Review of Technical Requirements for Inverter-Based Resources in Chile

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The Global Power System Transformation Consortium is an expert and practitioner-driven initiative engaging key power system operators, research and educational institutes, governments, businesses, and stakeholders to overcome common barriers around the globe for enabling clean energy transitions at an unprecedented scale.[1]

CEN was identified as a good partner for this technical assistance as Chile embarks on a transition of its grid to very high shares of wind and solar energy generation, which imposes new challenges for adapting and preparing the grid to this new scenario.

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[1] See www.globalpst.org for more details.

List of Acronyms

BPS	bulk power system
CEN	Coordinador Eléctrico Nacional (Chilean system operator)
dbOF	over frequency dead band
dbUF	under frequency dead band
EIRGRID	Ireland's transmission system operator
EMT	electro-magnetic transient
F	frequency
Fnom	nominal frequency
FFR	fast-frequency response
FRT	frequency ride through
GFL	grid-following
GFM	grid-forming
HIL	hardware in the loop
IBR	inverter-based resource
ICR	IBR continuous rating
IEEE	Institute of Electrical and Electronics Engineers
Imax	maximum current ac
ISR	IBR short-term rating
KOF	over frequency droop
KUF	under frequency droop
NESO	National Grid Electricity System Operator
NTSyCS	Grid Code of Chile
P	active power
Pmax	maximum active power
Pmin	minimum active power
Ppre	active power previous the frequency event
PFR	primary frequency response
PoC	point of connection
PoI	point of interconnection
POM	point of measurement
Ppre	pre-disturbance active power output
Q	reactive power
TSO	transmission system operator
ROCOF	rate of change of frequency
RPA	reference point of applicability
RMS	root-mean-square
SCR	short-circuit ratio
V	voltage
Vnom	nominal voltage
VRT	voltage ride through

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1 Motivation and Intention of This Document

This document compares the technical requirements in the grid code of Chile (NTSyCS) against the EirGrid (Ireland transmission system operator) and National Energy System Operator (NESO) of the United Kingdom grid codes and the Institute of Electrical and Electronics Engineers (IEEE) 2800-2022 standard for conventional inverter technology at the transmission and subtransmission levels in the process of being adopted by system operators in the U.S. The document is intended to be a guide and reference for future updates of the NTSyCS, considering the local system requirements and present improvements in inverter-based resource (IBR) technology.

In light of the findings of the aforementioned comparative review, this document proposes and describes the requirements for conventional IBRs that could be incorporated and updated into the Chilean grid code.

The document is structured around the main grid challenges posed by the transition to an IBR-dominated grid and conventional IBRs capabilities to help address them. This document does not provide guidance on how this specification should be implemented (e.g., through a mandate or market solution).

2 Definitions

Bulk Power System (BPS): The North American Electric Reliability Corporation (NERC) defines a bulk power system (BPS) as the facilities and control systems that are necessary to operate an interconnected electric energy transmission network, along with the electric energy from generation facilities that maintain transmission system reliability.

Deadband (db): Range within which the output of a controller does not change, despite fluctuations in the input that occur within this defined range.

Droop: The droop represents how much the frequency and voltage are allowed to deviate from their rated values to accommodate changes in active and reactive power.

Flicker: Degree of intensity of voltage variations in alternating current systems.

Fast-frequency response (FFR): Active power injected into the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event. FFR is faster than traditional primary frequency response. This action aims to improve the frequency nadir (lowest frequency), frequency zenith (highest frequency) and the initial rate-of-change of frequency.

Grid-following (GFL): Conventional IBRs. Mode of operation of an inverter in which the active power injected along with the voltage magnitude, reactive power, or power factor at the point of connection is controlled at high bandwidth, following the phase imposed by the external grid.

Grid-forming (GFM): Mode of operation of an inverter in which the magnitude and phase of the voltage at the point of connection of an inverter-based plant are controlled without the need for an external grid.

Hardware-in-the-loop (HIL): Tests that are conducted in a real-time simulator and involve connecting physical control or protection devices to the simulated grid in a closed loop.

Initial time: The time of initial response for fast frequency response.

Inverter-based resource (IBR): Any generating resource of electric power that is connected to the transmission system via power electronic interface and that consists of one or more inverter unit(s) capable of exporting active power from a primary energy source or energy storage system to a transmission system.

Inverter-Based Resource continuous rating (ICR): The continuous rating of an IBR is the amount of power that it is capable of handling for an indefinite period of time.

K-factor: It is used to define the voltage drop at which inverters increase current injection to support the voltage of the power system.

Maximum current (Imax): Maximum current ac.

NTSyCS: Technical Standard for Safety and Quality of Service (Chile's electric grid code).

Overshoot: The maximum system output value minus the final stabilized value, divided by the actual change in the system output (i.e., from its initial value to the final stabilized value), when the final stabilized value is within the defined settling band, expressed as a percentage.

Primary frequency response (PFR): Automatic adjustment of the power output of generating systems and loads to correct for changes in frequency

Point of connection (PoC): Point at which an inverter-based generation unit is electrically connected to a collector system, defined by the owner of the generation plant.

Point of interconnection (PoI): Point in the interconnected electrical system at which a generation plant connects to the transmission system.

Point of measurement (POM): A point between the high-voltage bus of the IBRs and the interconnection system. See IEEE STD 2800-2022-2022 for more information.

Reaction time: The time it takes for a system variable to have a measurable change in the direction of the control action after a disturbance occurs in the system.

Reference point of applicability (RPA): The location at which the interconnection and interoperability performance requirements are applicable.

Rise time: The time it takes for a system variable to rise from 10% to 90% of its final value after a disturbance.

Settling band: Region around the final value of a system variable, within which the variable is considered to have stabilized after a disturbance.

Settling time: The time it takes for a system variable to stabilize within a defined settling band around its final value after a disturbance.

3 Introduction

When IBRs were first introduced to the grid, they had no significant impact on the operation of the system. Therefore, grid operators did not define additional technical requirements different from what is specified for conventional synchronous generation facilities. This is known as the "do-nothing" phase for the definition of IBR technical requirements, shown in Figure 1.

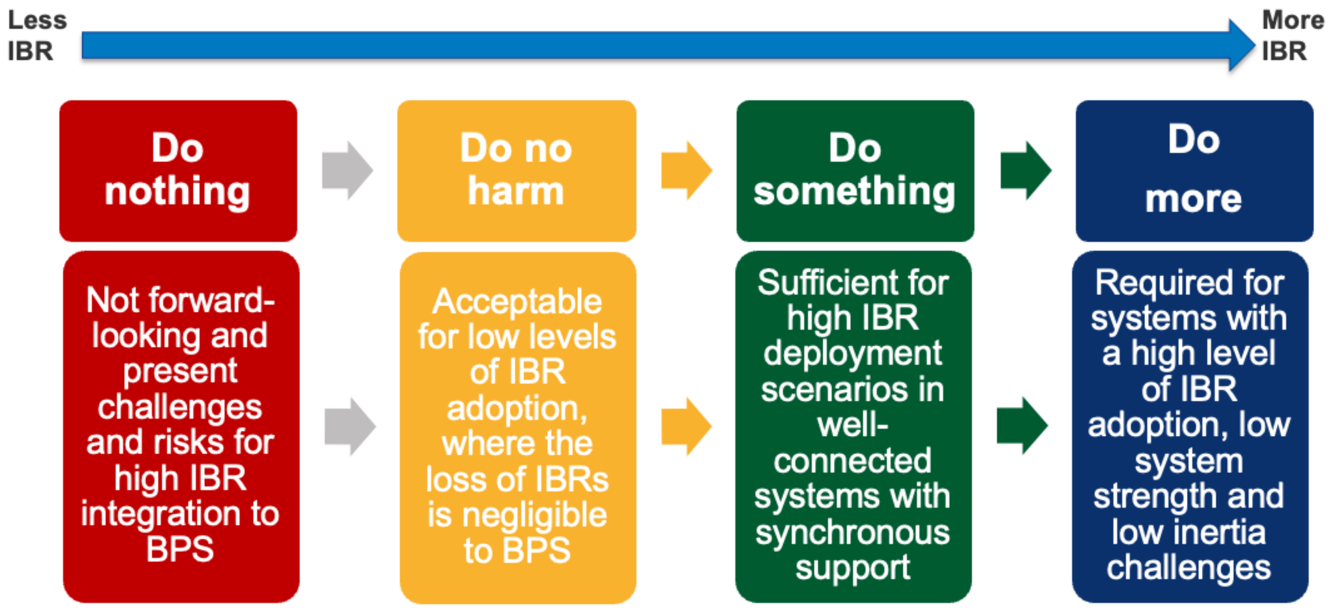

Figure 1. Progression of technical requirements as IBR penetration increases

The first grid code for IBRs connected to transmission and subtransmission was developed in Denmark in 1999 and required wind turbines to remain connected and continue to deliver power to support the grid in the event of a fault [1]. This is referred to in this report as the "do-no-harm" phase (Figure 1).

