LBNL-2001104

# Review of International Grid Codes

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**February 2018**

This work was supported by the Federal Energy Regulatory Commission, Office of Electric Reliability, under interagency Agreement #FERC-16-I-0105 and, in part, by the U.S. Department of Energy, Grid Modernization Lab Consortium, in accordance with the terms of Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

# Review of International Grid Codes

Prepared for the
Office of Electric Reliability
Federal Energy Regulatory Commission

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# Acknowledgements

The work described in this study was funded by the Federal Energy Regulatory Commission (FERC), Office of Electric Reliability, under interagency Agreement #FERC-16-I-0105 and, in part, by the U.S. Department of Energy, Grid Modernization Lab Consortium, in accordance with the terms of Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The authors acknowledge project management provided by Eddy Lim, FERC Office of Electric Reliability. The author thanks Sydney Niemeyer, NRG Energy (retired), and Julia Matevosyan, Electric Reliability Council of Texas, for review comments on an early draft of this report.

All opinions, errors, and omissions remain the responsibility of the authors. All reference URLs were accurate as of February 2018.

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# Acronyms and Abbreviations

| | |
|---|---|
| AC | Alternating current |
| AGC | Automatic Generation Control |
| BA | Balancing Authority |
| CAISO | California Independent System Operator |
| EFR | Enhanced Frequency Response |
| ERCOT | Electric Reliability Council of Texas |
| ERO | Electric Reliability Organization |
| FCR-D | Frequency Containment Reserves–Disturbance |
| FCR-N | Frequency Containment Reserves–Normal |
| FERC | Federal Energy Regulatory Commission |
| FFR | Fast Frequency Response |
| FRM | Frequency Response Measure |
| FSM | Frequency Sensitive Mode |
| GIR | Grid Interconnection Requirements |
| Hz | Hertz |
| IESO | Independent Electricity System Operator |
| ISO | Independent System Operator |
| ISO-NE | Independent System Operator-New England |
| LGIA | Large Generator Interconnection Agreement |
| LGIP | Large Generator Interconnection Procedures |
| MISO | Midcontinent Independent System Operator |
| MVA | Mega Volt Ampere |
| MW | Megawatt |
| NERC | North American Electric Reliability Corporation |
| ONS | Operador Nacional do Sistema Elétrico |
| PFR | Primary Frequency Response |
| ROCOF | Rate of Change of Frequency |
| RRS | Responsive Reserve Service |
| SIR | Synchronous Inertia Reserve |
| SOP | System Operational Requirements |
| TSO | Transmission System Operator |
| UFLS | Under Frequency Load Shedding |
| VoLL | Value of Lost Load |
| WECC | Western Electricity Coordinating Council |

# Glossary of Terms

| | |
|---|---|
| *Ancillary Services* | Services, as defined by the Transmission System Operator (TSO), necessary for the reliable operation of the system. |
| *Controller Insensitivity* | Inherent feature of the control system that dictates the minimum frequency change that results in a change in the active power output of the generating unit. |
| *Droop* | The ratio of the per unit change in steady-state frequency to the per unit change in active power generation of a generating unit, expressed in percent. |
| *Frequency Containment Reserves - Disturbance (FCR-D)* | FCR-D is a specific Nordic product with the purpose of balancing the system in case of disturbances where frequency drops below 49.90 Hz. |
| *Frequency Containment Reserves - Normal (FCR-N)* | FCR-N is a specific Nordic product with the purpose of balancing the system within the normal frequency band (49.90<f<50.10 Hz). |
| *Frequency Sensitive Mode (FSM)* | A mode of operation whereby the active power output of the generating unit changes in response to system frequency deviations. |
| *Governor Deadband* | The maximum frequency deviation from the nominal value for which the generating unit will not adjust its generation level when operating in Frequency Sensitive Mode. |
| *Primary Frequency Control* | The action of a generating unit to automatically adjust its active power output in the first few seconds following a frequency event in a manner which seeks to arrest the frequency decline and restore the frequency back towards its nominal value. |
| *Primary Frequency Response (PFR)* | Primary frequency response involves automatic, autonomous, and rapid (i.e., within seconds) changes in a generator's output to oppose sudden changes in frequency; refers to the actions of individual generators. |
| *Rate of Change of Frequency (ROCOF)* | A measure of how quickly frequency changes following a sudden imbalance between generation and load. ROCOF is expressed in Hertz per second (Hz/second). |
| *Synthetic Inertia* | A short injection of active power in response to a frequency deviation provided by asynchronously connected wind turbines. This injection is achieved by extracting the kinetic energy stored in its turbine. It is typically accompanied by a 'recovery period' where the active power of the wind turbine is less that its pre-disturbance active power generation. |
| *Under-Frequency Load Shedding (UFLS)* | An extreme measure to arrest frequency decline; disconnects large, pre-set groups of customers at predetermined frequency set points. |

# 1. Introduction

The electrical power system has established itself as one of the most critical components of today's modern society. Our daily interaction with this system has grown considerably over the past decade with increased electrification of services, most notably in the case of the transportation network. This growth in demand has occurred in parallel with a re-examination of our energy sources as both wind and solar energy continue to proliferate the electrical network. These resources, however, bring their own challenges to the reliable operation of an interconnected power system. This report deals with one challenge in particular: the ability of an interconnected power system to withstand the instantaneous loss of a block of generation.[1]

Alternating current (AC) electrical systems are designed to operate at a nominal frequency (e.g., 60 Hertz (Hz) in North America and 50 Hz in Europe). These systems are maintained at these nominal values through ensuring that, at all times, the electrical power being consumed on the network balances the electrical power being generated on the network. This 'balancing' is predominately carried out on three timescales: *primary frequency response* (PFR), *secondary frequency response*, and *tertiary frequency response*. The timescales of these responses can vary, depending on the specific interconnection in question. This report focuses on the primary frequency response of a synchronously interconnected power system.

The role of primary frequency control is to autonomously correct second-by-second imbalances between supply and demand. This has historically been carried out by a generator monitoring its own speed and adjusting its fuel in-feed to increase or decrease the power it is generating. This ability to autonomously operate and push the system frequency towards its nominal value is the most critical operational aspect of reliable power systems. Following the loss of a large generating unit, the system frequency will begin to decrease due to a generation/load imbalance. If this imbalance is not corrected in sufficient time, the system may reach an emergency state where operators may begin to disconnect customers in order to restore the balance and/or generators may intentionally trip offline to protect themselves, thus exacerbating the problem. The first emergency state is commonly referred to as Under-Frequency Load Shedding (UFLS), whereby large blocks of customers will be disconnected from the grid and receive no compensation for this action. This should not be confused with large customers voluntarily disconnecting themselves form the grid in response to a frequency excursion and being compensated for doing so. This will be further discussed throughout this report. The role of primary frequency response is analogous to the system graphically depicted in Figure 1.

[1] What is contained within this report also holds true for the case of a sudden decrease in load. These events, however, are typically both less frequent and less severe in magnitude, and consequently, less detrimental to a synchronous area than a loss of generating unit.

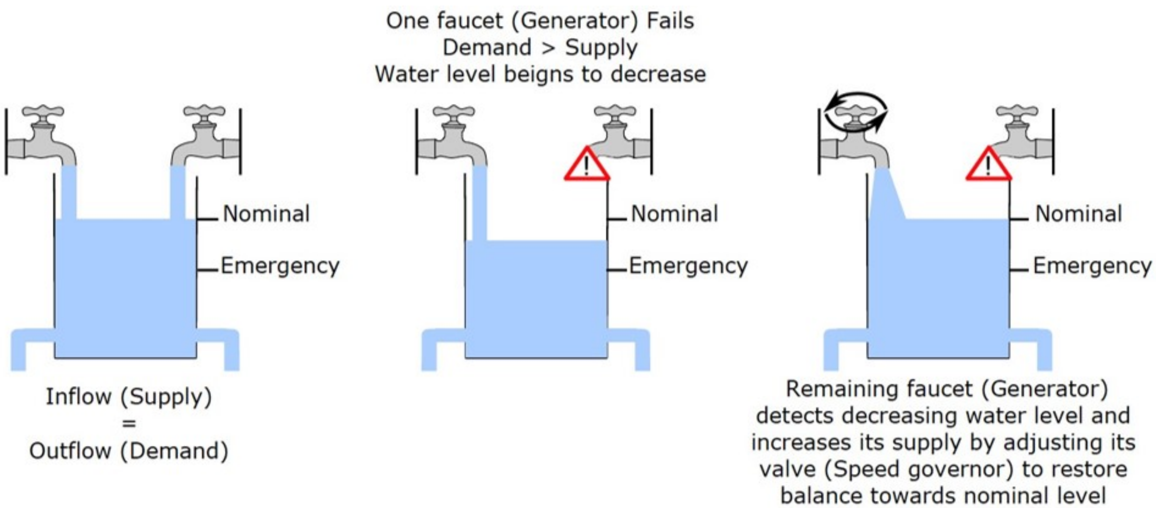


**Figure 1. Analogy outlining the role of primary frequency response in maintaining balance**

## 1.1 Establishing Primary Frequency Response Requirements

Typically, there exist various standards related to PFR requirements, commonly contained within a region's Grid Code, which generators must comply with—both prior to initial connection, and while operational. The entities responsible for creating and enforcing these standards can vary across regions; however, the predominant model involves governmental agencies, which approve standards, and a Transmission System Operator (TSO) or an Electric Reliability Organization (ERO), which is responsible for enforcing those standards. In the case of a single synchronously interconnected power system spanning multiple countries—as is the case in Europe—there can exist two sets of standards:

1. A synchronous area-wide minimum standard for connection and operating the network; and
2. A national- or regional-specific requirement which is more exhaustive, in its requirements for both connection and operation.

The existence of a system-wide minimum standard is in direct response to the fact that physical disturbances on the grid do not adhere to international boundaries and thus, in order to ensure reliable delivery of power, there must exist some homogeneity in the response of all generators across the system to disturbances.

As noted earlier, there is typically an independent entity responsible for ensuring compliance with the standards outlined within a Grid Code. These entities are granted the power to do so by the respective national or regional government. In North America this entity is the North American Electric Reliability Corporation (NERC); however, elsewhere it is typically the respective TSO responsible for operating the network. These entities are required to monitor the evolution of the power system to ensure continual reliable operation and make recommendations for modifications to the Grid Code in order to adapt to changing system conditions.

When considering Grid Codes from the perspective of PFR, there are typically two distinct set of requirements/practices. The first are Generation Interconnection Requirements (GIR). These are a set of requirements which a generator must fulfil prior to being granted a connection to the network. They typically specify a plant's technical requirements/performance for a variety of system conditions, including frequency deviations. The second set of requirements are System Operational Practices (SOP). Within this report, these practices relate to how PFR is dispatched within each of the regions examined. This includes how PFR is procured (e.g., whether it is a market product or mandatory participation), as well as how required reserves are determined. In some cases GIR and SOP may overlap, specifically in the case of mandatory PFR participation, while in other cases generating units may not be subject to a PFR capability test within its GIR. Instead, they may only be subject to a capability verification test if they wish to participate in the respective market.

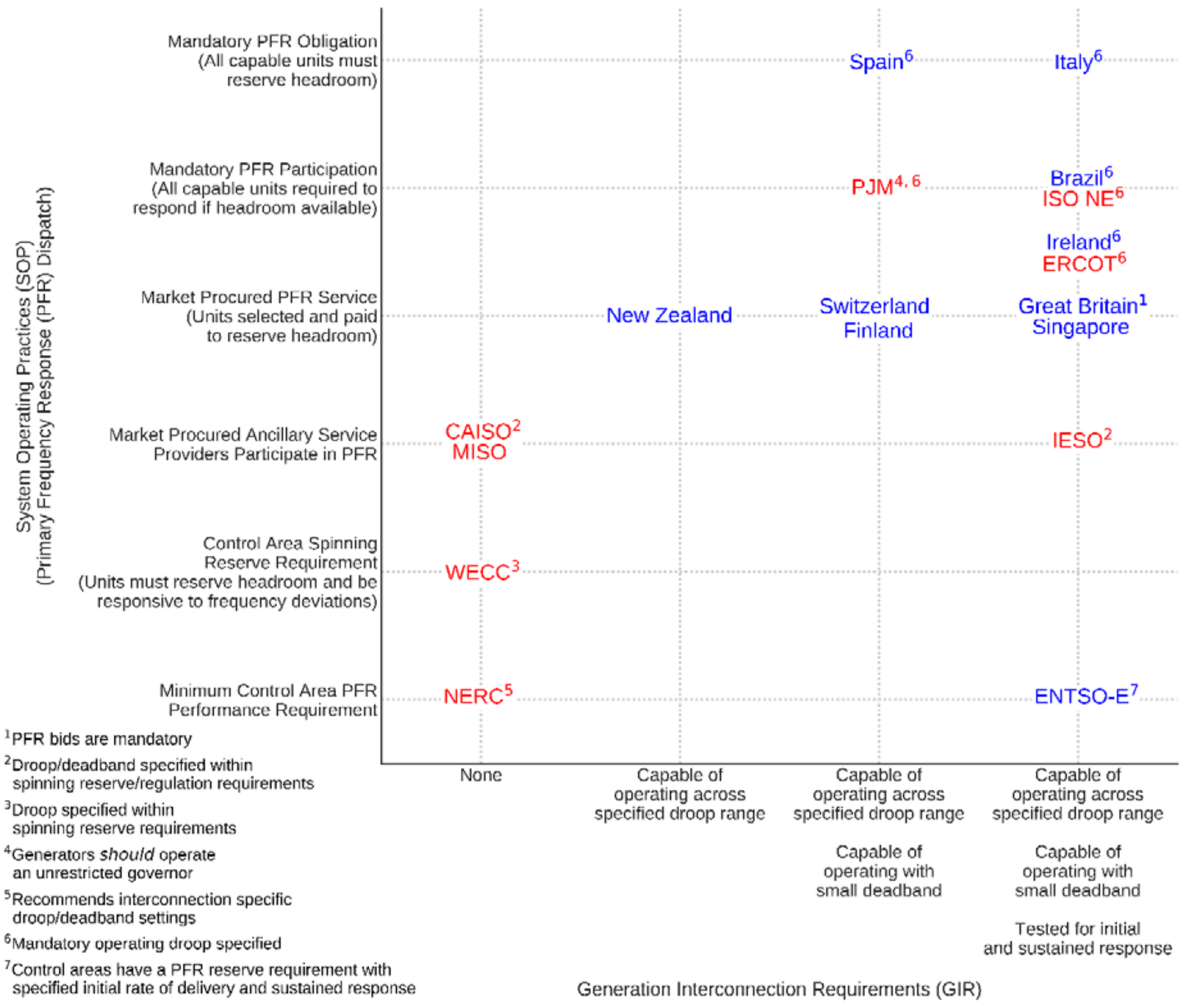


**Figure 2. Comparison of PFR requirements/standards**

The objective of PFR immediately following the loss of generation is common across all synchronous areas: arrest the frequency decline before involuntary UFLS, return the frequency towards its nominal operating value, and restore primary reserves in preparation for the next frequency event. There are, however, a number of approaches to satisfying this objective. Each synchronous system considered has its unique characteristics that make it suitable to certain approaches. There does exist, however, some general practices that help ensure sufficient PFR capabilities of a system (e.g., explicit deadband/droop requirements, and testing a generator's initial and sustained response), which will be discussed through this report. Figure 2 presents a high-level comparison of the regions considered and their respective policies/approaches concerning primary frequency response. These requirements and practices will be explored in more depth in the following sections.

Throughout this analysis, the focus will be on generation units that are considered *large generating units*. This is due to *small generating units* generally being exempt from PFR requirements. The definition of a large generating unit varies across the regions examined, and further information regarding the respective thresholds for each of the regions examined can be found in Appendices A and B. Therefore, throughout the following sections "all generating units" will be used when talking about units that are classified as large generating units with respect to their respective entities definitions. Furthermore, unless noted otherwise, PFR requirements for wind and solar generation pertain to a governor-like response.

## 1.2 Current North American Requirements and Practices

The electrical power networks that span North America cross multiple jurisdictions and, consequently, are subject to various governing bodies, dependent on the region in question. The following sections explore some of these regions and the relationships between the various entities involved in creating standards and requirements.

### 1.2.1 Continental United States

The following sections begin with an exploration of current PFR practices in the United States and Canada, and end with a high-level summary of some of the international practices considered. These international practices will be explored in more depth later in this report.

The primary entities responsible for standards and requirements in the United States are the Federal Energy Regulatory Commission (FERC) and NERC. FERC is a federal agency that regulates the interstate transmission of electricity, natural gas, and oil within the United States. In July 2006, FERC certified NERC as the ERO for the United States; through this role, NERC has the authority to create—through an open stakeholder process—reliability standards. Once these standards are finalized by NERC, they are then submitted to FERC for approval. Upon approval, NERC assumes the responsibility for ensuring compliance with these standards. Historically, these standards and requirements have not focused on generator requirements concerning PFR. FERC's Large Generator Interconnection Agreement (LGIA) was largely silent on the matter, noting that if a speed governor is present it should be operated in an automatic mode.

The most significant standard regarding PFR in the United States is NERC BAL-003-1, which was approved by FERC in 2014 and updated in 2015 as NERC BAL-003-1.1[2]. This standard requires that each Balancing Authority (BA) annually satisfies a minimum Frequency Response Measure (FRM) in order to ensure it is capable of avoiding UFLS for a specified loss of generation. The specific details regarding how BAs meet this target is left to the BAs themselves rather than directed by NERC. NERC has, however, outlined recommended speed governor settings for each of the three U.S. interconnections that support compliance with BAL-003[3].

In addition to BAL-003-1.1, NERC introduced MOD-027-1[4], which was approved by FERC in 2014. This standard requires validation of the model of a unit's speed governor and outer loop controls, either through comparison with the unit's response to a system disturbance or a test. Although this standard does not mandate a minimum performance requirement, it does ensure that system operators will be equipped with more accurate models when accessing how the system responds to a loss of generation. The effects of this standard will become apparent in 2018, whereby 30% of an entity's gross MVA capacity must be compliant with the standard—with 100% compliance required within 10 years of the standard coming into effect.

