-standard voltage/reactive power controls.
- limitations of maximum allowable installed generating capacity

1.5 Operational Requirements

Generators must meet all System Operator Operational Requirements which include all the Asset Owner Performance Obligations (AOPOs) and technical codes in Part 8 of the Code, subject to granted dispensation applications and approved equivalence arrangements. An overview of the operational requirements for asset owners is outlined in section A.3. These may vary depending on the size of the asset and the point of connection and are simplified below:

1. Generators with assets of 1 MW capacity and above must comply with the Code. Initially, the generator must supply asset capability information directly to the System Operator and to advise of the generators’ intention to connect and/or participate in the wholesale electricity market. This ensures the System Operator can engage with them directly on their obligations in the Code.
2. Generators between 1 and 10 MW may be required to provide SCADA indications. If SCADA indications are not required, the generator may be classed as a DNG.
3. Stations 10 MW or above must provide SCADA indications and offer their generation to the market as ‘full’ market participants. A formal request will be made by the System Operator to stations between 10 and 30 MW in size for this information.

4. Stations that are not an **excluded generating station**[1] (i.e., 30 MW and above), whether they inject into the grid or a local network, have frequency, and voltage fault ride through obligations.
5. Each generator with a point of connection to the grid must meet voltage support obligations that include dispatch of reactive power (Mvar) or voltage by the System Operator.

Owners of existing generation seeking to install inverter-connected assets should contact the System Operator to discuss their proposal.

1.5.1 AS/NZS 4777.2:2020

The System Operator advises that asset owners install inverter-connected assets which are compliant with AS/NZS 4777.2:2020 to ensure consistent operation of these assets across the system. However, it is recognised that there are differences in performance characteristics between Part 8 AOPOs and this standard.

Where an asset owner has a Code obligation and there is a difference between the AOPOs and this standard, the Code will take precedence.

1.6 Typical commissioning tests for inverter-connected assets

During the commissioning of a new generation station or asset to the power system, asset owners must conduct tests to ascertain or confirm asset capability.

Testing should verify any function or mode that is planned to be used in service even if the function or mode is not the primary mode. The requirements for testing are outlined in the Generator Testing Requirements and in Technical Code A in Part 8 of the Code.

All inverter-connected assets and their associated control systems and station level controllers must be tested according to the Code. Typical tests may include:

- Power quality measurements pre- and post-commissioning
- Frequency and voltage control system tests
- Active power and reactive power dispatch and step tests
- Power factor and voltage reference step tests
- Protection signal injection tests
- Transformer tap change and automatic voltage regulation tests

Outside Code requirements, asset owners may be required to carry out additional tests to ensure that their assets are safe and reliable.

1.7 Ramp rate considerations

Inverter-connected assets without mechanical constraints can change their output very quickly compared to other conventional generation.

When the capacity of generating stations using inverter-connected assets rises to a point where fast ramping may affect the ability of the system operator to meet its PPOs, ramp rate constraints may be placed on the rate of change of output to avoid this.

Each generation station and unit will be assessed on a case-by-case basis by the System Operator to determine if any ramp rate restrictions need to be applied for changes in loading during normal operation. The technical requirements are outlined in the Ancillary Services Procurement Plan.

[1] Refer: Code clause 8.21(1).

1.8 Demonstration of ancillary services performance

Ancillary service agents are required to conduct commissioning testing and provide test results as described in the Generator Testing Requirements. Performance requirements and periodic testing for interruptible load, generation reserve, frequency keeping, and voltage support are set out in each ancillary service contract. Generators wanting to provide ancillary services will not be classified as DNG.

1.9 Dispensations or equivalence arrangements required

Code obligations that cannot be met by the asset owner would require an equivalence arrangement or dispensation.

Where an inverter-connected asset does not match the technology stated or performance required in an asset owner performance obligation, but an equivalent performance can be achieved from that asset or others, then an equivalence arrangement should be applied for (e.g. provision of speed governors and excitation control systems). In cases where the assets are unable to comply with the AOPOs the asset owner must apply for a dispensation for the shortfall in performance. Granted dispensation applications and approved equivalence arrangements are subject to conditions applied by the System Operator and can be viewed on the Transpower website. In any case, please contact the System Operator to discuss.