In 2005 the so-called "German 50.2 Hz problem" occurred when photovoltaics in the distribution network disconnected anytime the frequency exceeded 50.2 Hz (with 50 Hz being nominal), but the capacity of the photovoltaic generation grew so large that a mass disconnection event could threaten system stability, new codes had to be adopted, and plants had to undergo retrofits, a highly costly endeavor [2].

Concerns started arising almost immediately after some disturbance events occurred in Southern California in 2016 and 2017 that appeared to be related to misinterpretation of performance requirements for IBRs resulting in potential incorrect settings within the IBRs' control and protection systems ([3];[4]). As more IBRs connect to the grid, the operational risks increase, as noted in [3], which recommends that "continued analyses of inverter-based resource performance under existing and future penetration levels are needed to determine if there are any reliability risks using control philosophies employed today." Similarly, the Panhandle Wind Disturbance, which occurred in Texas in 2022 when two normally cleared line-to-line faults caused 18 wind facilities with a combined output of 1,222 (around 2% of total system load) MW to trip offline unexpectedly [5] is an example of why clear IBR technical requirements are needed to support the grid and avoid events and extra cost due to plant retrofits.

Defining requirements in advance of larger-scale IBR equipment installation can avoid events in the system and avoid additional costs of retrofitting the IBR control system. As more IBRs are deployed and become important sources of energy, the requirements continue to change. In most interconnections around the world with high levels of IBRs, it has become necessary to ensure that these devices become "good grid citizens" and actively support the grid through capabilities such as fault ride-through and active voltage and frequency support. This is known as the "do-something" phase for the definition of IBR technical requirements (Figure 1).

The ultimate phase is known as the "do-more" phase (Figure 1). To date, a few countries [6] have reached this stage and are incorporating more advanced IBR requirements in their grid codes, and many more are expected to join them in the coming years. When this happens, IBRs can reliability account for much of the available generation and/or storage capacity, either in a region of the grid or in the entire grid. IBRs are already commercially available that actively supporting frequency and voltage, and grid codes will likely require grid-forming capabilities from IBRs, along with other supporting technologies such as synchronous condensers.

The accelerated energy transition currently underway in Chile increases the urgency of undertaking a comprehensive review and updating the technical requirements for conventional IBRs in the NTSyCS. This is necessary to ensure that the code can address the challenges that will arise in the future grid, which are expected to be characterized by high levels of variable renewable generation (wind and solar) and storage resources. Given the high costs of retrofitting IBRs, it is advisable to move to the "do something" or "do more" stage of grid code updates as early as possible without waiting for levels of IBRs to become high.

4 Comparison of Technical Requirements for Conventional IBRs in Chile, Ireland, the United Kingdom, and Standard IEEE 2800-2022

In this section, we compare the technical requirements for conventional IBRs in the Chilean grid code with the IEEE Std. 2800-2022 [7] standard and the grid codes of Ireland's EirGrid [8] and UK's NESO [9]. The selected grid codes are similar to the conditions of the Chilean system, though these systems are experiencing higher penetration of IBRs and have high decarbonization targets that will drive more IBRs in the near future.

We have divided the requirements into three main categories, as seen in the framework for requirements in Figure 2: frequency, voltage, and performance. System performance includes short-circuit ratio (SCR), power quality, forecasting, protection, and models. In addition, the technical requirements are classified by colors from less advanced to more advanced, as described in Figure 1.

Figure 2 shows a summary and comparison of technical requirements across the selected references. It weights the requirements from "do-no-harm" in yellow, "do something" in green, and "do more" in blue.

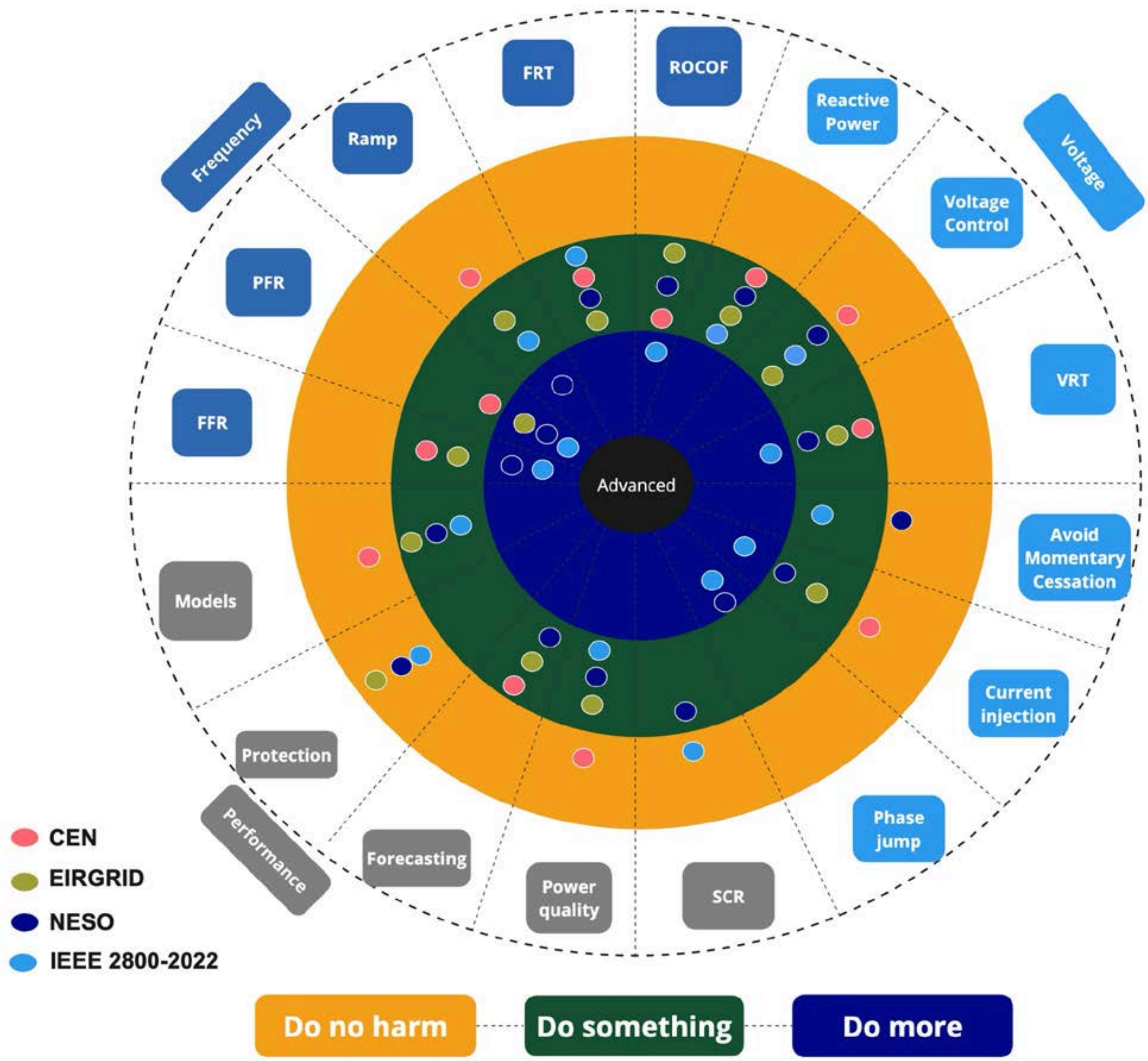

Figure 2. Comparison of progression of reviewed grid codes across a wide range of IBR technical requirements. Abbreviations can be found in Definitions section of this report.