Aside from interconnection-wide standards and requirements, there also exists the capability for a BA to seek approval for a region-specific standard from FERC. We next explore a subset of BAs that have taken additional actions to ensure sufficient PFR availability in the coming years. Specific details regarding their requirements and referenced documents can be found in Appendix A, and an exploration of international standards is presented in Appendix B.

### *ERCOT*

One such example of a regional standard is NERC BAL-001-TRE-1, which was approved by FERC in 2014 for the Texas Interconnection, which is operated by the Electricity Reliability Council of Texas (ERCOT).[5] Having already achieved a peak instantaneous renewable generation of 50% in March 2017, coupled with the need to ensure it can withstand the loss of two large nuclear units, ERCOT has been forced to pay particular close attention to PFR. Currently, PFR is mandated from all units, including wind and solar generation, with the exception of nuclear units and older wind generating units. In order to ensure compliance with this requirement, both the initial and sustained response of units are verified after every recorded frequency disturbance. ERCOT also procures an ancillary service, Responsive Reserve Service (RRS) in order to ensure that sufficient primary reserves are always maintained. Both controlled load, exhibiting a governor-like response, and uncontrolled load, triggered via under-frequency relays, can provide this service.

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[2] NERC (2015): *BAL-003-1.1: Frequency Response and Frequency Bias Setting.*
[3] NERC (2015b): *Reliability Guideline: Primary Frequency Control*
[4] NERC (2014b): *MOD-027-1: Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.*
[5] NERC (2014a): *BAL-001-TRE-1: Primary Frequency Response in the ERCOT Region.*

## WECC

The Western Electricity Coordinating Council (WECC) has been approved by the FERC as the Regional Entity for the Western Interconnection. WECC Reginal Standards requires that each of its Balancing Authorities (BAs) and Reserve Sharing Groups reserve headroom on spinning generation equal to at least half of its contingency reserve requirement.[6] Furthermore this headroom must be responsive to frequency deviations through a speed-governor or control scheme. The contingency reserve requirement is defined as the greater of:

- loss of the most severe single contingency
- the summation of 3% of hourly load plus 3% of hourly generation

WECC requires that all units providing this service have a droop between 3 to 5%.[7]

## CAISO

The California Independent System Operator (CAISO) is currently redesigning its approach to procuring PFR using a two-phase approach: the first to ensure short-term compliance with NERC BAL-003-1.1, and the second to develop a long-term market mechanism for PFR. The first phase, approved by FERC in 2016,[8] has two important implications for PFR procurement in CAISO. The first of these is that it allows CAISO to procure transferred PFR from other BAs in the Western Interconnection, which will help ensure they meet their BAL-003-1.1 requirements. The second is that it strengthens the requirements for generators providing PFR through their spinning reserve requirements. The main differentiable features between CAISO's revised requirements and WECC's system-wide Standard BAL-002-WECC-2[9] is the establishment of a maximum allowable deadband, specific droop requirements for combustion turbines, and requirements prohibiting the withdrawal of the initial response to a PFR event, except in the case of specific circumstances.  Verification of a plant's ability to adhere to these requirements is required prior to participating in the spinning reserve market.

## ISO-NE

ISO New England (ISO-NE) has also recently introduced more explicit requirements on its generators regarding PFR. These changes were introduced in a 2014 revision to its *Operating Procedure No. 14*[10]. PFR is now mandated from all generators—including wind and solar generation—with explicit requirements for both droop and deadband. Furthermore, it prohibits the withdrawal of this response via outer-loop plant controllers, with the exception of Automatic Generation Control (AGC). Compliance is verified via the ISO requesting the plant information, measured frequency, and MW output for an identified frequency event.

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[6] WECC (2014): WECC Standard BAL-002-WECC-2—Contingency Reserve
[7] WECC (2016): PRC-001-WECC-CRT-1.2
[8] FERC (2016): *156 FERC ¶ 61,182: Order on Proposed Tariff Revisions.*
[9] NERC (2017): *Standard BAL-002-WECC-2a—Contingency Reserve*
[10] ISO New England (2017): *Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources.*

### *PJM*

PJM Interconnection (PJM) has PFR requirements and practices with language that is less clear relative to those previously discussed. Section 7.1.1 of PJM's *Manual 14D*[11] notes the following concerning PFR:

> All generators, including pseudo tied or dynamically scheduled generating resources, should operate on unrestricted governor…

The use of "should" as opposed to "must" (or similar wording) introduces some uncertainty about whether this is a requirement or merely a recommendation. This uncertainty is again present when discussing governor settings:

> With exception of nuclear generators, all generating resources with gross plant/facility aggregate nameplate rating greater than 75 MVA are requested to ensure that, in the absence of technical or operational considerations, the generator governor (or equivalent electronic speed control device) and Distributed Control System (DCS) settings provide deadbands that do not exceed ± 36 mHz, and droop settings that do not exceed 5%.

Again, use of the phrase "requested to ensure" lacks the clarity typically associated with standards and requirements.

PJM, however, is clear on the matter that if a unit has a non-functioning governor, this information must be immediately reported to PJM through their online system, eDART. It also specifies that governor outages must be kept to a minimum.

## 1.2.2 Canada

### *Ontario Independent Electricity System Operator (IESO)*

The Independent Electricity System Operator (IESO) is the entity responsible for operating the electricity market and the bulk electrical system in the province of Ontario, Canada. Following the August 2003 blackout, NERC was appointed the Electric Reliability Organization for IESO in 2006 through a Memorandum of Understanding between the Ontario Energy Board and NERC.[12] This had the effect of subjecting IESO to NERC's common standards and requirements. IESO is also a member of the Northeast Power Coordinating Council (NPCC), which is responsible for monitoring the IESO for compliance with NERC reliability standards. The relationship between Ontario Energy Board, NERC, and NPCC is outlined in a Memorandum of Understanding between IESO, NERC and NPCC, which was amended and restated in 2010.[13]

Regarding PFR, IESO mandates that generators, including wind and solar generation, satisfy specific capabilities as part of its connection conditions, namely concerning the maximum deadband, adjustable droop range, and rate of delivery. The requirement to operate with a functioning governor in service

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[11] PJM (2017a): *Manual 14D: Generator Operational Requirements, Revision 41.*

[12] IESO (2006): *Memorandum of Understanding between the Ontario Energy Board and the North American Electric Reliability Cooperation.*

[13] IESO (2010): *Memorandum of Understanding between the Independent Electricity Operator and the North American Electric Reliability Cooperation and the Northeast Power Coordinating Council, Inc.*

satisfying these technical specifications is mandated for units providing IESO's frequency regulation ancillary service.

In addition to these requirements, IESO now mandates that wind generators have the capability to provide a *synthetic inertia* response to the system following a frequency deviation.[14] This response must be activated within one second and maintained for a minimum of ten seconds, for the case where the frequency has not sufficiently recovered. The motivation for this requirement was to enable wind generators to contribute to the PFR of the system without needing it to curtail itself to do so. IESO notifies wind generators when this service should be in operation.

## 1.3 International Practices

When selecting specific Grid Codes to examine we sought to select a group of Grid Codes that represented the spectrum of both the interconnection requirements and PFR procurement practices currently in place. In general we sought to choose Grid Codes from distinct synchronous interconnections; however, we included three Grid Codes from the European Network of Transmission System Operators for Electricity (ENTSO-E), in order to demonstrate that even within an interconnection, there can exist significant variations across both interconnection requirements and PFR procurement practices. The Nordic synchronous area has common practices/requirements for all its TSO members relating to PFR. Finland, however, was explicitly considered due to the ability to refer to specific interconnection agreements and testing requirements.

### 1.3.1 Continental Area Codes

#### *ENTSO-E*

In terms of organization, the European electric system is similar to North America. ENTSO-E is an umbrella organization representing 43 electricity transmission system operators (TSOs) from 36 countries across Europe, and is responsible for drafting network Grid Codes as well as assisting with their implementation—similar to the role of NERC in North America. A harmonized grid connection code was introduced in 2016, as described in the European Union Commission Regulation *EU 2016/631*[15], which sets a minimum standard that all members must adhere to in their respective Grid Codes. This will require some minor changes to some of its members Grid Codes[16,17] This standard is a minimum requirement rather than a recommended set of requirements and, typically, national Grid Codes are more exhaustive and more stringent in their allowable ranges for technical parameter ranges (e.g., droop and governor deadbands). This harmonized Grid Code is focused on the performance of PFR rather than on its procurement—which is left to the individual TSOs, with some opting for mandatory participation and others employing a market mechanism. Given that the ENTSO-E network

[14] IESO (2017): *Market Manual 2: Market Administration; Part 2.20: Performance Validation*.
[15] EU (2016): *Commission Regulation (EU) 2016/631: Establishing a network code on requirements for grid connection of generators.*
[16] ENTSO-E (2012): Network Code for Requirements for Grid Connection Applicable to All Generators: Requirements in the Context of Present Practices
[17] See https://docs.entsoe.eu/cnc-al/ for further information on the implementation of this Grid Code

codes set the minimum requirements, they are acknowledged here for reference and may be briefly referenced throughout this document rather than given explicit consideration, as will be the case for the national codes. A summary of both the minimum governor requirements and PFR delivery performance are shown below in Table 1 and Table 2. A more detailed analysis of ENTSO-E requirements can be found in Appendix B.

**Table 1: ENSTO-E Minimum Generator Technical Requirements**

| Parameter | Range |
|---|---|
| Active Power Range | 1.5 - 10% |
| Frequency Response Insensitivity | 10 - 30 mHz |
| Deadband | 0 - 500 mHz |
| Droop | 2 - 12 % |

**Table 2: ENTSO-E Minimum PFR Delivery Characteristics**

| Parameter | Range |
|---|---|
| Active Power Range $\Delta P_1/P_{Max}$ | 1.5 - 10% |
| Maximum Delay Unless Otherwise Justified | 2 seconds |
| Maximum choice for full activation time $t_2$ | 30 seconds |

### 1.3.2 National Codes

As previously noted, national Grid Codes tend to be more exhaustive and specific than continental Grid Codes. The specific Grid Codes considered, and a summary of their approach to PFR, are presented below. A more detailed exploration of their requirements can be found in Appendix B, and these will form the basis for discussion in the remainder of this report.

#### *Brazil*

Brazil’s system operator, Operador Nacional do Sistema Elétrico (ONS), has a policy of mandatory participation regarding PFR for thermal and hydro units. Wind generation must be capable of exhibiting a *synthetic inertia* response to an under-frequency event and exhibiting a governor-like response to over-frequency events. PFR is not remunerated and generators must undergo primary frequency capability verification prior to connection; however, the precise test specifications are left up to the plant manufacturer and operators. Brazil was the only region outside of North America with a nominal system frequency of 60 Hz.

Within Brazil, the responsibility of ensuring sufficient primary reserves lies with the individual control areas and their dispatch policy (i.e., generators are not required to explicitly reserve capacity for PFR). The reserve requirement of a control area is a function of its load and net exchange with other control areas. This has the result of ensuring that no control area is over-burdened with reserve requirements relative to its generation levels. Within control areas, reserve requirement are required to be distributed among all generators without discrimination.

### *Great Britain*

Great Britain's system is operated by National Grid, which is a member of ENTSO-E. National Grid mandates that all generators subject to the Grid Code, including asynchronously connected resources, have the capability to provide PFR. The ability of a plant to meet these requirements is verified through a standardized test prior to connection.

The service itself, however, is procured through a market-type mechanism whereby all generators submit mandatory bids for capacity reservation. This service is complimented by a Firm Frequency Response market that is open to both generating units and non-generating units—including interruptible load which must remain offline for 30 minutes once activated. National Grid has also recently procured storage resources through a service called Enhanced Frequency Response, which delivers a modulated frequency response activated within one second following a frequency disturbance.

### *Finland*

Finland's system is operated by Fingrid, which a member of ENTSO-E. Fingrid requires PFR capabilities, with specific adjustable droop and deadband ranges, on all synchronous and wind generating facilities. Compliance with these requirements is tested prior to connection. Procurement of this service, however, is carried out through two markets for primary frequency control services: *Frequency Containment Reserves–Normal* (FCR-N) and *Frequency Containment Reserves–Disturbance* (FCR-D).

For the purpose of this report, FCR-D will be of primary interest as its characteristics determine whether the system has the capability to withstand an instantaneous large load-generation imbalance. It will be assumed that FCR-N is operating as designed in order to regulate the frequency around 50 Hz. A generating unit must undergo verification to provide FCR-D prior to market participation, rather than as a condition of connection. Interruptible loads also have the ability to participate, with their activation time being a function of their tripping frequency. These loads can reconnect to the grid once the frequency has remained above 49.9 Hz for three consecutive minutes. As part of the Nordic synchronous area, Fingrid may procure up to one third of its primary reserve obligation outside of its service territory.

### *Ireland*

Ireland's system is operated by both EirGrid and SONI, which are members of ENTSO-E. Where the requirements differ, EirGrid will be discussed here due to its larger generation footprint. All synchronous and wind generating units are required to have PFR capabilities with specified droop/deadband requirements, which are verified prior to connection, and, unless by prior agreement with the TSO, are required to operate in Frequency Sensitive Mode (FSM) when connected to the network. They are not, however, required to reserve capacity unless contracted to do so.

Historically, primary frequency reserve has been procured through bilateral contracts with appropriate standardized testing for verification. EirGrid is currently redesigning its ancillary services markets/contracts through a program to facilitate the growth of non-synchronous technology while maintaining system reliability.[18] This has resulted in the creation of a *Synchronous Inertia* market service and the proposed implementation of a *Fast Frequency* response service.

### *Italy*

Italy's electric system is operated by Terna, a member of ENTSO-E. Generator participation in PFR is mandatory, excluding those fed by non-programmable renewable resources (i.e., wind and solar), and generators are required to reserve capacity to provide this service. Terna's specifications are the only international Grid Code examined that explicitly outlined technology-specific PFR droop/deadband requirements.

Since 2014, generators have had the option of applying for remuneration for energy delivered while providing this service—subject to demonstration of compliance.

### *New Zealand*

Transpower is the TSO in New Zealand; however, the Electricity Authority of New Zealand is responsible for the requirements for system connection/operation. New Zealand requires that all generators connected to the grid, including wind and solar generation, participate in the normal regulation of frequency. However, in the absence of a maximum allowable deadband, the Energy Authority of New Zealand has noted that hydro units are the dominant provider of this service, while thermal units have increased their deadband to avoid excessive mechanical wear and maintenance costs. There is the added concern that all units are increasing their deadband in order to increase demand for market-procured replacement products.[19]

In order to protect the system against a sudden load-generation imbalance, Transpower procures Fast Instantaneous Reserves (FIR), which are open to both generating and non-generating units, including interruptible load.

### *Singapore*

Singapore Energy Market Authority, the entity responsible for operation of the Singapore electric grid, requires PFR capabilities on all generating units, including wind and solar resources. Compliance with these requirements is verified prior to connection.

Singapore operates a market for primary reserves—with both generating units and interruptible loads allowed to participate—whereby the contribution of interruptible loads to the primary frequency reserves is capped at 20% of the total reserve requirement. It is the only region examined that requires generators to pay for the required primary reserves it procures through its market. Furthermore, it

[18] See http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/.
[19] Electricity Authority Te Mano Hiko (2017). *Normal Frequency Management Strategic Review*.

distributes the cost of procuring these reserves to individual generators as a function of their generation output (i.e., no generator should have to pay to protect against a loss larger than itself), and their probability of tripping offline (i.e., generators who are more prone to tripping offline have to pay more). This is unique, as it introduces additional incentives for generators to minimize their probability of tripping offline. Generators registered to bid to provide primary reserve are obliged to submit a bid, and this bid has an upper bound related to the Value of Lost Load (VoLL).

### *Spain*

Spain's power system is operated by Red Eléctrica de España, also a member of ENTSO-E, requires mandatory participation in primary frequency control without remuneration for all generating units, including wind and solar generation. All generating units must reserve 1.5% of their capacity for this purpose. Should generators be incapable of providing this response, they may contract their reserve responsibility for another generating unit and provide proof of such to Red Eléctrica de España.

Spain was the only region examined who prohibited the use of an intentional governor deadband on generating units.

### *Switzerland*

Switzerland's system is operated by Swissgrid, a member of ENTSO-E. Swissgrid requires PFR capabilities on all generating units, including wind and solar resources, with specified adjustable droop and deadband ranges.

Swissgrid procures its primary frequency reserves through a common market—Frequency Containment Reserve (FCR) Cooperation—serving Austria, Switzerland, The Netherlands, Belgium, France, and Germany. Currently, this market hosts weekly auctions for one symmetrical product (i.e., they must be capable of both increasing and decreasing their generation/demand level), with 1 MW being the minimum bid allowable. As will be discussed in Section 3, this market is expected to undergo adjustments to make it more accessible to emerging technologies. Generating units are not required to demonstrate their PFR capabilities prior to connection, but rather prior to market participation.

# 2. International Practices: Generator Interconnection Requirements

The Interconnection Requirements of a Grid Code describe the requirements that must be fulfilled by generating units prior to connection to the network. Depending on the region examined, and whether PFR participation is mandatory or a market-procured service, these conditions may vary. Typically, in the case of a market-procured resource, the capability to provide PFR is a requirement within the connection conditions; however, verification of a plant's capability to provide this service is only required should they wish to participate in the respective markets. Therefore, when discussing the requirements on generators, it shall be assumed the following requirements are contained within the Generator Interconnection Requirements, unless specifically noted otherwise.

Regarding PFR requirements, the generator interconnection requirements of most interest are the droop and deadband specifications and the testing/verification of a plant's capabilities.

### *Applicability to Non-Synchronous Units*

As non-synchronous generating units continue to displace conventional synchronous units, these resources may need to be deployed with the capability to provide PFR in order to ensure adequate reserves. This is reflected in some regions explicitly requiring these resources to meet minimum PFR requirements prior to connection. Typically, these requirements mirror those of conventional synchronous generators. In some cases there exist distinct requirements for non-synchronous resources; these requirements are reviewed in Section 2.6. Systems with significant penetration of renewable energy—particularly wind—are among those whose requirements have been extended to cover these new resources.