1.10 Modelling information submission requirements

Where AOPOs apply, the Code obilgates submission of a simulation model of the asset to the System Operator in order to complete planning studies. The System Operator Power Plant Dynamic Model Validation and Submission Prerequisites document provides direction to the asset owners and their consultants to ensure these models are fit-for-purpose and appropriately validated prior to submission.

For inverter-connected assets without AOPOs, the System Operator may require the asset owner to submit a simulation model. The requirement for provision of a simulation model will be assessed on a case-by-case basis. Please contact the System Operator to discuss.

2 Wholesale Market Entry Requirements

2.1 Market Participant Registration

Asset owners must register with the Authority as market participants in order to participate in the wholesale market. This is a requirement if you intend to use inverter-connected assets to provide energy or ancillary services.

2.2 Offer arrangements for generation

2.2.1 Obligations to offer on the wholesale market

Grid-connected generating stations of greater than 10 MW capacity[2] must offer energy on the wholesale market, which also applies to inverter-connected assets. Below 10 MW grid-connected assets may elect to offer or may be required to provide information in a form reasonably determined by the System Operator on the expected generation output [3]. For stations that are not required to provide SCADA indications, they may seek approval from the system operator to be classified as Dispatch Notified Generators (DNG). Full details about this classification, and approval and compliance conditions are detailed in Part 13 of the Code and the Policy Statement.

Offers must be made ahead of time and cover the next 72 trading periods (36 hours). Obligations concerning the accuracy and update of offers are contained within Part 13 of the Code.

Assets greater than 30 MW connected to either a local or embedded network must offer energy on the wholesale market. Assets between 10 and 30 MW connected to either a local or embedded network are required to offer to assist the System Operator in planning to comply, and complying, with the principal performance obligations and achieving the dispatch objective. This will be requested by the System Operator during the planning phase of commissioning when required[4].

Any offered generation including DNG will receive dispatch instructions, which must be acknowledged and complied with. Dispatch Notified Generators have the right to infrequently reject dispatch instructions from time to time the instruction cannot feasibly be actioned.

The generator must have the facilities and personnel to receive electronic and voice communications with back-up systems available.

Note the New Zealand electricity market dispatches on merit according to offer and does not provide for unconstrained dispatch. This applies equally to all generating unit classifications.

2.2.2 Dispatch of multiple generating units

Station dispatch can be used for multiple generating units offered independently[5]. When not constrained, participants are only required to meet the dispatched output for the station, with flexibility about which units are used to provide the energy injection. Station dispatch may be constrained at the System Operator's discretion to manage power system security. Participants must give 15 business days' notice to the System Operator to be considered a station dispatch group[6]. Station dispatch may also be considered for Dispatch Notified Generators.

[2] Refer: Code clauses 13.6, 13.25.
[3] Refer: Code clause 13.25.
[4] Refer: Code clause 8.25.
[5] Refer: Code clause 13.64.
[6] Refer: Code Form 8 of Schedule 13.1.

2.2.3 Wholesale Market Information, Clearing, Reconciliation

Generators participating in the wholesale market upload their bids and offers in the Wholesale Information and Trading System (WITS). The Clearing Manager manages the clearing and settlement process after which the Reconciliation Manager will ensure the cost allocation process is completed correctly.

The WITS, Clearing, and Reconciliation Manager roles are performed by NZX. Refer to the Electricity Authority website for more information about the service provider roles, and the NZX website for details on what is required to register and offer into the wholesale market. Note that as part of the commissioning process the System Operator will also liaise with NZX to complete system commissioning for new offered assets.

2.3 Bid arrangements for demand

BESS may also be classified a direct consumer if the BESS has a point of connection to the Grid, as they draw load from the Grid to charge.