4.1 Frequency Requirements

Frequency response is the ability of a power system to respond to imbalances between load and generation. Frequency response can be categorized in different ways, as static and dynamic, or according to the activation time and sustainability of the response. In this report we will look at the following frequency responses, focusing on fast frequency response and primary frequency response (Figure 3):

- Inertia: The energy stored in the rotating masses of rotating machines that gives them the tendency to continue rotating. This stored energy is used to resist changes in the frequency of the power system.
- Fast Frequency Response (FFR): The rapid response of IBRs to a locally sensed frequency change to arrest the frequency change during the first few cycles (arresting time). This should be maintained for several seconds to minutes.
- Primary frequency response: The automatic response of IBRs to load or generation, starting within seconds of a frequency deviation and lasting from seconds to minutes.
- Secondary frequency response: The automatic response of IBRs, load or generation that provides additional active power or reduces active power demand within 30 seconds of and it is sustained from minutes to hours.
- Tertiary frequency response: Response of IBRs, load or generation that provides additional active power or reduces active power demand to restores the power reserve of the devices used for secondary response in a power system from several minutes to several hours after a frequency event.

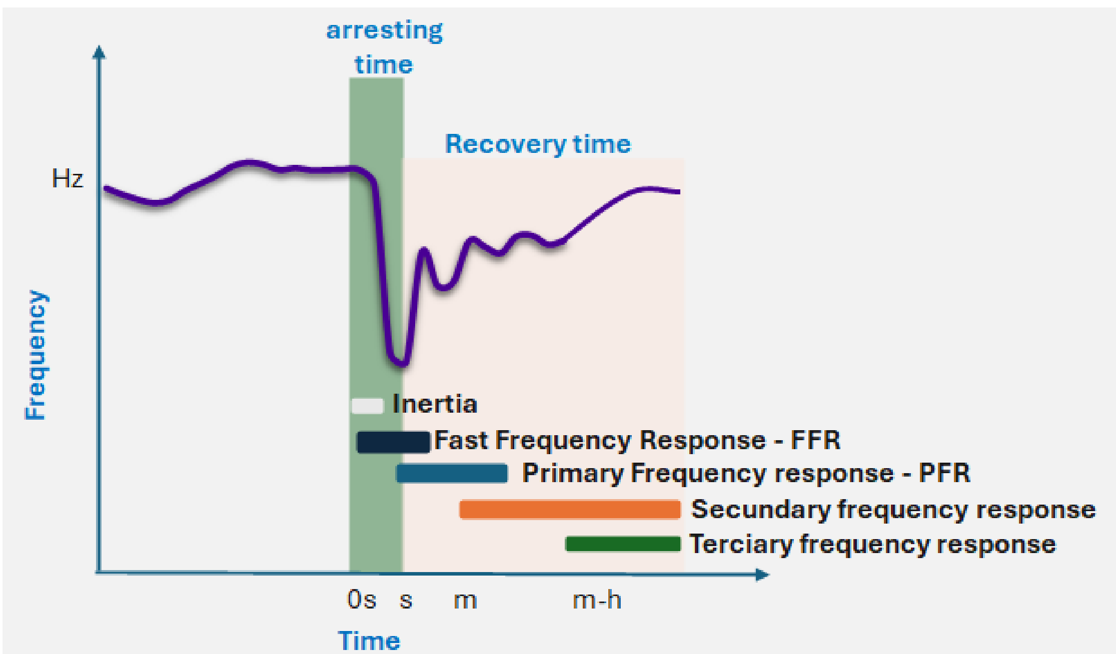

Figure 3. Type of frequency responses

4.1.1 Fast Frequency Response (FFR)

FFR is the first stage of overall frequency control from IBRs—the fast response of IBRs to a locally sensed frequency change to arrest the frequency change during the first cycles. This should be sustained for some seconds to minutes.

For IEEE Std. 2800-2022 and NESO, the requirements are consistent and categorized as "do more." Furthermore, IEEE Std. 2800-2022 and NESO have requirements regarding stability and the interaction between PFR and FFR. For EirGrid and Chile, FFR is not considering as a technical requirement, so the IBRs can be connected to the system without the capability, and it is classified as “do something.” For all four references, the time settings are different, depending on the system needs and the evolution of the frequency after events. (Table 1).

Table 1. Comparison of FFR Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid[2]	Chile
Initial Time	No requirement	0.5 s	No requirement	No requirement
Step Response Time/ Time of Full Delivery	90% of target in less than 1 s	Less than 1 s	2[3]–10 s	<1 s,[4] defined as the total activation time or as the period during which the entirety of the committed technical resource is delivered, including the start time of activation (step response time, or reaction plus rise time). This is part of the ancillary services definition report
Trigger	99.17%–99.94% Fn	±0.1–0.2 Hz	0.1-0.2 Hz	Not defined in the grid code, but CEN is allowed to require a trigger value
Droop	1%–5%	Starting from 0.2 Hz and 100% capability at 0.5Hz	No requirement	No requirement
Sustainable Time	IBR plant shall be capable of sustaining FFR for as long as IBR plant energy resource is available or until supplanted by primary response, whichever is less	15–30 min	10 s	5 minutes,[5] defined as minimum delivery time or the period in which the facilities shall be able to maintain the total committed technical resource, counted from the moment total activation time elapsed. This is part of the ancillary services definition report

[2] Defined by EirGrid but it is not part of the EirGrid grid code.
[3] In EirGrid the current definition of time of full delivery for FFR states a 2 seconds, and EirGrid incentivizes service providers to provide a response down to 150 ms. Also, EirGrid has proposed to reduce the time of full delivery for FFR from 2 seconds to 1 second (and create subcategories of FFR down to 150 ms).
[4] Section 3.2.1.1, Chile Definitions Report for Ancillary Services (NTSSCC Res. Exta. Nº 442, Nov 2020).
[5] Section 3.2.1.1, Chile Definitions Report for Ancillary Services (NTSSCC Res. Exta. Nº 442, Nov 2020).

Requirement	IEEE Std. 2800-2022	NESO	EirGrid[2]	Chile
Stability	-The response shall be stable, and any oscillations shall be positively damped with a damping ratio of 0.3 or better. -Stable and damped response shall take precedence over response time	Stable over entire operating range (49.8 Hz–50.2 Hz). Stable response to active power step change.	No requirement	No requirement
PFR-FFR	FFR and PFR shall actuate independently from each other and shall complement each other in output	The plant should remain stable when providing services; also, if the owner of the plant provide both PFR and FFR, they should be able to distinguish the different volume delivered	No requirement	No requirement

4.1.2 Primary Frequency Response (PFR)

PFR, the second stage of overall frequency control after FFR, is the response of IBRs to a locally sensed frequency change to arrest the frequency change and help the frequency to recover. For IEEE Std. 2800-2022, NESO, and EirGrid, the requirements are consistent and categorized as "do more." For Chile, it is not considering as a technical requirement, so the IBRs can be connected to the system without the capability, and it is classified as "do something.". The time settings are different, depending on the system needs and the evolution of the frequency after events (Table 2)

Table 2. Comparison of PFR Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Droop	2%–5%	3%–5%	2%–12%	Over-frequency droop >3.64%; under-frequency 2%<Droop<8%[6]
Deadband	0.025%–1.6 % f nom	+/-15 mHz	+/-15 mHz	+/-200 mHz[7]
Reaction Time	0.2–1 s	1–2 s	No requirement	<2 s[8]
Rise Time	2–20 s	8–9 s	60% of expected, additional P within 5 s	<10 s, defined as the total activation time or as the period during which the entirety of the committed technical resource is delivered, including the start time of activation. This is part of the ancillary services definition report
Settling Time	10–30 s	10 s	100% of expected, additional P within 15 s	Same as rise time
Active power limit	-Available active power for under-frequency -Where the operation of the IBR plant with a headroom is required by the transmission system operator to address under-frequency disturbances, the IBR plant shall have the capability to dynamically maintain this headroom	Active power as a percentage of maximum capacity equal to 10%	Available active power for under-frequency	No requirement
Stability	The response shall be stable, and any oscillations shall be positively damped with a damping ratio of 0.3 or higher	Stable over entire frequency range (47.5Hz-51.5Hz); capable of providing active power frequency response and disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz	Stable operation in response to low-frequency events shall be ensured	No requirement

[6] Article 3-17, letters b) and c), Chile Grid Code (NTSyCS, Sep 2020).
[7] Article 3-17, letter d), Chile Grid Code (NTSyCS, Sep 2020).
[8] Article 3-17, letter a), Chile Grid Code (NTSyCS, Sep 2020).