The following requirements cover the synchronous generators of all the regions examined and the non-synchronous resources of the regions noted in Table 3, where PFR requirements are common across both technologies.

**Table 3. Generator Interconnection PFR requirements**

| Common PFR Requirements for Synchronous and Non-Synchronous Generators | Specific Non-Synchronous Generator PFR Requirements | No Non-Synchronous Generator PFR Requirements |
|---|---|---|
| Great Britain | Brazil | Italy |
| Finland | Ireland | |
| New Zealand | | |
| Singapore | | |
| Spain | | |
| Switzerland | | |

## 2.1 Deadband

The deadband of a speed-governor controller is an operating region centered around nominal frequency within which the plant controller will not adjust its power generation in response to frequency deviations. The deadband of a governor consists of a small inherent controller insensitivity which cannot be adjusted and, sometimes, an additional larger intentional deadband, which can be adjusted. Some regions, such as Spain, prohibit the use of intentional deadbands.

### 2.1.1 Controller Insensitivity

Controller insensitivities, or unintentional deadbands, inherently exist in all control schemes as a result of mechanical imperfections and/or the inability to precisely measure the quantities of interest. A number of Grid Codes specify a maximum controller sensitivity of ± 10 mHz for a plant's frequency control scheme. This means that, in the absence of any intentional deadband, the maximum frequency deviation for which a plant can inherently remain unresponsive when operating in FSM, is ± 10 mHz. Any deviation above this requires the plant to adjust its active power output.

### 2.1.2 Intentional Deadband

A generator may, if allowed, decide to introduce an intentional deadband. It may decide to do so for a number of reasons, including to reduce wear-and-tear of its mechanical components from less-continuously adjusting its active power output to compensate for minor frequency deviations. Figure 3 shows the maximum allowable deadband for each of the regions examined, with the exception of New Zealand.

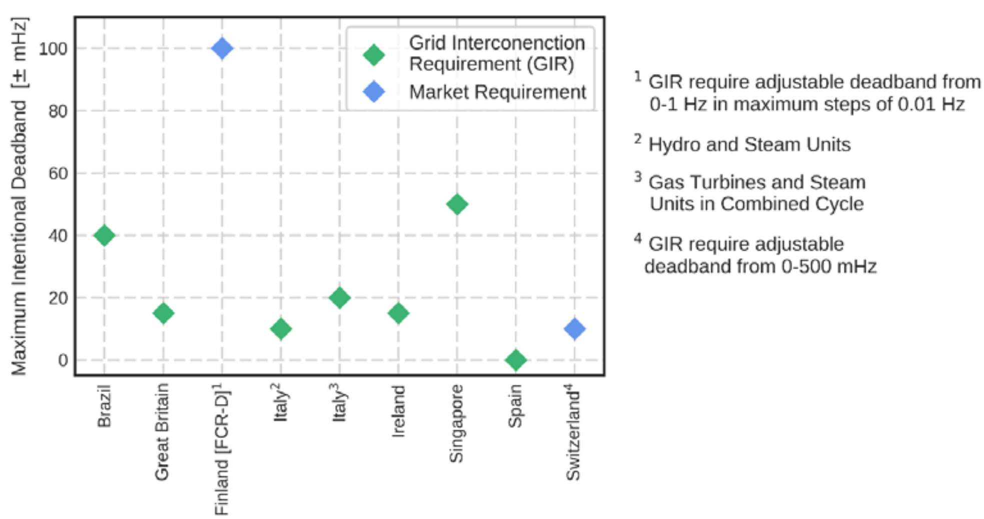


**Figure 3. Maximum allowable operational deadbands**

Currently, New Zealand does not specify a maximum allowable deadband. In 2014, the New Zealand Energy Authority proposed a maximum allowable deadband of ± 25 mHz, but due to concerns raised, this proposal was not implemented. It has been noted that the absence of a deadband has allowed thermal units to operate with a larger deadband and resulted in hydro generators largely providing the mandated normal frequency management.[20]

The regions shown in Figure 3, whose deadbands were described by the current market participation requirements, also specify deadband requirements within their connection conditions. Fingrid requires the ability to set a deadband between 0 and 1 Hz (in maximum increments of 0.01 Hz), while Swissgrid requires an adjustable deadband range of 0–500 mHz.

## 2.2 Droop

A generator's response to frequency deviations, when operating in FSM, is characterized by its droop. Droop is the ratio of the change in frequency per unit to the change in active power output per unit, expressed as a percentage. A lower droop corresponds to a larger change in a unit's generation output for a given frequency deviation, as described by Equation 1, where $\Delta_{fp.u.}$ is the measured change in system frequency expressed as a percentage of the nominal frequency (60 Hz in the U.S.) and $\Delta_{Pp.u.}$ is the corresponding change in a unit's generation output expressed as a percentage of its maximum generation capability. Figure 4 shows the relationship between frequency and power for a generator with three different droop settings.

$$Droop(\%) = 100\left(\frac{\Delta f_{p.u.}}{\Delta P_{p.u.}}\right)$$

Equation 1

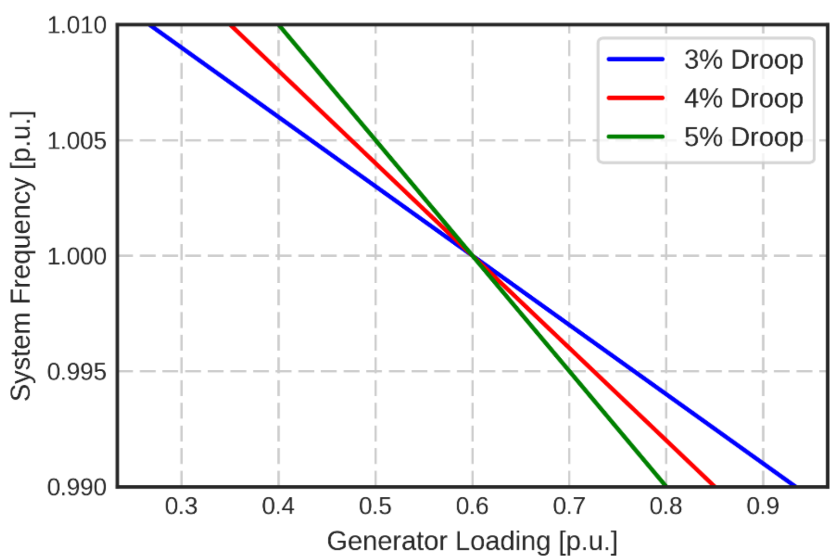


**Figure 4. Effect of various droop settings**

[20] Electricity Authority Te Mano Hiko (2017).

Within generator types (e.g., hydro and gas turbine units), a consistent droop across all generators ensures that all generators contribute equally, relative to their capacity, to the PFR of the system[21]. Figure 5 shows the required adjustable range for droop for each of the regions examined, where specified, as outlined in the connection conditions. Depending on the procedure for PFR procurement, the TSO may specify a required droop within this range or a generator may adjust its droop setting in order to increase or decrease its market participation capabilities. It is worth noting that the three regions with the largest adjustable range requirement all procure their primary reserves through a market mechanism. These markets quantify the reserve capability of a generating unit as its change in active power delivered within *x* seconds, and therefore a unit can increase or decrease its droop should it wish to provide more or less reserves into the market.

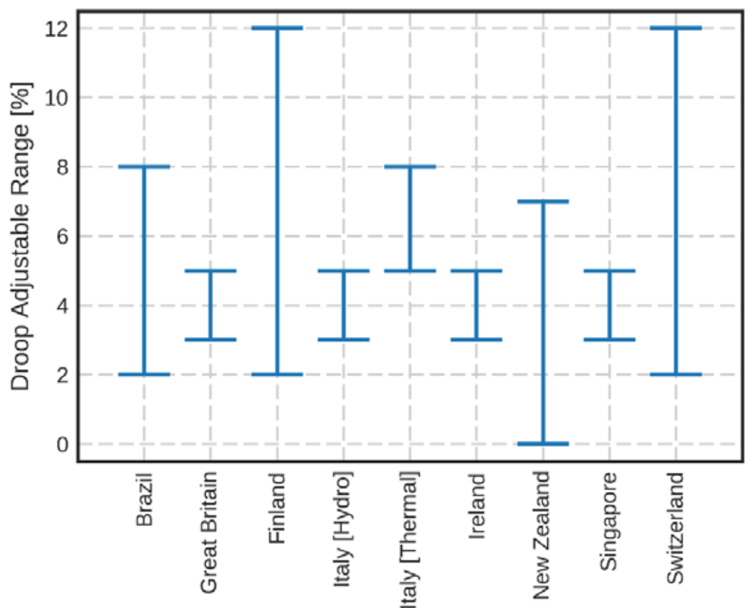


**Figure 5. Adjustable droop requirements**

Of the Grid Codes examined, Spain is the only Grid Code which does not explicitly specify an adjustable range for droop. Instead, it requires that generators supply the specifications of primary controllers upon connection, and that droop is set to achieve a minimum response of 1.5% of rated capacity for a 200 mHz deviation[22] while synchronously connected.

### 2.2.1 Droop Compensation for Deadband

The existence of an intentional deadband requires additional consideration regarding the implementation of droop. A governor with an intentional deadband and unadjusted droop will not produce the response as predicted by Equation 1. Possible implementations of droop in response to the existence of an intentional deadband are shown in Figure 6.

[21] Assuming headroom is available
[22] Equivalent to a droop of 26.67 % for a 50 Hz system

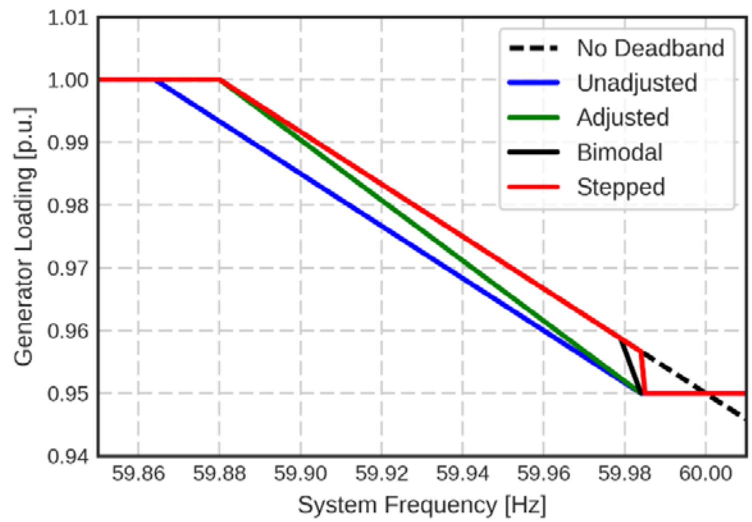


**Figure 6. Examples of deadband implementation**

The adjustment of droop in the presence of a deadband is only of significance when considering the response of a generating unit to naturally occurring frequency fluctuations rather than a critical component in determining whether a system will avoid UFLS due to a large disturbance. Nonetheless, the behavior at the boundary of a deadband is discussed in a number of the codes examined and it is included here for completeness. The Italian Grid Code in particular addresses this issue, with the discussion of a bimodal implementation as shown in Figure 7.

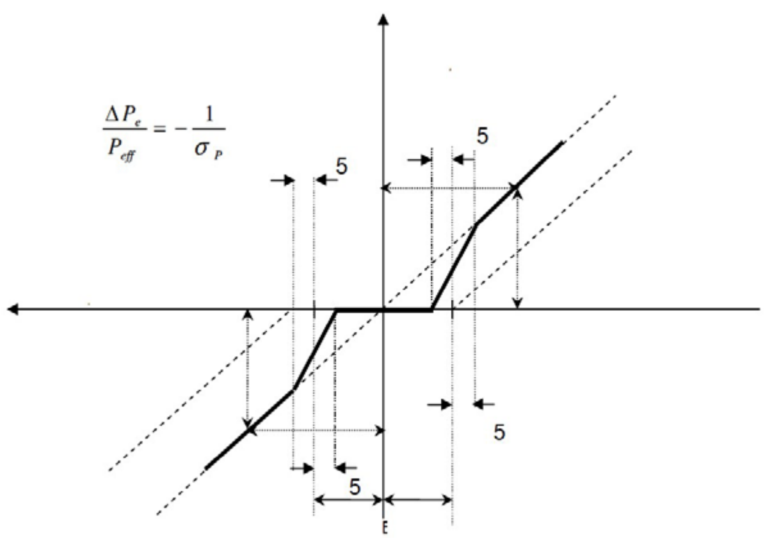


**Figure 7. Droop implementation to compensate for deadband as specified in the Italian Grid Code**

*Source: Terna, Grid Code Annex A.15, Figure 4*

The Singapore Grid Code also alludes to the treatment of droop at the boundary of a deadband by explicitly noting that a generator must respond to the full frequency deviation once outside its deadband, which resembles a stepped deadband implementation.

## 2.3 Quantifying Reserves

While Sections 2.1 and 2.2 provide an exploration of the most common technical specifications of speed-governor controllers, they do not give an intuitive sense of whether a system is capable of withstanding a large generation-load imbalance. This is due to the speed-governor controller only being one component of a larger system whose associated characteristics will dictate its speed of response when operating in FSM. Therefore, from a systems perspective, the ability of a system to survive a large generation loss for a given operating condition will depend on two criteria:

1. **Quantity of reserves**: the magnitude of primary frequency control reserves available; and
2. **Quality of reserves:** the speed at which these reserves can be delivered and sustained.

The former of these questions can often be readily answered by examining the market procurement of the corresponding ancillary service or, in the case of mandatory participation, by examining the droop and available headroom from the generators synchronized to the network. The latter of these questions, however, is not easily answered via a simple calculation. This question is becoming increasingly important as system inertia decreases and, correspondingly, the time window over which a nadir must be formed decreases.

The ability of a system operator to ensure that the system has the capability to withstand a large generation loss will depend largely on the fidelity of their models of generator response to such a disturbance. This is one of the primary motivating factors for the inclusion of testing and performance requirements across all of the Grid Codes examined.

### 2.3.1 Duration of Required Response

Table 4 specifies the duration of response required for PFR for each region. The duration of required response is directly related to the activation of secondary frequency response and varies significantly across the regions examined. Explicit requirements on the length of the sustained response prevent premature withdrawal of primary frequency response before sufficient secondary response has been activated.

**Table 4. Duration of PFR response**

| 30 Seconds | 1 Minute | 2 Minutes | 10 Minutes | 15 Minutes |
|---|---|---|---|---|
| Ireland | New Zealand | Finland | Singapore | Switzerland |
| Great Britain | Brazil | | | Italy |

### 2.3.2 Verification of Primary Control Response

Table 5 outlines the performance specifications of the Grid Codes examined and, where appropriate, the corresponding test-signal requirement. Brazil requires a test to verify compliance; however, there exists no standardized required test signal. Spain does not require a test prior to connection, but continuously monitors units to ensure compliance with its mandatory frequency response obligations.

**Table 5. Testing PFR capabilities**

| | Region | Test Signal | Delivery Requirements |
|---|---|---|---|
| Requirement for Grid Connection | Brazil | Not Specified | Generators must reach 90% of their final value within 9 seconds when subject to a frequency deviation step and remain above 95% and below 105% of its final response for 60 seconds |
| | Great Britain | Linear ramp to Δ0.5 Hz over 10 seconds | Primary response capability of plant is the minimum $\Delta P$ between 10 and 30 seconds |
| | Italy | Step deviation - Magnitude not specified | Generators must reach 50% of their final value within 15 seconds with full delivery within 30 seconds |
| | Ireland | Step deviation of -Δ0.2 Hz | $\Delta P$ of 5% of rated capacity must be delivered between 5 and 15 seconds |
| | Singapore | Linear ramp to -Δ0.5 Hz over 5 seconds | $\Delta P$ measured at 9 seconds and sustained for a further 9 minutes 51 seconds |
| | Spain | N/A | For $\Delta f < 100$ mHz: Full response delivered within 15 seconds<br>For $\Delta f \geq 100$ mHz: 50% of response delivered within 15 seconds and 100% of response must be delivered before 30 seconds |
| Requirement for Market Participation | Finland (FCR-D)[23] | Step deviation of -Δ0.5 Hz | Capability is the minimum of (1) $\Delta P$ at 30 seconds or (2) $\Delta P$ at 5 seconds multiplied by 2 |
| | New Zealand (FIR) | Decreasing signal of amplitude -Δ2 Hz | Capability is $\Delta P$ measured at 6 seconds |
| | Switzerland | Linear ramp to Δ0.2 Hz over 10 seconds | $\Delta P$ delivered within 30 seconds |

## 2.4 Non-Synchronous GIR PFR Requirements

### 2.4.1 Brazil

Brazil's Grid Code addresses the PFR requirements of wind generation explicitly. Wind generation typically does not have available headroom, in a conventional sense, to respond to under frequency. This, coupled with the associated reduction in inertia as wind penetration increases, has motivated the requirement for a *synthetic inertia* response from wind generation to an under-frequency event. Wind generators ≥ 10 MW are subject to the following connection conditions:

- Response to under-frequency events
- Injection of active power proportional to frequency deviation–similar to a governor-like response

[23] Fingrid (2018) Application instruction for the maintenance of frequency controlled reserves Section 7.2.2

- Minimum 10% of rated capacity sustained for a minimum period of 5 seconds for deviations > 0.2 Hz if turbine is operating at > 25% of its rated power
- The operator should be notified of the plant's capability to respond to frequency deviations when it is operating < 25% of its rated output
- Wind plants must also exhibit a governor-like response to over-frequency events and reduce power when frequency is ≥ 60.2 Hz at a rate of 3%/0.1 Hz

### 2.4.2 Ireland

EirGrid's Grid Code is also explicit regarding its PFR requirements for wind generation. Wind generation is not required to reserve headroom to provide PFR unless contracted to do so; however, it is expected to provide PFR if operating below its rated power (e.g., due to transmission congestion). Generally, the frequency control requirements for wind generation are similar to that of conventional synchronous generators with the following minor discrepancies:

- The droop, calculated with respect to rated capacity, must be adjustable from 2 to 10% and set to a default value of 4%
- When operating in FSM, a wind plant must deliver 60% of its expected additional active power response within 5 seconds, and 100% of its expected additional Active Power response within 15 seconds
- Wind plants must be remotely dispatchable by the TSO to operate in FSM

## 2.5 Summary Table

**Table 6. Generator Interconnection Requirements**

| Region | Droop Range | Maximum Intentional Deadband (±mHz) | Tested for Compliance |
|---|---|---|---|
| **Brazil** | 2-8% | 40 | Connection Condition<br>No standardized test |
| **Great Britain** | 3-5% | 15 | Connection Condition |
| **Finland** | 2-12% | 100* | Prior to Market Participation |
| **Ireland** | 3-5% | 15 | Connection Condition |
| **Italy** | Hydro: 3-5%<br>Thermal: 5-8% | Hydro/Steam: 10 mHz<br>Gas Turbine/Steam in CC: 20 mHz | Connection Condition |
| **New Zealand** | 0-7% | No Requirement | Prior to Market Participation |
| **Singapore** | 3-5 % | 50 | Connection Condition |
| **Spain** | Not Specified | 0 | No Specified Test |
| **Switzerland** | 2-12% | 10* | Prior to Market Participation |

**Market participation requirement*

# 3. International Practices: Dispatch and Procurement of Primary Frequency Control Reserves

## 3.1 Reserve Requirements

The reserve requirements and allocation policy for each of the regions considered are outlined in Table 7. Where applicable, the reasoning behind the dimensioning of the required reserves is presented rather than its associated magnitude in order to comparably compare different synchronous areas.