Bids will be required for load connected at a non-conforming Grid Exit Point (GXP). If the charging load is a significant portion of total load at a GXP, the GXP may be re-classified as non-conforming. The Authority classifies GXPs as either conforming or non-conforming and may consider a reclassification application[7].

Bids are supplied through WITS, in a similar way to generator offers.

2.3.1 Dispatchable Demand

BESS may also provide dispatchable demand. Providers must ensure bids are accurate, reflecting the load which is available, and observe market rules such as gate closure.

Participants can apply to the System Operator to participate in dispatchable demand with assets classified as Dispatch-Capable Load Stations. More information is available on the Transpower website.

Dispatchable Demand is dispatched ahead of real-time, using a forward schedule. Dispatch instructions are presented on WITS and can be retrieved through the WITS API.

BESS may provide interruptible load and dispatchable demand. Dispatchable demand and interruptible load is co-optimised within the market solver. However, BESS injection and offtake is not co-optimised. Therefore participants must validate their bids and offers to avoid situations where they could be scheduled to both inject and consume load at the same time.

BESS less than 10 MW capacity may also apply for approval from the system operator to be a Dispatch Notified Load (DNL). This is a lower-compliance version of dispatchable demand, equivalent to the distinction between 'full' generation and DNG. Note that a BESS that is classified as a DNG and/or DNL may not offer ancillary services.

2.4 Provision of ancillary services

Transpower, in its role as System Operator, procures ancillary services in support of operating a reliable power system and meeting its Principle Performance Obligations (PPOs).

Inverter-connected assets may provide several services including frequency keeping[8], instantaneous reserve (as interruptible load and/or generation reserve depending on expected operating point), over-frequency reserve, and voltage support.

The Transpower website provides more information on what ancillary services Transpower procures and the mechanisms for procuring these services. These mechanisms are detailed in the Ancillary Services Procurement Plan.

[7] Refer: Code clauses 13.27A-K.

[8] Subject to meeting the System Operator's market system requirements.

2.4.1 Instantaneous reserve

The instantaneous reserve products available are fast instantaneous reserve and sustained instantaneous reserve. The forms of instantaneous reserve are interruptible load and generation reserve, with the latter being split into two offer types comprising of partly loaded spinning reserve and all other types of generation reserve (such as tail water depressed reserve and injectable BESS response).

Definitions of the above mentioned reserve products, forms of instantaneous reserve, and reserve offer types are detailed in Part 1 of the Code.

Partly loaded spinning reserve will require the generating unit to be at a particular operating point to release the offered amount of reserve at that operating point. Therefore, a partly loaded spinning reserve form of offer is linked to an energy offer.

Whereas generation reserve is not linked to an energy offer. Ancillary Service Agents are able to offer generation reserve independent of their energy offer or lack thereof. Generation reserve can even be offered when the BESS is charging (similar to when a hydro unit is in tail water depressed mode).

2.4.1.1 Reserve response from BESS

Under the current market arrangements, BESS may offer interruptible load to reduce the BESS demand when it is charging, and generation reserve to increase the BESS generation output after charging demand is reduced to zero. When the BESS is charging, both interruptible load and generation reserve may be offered in the same trading period. It is expected that BESS would be offered using Form 6 in Schedule 13.1 of the Code for interruptible load and Form 5 (2) in Schedule 13.1 of the Code for all other forms of generation reserve. The Form 5 (2) reserve offer type does not require a subsequent energy offer to release a specific reserve response.

The Asset Owner is accountable for ensuring the reserve offers from an inverter connected device is as accurate as practicable, which for BESS will be subject to energy capacity and residual state of charge for each trading period. Transpower and the Authority are currently working on regulatory changes to clarify how aggregated BESS, among other DER responses, can offer their instantaneous reserve response.

2.4.1.2 Reserve response from Solar farms

Similar to wind farms, although not prohibited, it is not expected that reserve would be offered from intermittent generating stations in isolation due to the variable nature of renewable energy sources.