4.1.3 Active Power Ramps

Active power ramps can be defined for frequency response performance, as in the case of IEEE Std. 2800-2022, and for ramp rate limit to avoid system events, as in the case of NESO. Table 3 shows the uses and expected ramp rate for the references analyzed. It is classified as "do not harm" for Chile because the expected range of adjustable ramp rates does not cover 100% of the rated power. The active power ramp requirements in EirGrid, and IEEE Std. 2800-2022 are classified as ¨do something¨ as the expected ramp rate is according to the capability of the IBR. The requirement in NESO is defined as a "do more" because it aims to prevent ROCOF issues.

It is important to clarify that this ramp rate for PFR and FFR responses should be according to the requirements for those capabilities. In addition, this ramp rate limit should be analyzed during fault recovery; this could cause problems where IBRs take a long time to recover to pre-event active power following a fault, which results in underfrequency problems.

Table 3. Comparison of Active Power Ramp Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Uses	Smooth the transition between parameter changes related to frequency response	To increase/decrease power output	Resource following mode,[9] active power control set point, frequency response	Smooth transitions due to resource following and commands
Expected Ramp Rate	As fast as technically feasible for frequency response. Ramping or similar smooth transition of IBR plant output shall be required for control parameter setting changes. For all control and protective function parameter settings, the time following the input to the IBR communication interface and preceding the point in time when the invoked action begins shall be no greater than required by the TSO.	Maximum ramp rate is specified to avoid large rate of change of frequency (ROCOF) issue, with all ramp cases, the IBR should remain stable	Specified amount by transmission system operator as percentage of registered capacity per minute.	Adjustable: 0%–20% of nominal power per minute. It does not apply for frequency response.

4.1.4 Frequency Ride-Through

Frequency ride through refers to the ability of IBRs to remain connected to the grid during grid disturbances within a range of under-frequency and over-frequency conditions. For the references analyzed, the requirements are consistent and categorized as "do something." The time settings are different, depending on the system needs and the evolution of the frequency after events (Table 4).

[9] EirGrid defines resource-following mode as: "A mode of operation of a Controllable PPM [power park module], with the exception of ESPSs [Energy Storage Power Station] where the system frequency is within normal range and the Controllable PPM is not under Active Power Control by the TSO [transmission system operator], allowing the Controllable PPM to produce up to 100% of its Available Active Power, depending on the Power-Frequency Curve in operation" [6].

Table 4. Comparison of Frequency Ride-Through Requirements IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Shall-Not-Trip Range	Frequency/time • .95–98 pu/299 s (~5 min) • .98–1.02 pu/unlimited • 1.02–1.03 pu/299 s (~5 min)	Frequency/time • .94–95 pu/20 s • .95–.98 pu/90 min • .98–1.02 pu/unlimited • 1.02–1.03 pu/90 min • 1.03–1.04 pu/15 min IBRs providing active power frequency response are not allowed to disconnect by frequency or speed-based relays within the frequency range 47.5Hz to 51.5Hz	Frequency/time • .94–.95 pu/20 s • .95–.97 pu/90 min • .97–.98 pu/90 min • .98–1.02 pu/unlimited • 1.02–1.03 pu/90 min • 1.03–1.04 pu/60 min	Frequency/time • .95–.96 pu/30 min • .96–.98 pu/90 min • .98–1.02pu/unlimited • 1.02–1.03 pu/90 min

4.1.5 ROCOF

ROCOF is a measure, over a defined period of time, of how quickly the frequency changes following a sudden imbalance between generation and load. The initial ROCOF after a load or generation imbalance is most commonly calculated as the change in frequency over a 0.1 to 0.5 second period immediately following the imbalance (Table 5). This period is chosen because in a conventional power system, the frequency recovery during this time is dominated by the inertial response of synchronous generation on the system. IBR requirements to overcome extremely high ROCOF are important to avoid both under frequency/over frequency, and load/generation shedding. The ROCOF in IEEE Std. 2800-2022 is classified as ¨do smore¨ as the IBR must not trip up to 5Hz/sec, and the system operator may be required to ride through higher ROCOF events. Fo the other references is considered "do something" as the must nor trip is lower than 2 Hz/sec.

Table 5. Comparison of ROCOF Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Must Not Trip (in continuous operation region)	Up to 5 Hz/second on average measured over a 0.1-s window.	Up to 1 Hz/sec on average measured over a rolling 500-millisecond window. Up to 2Hz/s for power park module with GFM.	Up to 1 Hz/sec on average measured over a rolling 500-millisecond window.	Up to 2 Hz/sec on average measured over a rolling 500-millisecond window.
Comments	If mutually agreed upon between transmission system operator and IBR operator may be required to ride through higher ROCOF levels.	Fault ride-through requirements supersede ROCOF requirements.		No mention of the specifics of ROCOF measuring (moving average timeframe, instantaneous measure, discrete, etc.)

4.2 Voltage Requirements

4.2.1 Reactive Power Capability

Reactive power capability is important for inverter-based resources (IBRs) because it helps to regulate the voltage on the grid. IBRs can adjust their output to track an external voltage reference, providing both active power and reactive power. Reactive power is a requirement classified in general as "do something" for the references selected, with the requirements highlighted in green in Table 6. The requirements are consistent, and a power factor requirement of ±0.95 is common for all references. Active power range for reactive capability is specified for all power levels in IEEE Std. 2800-2022 except for wind turbines Type III, above 12% active power (Pgen) in EirGrid, and 20 % in NESO, and wind turbines in Chile. For EirGrid, NESO, and IEEE Std. 2800-2022, additional reactive power compensation requirements are required when the connection point is remote from the grid connected transformer to provide the reactive power required for system stability (Table 7).

Table 6. Comparison of Reactive Power Capability Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Power Factor	±0.95			
P Output Levels	All power levels except for Type III wind turbines	>20% Pgen	>12% Pgen	>20% Pgen wind > 0 for photovoltaics[10]
Reactive Power Capability	Must be able to absorb or inject a minimum of .3287 IBR continuous rating (ICR), except Type 3 wind turbines, which must meet a proportion of that rating until it is operating at 0.1* ICR, beyond which point it must meet full rating. Must be able to absorb or inject .3287* IBR continuous absorption rating.	Must be able to inject or absorb a minimum of 0.12*Pmax at 0.2 pu power output, then increase to 0.33*Pmax at 0.5 pu and continue at that value up to 1.0 pu power output.	Must be able to inject or absorb a minimum of 0.33*Pmax from 0.12–1.0 pu Pmax.	0.33 pu Q *capability* is required (injecting or absorbing), nor the apparent power surpass 1 pu. Solar photovoltaics shall be able to meet the Q requirements from zero apparent power, and for wind from 0.2 pu apparent power.

[10] Article 3-9 Chile Grid Code (NTSyCS, Sep 2020).