**Table 7. Primary Reserve Requirements**

| Synchronous Region | Requirements/Allocation |
|---|---|
| **Brazil**[24] | – ±1% of Scheduled Generation<br>– Individual Control Area Obligation<br>o $0.01RGA_k$ where $RGA_k$ us the load of area k + the net generation of area k |
| **Continental Europe**[25] | – ±3,000 MW (the tripping of two of the largest generating facilities connected to the same busbar[26])<br>– Reserve responsibility for each TSO is calculated using Equation 2, below |
| **Great Britain**[18]<br>**Ireland/Northern Ireland**[18]<br>**Nordic**[18] | – Largest imbalance that may result from tripping of<br>o Single power generating module<br>o Single demand facility<br>o Single HVDC interconnector or AC line<br>– Reserve responsibility for each TSO is calculated using Equation 2 |
| **New Zealand**[27] | – Largest imbalance that may result from tripping of<br>o A single pole of the HVDC interconnector connecting the North and South Island<br>o The largest single generating unit |
| **Singapore**[28] | – Loss of largest single generating unit |

$$\text{TSO Reserve Req.} = \frac{\text{TSO Annual Net Gen.} + \text{TSO Annual Load}}{\text{System Annual Net Gen} + \text{System Annual Load}} \times \text{System Reserve Req.}$$

Equation 2

[24] ONS (2017): *Networking Procedures Sub-module 23.3 Guidelines and criteria for electrical studies*
[25] EU (2017): *Establishing a guideline on electricity transmission system operation*
[26] ENTSO-E (2016a): *Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe.*
[27] NZ-EA (2013): Electricity Industry Participation Code Schedule 13.3
[28] EMA(2017b): *Singapore Electricity Market Rules Appendix 7A*

In order to ensure that the loss of a unit providing primary reserve does not adversely impact the system's ability recover from the resulting active power imbalance the following additional constraints exist within ENTSO-E[18]:

- For both the Continental Europe and Nordic Synchronous System, the maximum reserve capacity that an individual generating unit can provide is 5% of the total reserve obligation of the synchronous area
- For Great Britain, Ireland/Northern Ireland, and the Nordic synchronous areas, the reserves provided by the largest generating unit do not count towards satisfying the minimum reserve requirement

### 3.1.1 Exchange of Reserves between TSO's

Where allowable, TSOs may procure reserve capacity towards their requirements from outside their own control area. A particular example of such a case, the Frequency Containment Reserve (FCR) Cooperation, a common market across six countries, will be discussed in Section 3.2.2. Where it is allowable, there typically exist limits on both the amount of reserves that an individual TSO can procure from, or provide to, TSOs outside of its own area in order to ensure sufficient geographical distribution of reserves.

For the synchronous area of Continental Europe these limits are[29]:

- At least 30% of a TSO's reserve obligation is located inside their control area
- The amount of reserve capacity that an individual TSO can provide to one or more TSOs outside of its control area is the maximum of:
    - 30% of the total reserve obligation of the TSOs in question
    - 100 MW

## 3.2 Procurement

Broadly speaking, in the regions examined, the procurement of primary frequency reserves is currently achieved in one of two ways: (a) requiring mandatory participation; or (b) procuring the resource through a market mechanism. Figure 8 outlines which of these approaches the regions of interest have chosen to adopt. These approaches are further examined in the following sections.

[29] EU (2017): *Establishing a guideline on electricity transmission system operation*

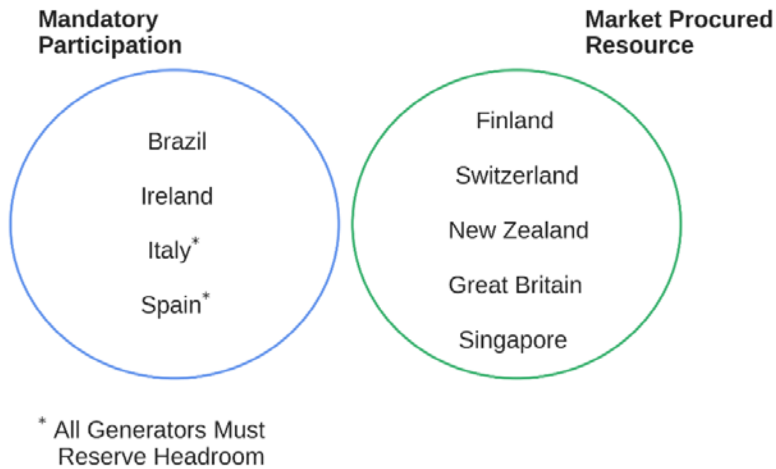


**Figure 8. Methods for procuring primary reserve capabilities**

### 3.2.1 Mandatory Participation

Concerning mandatory frequency response, the distinguishing feature is whether units are required to reserve capacity or not. In the case of Italy and Spain, the units are required to reserve a minimum of 1.5% of their capacity. The requirement of reserve capacity, along with delivery specifications, results in a very clear understanding of both the quantity and quality of a system's primary frequency response capabilities.

In the case of both Ireland and Brazil, generating units are not required to reserve capacity for primary reserves. Instead, units are required to contribute to the primary frequency response of a system using their available capacity, subject to their min/max operating limits. In addition to units mandated to operate in FSM when connected, EirGrid awards long-term Primary Operating Reserve contracts (POR) through an auction mechanism. In the case of Brazil, each control area is to dispatch units to ensure sufficient primary frequency reserves are available, where its reserve obligation is a function of load and net exchange across control areas.

### 3.2.2 Market Procured Resource

#### *Frequency Containment Reserve Cooperation*

The Frequency Containment Reserve (FCR) Cooperation is a common market for the procurement of ancillary services serving Austria, Switzerland, The Netherlands, Belgium, France, and Germany, with Denmark expected to join in the near future. Currently, it is responsible for the procurement of roughly ± 1,400 MW of Continental Europe's ± 3,000 MW primary frequency reserve requirement. The current reserve obligations and import/export limits of reserves for each of the countries participating in the market can be seen in Figure 9.[30] The existence of import and export limits helps ensure that the primary frequency reserves remain geographically dispersed across the region.

[30] Belgium and the Netherlands procure a portion of the FCR obligation through a national tender.

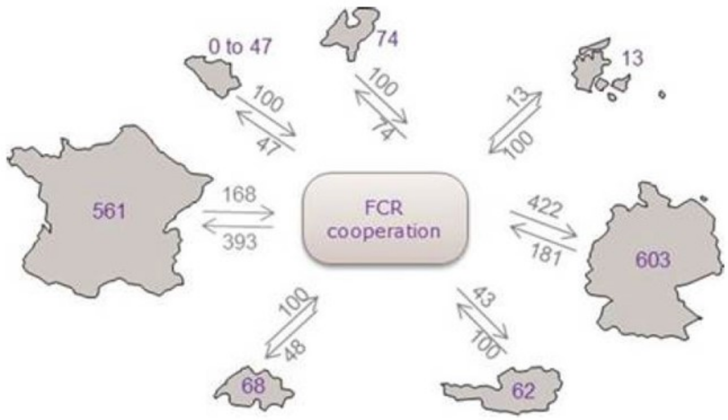


**Figure 9. FCR Cooperation import/export limits per county**

*Source: Public Consultation on "FCR Cooperation" Potential Market Design Evolutions, Figure 4*

This market has historically held weekly auctions for one symmetrical product with a minimum bid size of 1 MW—with pooling of resources allowable to meet this threshold. This has alleviated the entry barrier for emerging resources to participate. Additionally, this market has recently undergone a public consultation aimed at exploring market design evolutions. One of the major suggestions adopted was the transition from a weekly auction to daily auctions with product offerings of four-hour duration.[31] This was seen as a way to further reduce the entry barrier to the market for new resources whose availability is less deterministic than traditional resources.

## *Finland*

Fingrid operates annual and hourly markets for its service, FCR-D. As part of the Nordic synchronous area it can procure FCR-D from outside its system, however two thirds of its resource obligation must be maintained within its subsystem.[32] Fingrid allows reserve holders to aggregate resources for which they are neither the owner nor operator, thereby restricting the barrier to market participation for emerging resources, provided they can demonstrate compliance. Relay-connected resources (i.e., loads) may also participate in the market and may be disconnected in a linear fashion as a function of frequency or in a stepped-like manner, whereby the maximum disconnection time is a function of the tripping frequency. Load can be reconnected to the grid when the frequency is above 49.90 Hz for three consecutive minutes.

## *Great Britain*

National Grid have two mechanisms for frequency reserve procurement:

- *Mandatory Frequency Response:* Generators above a capacity threshold (generally ≥ 100 MW)[33] are obligated to have the ability to provide mandatory frequency response. A Mandatory

[31] FCR Cooperation (2017a). *Consultation Report "FCR Cooperation"*.
[32] ENTSO-E (2016b) Nordic Balancing Philosophy
[33] Exact thresholds are a function of capacity, location and completion date.

Services Agreement is set up between the generator and the operator prior to the commissioning of the plant that allows the operator to direct the generator to operate in FSM. In practice, however, this service is more similar to a market-procured service. Generators are obliged to submit bids of holding prices to the network operator for reserves, with the maximum allowable offering capped at £9999.99/MWh.[34] This effectively allows generators to submit an unattractive holding price for primary reserves and significantly reduces their probability of being directed to operate in FSM.

- *Firm Frequency Response:* Firm frequency response is a market-procured service open to both generating units (including those covered by the Mandatory Frequency Response requirements) and non-generating units (including interruptible loads). In order to participate in the market, suppliers must demonstrate their capability via pre-qualification and be capable of delivering a minimum of 1 MW of response.
    - Dynamic sources of primary frequency response are subject to the same performance standards as generators, described in Section 2.3.
    - Static sources (e.g., interruptible loads) must be activated within 2 seconds of their triggering frequency threshold and sustain this response for 30 minutes.[35]

Figure 10 shows the capacity of both primary frequency reserve services procured over a six-month period within which both services contribute almost equally to the system requirements.

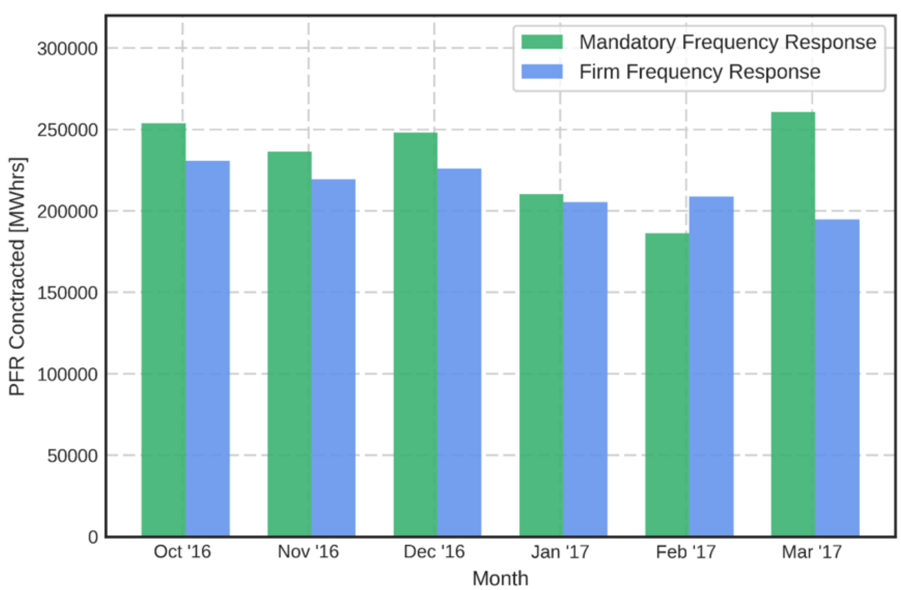


**Figure 10. National Grid's primary frequency procurement[36]**

[34] National Grid (2015): *Connection and Use of System Code (CUSC) v1.12*.
[35] National Grid (2017): *Testing Guidance for Providers of Enhanced Frequency Response Balancing Service*.
[36] Data from 2016-17 Frequency Response Volumes D9.xls and April 2016 - March 2017 FFR Market Report.xls. See http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-explorer/Outcome-Energy-Services/.

### *New Zealand*

New Zealand's FIR service is open to both dynamic and static resources. For dynamic resources, FIR is the additional power delivered 6 seconds after a contingency event and sustained for a minimum of 54 seconds; for static resources, FIR is the drop in load that occurs within 1 second of the frequency falling below 49.2 Hz and sustained for a minimum of 59 seconds.

### *Singapore*

Singapore operates a market for its primary reserves in which all generators registered to provide primary reserves are obliged to have a valid reserve bid offer, whose upper limit is bounded by the VoLL.[37, 38] Interruptible loads are also permitted to participate in this market provided they are capable of withdrawing a minimum of 0.1 MW at a triggering frequency of 49.4 Hz. These resources are permitted to reconnect to the network upon receipt of a Restoration Order. Currently the contribution of interruptible loads to the primary frequency reserves is capped at 20%.

## 3.3 Remuneration

The remuneration for primary frequency response varies across all the regions examined. In can be broadly be classified into three options for remuneration, as shown in Figure 11.

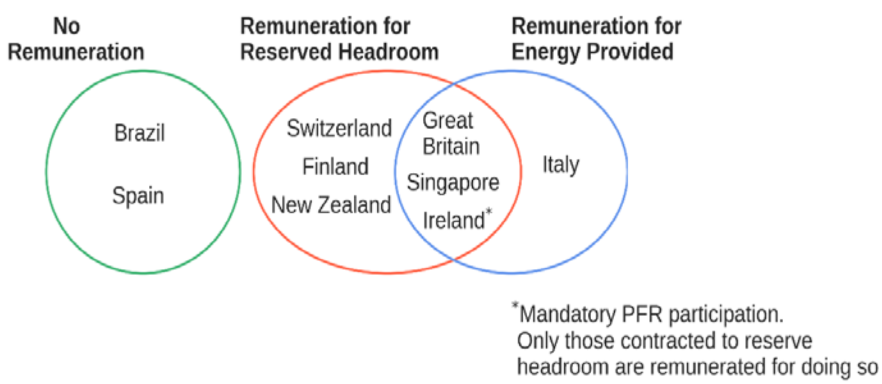


**Figure 11. Primary frequency response remuneration policies**

Singapore is the only region examined that requires generators to be financially responsible for the primary reserve requirements of the system. The financial responsibility of each individual generator is a function of:

(a) Their responsibility towards the reserve requirement. This is done so that no unit is required to pay to protect the system against a larger loss than itself; and

(b) Their probability of tripping offline (i.e., a generator who rarely trips offline will pay less than a generator who frequently trips offline), all else considered equal.

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37 Currently set at 0.85*VoLL. Currently the VoLL is $5,000/MWh

38 EMA (2017a): Singapore Electricity Market Rules Appendix 6J

## 3.4 Summary Table

**Table 8. Procurement and remuneration of PFR**

| Region | Procurement Policy | Remuneration |
|---|---|---|
| **Brazil** | Mandatory participation without reservation | No remuneration |
| **Great Britain** | Market procured resource with mandatory generator bids | Remuneration for capacity reserved and energy delivered |
| **Finland** | Market procured resource | Remuneration for capacity reserved |
| **Ireland** | Headroom reservation is a market procured resource; non-contracted units are expected to respond with available headroom | Remuneration for capacity reserved and energy delivered |
| **Italy** | Mandatory participation with reservation | Remuneration for energy delivered |
| **New Zealand** | Market procured resource | Remuneration for capacity reserved |
| **Singapore** | Market procured resource | Remuneration for capacity reserved and energy delivered |
| **Spain** | Mandatory participation with reservation | No remuneration |
| **Switzerland** | Market procured resource | Remuneration for capacity reserved |

# 4. Emerging Markets/Requirements

As the generation mix continues to evolve and units who have historically provided PFR, namely synchronous units, are replaced by non-synchronous resources, systems may need to re-examine their requirements and practices. Section 4.1 - 4.3 examine both proposed and implemented changes to respective Grid Codes to cope with these operational challenges.