2.4.1.3 Reserve response from hybrid intermittent generating stations

Hybrid intermittent generating stations, such as solar+BESS or wind+BESS, may consider offering reserve. Any offered reserve must meet the performance requirements defined in the Ancillary Services Procurement Plan.

2.4.2 Over frequency reserve

The System Operator currently contracts with generators to provide Over-Frequency Reserve (OFR), which relies on consistent, continuous output. Under the current procurement arrangements, it is unlikely BESS and solar farms would be able to be contracted to provide OFR. Demonstration of capability or futher queries can be discussed with the System Operator.

2.4.3 Voltage support contracts

The System Operator may contract with asset owners to provide voltage support (injection and absorption of reactive power, Mvar) on a case-by-case basis. Inverter-connected assets may meet the requirements of these contracts.

2.4.4 Frequency keeping

Inverter-connected assets may provide frequency keeping, either as Multiple-provider Frequency Keeping (MFK) or back-up Single-provider Frequency Keeping (SFK). The current minimum offer for frequency keeping is 4 MW. Inverter-connected asset owners need to ensure they have sufficient primary energy source or stored capacity to keep frequency for at least a 30-minute trading period. Under the current market arrangements, BESS may offer frequency keeping only when it is generating.

2.4.5 Black Start

BESS may be able to complement existing generating facilities to provide black start capability. This can be discussed with the System Operator.

3 Data Provision and Communication Requirements

3.1 Real-time indication and measurement requirements

The Code stipulates the minimum requirements for asset owners, including generators, to provide real-time indications and measurements to the System Operator[9]. For inverter-connected assets, the System Operator may request additional indications or measurements such as charging or discharging status or a State of Charge (SOC).

Assets connected via a local distribution network which offer to the wholesale market will be required to provide the System Operator with indications and measurements for generation and load.

Dispatch notified generation (DNG) does not need to provide real-time indications.

3.2 Operational Communications

3.2.1 Dispatch

Wholesale market participants, including owners of dispatched inverter-connected assets, are required to receive and acknowledge dispatch instructions. Participants must provide appropriate facilities to achieve this, which requires connection to the dispatch system. This is provided with several communications protocols:

- ICCP (Block 2 ~~or Block 5~~ conformance)
- Web Services (over private VPN or public internet)

More information is available on the Transpower website. Technical details on the software implementations of the dispatch communication protocols may be provided on request.

3.2.2 Other communications

Participants must make facilities and personnel available to receive voice communications from the System Operator co-ordination centre at all times.

3.3 Metering requirements and obligations

3.3.1 General requirements

Any load connected to the grid is treated as a GXP, including a grid connected generating unit that acts as a load while not generating. Asset owners with grid connection need to enter into an agreement with Transpower (as grid owner) to provide metering at the GXP for the purposes of scheduling, pricing, and dispatch.

Inverter-connected asset owners must arrange a metering installation that complies with the Code[10]. For injection onto the grid at a Grid Injection Point (GIP), generators must arrange metering installation. For offtake from the grid at a GXP, the Grid Owner requires meter data for the load. Contact the Grid Owner's GXP Metering Team to discuss your requirements. Refer to Appendix A.2 for relevant contacts.

If the Grid Owner needs data from your metering installations, then you will need to provide a communication link for remote data collection. Contact the Grid Owner's GXP Metering Team to discuss your requirements. Refer to Appendix A.2 for relevant contacts.

[9] Refer: Code, Schedule 8.3 Technical Code C.
[10] Refer: Code clause 10.26. Note the requirement to provide the grid owner with a copy of the metering installation design report.
Refer: Code clauses 13.136 – 13.140 for embedded generators subject to dispatch.

3.3.2 Metering location at Grid connection point

If practical, the metering installation should be located at the point of connection. If the metering installation is not at the point of connection, then the quantity conveyed through the point of connection must be calculated using an approved process.