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Power Capability Q–V	Voltage/min Q injection 0.9 pu/0.7*(.3287*ICR) 0.9 pu/0.0 (Type 3 wind turbines) Slope up to 0.95/.3287*ICR V3/.3287*ICR Slope down to V4/0.0 Slope down to 1.10 pu/-.3287*ICR (30-min operation). Voltage/min Q absorption 0.95/0.0 Slope up to V2/.3287*ICR V4/.3287*ICR 1.10 pu/.3287*ICR (30-min operation). V2 = 0.99 at <200 kV, 1.0 at >=200 kV except 500 kV and 735 kV, 1.02 at 500 kV and 735 kV. V3 = 1.03 at <200 kV, 1.04 at >=200 kV except 500 kV and 735 kV, 1.06 at 500 kV and 735 kV. V4 = 1.05 at <200 kV and >=200 kV except 500 kV and 735 kV, 1.10 at 500 kV, and 1.088 at 735 kV.	Fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages except for Onshore generating unit embedded at 33 kV and below then follow the requirements: Production of reactive power: For voltage between 95% to 100%, a power factor of 0.95. For voltage between 100% to 105%, a slope up to a power factor of 1. Consumption of reactive power: For voltage between 100% to 105%, a power factor of -0.95. For voltage between 95% to 100%, a slope up to a power factor of 1.	110 kV: Must be able to inject or absorb 0.33*Pmax of reactive current when the voltage is between 0.9–1.118 pu. 220 kV: Must be able to inject or absorb 0.33*Pmax of reactive current when the voltage is between 0.9–1.114 pu. 400 kV: Must be able to inject or absorb 0.33*Pmax of reactive current when the voltage is between 0.9–1.05 pu.	The PQ-capability applies for voltages between 0.97 and 1.03 pu, when Vnom>=500 kV 0.95 and 1.05 pu, when 200<=Vnom<500 kV 0.93 and 1.07 pu, when Vnom<200 kV.

Table 7.Comparison of Reactive Power Compensation When the Connection Point Is Remote for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Reactive Power Compensation When the Connection Point Is Remote from the Grid-Connected Transformer	IEEE Std. 2800 gives the TSO the ability to move the RPA to the POI, which effectively makes all requirements (including Q-V requirements) apply at the “connection point”. By default, IEEE St. 2800 does not have a requirement for this, it explicitly gives the TSO the right to apply all requirements at the POI.	Shall be required to be capable of full leading power factor from 100% to 20% of Rated MW output. Company has the right to dispatch reactive power.	Where the connection point is remote from the grid-connected transformer, any supplementary reactive power compensation required to offset the reactive power demand of the high-voltage line, or cable, between the connection point and the controllable power park module shall be identified during the transmission system operator’s connection offer process.	No requirement

4.2.2 Voltage Control in Normal Operation

In the selected references, the voltage control is maintained at levels within the acceptable range, typically between 90% and 110% of the nominal value. This requirement is classified as a general "do something" for the references selected, except for Chile that it is classified as "do not harm" because the requirement is not specifying droop, reaction time, response time, settle time, stability, and operation modes (Table 8).

Table 8.Comparison of Voltage Control Requirements Within the Continuous Operation Region for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Range	±5%–10% V rated	±5% V rated	±5% V rated	±10% rated voltage[11]
Droop	0 to 0.3 pu V change for 1.0 pu Q	2-7%		No requirement
Reaction Time	<200 ms	0.2 s	No requirement	No requirement
Response Time	As required by the transmission system operator (1–30 s)	90% of the change in the **reactive power** will be achieved within 1 s.		No requirement
Settle Time	No requirement	5 seconds, with a steady-state reactive power tolerance no greater than 5% of the maximum reactive power.		No requirement
Oscillations	Any oscillations shall be positively damped with a damping ratio of 0.3 or Higher.	Voltage control system to be fitted with a power oscillation damping shall be specified in the bilateral agreement if this is required for system reasons.	In the event of power oscillations, shall retain steady-state stability when operating at any operating point of the reactive power capability.	No requirement
Operating Modes	Mutually exclusive operating modes of reactive power control functions: voltage control, power factor control, and reactive power set point control.	Voltage control, power factor control, and reactive power set point control	Mutually exclusive operating modes of reactive power control functions: voltage control, power factor control, reactive power set point control.	No requirement

4.2.3 Voltage Ride-Through

As IBRs become larger contributors to the power grid it becomes critical for these resources to stay connected to the grid even during low or high voltage excursions and potentially to help support resolving these challenges. As such, all the selected references included requirements for low voltages rid through, stipulating that the plans must be connected for a specified period of time under low voltages. However, only IEEE Std. 2800-2022 has specific values recommended for over-voltages, and it is classified as “do more”. This requirement is classified for the other references as "do something" (Table 9).

[11] Article 5-47 Chile Grid Code (NTSyCS, Sep 2020).

Table 9. Comparison of Voltage Ride-Through Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Must Not Trip	Plants with auxiliary equipment that limit ride through: <0.25 pu/0.16 s <0.5 pu/1.20 s <0.7 pu/2.50 s <0.9 pu/3.00 s <1.05 pu/continuous >1.05 pu/1,800 s >1.0 pu/1.0 s Plants without auxiliary equipment that limit ride-through: <0.25 pu/0.32 s <0.50 pu/1.20 s <0.70 pu/3.00 s <0.90 pu/6.00 s <1.05 pu/continuous >1.05 pu/1,800 s >1.10 pu/1.0 s	Voltage/time <0.15 pu/.14 s, then increase boundary linearly up to 0.8 pu/1.2 s. <0.85 pu/2.5 s <0.9 pu/3 min	At 0.0 pu, must stay connected 0.15 seconds, then boundary increases linearly up to 0.85 pu at 2.9 seconds.	Voltage/time 0.0 pu/.14 seconds, then increase boundary linearly up to 0.8 pu/1 second. Then, at 0.8 pu, should remain connected indefinitely.[12]
Transient Over-Voltage Ride-Through	>1.20 pu/15 ms >1.40 pu/3.0 ms >1.6 pu/1.0 ms >1.8 pu/0.2 ms	Set by transmission owners	No requirement	No requirement

4.2.4 Momentary Cessation

Momentary cessation is an inverter operating state where the power electronics are blocked, resulting in zero real and reactive power output currents. Even though the IBR stays connected and ready to quickly return to providing output, this condition is still detrimental to bulk power stability and the best practice is to avoid momentary cessation as far as possible. As seen in Table 10, IEEE Std. 2800-2022 provides requirements that aim to avoid momentary cessation except in certain extreme circumstances, and it is classified as "do something". For NESO it is not called momentary cessation but the grid code makes it clear that after a fault, the plant should continue to inject active and reactive power as long as the plant capability is not reached. Also, momentary cessation should be reported and modelled, and it is allowed in some cases, as described in the section on power injection, where blocking (momentary cessation) is allowed after fault clearance. For these reasons it is considered as "do no-harm" in NESO.

Table 10.Comparison of Momentary Cessation Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Momentary Cessation	Only allowed below 0.1 per unit voltage, or above 1.2 pu per unit voltage, assuming appropriate surge protection has been applied as necessary ride-through	It is not called momentary cessation, but grid code makes clear that after a fault, plant should still inject active and reactive power as long as equipment capability is not reached. IBRs should not cause any system events during the disconnection and reconnection. Need to be reported and modeled; the model shall include any blocking, deblocking, and protective trip features that are part of the power park unit.	No requirement	No requirement

[12] Article 3-8, Chile Grid Code (NTSyCS, Sep 2020).

4.2.5 Current Injection During Voltage Ride-Through

Reactive current injection during faults is essential for restoring voltage levels and ensuring the reliability of system protections. The selected references all include requirements for current injection during such faults. As shown in Table 11, IEEE Std. 2800-2022 offer more detailed specifications, stating that the IBR must inject negative sequence current. This requirement is classified as a "do something" for NESO, and EirGrid because they do not currently mandate that the IBR unit inject negative sequence current. For Chile is classified as a "do no-harm" as it is not considered time response requirements.

In Chile, the k-factor is established at a value of two. A flexible range for the k-factor will allow the system operator to define adjustments to suit various operational scenarios. As outlined in IEEE Std, 2800-2022, the system operator needs to consider the precise requirements for both incremental positive and negative sequence reactive currents during fault conditions. This involves an evaluation, supported by studies, to determine whether maintaining a k-factor of 2 is beneficial for all IBR plans. Furthermore, the analysis could explore the possibility of modifying the k-factor in specific situations to mitigate the risk of over voltages, ensuring that the system remains stable and operates within safe limits under varying circumstances.