## 4.1 National Grid: Enhanced Frequency Response

National Grid have recently procured resources for a new PFR service called Enhanced Frequency Response (EFR). This service differs from conventional primary frequency response in its speed of response. EFR resources are required to have the following performance characteristics, which are verified through prequalification testing for the following performance criteria:[39]

- A maximum deadband of either ± 50 mHz (Service 1) or ± 15 mHz (Service 2)
- Ability to detect a frequency deviation within 500 ms and to deliver the full contracted response within 1 second
- Ability to sustain the response for 15 minutes

In its initial round of procurement in July 2016, National Grid contracted 200 MW of this service solely from storage providers and all of Type 2 service (± 15 mHz deadband).

## 4.2 EirGrid/SONI: DS3

EirGrid/SONI are in the midst of a multi-year program called "Delivering a Secure, Sustainable Electricity System (DS3)", which is re-examining the services necessary for reliable operation of the grid. Two of the additional ancillary services which are being introduced—Fast Frequency Response (FFR) and Synchronous Inertia Reserve (SIR)—will supplement the ability of the system to withstand a sudden load-generation imbalance:

- The FFR service is defined as the additional MW delivered between 2 and 10 seconds.
- SIR will be limited to generators which have a SIR Factor above 15 (as defined by Equation 3).[40] This means that only generators that can provide a high amount of inertia to the system while also having a low minimum operating point will be allowed to participate in the market. The objective of this is to maximize the amount of online inertia while minimizing generation that must be provided by synchronous machines. This would thereby attempt to maintain a minimum operating inertia while allowing for greater amounts of non-synchronous generation.

[39] National Grid (2017): *Testing Guidance for Providers of Enhanced Frequency Response Balancing Service*.
[40] EirGrid and Soni (2014): *DS3 System Services: Portfolio Capability Analysis*.

$$\text{SIR Factor} = \frac{Kinetic\ Energy\ Sotread\ at\ f_{Nominal}}{Generating\ Unit\ P_{Minimum}}$$

Equation 3

In terms of speed of response, FFR lags behind that of the Enhanced Frequency Response product introduced by National Grid, and typical speed of response associated with static frequency response, where implemented. EirGrid's SIR product was introduced primarily arising from concerns regarding the length of time required to obtain a reliable estimation of frequency and the corresponding Rate of Change of Frequency (ROCOF) that generators would have to withstand during this period. EirGrid is currently revising its ROCOFROCOF ride-through requirements and it is expected that the SIR product will decrease in importance as these new standards are introduced.[41]

## 4.3 ROCOF Ride-Through Requirements

One issue that has attracted attention recently is the ROCOF following a large generation loss. Historically, one of the primary applications of ROCOF relays was for the purposes of islanding detection and subsequent disconnection of a generating unit. Recently, however, there have been concerns regarding the ability of generating units to withstand severe ROCOFs following large generation losses (which are indicative of systems with significant levels of non-synchronous generation) rather than tripping offline in order to protect themselves. This has motivated explicit ROCOF ride-through requirements to be introduced in some Grid Codes. Table 9 summarizes some of the regions which have or are in the process of introducing ROCOF requirements.

**Table 9. ROCOF Ride-Through requirements**

| Region | ROCOF Ride-Through Requirement | Status/Applicability |
|---|---|---|
| Denmark[42] | 2.5 Hz/s | Active |
| Finland[43] | 2 Hz/s | Active |
| Ireland[44,45] | 0.5 Hz/s<br>1 Hz/s | Active<br>Approved for implementation |
| Spain[46] | 2 Hz/s | Proposal |

41 Eirgrid and Soni (2014): *Consultation on DS3 System Services Interim Tariffs.*
42 ENERGINET (2017): *Technical Regulation 3.2.3 for Thermal Plants Above 11 KW. Revision 1*.
43 Fingrid (2013): *Specifications for the Operational Performance of Power Generating Facilities VJV2013.*
44 EirGrid (2015) EirGrid Grid Code
45 Commission for Energy Regulation (2014): *Rate of Change of Frequency (ROCOF) Modification to the Grid Code.*
46 Red Eléctrica de España S.A. (2017): *Desarrollo de los requisitos técnicos del Reglamento (UE) 2016/631*.

# 5. Conclusion

This report is intended to explore some of the current standards and practices surrounding PFR, both within the United States and internationally. Historically, the United States been less prescriptive relative to its international counterparts regarding explicit PFR standards/requirements. This however, is changing, as a number of individual entities have paid particular attention to their systems' PFR requirements and adjusted their standards/practices in line with the international practices discussed herein.

This will need to continue in the future given the rate of non-synchronous adaption. PFR is critical to ensuring the reliable operation of a synchronous power system, and therefore it is critical that standards and requirements for these systems evolve to meet the evolving fleet composition.

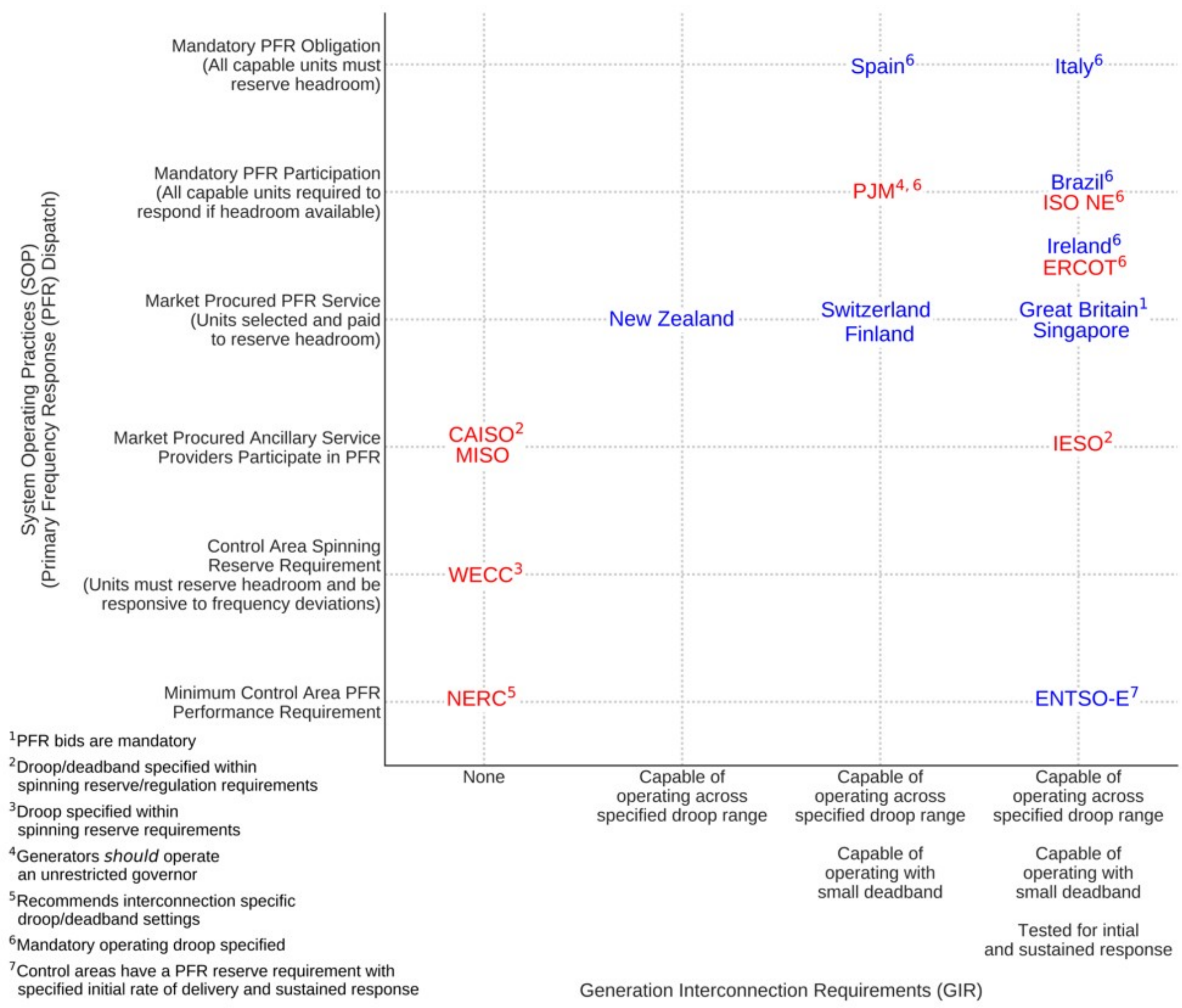


**Figure 12. Comparison of PFR requirements/standards**

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# Appendix A. North American Grid Codes and Operating Practices Related to Primary Frequency Response

## A.1. California ISO (CAISO)

### CAISO Relevant Documents

- CAISO, Tariff, Chapter 8: Ancillary Services; March 2017[47]
- CASIO, Tariff, Appendix K: Ancillary Service Requirements Protocol; October 2016[48]
- CAISO, Tariff, Appendix BB: Standard Large Generator Interconnection Agreement; September 2016[49]

### CAISO Generator Connection Conditions

#### *Applicability*

- Generating units ≥ 20 MW [see *Appendix BB*, Article 1]

**Table A - 1. CAISO generator connection conditions**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | N/A |
| Droop | N/A |

### CAISO Primary Frequency Control Characteristics

- Units contracted to provide spinning reserve shall be responsive to frequency deviations [see *CAISO Tariff*, Chapter 8.4.4]
- Participating units shall have a droop of 5% (4% for combustion turbines) [see *Appendix K*, Section B1.2(a)]
- Units will have a maximum deadband of ± 36 mHz [see *Appendix K*, Section B1.2(b)]
- Units will not inhibit the response unless necessary to address physical operating constraints [see *Appendix K*, Section B1.2(d)]
- Plant control systems will be coordinated to include a frequency bias [see *Appendix K*, Section B1.2(e)]

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47 See http://www.caiso.com/Documents/Section8_AncillaryServices_asof_Mar6_2017.pdf
48 See https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=16204F9F-158C-4FD0-A053-BF79A2847466
49 See https://www.caiso.com/Documents/AppendixBB_StandardLargeGeneratorInterconnectionAgreement_asof_Sep21_2016.pdf

## CAISO Performance/Testing

- Generating unit must exhibit a power output change within one second for any frequency deviation outside its deadband [see *Appendix K*, Section B1.2(c)]
- For resources without a governor the following minimum performance criteria must be satisfied [see *Appendix K*, Section B1.2(e)]
    - If frequency is ≤ 59.92 Hz, the resource must reach 10% of its awarded spinning capacity within 8 seconds
    - The resources must change the power it delivers or consumes in within 1 second if system frequency is ≤ to 59.92 Hz
- Prior to certification, testing shall be performed under the direction of the CAISO [Appendix K B12] and shall include testing the speed-governor by simulating frequency deviations outside its deadband and measuring the response of the resource [see *Appendix K*, Section B 12.4]

## A.2. Electric Reliability Council of Texas (ERCOT)

### ERCOT Relevant Documents

- BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region[50]
- ERCOT, Planning Guide, Section 5: Generation Resource Interconnection or Change Request; August 1, 2017[51]
- ERCOT, Nodal Operating Guides:[52]
    - *Section 2:* System Operations and Control Requirements; May 2017
    - *Section 8, Attachment C:* Turbine Governor Speed Tests; November 2016
    - *Section 8, Attachment G:* Load Resource Tests; December 2010
    - *Section 8, Attachment J:* Initial and Sustained Measurements for Primary Frequency Response; October 2016
- ERCOT Nodal Protocols Section 3: Management Activities for the ERCOT System January 1, 2018[53]

### ERCOT Generator Technical Connection Conditions

#### *Applicability*

- Requirements are inherited from obligation to comply with Operating Guides [see *Planning Guide*, Section 5.6(1)]
- Applicable to all generating units ≥ 10 MW [see *Planning Guide*, Section 5.1.1 (1)(a)] excluding Nuclear Generating units [see *Nodal Operating Guides*, Section 2.2.8 (1)]

**Table A - 2. ERCOT generator technical connection conditions**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | • Maximum ± 34 mHz for Steam/Hydro turbines with mechanical governor<br>• Maximum ± 17 mHz for all other generating units |
| Droop | • Maximum of 4% for combustion turbine<br>• Maximum of 5% for all other generating units |

*Source: Nodal Operating Guides Section 2.2.7 (3)*

50 See http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf
51 See http://www.ercot.com/mktrules/guides/planning/current
52 See http://www.ercot.com/mktrules/guides/noperating/current
53 See http://www.ercot.com/mktrules/nprotocols/current

## ERCOT Primary Frequency Control Characteristics

- All generation resources, with the exclusion of nuclear units and any wind generation units with an approved exception from ERCOT, must respond to frequency deviations in a manner consistent with the specification outlined below in Section A.2.2 [see *Nodal Operating Guides*, Section 2.2.8 (1)]
- ERCOT procures Responsive Reserve Service (RRS) to help control the system frequency. The RRS obligation is a minimum of 2300 MW [*Nodal Operating Guides Section*, 2.3.1.1]. ERCOT specifies the minimum amount of RRS that must come from generators. Generators must reserve headroom in order to provide this service.
- Loads too may choose to participate by providing RRS; a controllable-load is required to respond in a manner consistent with generation resources while non-controllable loads under the operation of under-frequency relays must meet the following specifications [see *Nodal Operating Guides*, Section 2.3.1.2 (6)]
    - Relay must not have a delay > 20 cycles (0.333 seconds) and the total activation time upon crossing the tripping frequency should be no more than 30 cycles (0.5 seconds)
    - The triggering frequency must not be lower than 59.7 Hz
    - The interrupted load may not reconnect to the network without approval from ERCOT
- Currently the amount of non-controllable loads on under-frequency relays providing RRS is limited to 50% of the total ERCOT RRS requirement, however, this is proposed to increase to 60%. [see ERCOT Nodal Protocols Section 3: Management Activities for the ERCOT System January 1, 2018 3.16 (5)].

## ERCOT Performance/Testing

- Compliance will be ensured by examining at least 8 frequency events in a minimum 12 month rolling window; both the initial response and sustaining of the response will be considered, for which the calculations are outlined in *Nodal Operating Guides*, Section 8 Attachment J, to ensure compliance [see *Nodal Operating Guides*, Section 2.2.8 (1)]
- Resources which have not been verified against 8 events within 36 months must conduct governor performance tests within 12 months as specified in Nodal Operating Guides Section 8 Attachment C [see *Nodal Operating Guides Section*, 2.2.7 (2)]
- Loads under the control of an under-frequency providing RRS must verify operation of its relay or solid-state controller on a biannual basis, either via referencing an event it responded to or by demonstration, as described in *Nodal Operating Guides*, Section 8 Attachment G

## A.3. ISO New England (ISO-NE)

### ISO-NE Relevant Documents

- ISO New England, Operating Procedure No. 14 (OP-14): Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources; January 2017[54]

### ISO-NE Generator Technical Connection Conditions

#### *Applicability*

- Applicable to all generating units ≥ 10 MW [see *OP-14*, Section I.1]

**Table A - 3. ISO New England generator technical connection conditions**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Maximum ± 36 mHz |
| Droop | Between of 4 - 5% |

*Source: OP-14, Section I.1 (a)-(b)*

### ISO-NE Primary Frequency Control Characteristics

- All generating units must operate a functioning governor responsive to frequency deviations [see *OP-14*, Section I.1]
- Frequency response must not inhibited by effects of outer loop controls (excluding AGC commands) that would override the governor response [see *OP-14*, Section I.1 (c)]

### ISO-NE Performance/Testing

- Upon ISO request, the unit will verify its compliance with the requirements by submitting its plant information, frequency and MW output, for a period of 15 minutes, 5 minutes before and 10 minutes after, for an identified frequency event. [see *OP-14*, Section I.2 (c)]
- Each generating resource is responsible for periodic testing and maintenance of the generator governor [see *OP-14*, Section I.3]

[54] See https://www.iso-ne.com/participate/rules-procedures/operating-procedures

## A.4. Ontario Independent Electricity System Operator (IESO)

### IESO Relevant Documents

- Market Rules Chapter 4: Grid Connection Requirements—Appendices Issue 12.0[55]
- Market Manual 2: Market Administration Part 2.20: Performance Validation Issue 7.0[56]
- Market Rules Chapter 5: Power System Reliability – Appendices Issue 6.0 - December 6, 2017[57]

### IESO Generator Technical Connection Conditions

#### *Applicability*

- All aggregated generation facilities > 50 MW or all generation units > 10 MW [see Chapter 4 Appendix 4.2]

**Table A - 4. Ontario IESO generator technical connection conditions**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Maximum ± 36 mHz (0.06%) for all units |
| Droop | Adjustable between 2 - 7% with its default value set to 4% |

*Source: Chapter 4: Grid Connection Requirements Appendix 4.2*

#### *Additional Requirements on Wind Generation*

- Wind turbines required to have the ability to provide *synthetic inertia* in response to system frequency disturbances [see *Market Manual 2: Market Administration*, Part 2.20, Section 3.2]
- IESO will notify generators equipped with this service when this service must be placed in service
- The functional requirements for this service are outlined below and shown in Figure A - 1:
  - Activated when frequency < 59.7 Hz
  - Activation time ≤ 1 second
  - ΔP > 10% of pre-disturbance active power generation
  - Remain activated for ≥ 10 seconds if frequency remains < 59.964 Hz
  - Response withdrawn if frequency > 59.964 Hz
  - Rate of energy recovery post response must be less than rate of energy injection during activation
  - Response shall be available again within 30 minutes

[55] See http://www.ieso.ca/sector-participants/market-operations/market-rules-and-manuals-library
[56] See http://www.ieso.ca/sector-participants/market-operations/market-rules-and-manuals-library
[57] See http://www.ieso.ca/sector-participants/market-operations/market-rules-and-manuals-library