3.3.3 Loss adjusted metering

Meter data will need to be adjusted for losses if:

- it is not located at the point of connection
- if embedded generation[11] meter data is being provided to the Grid Owner for inclusion in the ~~daily pricing~~ reconciliation process

3.3.4 Multiple points of connection to the grid for charge and discharge

If there are multiple points of connection to the grid, for example injection at 220 kV and a local service supply at 33 kV, then there must be separate meter data for each connection.

3.3.5 Multiple metering installations at a point of connection to the grid for charge and discharge

If there are multiple metering installations on the same point of connection to the grid, then data will need to be aggregated to give the total quantities conveyed at the point of connection.

[11] Embedded generation definition as per Part 1 of the Code.

A.1 Glossary

Term	Acronym/ Abbreviation	Description
Ancillary Service Agents		A person who provides an ancillary service
Asset Owner Performance Obligations	**AOPO**	A performance obligation specified in subpart 2 of Part 8 of the Code that an asset owner must comply with so that the System Operator can plan to comply and comply with its principal performance obligations
Battery Energy Storage System	**BESS**	A BESS is a system that stores energy using a battery technology and can be used at a later time.
Dispatch Notified Generation/Generator	**DNG**	DNG is a lower-compliance form of market participation for generators.
Dispatch Notified Load	**DNL**	DNL is a lower-compliance form of dispatchable demand market participation.
Energy Storage System	**ESS**	An energy storage system that takes electricity from a network, stores the energy in another form and provide injections at a later time.
Generation Reserve	**GR**	Generation reserve means a form of instantaneous reserve (including, without limitation, partly loaded spinning reserve, tail water depressed reserve and that provided by energy storage systems) which comprises generating capacity that is able to provide fast instantaneous reserve or sustained instantaneous reserve in accordance with the Ancillary Services Procurement Plan.
Grid Exit Point	**GXP**	Any point of connection on the grid - (a) at which electricity predominantly flows out of the grid; or (b) determined as being such by the Authority following an application in accordance with clause 13.28 of the Code, such point of connection may, at any given time, be a grid exit point or a grid injection point but may not be both at the same time.
Grid Injection Point	**GIP**	Any point of connection on the grid at which electricity predominantly flows into the grid. A point of connection may, at any given time, be a grid injection point or grid exit point, but may not be both at the same time.
Interruptible Load	**IL**	Interruptible load is a form of instantaneous reserve comprised of energy being consumed that is able to be reduced to balance the injection supply and the offtake of electricity following a drop in system frequency to a specified level below 50 Hz.
Over Frequency Reserve	**OFR**	An ancillary service that comprises an automatic reduction in the level of injection by a generating set to arrest an unplanned rise in system frequency
Partly Loaded Spinning Reserve	**PLSR**	A form of instantaneous reserve consisting of spare capacity, held in reserve on a generating unit, generating, but not operating at full output, which is able to provide fast instantaneous reserve or sustained instantaneous reserve following a drop in system frequency.
Principal Performance Obligations	**PPO**	A System Operator obligation set out in any of clauses 7.2A to 7.2D of the Code
Tail Water Depressed Reserve	**TWDR**	A form of instantaneous reserve comprising a generating capacity on a motoring hydro generation set with no water flowing through the

		turbine that is available following a drop in system frequency to a specified level below 50 Hz.
Wholesale Information and Trading System	**WITS**	The system in which generators, who are participating in the wholesale market, upload their bids and offers

A.2 Relevant Contacts

Contact Name	Contact Email
Customer Solutions	customer.solutions@transpower.co.nz
GXP Metering Team	gxpmetering@ems.co.nz
SO Market Operations	market.operations@transpower.co.nz
System Operator	system.operator@transpower.co.nz