Table 11. Comparison of Current Injection During Voltage Ride-Through Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Fault Current Injection	The type and magnitude of current injection during a ride-through mode of operation shall be dependent on voltage deviation from the IBR unit terminal (point of connection) nominal voltage when the applicable voltage at the IBR unit terminals is outside of the continuous operation region. The IBR unit shall maintain automatic voltage control during a ride-through mode. If requested by the transmission system operator, automatic voltage control may be disabled. For unbalanced faults, in addition to increased positive-sequence reactive current, the IBR unit shall inject negative sequence current. The TS owner should consider specifying required magnitude of incremental positive and negative sequence reactive currents during faults per respective system needs. The commonly used approach is to specify a relationship between voltage change at IBR unit terminals (POC) and required incremental reactive current[13].	At V = 0.9 pu, reactive current (IR) must be at minimum -0.312 pu. This amount increases linearly until V = 0.5 and IR = 1.0. Beyond that operation is not required, but not prohibited either. The actual reactive current injection must be equal to or greater than the pre-fault reactive current up until 20 ms, at which point the reactive current injection floor increases linearly up to 0.65*IR at 60 ms, and IR at 120 ms. Blocking (momentary cessation) is permitted after fault clearance.	Response supplied within rating of the IBR, with a rise time no greater than 100ms and a settling Time no greater than 300ms. The provision of reactive current shall continue until the transmission system voltage recovers to within the normal operational range, or for at least 500 ms, whichever is the sooner. During and after faults, priority shall always be given to the Active Power.	k-factor = 2, where the reactive power related current is increased K-factor times the voltage dip.[14]

[13] K-factor range is specified in the German grid code VDE-AR-N 4120 [B110] and VDE-AR-N 4130 [B111].
[14] Article 3-8, Chile Grid Code (NTSyCS, Sep 2020).

4.2.6 Phase Jump Ride-Through Requirements

In the event of a disturbance, such as a close-in fault or a transmission line switching event, there is a possibility of a rapid phase angle shift in the grid voltage. In such cases, the phase displacement can be significant enough to present challenges for the phase lock loop used in IBR control systems to track the terminal voltage. In some instances, these challenges can result in the inverter tripping due to pre-set trip thresholds.

In the references selected, IEEE Std. 2800-2022 indicates that the IBR should be designed and operated to ride through a minimum positive sequence phase angle jump of 25 electrical degrees. For NESO, phase jump is not explicitly addressed in grid code; however, NESO states that if the voltage and system frequency are within the operational limits, IBRs are required to ride through all phase jump events. This requirement are classified as a "do more" (Table 12).

Table 12. Comparison of Phase Jump Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Positive Sequence Phase Angle Ride-Through	Within a sub-cycle-to-cycle time frame of the applicable positive sequence voltage of less than or equal to 25 electrical degrees.	Phase jump is not explicitly addressed in grid code; however, NESO states that, as long as the voltage and system frequency are within the grid code required limits, IBRs are required to ride through all phase jump events, no matter how much angle jump is experienced.	No requirement	No requirement
Unbalanced Phase Angle Ride-Through	Any change in the phase angle of individual phases, assuming the positive sequence does not exceed the above criteria.		No requirement	No requirement
Performance	Active and reactive current oscillations post disturbance that are positively damped are acceptable. Current blocking post disturbance not permitted.		No requirement	No requirement

4.3 Performance Requirements

In addition to meeting the fundamental technical requirements for frequency and voltage, there are several other critical capabilities that are essential to ensure the safety and reliability of the power system. These include:

- Short-Circuit Ratio: This parameter is vital for assessing the robustness of the system in the event of faults. A higher short-circuit ratio indicates a more stable system that can handle sudden disruptions.
- Power Quality: Maintaining power quality is important for the proper functioning of electrical equipment and overall system performance. This includes monitoring parameters like voltage changes, harmonic distortion, and flicker to ensure that the power supplied meets the necessary standards.
- Forecasting: Accurate forecasting of IBRs is important for effective system operation. By predicting fluctuations in renewable energy output, operators can make informed decisions to optimize resource allocation and grid stability.
- Protection: Implementing effective protection mechanisms safeguards the power system from faults and operational anomalies.

- Modeling: Developing models of the power system and validating those is essential for simulation and analysis. These models help in understanding system dynamics, assessing the impact of various scenarios, and guiding decisions for system operators.

Together, these IBR capabilities enhance the overall resilience, efficiency, and reliability of the power system, ensuring it can withstand challenges and operate smoothly under varying conditions.

4.3.1 Short Circuit Ratio (SCR)

The SCR is an indicator of system strength. It is calculated by dividing the synchronous three-phase fault level (in MVA) by the rated output of an IBR generating system (in MW or MVA), as measured at the generating system's connection point.

In systems with a low SCR, there is a possible risk of GFL IBR experiencing issues with control stability. Generally, GFM IBRs are able to operate even at extremely low SCR, and can also stabilize nearby GFM IBRs in low SCR conditions. Additional GFM IBR requirements will be address in and supplementary document by CEN, considering some G-PST references.

In the references selected, IEEE Std. 2800-2022 includes different metrics. Of these, the SCR with interaction factors is the only metric that provides a reasonably accurate representation of the system strength for individual IBRs within a larger group. In NESO, the IBR owners must make sure they can meet all grid code requirements under all SCR conditions. This requirement is classified as a "do something" for NESO, and "do no harm" for IEEE Std. 2800-2022. (Table 13).

Table 13. Comparison of SCR Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
SCR	-The SCR is a convenient metric to use when considering a single IBR operating into a relatively conventional power system. -SCR with interaction factors is the only metric presented in IEEE Std. 2800-2022 that gives a reasonably accurate representation of the system strength for individual IBRs within a larger group. -The SCR-based metrics should be used carefully, understanding the assumptions and limitations of usage of the selected SCR-based metrics. When in doubt, electro-magnetic transient (EMT) studies should be conducted to investigate and verify IBR stability.	The IBR owners must make sure they can meet all grid code requirements under all SCR conditions. Other solutions different from requirements: stability pathfinder projects.	No requirement. EirGrid is planning to include a system strength metric.	No requirement

4.3.2 Power Quality

The generation of power by IBRs into the grid via power electronic interfaces has prompted concerns regarding the potential impact of IBRs on power quality, particularly in the form of harmonic distortions within interconnected power systems. To prevent any potential issues with the grid, the selected references stated that IBR must not cause flicker or harmonic distortions in the grid (Table 14). This requirement is classified for IEEE Std. 2800-2022, NESO, and EirGrid as "do something." For Chile is classified as "do no-harm" as total demand distortion and total harmonic distortion are not recommended because when the current is extremely low, any harmonic current will result is a large current total demand distortion. For example, a PV plant at night may have a small amount of harmonic current entering the transformer and auxiliar loads, and this will show up as very high total demand distortion because the denominator (total current) is very small, but the impact on the system is negligible. This is why IEEE Std. 2800-2022 uses total rated harmonic distortion in which the denominator is the plant's rated current instead of its actual current output.

Table 14. Comparison of Power Quality Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Flicker	Shall not create unacceptable flicker at the point of measurement. Flicker emission values must not exceed 0.35 measured over 600 seconds or 0.25 measured over 2 hours. Assessed and measured with IEEE Std. 1453TM (Subclause 6.3) and International Electrotechnical Commission TR 61000-3-7 (Subclause 6.3).	Studies are done at the connection stage to ensure that the plant does not cause or increase the level of flicker in the grid. Must provide data on: -Flicker coefficient for continuous operation -Flicker step factor -Number of switching operations in a 10-minute window -Number of switching operations in a 2-hour window -Voltage change factor -Current injection at each harmonic component for each power park unit and for each power park module.	Voltage flicker limits at the connection point as allocated to them by the TSO or, as a minimum, those defined in Table 5 International Electrotechnical Commission TR 61000-3-7.	Must comply with the flicker severity limits of the international standards International Electrotechnical Commission 868, EN 60868, and EN 61000-4.[15] Although Art. 5-68 states 0.8 and 0.6 for perceptibility short term limit, V<=100 kV and above, respectively, it does not mention sources of flicker such as inverters. It is mentioned regarding transmission, although this is not imposed onto IBR power plants.
Power Quality	-IBR shall not cause rapid voltage changes at the reference point of applicability to exceed 2.5% of nominal voltage. Maximum current distortion in % of Irated: -When line -to-line voltage <69 kV, 4% (harmonic order, h<11), 2% (11<=h <17), 1.5% (17<=h <=50). Total rated current distortion <5%. -When line -to-line voltage is 69.001–	-Transmission owners work with the owner of the plant before connecting to ensure that the new plant harmonics emission is within acceptable limits. -Unbalance of less than 1.5% in England and Wales, and less than 2% except under abnormal conditions. -Unbalance of less than 1.5% in England and Wales, and less than 2% in	IBR shall not cause rapid voltage changes exceeding: -Temporary voltage depression of 5% and must recover the nominal voltage in 3 seconds. -Step change of 3 % in a timeframe of one cycle. Plant owners shall ensure that their	Total demand distortion <5%, V<100 kV Total demand distortion <2.5%. V>100 kV[16] Total Harmonic Distortion <3%. Maximum current distortion: -When Isc/IL<=20, 4% (h<11), 2% (11<=h<17), 1.5% (17<=h<23), 0.6% (23<=h<35), 0.3% (35<=h). -When Isc/IL is 20–50, 7% (h<11), 3.5% (11<=h<17), 2.5% (17<=h<23), 1% (23<=h<35), 0.5% (35<=h). -When Isc/IL is 50–100, 10% (h<11), 4.5% (11<=h<17), 4% (17<=h<23), 1.5% (23<=h<35), 0.7% (35<=h)