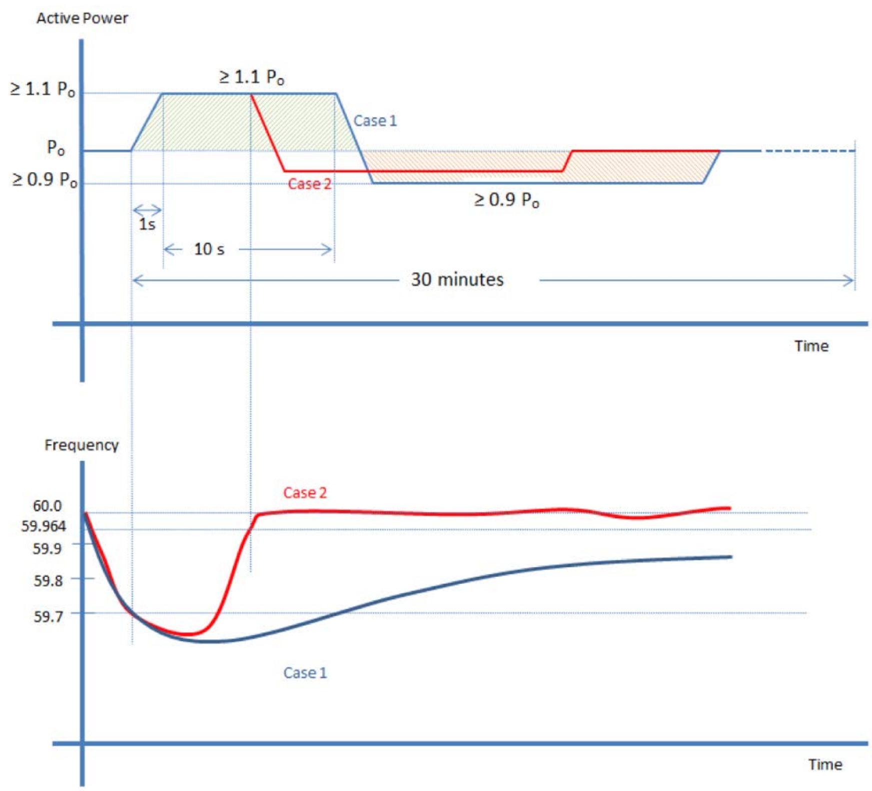


**Figure A - 1. IESO Wind generation synthetic inertia response**

*Source: Market Manual 2: Market Administration Part 2.20 Figure 5*

## IESO Primary Frequency Control Characteristics

- All *resources* providing frequency *regulation* must meet, at a minimum, the following performance requirements [see *Market Rules Chapter 5: Power System Reliability – Appendix 5.1.1.7]*
    - Operate with a droop of 4% and a maximum deadband of ± 0.06 % [see *Market Rules*, Chapter 4, Appendix 4.2]
    - A sustained 10% change of rated active power after 10 s in response to a constant rate of change of speed of 0.1%/s during interconnected operation shall be achievable [see *Market Rules*, Chapter 4, Appendix 4.2]
- Control systems that withdraw governor response must be supported by a rationale that justifies this withdrawal [see *Market Manual 2*, Part 2.20 Section 3.2]
- IESO will notify wind generators when their synthetic inertia response must be in service

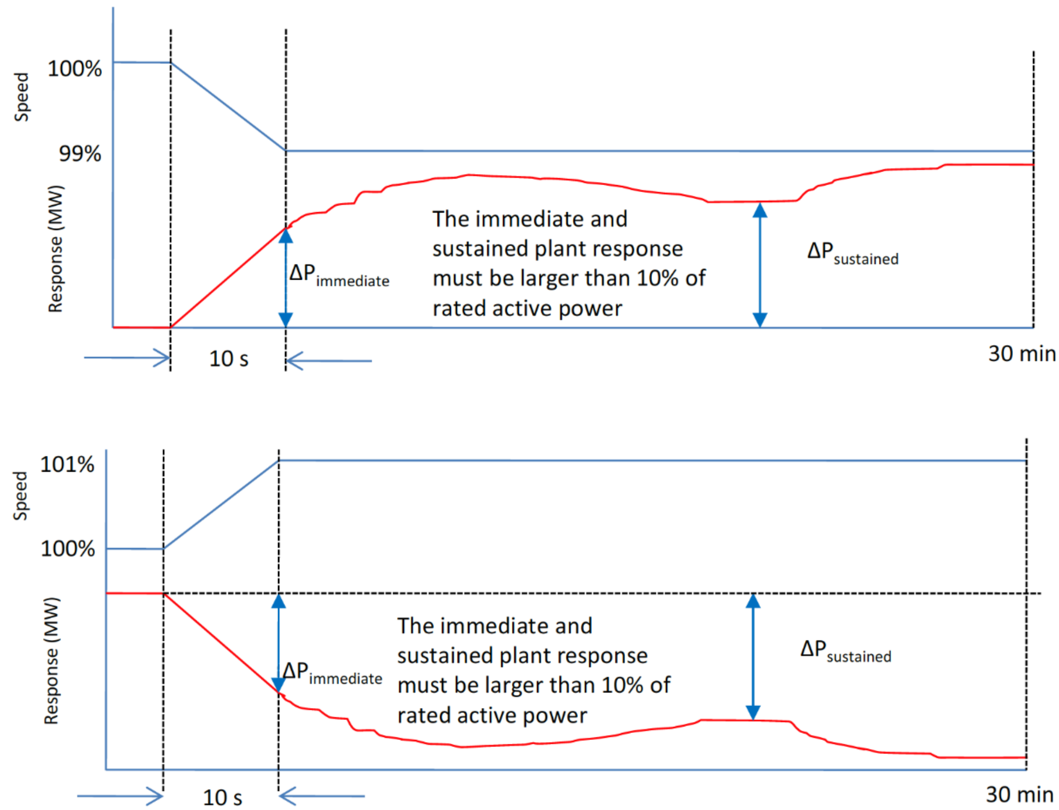


**Figure A - 2. IESO Required PFR Delivery**

*Source: Market Manual 2: Market Administration Part 2.20 Figure 4*

## IESO Performance/Testing

- Generating units must validate their droop and deadband by means of a test and provide a model and parameters from which their response can be replicated [see *Market Manual 2*, Part 2.20 Section 5]
- Dynamic capability must be re-validated at least every ten years [see *Market Manual 2*, Part 2.20 Section 2.5]
- A disturbance recorder must be installed to provide capability to demonstrate compliance with dynamic performance requirements during and after commissioning. [see *Market Manual 2*, Part 2.20 Section 2.7]

## A.5. PJM Interconnection (PJM)

### PJM Relevant Documents

- PJM, Manual 14D (M-14D): Generator Operational Requirements, Revision: 41; June 1, 2017[58]

### PJM Generator Technical Connection Conditions

#### *Applicability*

- Applicable to generating units ≥ 75 MVA, with the exception of nuclear units [see *M-14D*, Section 7.1.1]

**Table A - 5. PJM generator technical connection conditions**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Maximum ± 36 mHz for all units |
| Droop | Maximum of 5% for all generating units |

*Source: M-14D, Section 7.1.1*

### PJM Primary Frequency Control Characteristics

- All generating units ≥ 75 MVA, with the exclusion of nuclear units, should operate with an unrestricted governor [see *M-14D*, Section 7.1.1]

### PJM Performance/Testing

- Not discussed

58 See http://www.pjm.com/library/manuals.aspx

# Appendix B. International Grid Codes and Operating Practices Related to Primary Frequency Response

## B.1. European Network of Transmission System Operators for Electricity (ENTSO-E) Regulations

### ENTSO-E Relevant Documents

- ENTSO-E, Commission Regulation (EU) 2016/631: Establishing a Network Code on Requirements for Grid Connected Generators; April 2016[59]

### ENTSO-E Generator Connection Conditions

#### *Applicability*

- Type C and Type D power generating units must be capable of operating in Frequency Sensitive Mode. These units are defined as [see *EU 2016/631,* Article 5(2)]
    - Type C: Connection below 110 kV and capacity at or above the threshold identified by the individual TSOs
    - Type D: Connection above 110 kV and capacity at or above the threshold identified by the individual TSOs
- These thresholds shall not be above those specified in EU 2016/631, Article 5, Paragraph 2, Table 1, shown here in Table B - 1 for reference

**Table B - 1. ENTSO-E Limits for thresholds for classification of generating units**

| Synchronous Area | Limit for maximum capacity threshold from which a power-generating module is of type C | Limit for maximum capacity threshold from which a power-generating module is of type D |
|---|---|---|
| Continental Europe | 50 MW | 75 MW |
| Great Britain | 50 MW | 75 MW |
| Nordic | 10 MW | 30 MW |
| Ireland and Northern Ireland | 5 MW | 10 MW |
| Ireland | 10 MW | 15 MW |

*Source: EU 2016/631, Article 5(2), Table 1*

#### *Requirements*

- Generating units shall be capable of providing active frequency response in accordance with parameters specified by each TSO within the ranges specified in Article 15, Paragraph 2, Table 4, shown here in Table B - 2 for reference

[59] See https://electricity.network-codes.eu/network_codes/rfg/

- The deadband and droop must be able to be re-selected repeatedly
- TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations [see Article 21 Paragraph 2]

**Table B - 2. ENTSO-E PFR Generator Technical Specifications**

| Parameter | Range |
|---|---|
| Active Power Range | 1.5 - 10% |
| Frequency Response Insensitivity | 10 - 30 mHz |
| Deadband | 0 - 500 mHz |
| Droop | 2 - 12% |

*Source: EU 2016/631, Article 15 (s) Table 4*

## ENTSO-E Primary Frequency Control Characteristics

In the event of a frequency step change the generating unit shall be capable of activating its full active power frequency response at or above the full line in Article 5, Paragraph 2, Figure 6, shown here in Figure B - 1, in accordance with the parameters defined by each TSO within the ranges given in Article 5, Paragraph 2, Table 5, summarized here in Table B - 3.

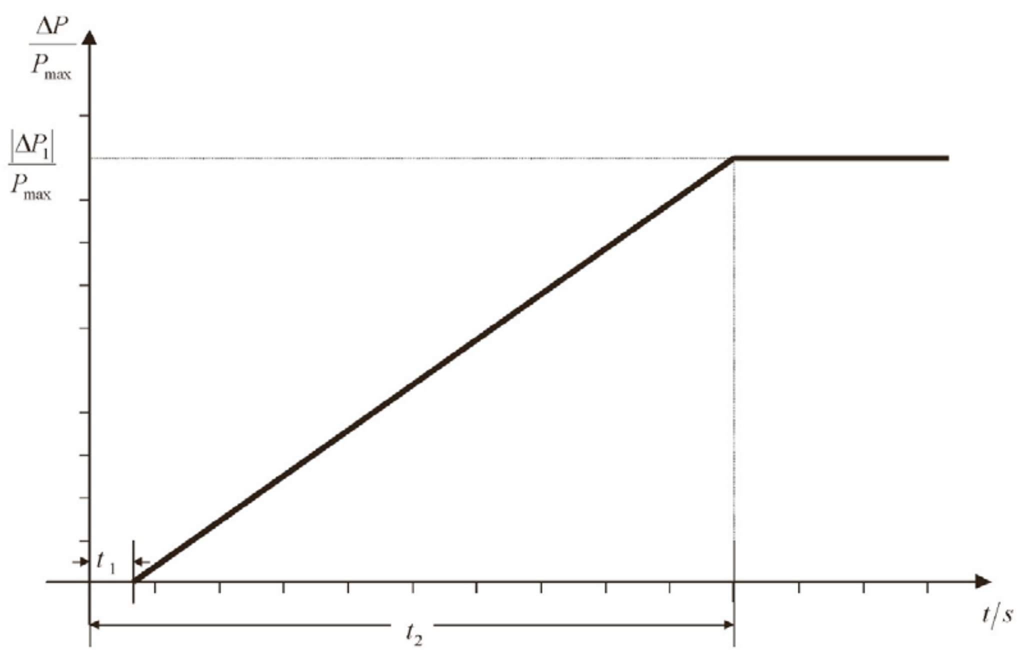


**Figure B - 1. ENTSO-E PFR delivery requirements**

*Source: EU 2016/631, Article 5 (2), Figure 6*

**Table B - 3. ENTSO-E PFR delivery requirements**

| Parameter | Range |
|---|---|
| Active Power Range $\Delta P_1/P_{Max}$ | 1.5 - 10% |
| Maximum Delay Unless Otherwise Justified | 2 seconds |
| Maximum choice for full activation time $t_2$ | 30 seconds |

*Source: EU 2016/631, Article 5 (s), Table 4*

## ENTSO-E Testing/Monitoring

- Testing shall be carried out by simulating frequency steps and ramps large enough to trigger the whole active power frequency response range [see Article 45(2)3]
- Droop and deadband shall be verified as well as compliance with specifications summarized in Section B.1.3
- Regarding real-time monitoring of FSM, the generating unit should be capable of transferring the following information to the TSO [see Article 15(2)(g)
    - status signal of FSM (on/off)
    - scheduled active power output
    - actual value of active power output
    - actual parameters settings for active power frequency response
    - droop and deadband

## B.2. Brazil (Operador Nacional do Sistema Elétrico, ONS)

### ONS Relevant Documents

- ONS[60]
  - *Submodule 3.5:* Inspection and tests on connection installations
  - *Submodule 3.6:* Minimum technical requirements for connection to transmission system
  - *Submodule 10.6:* Generation Control
  - *Submodule 14.2:* Trade arrangements for ancillary services

### ONS Generator Connection Conditions

#### *Applicability*

- Hydroelectric and thermoelectric plants with total power ≥ 30 MW [see *Submodule 3.6*, Section 7.1.1]
- Wind turbine plants with installed capacity ≥ 10 MW [see *Submodule 3.6*, Section 8.2, Table 6]

#### *Synchronous Generator Requirements*

**Table B - 4: Operador Nacional do Sistema Elétrico generator requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Deadband should be ≤ 40 mHz |
| Droop | Adjustable between 2 - 8% |

*Source: Submodule 3.6, Section 7.4, Table 5*

#### *Wind Generator Requirements [Submodule 3.6 Section 8.2 Table 6]*

- Under-frequency – Capability to provide synthetic inertia response
  - Injection of active power proportional to frequency deviation
  - Minimum 10% of rated power for a minimum period of five seconds for deviations > 0.2 Hz if turbine is operating at > 25% of its rated power
  - The operator should be notified of the plant's capability to respond to frequency deviations when it is operating < 25% of its rated output
- Over-frequency
  - Must reduce power when frequency is ≥ 60.2 Hz at a rate of 3%/0.1 Hz

[60] See http://www.ons.org.br/pt/paginas/sobre-o-ons/procedimentos-de-rede/vigentes; only available in Portuguese.

## ONS Primary Frequency Control Characteristics

- Primary frequency control shall be provided by all generators [see *Submodule 14.2*, Section 5.1.1(A)]
- Droop shall be set to 5% [see *Submodule 10.6*, Section 7.2.2]
- The primary reserve obligation of a control area, $R_k$, is determined by Equation B.1:

$$R_k = 0.01RGA_k$$

Equation B.1

whereby
$RGA_k$ = Control Area Load + Control Area Net Exchange

- The primary reserve requirement obligation is distributed among all generators with a functional speed governor and not operating at their maximum output

## ONS Testing/Monitoring

- Generators must reach 90% of their final value within nine seconds when subject to a frequency deviation step [see *Submodule 3.6*, Section 7.4, Table 5]
- Generators response must remain above 95% and below 105% of its final response for a further 51 seconds [see *Submodule 3.6*, Section 7.4, Table 5]
- Testing is conducted based on the internal procedures of each agent, manufacturers recommendations and national technical standards [see *Submodule 3.5*, Section 5.3.1.1]

## B.3. Great Britain (National Grid)

### National Grid Relevant Documents

- National Grid, *The Grid Code*, Issue 5, Revision 21; March 2017[61]
- National Grid, Connection and Use of System Code (CUSC), Section 4: Balancing Services, v1.21; February 2017[62]

### National Grid Generator Connection Conditions

#### *Applicability*

- The applicability of the requirements discussed here are dependent on both the location and competition data of the generating unit
- In general, all units with a registered capacity ≥ 100 MW are subject to the conditions discussed here

#### *Requirements*

**Table B - 5. National Grid generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | Not Specified |
| Deadband | Other than the steam unit within a CCGT module, the maximum allowable deadband ±15 mHz |
| Droop | Adjustable between 3 - 5% |

*Source: The Grid Code, Section CC.6.3.7 (c)*

### National Grid Primary Frequency Control Characteristics

- Generating units must be capable of providing primary frequency control
- Frequency control by generating units in considered an ancillary service which requires an Ancillary Services Agreement with the generating unit [see *The Grid Code*, Section BC2.A.2.1]
- National Grid can instruct a generating unit to operate in Frequency Sensitive Mode, as per the conditions agreed in the Ancillary Service Agreement [see *The Grid Code*, Section BC3.5.4]

### National Grid Testing/Monitoring

- Generating units must undergo testing as described in *The Grid Code*, Section CC, Appendix 3 to demonstrate the capability to provide frequency response and to validate the content of the Ancillary Services Agreements

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61 See https://www.nationalgrid.com/uk/electricity/codes/grid-code?code-documents
62 See https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code?code-documents

- The minimum frequency response profile for a 0.5 Hz frequency deviation as a function of generator loading is shown here in Figure B - 2