A.3 Summary of current Code and operational requirements

		Performance Requirements					Market Requirements	
		Indications (SCADA)[12]	**Frequency Support**	**Voltage Support**	**Fault Ride Through**	**Asset Capability Statement**	**Bids / Offers**	**Gate Closure**
Generation (BESS / Solar farms)	With a point of connection to the grid	≥ 10 MW Yes	≥ 30 MW Yes	≥ 1 MW Yes	≥ 30 MW Yes	≥ 1 MW Yes	> 10 MW Yes	1 hour
		< 10 MW if requested	< 30 MW if directed	< 1 MW No	< 30 MW if directed	< 1 MW No	≤ 10 MW if directed	
	With a point of connection to a Local Network or an Embedded Network	≥ 10 MW Yes	≥ 30 MW Yes	n/a	≥ 30 MW Yes	≥ 1 MW Yes	≥ 10 MW Yes	30 minutes
		< 10 MW if requested	< 30 MW if directed		< 30 MW if directed	< 1 MW No	≤ 10 MW if directed	
Demand (BESS only)	Dispatchable Demand	Yes	n/a	n/a	n/a	Yes	No size limit	30 minutes
	Interruptible Load	n/a	n/a	n/a	n/a	Yes	No size limit	1 hour
	Direct Connect – Non-Conforming Load (NCL)	Yes[13]	n/a	n/a	n/a	Yes	No size limit	30 minutes

[12] Schedule 8.3, Technical Code C, Appendix A, Table 1
[13] Schedule 8.3, Technical Code C, Appendix A, Table 3

A.4 Discussion and FAQ

What effect does a faster reserve response have?

Response speed can affect the total Fast Instantaneous Reserve (FIR) requirement calculated by the System Operator using the Reserve Management Tool (RMT); the faster the response, the less reserves are needed overall to cover a given event.

Section 6 "Implications for frequency management" of the System Operators report on [Distributed Battery Energy Storage Systems in NZ] demonstrates the impact of response time.

FIR response considerations for frequency stability?

The System Operator requires reserve providers to act in such a way that stable frequency control can be achieved. The combination of a very fast acting control with a large MW/Hz response is problematic as the dynamic response may not be stable if the frequency change created by the injection can result in a reversal of the response.

For a low droop setting on a large MW reserve source it is necessary to manage the MW of reserve being provided to a level which the system can accommodate. BESS injection with low droop presents an additional challenge over load tripping, because the BESS would be expected to respond not just to the fall in frequency, but also to the recovery and it is this dynamic that is a risk to frequency stability. The technology is capable of ramping full power output up and down in sub-second timeframes which would not be acceptable.

However, the management of frequency response does not require a large BESS to operate with a high droop setting. Any droop setting above 1.5% would impact on the proportion of BESS capacity that could be contracted for FIR. This is because the assessment of FIR is based on an injection curve where the frequency recovers to 49.25Hz, and the steady state output of the BESS at this frequency would limit the contracted FIR value.

For BESS injection of reserves the System Operator considers that a subsidiary ramp rate control (in MW/sec) would be one option that would allow a large battery to offer a 1.5% droop control and be contracted for FIR for all of its capacity with no risk to system frequency stability. A faster ramp rate would reduce the overall system reserve requirements, as it would raise the minimum frequency reached during an event. The fastest acceptable ramp rate would need to be determined, but for a 200 MW battery any ramp rate above 33.33 MW/sec would still meet the existing requirement for 200 MW FIR capability. Such a low ramp rate clearly poses no risk to frequency instability.

A ramp rate would have a minor impact on the contractable SIR from BESS, as that is measured as the average output achieved over a 60 second period. This impact is small, a 200 MW BESS with 1.5% droop control and no ramp limit could achieve 198.7 MW SIR, limited to 50 MW/sec and this would reduce to 193.5 MW (assuming no dead band in the control).

In making these assumptions regarding the control of the reserve response, the System Operator does not foresee any de-rating of BESS capacity for FIR reserves, and a de-rating in the order of only 2 to 3% for SIR reserves.

If the BESS is not offering SIR, the transition from FIR to normal dispatch must be managed to avoid causing another under-frequency event. The system will be in a relatively weak condition post-event, and should the BESS rapidly reduce its active power by up to 200 MW this would likely cause the system frequency to drop below 49.2 Hz again. A response of this nature would be unacceptable to the System Operator.