[15] Article 5-68, Chile Grid Code (NTSyCS, Sep 2020).
[16] Article 5-69, Chile Grid Code (NTSyCS, Sep 2020).

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
	161kV, 2% (h <11), 1% (11 <= h <17), 1% (17 <=h<=50). Total rated current distortion <2.25%. -When line -to-line voltage >161 kV, 1.5% (h <11), 1% (11 <=h <17), 1% (17 <= h <= 50). Total rated current distortion <2%. At any voltage: If h = 2, maximum current distortion as % of Irated must be <1%. If h = 4, <2%. If h = 6, <3%.	Scotland and across Great Britain except under abnormal conditions. -Measured harmonic emission limits are specified in the bilateral connection agreement, or if not specified, the relevant planning level specified in Engineering Recommendation G5/5 takes precedence.	connection to the transmission systems does not result in an increase in the level of harmonic distortion of the supply voltage on the transmission system at the connection point. Harmonic voltage distortion shall ensure compliance International Electrotechnical Commission TR 61000-3-7 and by default, CENELEC Standard EN 50160, on the transmission system.	-When Isc/I_L is 100–1,000, 12% (h<11), 5.5% (11<=h<17), 5% (17<=h<23), 2% (23<=h<35), 1% (35<=h). -When Isc/I_L is >1,000, 15% (h<11), 7% (11<=h<17), 6% (17<=h<23), 2.5% (23<=h<35), 1.4% (35<=h). Non-third-order harmonics: -Order 5, 6% (<=110 kV), 2% (>100 kV) -Order 7, 5% (<=110 kV), 2% (>100 kV) -Order 11, 3.5% (<=110 kV), 1.5% (>100 kV) -Order 13, 3% (<=110 kV), 1.5% (>100 kV) -Order 17, 2% (<=110 kV), 1% (>100 kV) -Order 19, 1.5% (<=110 kV), 1% (>100 kV) -Orders 23 and 25, 1.5% (<=110 kV), 0.7% (>100 kV) -Orders>25, 2%+1.3%*25/h (<=110 kV), 0.5%+0.5%*25/h (>100 kV). Third-order harmonics: -Order 3, 5% (<=110 kV), 2% (>110 kV) -Order 9, 1.5% (<=110 kV), 1% (>110 kV) -Order 15, 0.3% (<=110 kV), 0.3% (>110 kV) -Orders>=21, 0.2% (<=110 kV), 0.2% (>110 kV). Second-order harmonics: -Order 2, 2% (<=110 kV), 1.5% (>110 kV) -Order 4, 0.5% (<=110 kV), 0.5% (>110 kV) -Orders 8 and 10, 0.5% (<=110 kV), 0.4% (>110 kV) -Orders>=12, 0.2% (<=110 kV), 0.2% (>110 kV).

4.3.3 Forecasting

A reliable forecast for IBRs enables defining the necessary ancillary services and supports maintaining the balance of the power system. For NESO, EirGrid and Chile, they can request the specific forecast required to operate the system. This requirement is classified in general as "do something". Since IEEE Std. 2800-2022 focusses on technical electrical specifications, it is out of the scope, but it does not imply that forecasting is not important. Instead, it just means that forecasting is not in the scope of the standard, and instead any forecasting requirements would be in the interconnection agreement (Table 15).

Table 15. Comparison of Forecast Requirements IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Forecast	No requirement, out of the scope of the standard.	As requested from the transmission system operator.	As requested from the transmission system operator.	Wind: -12-hour-ahead hourly generation updated hourly with 25%, 50%, and 75% probabilities of occurrence. - 48-hour-ahead hourly generation, updated every 6 hours with 25%, 50%, and 75% probabilities. -168-hour (weekly)-ahead hourly generation, updated every 24 hours with 50% probability. -Hourly probability of occurrence of significant (in magnitude or speed) variation in generation in next 12 hours, updated hourly. -Wind speed/direction, temperature, and atmospheric pressure for site for next 48 hours, updated every 6 hours. Solar: -48-hour-ahead hourly generation, updated every 12 hours with 50% probability. -168-hour-ahead hourly generation, updated every 24 hours with 50% probability. -System operator may request to audit prediction methodology.

4.3.4 Protection

Protective devices are used to safeguard grid equipment from harm by detecting problems such as short circuits, equipment failures, and other abnormal conditions with power system components and their isolation. The protections must operate in accordance with the technical requirements. It is essential to have effective protection coordination in place to prevent the unplanned disconnection of IBRs, the setting of the protection triggers should be outside the frequency and voltage ride through range. The selected references have highlighted that protection methods must comply with all technical requirements for IBRs (Table 16). This requirement is classified in general as "do-no-harm." This is because protection topics are considered to be in scope of the utility protection engineer and are typically plant specific, so specifying protection requirements is not in the scope of grid codes.

Table 16. Comparison of Protection Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Protection	-Any frequency, ROCOF, voltage, instantaneous over-voltage protection, or AC overcurrent protection shall allow plant to meet ride-through requirements. -Any instantaneous over-voltage protection shall be coordinated with instantaneous over-voltage capability of IBR unit, and any surge protection within IBR and at point of applicability. -AC overcurrent protection applicable to phase and sequence quantities. If employed, coordinated with protection schemes on transmission system. Shall use filtered quantities. -Shall implement protection for the interconnection system in accordance with the requirements of the transmission system owner and/or the requirements of the owners of electrically joined facilities. This protection shall be coordinated with the transmission system protection system.	The owner of the plant is responsible for choosing protection methods to comply with technical requirements.	There are not requirements differentiated for IBRs, the requirements apply to the distribution system operators, generators, interconnectors and demand customers.	No requirement

4.3.5 Model and Model Validation Requirements

Several incidents in power systems worldwide involving IBRs have highlighted the need for IBR model requirements and model validation to reflect real-time operation in simulations and analyses. The selected references emphasize the necessity for and validation of phasor-domain transient (PDT) and EMT models. PDT models are sometimes referred to as positive-sequence (fundamental-frequency) stability models or “RMS” models, although they simulate phasor-domain values, not root-mean-square values. This can be categorized as a general "do something" requirement for IEEE Std. 2800 2022, NESO and EirGrid. For Chile is considering "do no-harm" as it is not required EMT models in the grid code (Table 17).

Table 17.Comparison of Model and Model Validation Requirements for IEEE Std. 2800-2022 and UK (NESO), Ireland (EirGrid), and Chile Grid Codes

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Model Requirements	By request, plant owner shall provide plant–level models, including a steady-state power-flow model, positive-sequence (fundamental-frequency) stability dynamic model (user written and/or generic), an EMT model, and short-circuit and harmonics models to perform IBR plant design evaluation and system studies.	-RMS models that represent the users' plant and apparatus and controllers in balanced, RMS, positive phase-sequence, time domain studies. Submitted as block diagram of all transfer functions. -EMT models that represent the users' plant and apparatus in EMT studies on the transmission and distribution system.	The owners of the plant shall supply models that shall be capable of representing the behavior of the plant in balanced RMS positive phase-sequency, time-domain studies and where specified, EMT and harmonic studies. The owners of the plant must provide models in software packages as defined by the TSO. The TSO may from time-to-time request that the models be updated to be compatible with changes in the TSO´s computing environment. The models are provided without undue delay or in any event, within 90 business days of the date of request.	RMS models are required.[17] EMT models are requested on demand by the operator but are not required by the grid code.