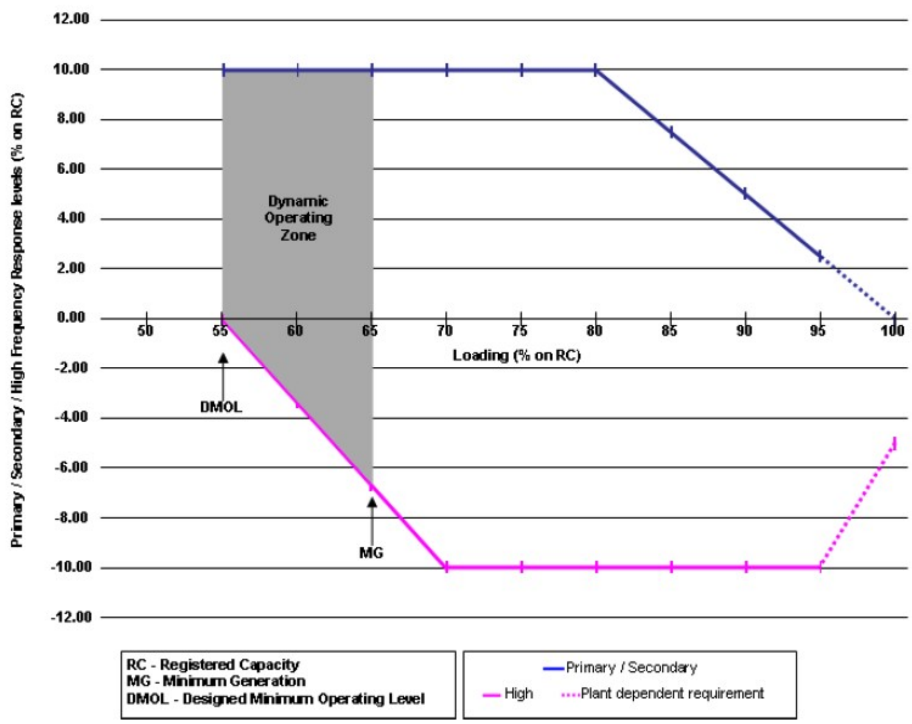


**Figure B - 2. National Grid PFR quantity Requirements**

*Source: The Grid Code, Figure CC.A.3.1*

- Testing of frequency response capability is shown graphically in Figure B - 3 for the case a frequency drop and is carried out as follows:
    - Injection of a linear ramp, from 0 Hz to -0.5 Hz frequency deviation, into plant control system over 10 seconds and sustained for duration of test
    - Primary response capability of plant is the minimum active power increase between 10 and 30 seconds
- National Grid shall monitor the performance of units to ensure compliance with connection conditions and the delivery of their Ancillary Services [see *The Grid Code*, Section C5.4]
- National Grid may at any time, although not more than twice in a calendar year, request a generating unit to carry out a test providing National Grid has reasonable justification [see *The Grid Code*, Section OC5.5.1.1]
- This test is described in *The Grid Code*, Section OC5.A.2: Compliance Testing of Synchronous Plant*,* specifically Section OC5.A.2.8 and shown here in Figure B - 4

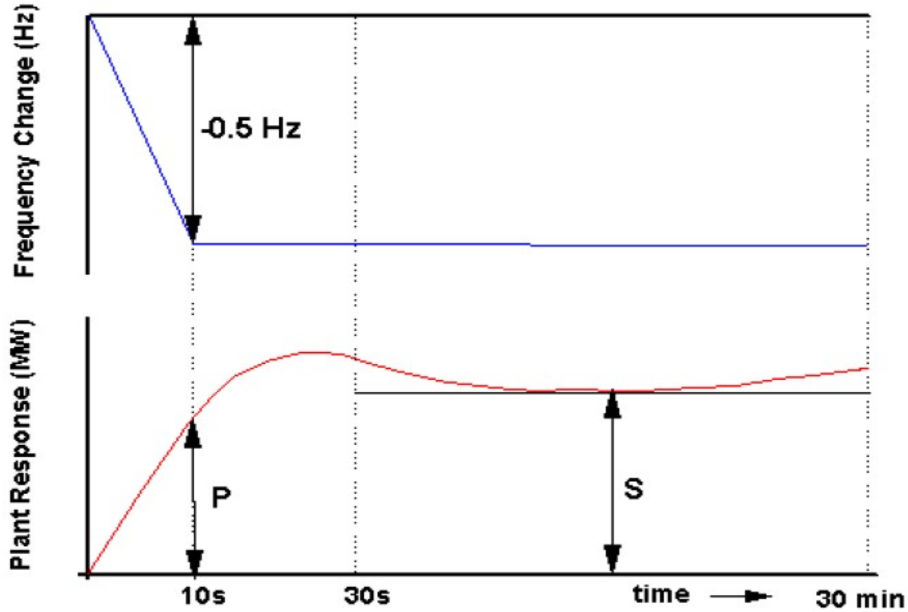


**Figure B - 3. National Grid PFR validation**

*Source: The Grid Code, Figure CC.A.3.2*

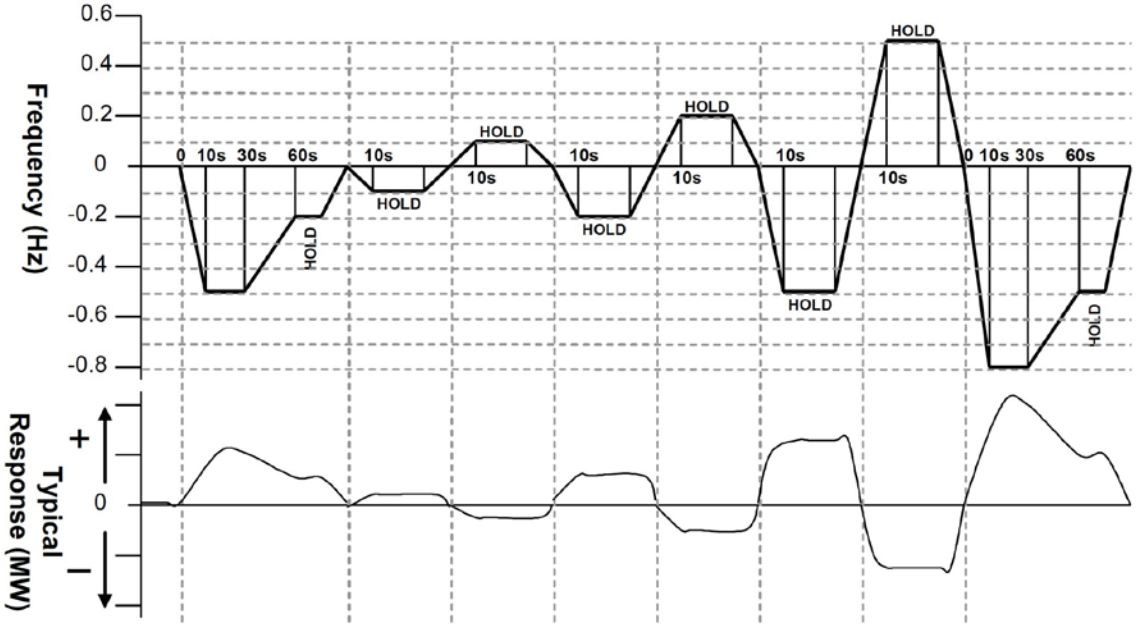


**Figure B - 4. National Grid requested frequency response capability test**

*Source: The Grid Code, Section, OC5.A.2.8, Figure 1*

## B.4. Finland (Fingrid)

### Fingrid Relevant Documents

- Fingrid, Yearly Agreement and Hourly Market Agreement for Frequency Controlled Normal Operation Reserve and Frequency Controlled Disturbance Reserve, Appendix 2: Application instruction for the maintenance of frequency controlled reserves; January 2017[63]
- Fingrid, Specifications for the Operational Performance of Power Generating Facilities VJV2013, Unofficial Translation; September 2013[64]

### Fingrid Generator Connection Conditions

#### *Applicability*

- All synchronous and wind power generating facilities ≥ 10 MW (Power Classes 2, 3, and 4)

#### *Requirements*

**Table B - 6. Fingrid generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | ≤ 10 mHz |
| Deadband | Adjustable between 0 and 1 Hz in steps of a maximum of 0.01 Hz |
| Droop | Adjustable between 2 - 12% in maximum steps of 1% |

*Source: Specifications, Section 11.2.3.3*

### Fingrid Primary Frequency Control Characteristics

- Frequency controlled disturbance reserve (FCR-D) is a market procured ancillary service
- Activation of this service begins when the frequency decreases below 59.9 Hz
- Full reserve shall be activated at a frequency of 49.5 Hz
- Half of the reserve shall be activated in 5 seconds and the full reserve activated in 30 seconds for a stepped frequency change of -0.5 Hz

### Fingrid Testing/Monitoring

#### *Connection Conditions*[65]

- During testing the active power generation shall be at least 30% of rated capacity

[63] See http://www.fingrid.fi/en/powersystem/Power%20system%20attachments/2017/Liite2%20-%20Taajuusohjattujen%20reservien%20yll%C3%A4pidon%20sovellusohje%202017_eng.pdf
[64] See http://www.fingrid.fi/en/customers/connection/Specifications/Pages/default.aspx
[65] See *Specifications*, Section 14.3.4.4

- Frequency control range shall be at least ± 10% of rated capacity
- The characteristic of a fast (a few seconds) response of frequency control shall be verified via major step-like and ramp-like frequency deviations

### *Verification of Capability to provide FCR-D*

- Test is carried out by supplying a step frequency deviation signal of -0.5 Hz to the turbine controller
- Frequency controlled disturbance reserve capability of the unit is the smaller of the following two value
    - The active power measured at 30 seconds after the step change or
    - The active power change measured at 5 seconds multiplied by 2

### *Monitoring*

- Online monitoring is specified in *Specifications*, Section 8
- Generating Units with a rated capacity ≥ 10 MW but < 100 MW must deliver real-time active and reactive power measurement data
- Generating units with registered capacity ≥ 100 MW must be equipped with a swing recorder whose recording frequency can be 50 Hz or higher; the period of recording must be a few dozen seconds

## B.5. Italy (Terna)

### Terna Relevant Documents

- Terna, *Grid Code*; November 2005[66]
- Annex A15: Participation in Frequency Control and Frequency-Power[67]
- Annex A73: Technical Specifications for Checking and Enhancement of Primary Frequency Control Service, Revision 1; March 2014[68]

### Terna Generator Connection Conditions

#### *Applicability*

- All units with nominal power ≥ 10 MVA, excluding those fed by non-programmable renewable sources [see Annex A15 4.1], must contribute to primary frequency control as per the conditions summarized here [see *Grid Code* Section 1B.5.6.1]

#### *Requirements*

**Table B - 7. Terna generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | Controller insensitivity must be ≤ 10 mHz for all installations |
| Deadband | • ± 10 mHz for hydro units and steam simple cycle units<br>• ± 20 mHz for gas turbine units and for steam units of combined cycles |
| Droop | • For hydroelectric groups, the droop must be adjustable between 2 - 5%<br>• For thermal groups, the droop must be adjustable between 5 - 8% |

*Source: Grid Code, Section 1B.5.7 and Annex A15: Participation in Frequency Control and Frequency-Power*

#### *Deadband Implementation*

In the event of the frequency exiting the controller deadband, the active power contribution must be compensated for by a droop implementation as shown in Figure B - 5.

66 See https://www.terna.it/en-gb/sistemaelettrico/codicedirete.aspx
67 See https://www.terna.it/it-it/sistemaelettrico/codicedirete.aspx; Italian-language only.
68 Same as above.

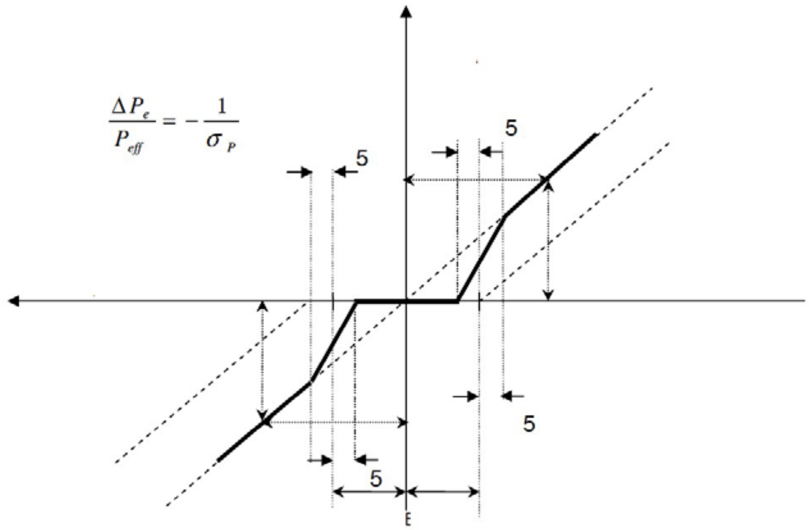


**Figure B - 5. Italy droop implementation to compensate for deadband**

*Source: Annex A15, Section 4.6, Figure 4*

## Terna Primary Frequency Control Characteristics

- Mandatory participation for all units whose nominal power ≥ 10 MVA [See *Annex A15*, Section 4.1]
- Units must reserve a minimum of ± 1.5% of their maximum generation capabilities [see *Annex 15*, Section 4.4.2.3(a)]
- Units must operate with the following droop [see *Annex A15*, Section 4.6]
  - Hydroelectric Units: 4%
  - Thermal Units: 5%
- Within 15 seconds from the beginning of a frequency change a unit must deliver at least half of the ΔP requested [see *Annex A15*, Section 4.4]
- Within 30 seconds from the beginning of a frequency change a unit must deliver all of the ΔP requested [see *Annex A15*, Section 4.4]
- Once activated, the unit must be able to continue to stably supply the required ΔP for a minimum of 15 consecutive minutes [see *Annex A15*, Section 4.4]

## Terna Testing/Monitoring

Testing procedure is outlined in Annex A18: Verification of Compliance of the Unit with the Requirements of Production Techniques[69]

- Droop is verified by one of the following methodologies [See *Annex A18*, Section 6.1]

[69] See https://www.terna.it/it-it/sistemaelettrico/codicedirete.aspx; Italian-language only.

- By observing normal variations of the grid frequency and the associated active power variations of the generating unit. This test must be performed at least twice, at medium-low loading of the unit and high loading of the unit.
- By injection of a step-change of suitable amplitude to the plant speed controller, one increasing and one decreasing. This test must be performed twice, with the plant loaded at 90% and 60% of its nominal capacity. The step size shall be chosen so as to not saturate the active power response of the unit.

- The insensitivity of the controller is measured by setting the intentional deadband to 0 mHz and observing the plant's response to either normal grid frequency variations or the injection of a ramp to the speed controller with a maximum amplitude of 40 mHz [See *Annex A18*, Section 6.2]
- The capability to provide primary frequency control is discussed in both *Annex A18* and *Annex A73*[70]
    - Performance is verified by injection of a step-change of suitable amplitude to the plant speed controller and the production of a plot that examines the power produced as a functions of time
    - It must be shown that the unit delivered half of its primary reserve after 15 seconds and its full reserve within 30 seconds and sustains this response for 15 minutes

[70] Same as above

## B.6. Ireland (EirGrid)

### EirGrid Relevant Documents

- EirGrid, *The Grid Code*, Version 6.0; July 2015[71]
- EirGrid, Test 46 & 48 Operating Reserves, Governor Droop and ROCOF, Version 0.1[72]
- EirGrid, Test 49 Demonstration of Governor Deadband, Version 0.1[73]

### EirGrid Generator Connection Conditions

#### *Applicability*

- All generating units with registered capacity ≥ 2 MW are subject to the conditions summarized here [*The Grid Code*, Section CC.3 and Section OC4.2]

#### *Requirements*

**Table B - 8. Eirgrid synchronous generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Deadband shall be ≤ 15 mHz [*The Grid Code*, Section OC.4.3.4.1.2 (c)] |
| Droop | Adjustable so that unit has an overall droop of 3% to 5% [see *The Grid Code*, Section CC.7.3.7] |

**Table B - 9. Eirgrid wind generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Deadband shall be ≤ 15 mHz [*The Grid Code*, Section WFPS 1.5.3.2] |
| Droop | Adjustable from 2 - 10% and nominally set at 4% [*The Grid Code*, Section WFPS 1.5.3.1] |

### EirGrid Primary Frequency Control Characteristics

- All generating units must operate in FSM
- Each generating shall have a Primary Operating Reserve (POR) of ≥ 5% of the registered capacity in the range from 50 to 95% of its registered capacity [*The Grid Code*, Section CC 7.3.1.1]
  - The POR requirement in the range 95 to 100% is not less than indicated by a straight line from 5% of registered capacity to 0% at 100% [*The Grid Code*, Section CC 7.3.1.1]

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[71] See http://www.eirgridgroup.com/customer-and-industry/general-customer-information/grid-code/
[72] See http://www.eirgridgroup.com/site-files/library/EirGrid/Test_46_48_Operating-Reserves-Final.docx
[73] See http://www.eirgridgroup.com/site-files/library/EirGrid/Test49TestProcedureDraft.docx

- POR is the MW output required at the nadir when then nadir occurs between 5 and 15 seconds after the event [see *The Grid Code*, Section OC4.6.3.3.1]
    - If the nadir is before 5 seconds or after 15 seconds then for the purpose of POR monitoring the nadir is deemed to be the lowest frequency that occurred between 5 and 15 seconds after the event [see The Grid Code, Section OC4.6.3.3.2]
- EirGrid procures long term POR reserve contracts through an auction mechanism whereby awarded generators must reserve headroom

### EirGrid Testing/Monitoring

All generators must undergo Governor Droop Response (Test 48) testing and Demonstration of Governor Deadband (Test 49) to demonstrate compliance with Grid Code. In Test 48, the generating unit must demonstrate the minimum levels of primary operating reserves are provided and that the governor responds as expected for the following test cases described in *Test 46 & 48*, Section 9.1, and summarized here in Table B - 10.

**Table B - 10. EirGrid primary frequency control test**

| Test No. | Load Level | Frequency Injection | POR (5 – 15 sec) Requirement |
|---|---|---|---|
| 1 | Min Load | -0.2Hz (Step) | 5% |
| 4 | 75% | -0.2Hz (Step) | 5% |
| 7 | 90% | -0.2Hz (Step) | 5% |
| 9 | 92% | -0.2Hz (Step) | 5% |
| 10 | 95% | -0.2Hz (Step) | 5% |

*Source: Test 46 & 48 Operating Reserves, Governor Droop and ROCOF*

#### *Demonstration of Governor Deadband (Test 49)*

The speed-governor deadband is tested out by injecting a series of step changes into the frequency inputs of the governor or by ramping the governor from one side of the deadband to the other and recording the active power generation of the generating unit.