[17] Article 6-21 Chile Grid Code (NTSyCS, Sep 2020).

Model Validation	-Non-aggregated IBR unit EMT model—may be developed based on actual code and may be verified with type and/or hardware-in-the-loop test results. -IBR unit stability dynamic (user-written and/or generic), short-circuit, etc., models—verified against non-aggregated IBR unit EMT model. This includes converter and respective electrical control models. -Once the IBR plant is operational, system event data could be used to verify various plant-level models. -A post-commissioning model validation confirms and calibrates that the models supplied during the design evaluation accurately represent the IBR plant.	-Provide simulation studies to prove voltage and frequency controllers are fit for purpose. -Provide dynamic time series simulation report containing: 1. Response to large negative step in voltage to cause a change in reactive power from zero to the maximum lagging value. 2. Response to large positive step in voltage to cause a change in reactive power from zero to the maximum leading value. 3. Response to a -2% voltage step while operating within 5% of the lagging reactive power limit. 4. Response to a +2% voltage step while operating within 5% of the leading reactive power limit. 5. Response to large negative step in system voltage to cause a change in reactive power from the maximum leading value to the maximum lagging value. -Provide signals for on-site monitoring: 1. Reactive range tests (1-Hz frequency) 2. Frequency control tests (10-Hz frequency) 3. Voltage control tests (100-Hz frequency) 4. DC voltages and appropriate scaling to monitor interface point capacity, reactive power, frequency, nominal terminal point voltage.	All models provided to the TSO for use in dynamic simulations must be validated. For validation purposes the owners of the plant shall ensure that appropriate tests are performed and measurements taken to assess the validity of the dynamic model. The tests and measurements required shall be agreed between the owners of the plant and the TSO.	RMS model validation against field tests before commercial operation date.

Requirement	IEEE Std. 2800-2022	NESO	EirGrid	Chile
Model Maintenance	Any changes to controls during commissioning must be agreed upon and reported to transmission system operator. Post-commissioning monitoring verifies that the IBR plant continues to meet the requirements of this standard over its operational lifetime by evaluating plant's performance in the field during operation, especially following transmission system events in which the measured voltage and/or frequency deviate from the normal operating region.	Transmission system operator notified any change to an item of data registered with the operator. Some changes need to be discussed and agreed with NESO in advance.	All Models provided to the TSO must be maintained and updated to accurately reflect the operational performance of the user's plant over the lifetime of the plant. The owners of the plant shall inform the TSO of any changes to the plant which may materially affect the accuracy of the dynamic model in predicting the active power and reactive power output of the plant with respect to changes or excursions in voltage and frequency at the connection point. In this case the owner of the plant shall re-submit the parameters associated to the dynamic model or fully re-submit the dynamic model of the plant. Changes which shall be reported to the TSO may include but are not limited to alterations in plant protection settings, modifications to plant controller settings and alterations to droop or plant frequency response. In the event of scheduled plant outages or maintenance the owner of the plant must provide appropriate model updates in advance of the scheduled outage.	RMS model must be updated for any significant changes in equipment and control or new firmware version.

5 Proposed Review and Update of Requirements for Conventional IBRs in the NTSyCS

Based on the comparison made in Section 4, IEEE Std. 2800-2022 generally provides the most comprehensive set of requirements and could serve as a strong reference for conventional IBR technical requirements that may be adopted by the Chilean grid code. Conventional IBRs may not be able to survive the loss of last synchronous machine tests, but they may still be able to provide a variety of grid support services that can help enable the increased percentage of IBRs.

In some cases, it could be helpful to adapt individual technical requirements from other grid codes that may provide additional specifics beyond those found in IEEE Std. 2800-2022, such as ramping capabilities, and SCR. Also, for some requirements as FRT and reactive power the Chile grid code is similar to IEEE Std. 2800-2022. However, due to the comprehensive capabilities of the IEEE Std. 2800-2022, it was selected as the reference for Chile to ensure consistency and uniformity throughout the grid upgrade process. Forecasting is currently in the Chilean grid code and, as mentioned above, is not covered by IEEE Std. 2800-2022. Table 18 summarizes the requirements that could be included or updated in the NTSyCS:

Table 18. Summary of the requirements that could be incorporated or updated in the NTSyCS

Topic	Requirement	Reference
Frequency	FFR	Consider adopting Section 6.1 of IEEE Std. 2800-2022.
	PFR	Consider adopting Section 6.2 of IEEE Std. 2800-2022.
	Ramping for control parameter change[18]	Consider adopting Section 4.6.2 of IEEE Std. 2800-2022.
	Frequency ride-through	Consider adopting Section 7.3 of IEEE Std. 2800-2022.
	ROCOF	Consider adopting Section 7.3.2.3.5 of IEEE Std. 2800-2022.
Voltage	Reactive power capability	Consider adopting Section 5.1 of IEEE Std. 2800-2022.
	Voltage control	Consider adopting Section 5.2 IEEE Std. 2800-2022.

[18] This requirement is identified as more advanced within the NESO grid code. However, due to the comprehensive capabilities of the IEEE 2800-2022 standard, it was selected as the reference for Chile to ensure consistency and uniformity throughout the grid upgrade process.

Topic	Requirement	Reference
	Voltage ride-through	Consider adopting Section 7.2.2 and 7.2.3 of IEEE Std. 2800-2022.
	Momentary cessation	Consider adopting Section 7.2.2.3.3, 7.2.2.6, 7.2.3, and 7.3.2.4 of IEEE Std. 2800-2022.
	Current injection during voltage ride-through	Consider adopting Section 7.2.2.3 of IEEE Std. 2800-2022.
	Phase jump ride-through	Consider adopting Section 7.3.2.4 of IEEE Std. 2800-2022.
Performance	SCR[19]	Consider adopting Section C.2 of IEEE Std. 2800-2022.
	Power quality	Consider adopting Section 8 of IEEE Std. 2800-2022.
	Protection	Consider adopting Section 9 of IEEE Std. 2800-2022.
	Models and validation	Consider adopting Sections 10 and 11 and Annex G of IEEE Std. 2800-2022.

[19] This requirement is identified as more advanced within the NESO grid code. However, due to the comprehensive capabilities of the IEEE 2800-2022 standard, it was selected as the reference for Chile to ensure consistency and uniformity throughout the grid upgrade process.

6 Conclusions

This document compares the technical requirements in the Chilean grid code (NTSyCS) with the EirGrid, NESO grid codes and the IEEE2800-2022 standard for conventional IBRs at transmission and sub-transmission levels, to have a reference for future updates of the NTSyCS, considering local system requirements and current improvements in inverter-based resource technology.

Based on the results of the comparative study, this document proposes and describes the requirements for conventional IBRs that could be included and updated in the Chilean grid code, which is proposed to be aligned with the IEEE2800-2022 standard. Some additional suggestions of the report are

1. IEEE Std. 2800-2022 can be a guideline for updating the required interconnection capability and performance criteria of IBRs interconnected in the transmission and subtransmission system in Chile.

2. Accurate modeling and validation of the power system components are important to identifying system needs and future IBR requirements.

3. Long- to medium-term planning studies could be used to define IBR control and protection-setting requirements according to system needs.

4. IBR technical requirements are defined with flexible and adjustable control settings according to system needs.

5. It is desirable that all IBRs connected to the bulk power system have high resolution transient data recording capability to capture voltage and current waveforms during faults.

6. Post-operation analysis of technical requirements is required to assess their performance, ensure compliance, and guide future grid code updates.

7. Ensuring compliance with technical requirements is critical during testing, commissioning, and operation.

8. The definition of technical requirements for IBRs is dynamic as technology evolves and system needs increase. Evaluation and review of IBR requirements must be an ongoing process.

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