#### *Monitoring*

- Monitoring is continuous on all generation unit(s) with a total registered capacity > 4MW [*The Grid Code*, Section OC10.3 (a)]
- Monitoring may be carried out at any time by the TSO and may be used to demonstrate non-compliance with requirements. This includes the following:
    - ensuring compliance with primary operating reserve requirements following a low frequency event on the transmission system
    - examining frequency regulation provided by each generating unit to confirm that it is consistent with the declared governor droop

## B.7. New Zealand (Transpower)

### Transpower Relevant Documents

- Electricity Authority, Electricity Industry Participation Code; 2010[74]
- Electricity Authority, Electricity Industry Participation Code, Part 8: Common Quality; January 2017[75]
- Transpower, GL-EA-010: Companion Guide for Testing of Assets; August 2016[76]
- Transpower, Operator Standard Contract Terms for Instantaneous Reserve; 2015[77]

### Transpower Generator Connection Conditions

#### *Applicability*

- All generating units ≥ 30 MW [see Electricity Industry Participation Code]

#### *Requirements*

**Table B - 11. Electricity Authority/Transpower generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | Not Specified |
| Droop | Adjustable between 0 - 7% |

*Source: Electricity Industry Participation Code, Part 8, Schedule 8.3—Technical Code A 5(1)(c)*

### Transpower Primary Frequency Control Characteristics

- Fast instantaneous reserve (FIR) is an ancillary service procured through a market mechanism
- FIR is the additional generation provided 6 seconds after a frequency event and sustained for a period of at least 60 seconds [see *Electricity Industry Participation Code*, Part 1]

### Transpower Testing/Monitoring

- All generating unit must undergo the following tests as described in *Companion Guide for Testing of Assets:*
    - Section 5.6.1: Governor Block Diagrams/Models
    - Section 5.6.2: Governor Stability
    - Section 5.6.3: Example governor frequency injection curves

[74] See https://www.ea.govt.nz/code-and-compliance/the-code/
[75] Same as above.
[76] See https://www.transpower.co.nz/system-operator/resources-asset-owners/asset-testing
[77] See https://www.transpower.co.nz/system-operator/electricity-market/instantaneous-reserve

- Tests must be repeated at least once every five years for a mechanical or analogue governor and at least once every 10 years for a digital or electro-hydraulic governor
- Generating units wishing to provide FIR must conduct additional testing at least once a year [see *Operator Standard Contract Terms*]
    - Generators are not required to conduct such tests if it has demonstrated its FIR capability by responding to a under-frequency event in the preceding year
- An example of a test to demonstrate a generators capability to provide FIR is presented in *Companion Guide for Testing of Assets,* Appendix A, Section 5.8
    - A frequency signal is injected into the plant's control system, as shown in Figure B - 6
    - FIR is the additional MW output measured at six seconds after the start of the event
    - This test should be carried out at various machine loading levels

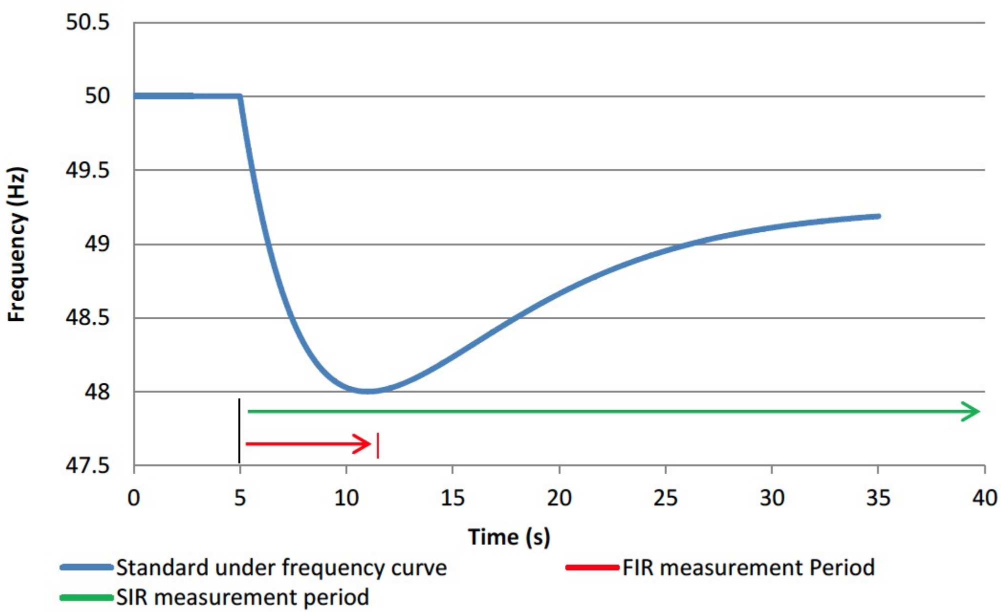


**Figure B - 6: New Zealand sample FIR verification test**

*Source: Companion Guide for Testing of Assets, Appendix A, Section 5.8, Figure 11*

## *Monitoring*

- Monitoring requirements are stipulated in *Operator Standard Contract Terms*, Section 5.3
- Units participating in FIR are required to have monitoring equipment that measures the instantaneous reserve response in intervals no greater than six seconds
- Measurements must begin no less than six seconds before the under frequency event occurring and end no less than 60 seconds after the event

## B.8. Singapore (Energy Market Authority of Singapore)

### Singapore Relevant Documents

- Energy Market Authority of Singapore, *Transmission Code*; October 2017[78]
- Energy Market Company, *Market Rules Chapter 6 Market Operation;* January 2018[79]
- Energy Market Company, *Market Rules Appendix 6J Price Limits and Constraint Violation Penalties* January 2018[80]
- A Guide to Providing Interruptible Load in Singapore's Wholesale Market[81]

### Singapore Technical Connection Conditions

#### *Applicability*

- All generating units with registered capacity ≥ 10 MW are subject to the conditions summarized here [see *Transmission Code*, Section C4.1]

#### *Requirements*

**Table B - 9. Energy Market Authority of Singapore technical connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | N/A |
| Deadband | • Deadband shall be ≤ ± 50 mHz<br>• Governor shall respond to full frequency deviation once outside its deadband |
| Droop | • Adjustable so that unit has an droop of 3 - 5% |

*Source: Transmission Code, Section C4.1 (e)*

### Singapore Primary Frequency Control Characteristics

- Each generating unit must be capable of providing the following minimum primary reserves [see *Transmission Code*, Section F8.1]:
  - 5% of rated MW capacity at 90% of rated MW output
  - 9% of rated MW capacity at 75% of rated MW output
  - Primary reserve between 75% and 90% shall be linearly interpolated from their respective requirements [see Transmission Code, Section F8.2]
- Primary reserve is defined as the change in MW output, in response to a frequency change,

78 See https://www.ema.gov.sg/cmsmedia/Licensees/Electricity/Transmission%20Code_12%20Oct%202017%20Final.pdf
79 See https://www.emcsg.com/marketrules
80 See https://www.emcsg.com/marketrules
81 See https://www.emcsg.com/f146,16653/Guide_to_providing_IL_website_21082012.pdf

measured at 9 seconds and sustained for a further 9 minutes and 51 seconds [see *Transmission Code*, Section F.7.4.2]

   - If the change is not sustained, the primary reserve is the minimum change in MW output during that period

- Generators whom wish to provide primary reserve must register to do so and undergo verification testing. Once a generating unit is registered to provide primary reserve it is obliged to submit a valid standing offer to provide this service whose upper limit is bounded by a fraction of the Value of Lost Load (VoLL), currently set at 0.85*VoLL. [See *Market Rules Appendix 6 J.1.7]*
- Interruptible load may also offer primary reserve whereby they are required to trip instantaneously if the frequency falls below 49.4 Hz [see *A Guide to Providing Interruptible Load in Singapore's Wholesale Market Section D]*
- The maximum contribution from interruptible load is capped at 20% of the total primary reserve requirement [see *A Guide to Providing Interruptible Load in Singapore's Wholesale Market Section C]*

## Singapore Testing/Monitoring

- Units are tested by injecting a frequency signal graphically shown in Figure B - 7
- Response is measured to ensure compliance with requirements
- Generating units shall install a high-resolution recorder for monitoring and assessment of, among other, the frequency response of the unit by the system operator [see *Transmission Code*, Section C4.1(h)]
- Generators not capable of providing the minimum FSM specifications in accordance with *Transmission Code*, Section C4.1(e) may either be denied connection to the network or, if already connected, may not be permitted to operate as noted in *Transmission Code*, Section C5

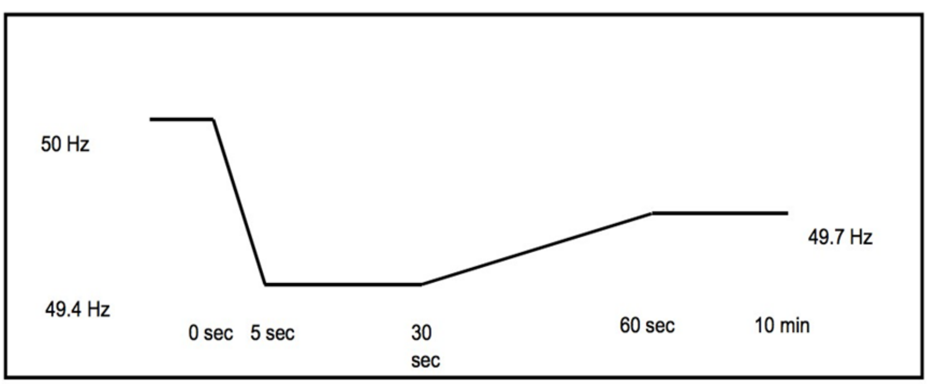


**Figure B - 7. Singapore PFR test**

*Source: Transmission Code, Section F.7.4.1*

## B.9. Spain (Red Eléctrica de España)

### Red Eléctrica de España Relevant Documents

- Operating Procedures, PO 7.1: Primary Regulatory Supplementary Service Resolution of 7/30/1998, BOE 18/08/98[82]

### Red Eléctrica de España Generator Connection Conditions

#### *Applicability*

- All generating units

#### *Requirements*

**Table B - 10. Red Eléctrica de España generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | ± 10 mhz |
| Deadband | No intentional deadband |
| Droop | Droop should allow generator to vary its output by 1.5% for a frequency deviation of 200 mHz |

*Source: PO-7.1 4*

### Red Eléctrica de España Primary Frequency Control Characteristics

- Participation in primary frequency control is mandatory
- Generators incapable of providing primary regulation must provide proof that they have procured their primary regulation obligation from another generating unit
- Response shall be fully delivered within 15 seconds for a deviation < 100 mHz
- In case of deviation > 100 mHz
  - 50% of the reserve must be delivered within 15 seconds
  - 100% of the reserve must be delivered before 30 seconds with a minimum linear delivery rate between 15 and 30 seconds

[82] See http://www.ree.es/es/actividades/operacion-del-sistema-electrico/procedimientos-de-operacion; Spanish-language only.

## B.10. Switzerland (Swissgrid)

### Swissgrid Relevant Documents

- Swissgrid, *Transmission Code*; December 2013[83]
- Swissgrid, *Test for primary control capability*, Version 1.1; April 2011[84]
- Swissgrid, Basic principles of ancillary service products, Version 9.2; February 2017[85]
- Swissgrid, Requirements for Monitoring Data, Version 3.1[86]
- Swissgrid, Grid Connection Agreement Annex 1, Data and Requirements, Version 13.12.2014[87]

### Swissgrid Generator Connection Conditions

#### *Applicability*

- All generating units

#### *Requirements*

**Table B - 11. Swissgrid generator connection requirements**

| Parameter | Range |
|---|---|
| Frequency Response Insensitivity | 10–30 mHz |
| Deadband | Adjustable between 0-500 mHz |
| Droop | Adjustable between 2 - 12% |

*Source: Grid Connection Agreement Annex 1 Data and Requirements, Section 4.3*

### Swissgrid Primary Frequency Control Characteristics

- PFR is a market procured service
- Generating units must pre-qualify by verifying their primary control capability to participate in the market
- Generating units may be combined into a portfolio in order to participate in the market [4.3 (3)]
- Generators submit tenders to the market; offers must be symmetrical control bands
- Offer sizes are 25 MW per bid as specified in Basic principles of ancillary service products, Version 9.2

83 See https://www.swissgrid.ch/swissgrid/en/home/experts/topics/transmission_code.html; German-language only.
84 See https://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/prequalification/en/D110426_test-for-primary-control-capability_V1R1_EN.pdf
85 See https://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/Dokumente/D170214_AS-Products_V9R2_en.pdf
86 See https://www.swissgrid.ch/dam/swissgrid/experts/ancillary_services/prequalification/en/131014_requirements-for-monitoring-data_V3R1_EN.pdf
87 See https://www.swissgrid.ch/swissgrid/en/home/experts/topics/legal_system/grid_connection.html; German-language only.

## Swissgrid Testing/Monitoring

There are two methods of demonstrating primary control capabilities as outlined in *Test for primary control capability*:

1. The preferred method subjects generators to a linearly increasing/decreasing rate to a quasi-static frequency deviation of 200 mHz within 10 seconds as depicted in Figure 1 of the document, shown here for the case of a frequency deviation for reference as Figure B - 8.
    - o The change in active power is measured at 30 seconds to ensure full delivery of primary control reserves
    - o This power characteristic is used to determine the generators droop [See *Test for primary control capability*, Section *3.3.2*]
2. If technical factors prevent the use of test signals an alternative method of verification of capabilities is recording the plant's response to naturally occurring grid frequency excursions.

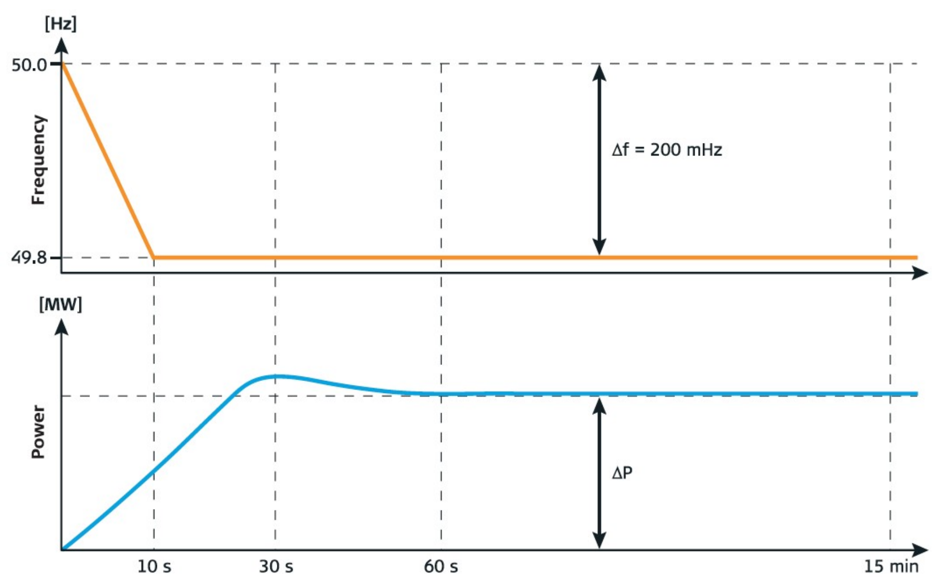


**Figure B - 8. Switzerland PFR test**

*Source: Swissgrid, Test for primary control capability, Version 1.1 Figure 1*

Another test required to verify the primary control capabilities of a generating unit is one which determines the deadband. This test is carried out with the aid of hysteresis as shown in Figure 2 of *Test for primary control capability*, shown here for reference as Figure B - 9.

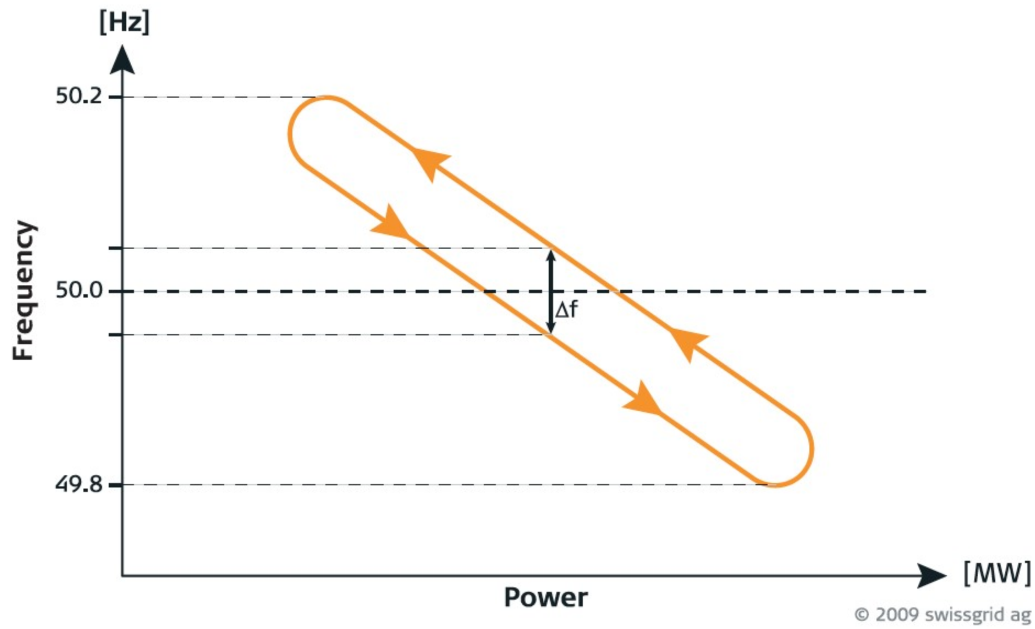


**Figure B - 9. Switzerland deadband test**

*Source: Swissgrid, Test for primary control capability, Version 1.1 Figure 2*

### *Monitoring*

- Online monitoring is used for continuous monitoring of ancillary services during operation, details of which can be found in *Requirements for Monitoring Data, Version 3.0*
- Generating unit must provide Swissgrid with both positive and negative active power reserves at an update rate ≤ 10 seconds
- Generating unit must also preserve data for one month after the tendering period and this data should contain synchronized frequency and power measurements at a minimum of 1 Hz