IEC TR 63401-3

Edition 1.0 2023-12

TECHNICAL REPORT

colour inside

Dynamic characteristics of inverter-based resources in bulk power systems – Part 3: Fast frequency response and frequency ride-through from inverter-based resources during severe frequency disturbances

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

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CONTENTS

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DYNAMIC CHARACTERISTICS OF INVERTER-BASED RESOURCES IN BULK POWER SYSTEMS –

Part 3: Fast frequency response and frequency ride-through from inverter-based resources during severe frequency disturbances

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Draft	Report on voting
8A/130/DTR	8A/150/RVDTR

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this Technical Report is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/standardsdev/publications.

A list of all parts in the IEC 63401 series, published under the general title *Dynamic characteristics of inverter-based resources in bulk power systems*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

- reconfirmed,
- withdrawn, or
- revised.

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INTRODUCTION

Primary frequency response (PFR) denotes the autonomous reaction of system resources to change in frequency. In most power systems, the main contributor to PFR is the governor response of synchronous generation. In the systems with less synchronous generators, the system inertia is relatively low and PFR capability is relatively weak and slow, so the system frequency tends to change dramatically in severe power imbalance disturbances, which will trigger under-frequency load shedding (UFLS) or OPC (over speed protection control) of synchronous generators possibly. Therefore, it is an effective coping method to introduce some new frequency responses in the systems with high penetration of inverter-based resources.

This document studies fast frequency response (FFR) as a potential mitigation option in maintaining grid security during severe frequency disturbances. Broadly, FFR is some kind of rapid injection of electrical power from inverter-based resources or relief of loads that helps arrest the decline of system frequency during severe disturbances.

DYNAMIC CHARACTERISTICS OF INVERTER-BASED RESOURCES IN BULK POWER SYSTEMS –

Part 3: Fast frequency response and frequency ride-through from inverter-based resources during severe frequency disturbances

1 Scope

This part of IEC 63401, which is a Technical Report, provides an insight into the various forms of fast frequency response and frequency ride-through techniques that involve inverter-based generation sources (mainly wind and PV) in a bulk electrical system.

This document first focuses on extracting the clear definition of FFR from different references around the world, while studying the mechanism of FFR acting on system frequency and the unique features of FFR. It then compares various kinds of frequency response and demonstrates the relationship among synchronous inertia response, fast frequency response, and primary frequency response. Several system needs and conditions where FFR is suitable are identified. This document also focuses on the performance objectives, practicality and capabilities of various non-synchronous resources, and discusses the test methods for verifying FFR capability at different levels. Finally, it focuses on the ROCOF issues and on the robust performances of FFR.

2 Normative references

There are no normative references in this document.

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

No terms and definitions are listed in this document.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

3.2 Abbreviated terms

Abbreviated term	Description
AEMO	Australian Energy Market Operator
AGC	automatic generation control
BESS	battery energy storage systems
BMS	battery management system
BPS	bulk power system

Abbreviated term	Description
CLM	composite load model
CLOD	complex load model
DFIG	doubly fed induction generator
EFCC	enhanced frequency control capability
EFR	enhanced frequency response
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas (US)
FCR	frequency containment response
FFR	fast frequency response
FLC	frequency limit control
IBFFR	inertia-based FFR
IBR	inverter-based resources
MPPT	the maximum power point tracking
NC RfG	Network code on Requirements for Generators
NERC	North American Electric Reliability Council
OPC	over speed protection control
PCS	power conversion system
PFR	primary frequency response
PMSG	permanent magnet synchronous generator
PMU	phasor measurement units
PSSE	Power System Simulator for Engineering
PV	photovoltaic
RES	renewable energy system
ROCOF	rate of change of frequency
SFR	system frequency response
SIR	synchronous inertial response
SNSP	system non-synchronous penetration
SONI	System Operator for Northern Ireland
UFLS	under-frequency load shedding
WECC	Western Electricity Coordinating Council (US)

Abbreviated term	Description
WSCC	Western Systems Coordinating Council (US)
WTG	wind turbine generators

4 Definition of fast frequency response (FFR)

4.1 General

In existing literature, there is no unified definition of fast frequency response, which seems sometimes to have different meanings depending on the context.

The typical definitions from different organizations or authors are reviewed here. Some existing usage does not give a clear definition in certain cases; thus the meaning of FFR is speculated from the context. In this case the recommended definition of FFR from inverter-based resources is given based on its impact mechanism on the system frequency.

4.2 Existing usage of term FFR

4.2.1 FFR in Australia and Texas

4.2.1.1 General

GE has prepared a report about FFR technology capabilities for the Australian Energy Market Operator (AEMO), in which a description of FFR is given [1][1]. It is summarized as follows:

- Broadly, FFR is the rapid injection of power or relief of loading that helps arrest the decline of system frequency during disturbances.
- FFR is similar to PFR but acts much faster, providing power during the arresting phase, with the specific objective of providing arresting power before the frequency nadir.
- FFR and PFR both help to arrest frequency and interact with inertia to determine the frequency nadir. FFR will also contribute to establishing the settling frequency if the FFR is sustained past the time of the nadir into the rebound period.
- Both FFR and PFR are autonomous controls that act based on local conditions, that is, they respond to quantities like local frequency (or machine speed) that can be measured at, or very close to, the equipment providing the service.

The definition of FFR that was approved in the Electric Reliability Council of Texas (ERCOT) NPPR 863 [2] as a new reserve service is shown below.

The automatic self-deployment and provision by a resource of their obligated response within 15 cycles after frequency meets or drops below a pre-set threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes.

In general, this version of FFR is similar to PFR in function. The only difference between FFR and PFR is the response time. Figure 1 shows an example relationship between the three responses that was discussed in ERCOT.

[1] Numbers in square brackets refer to the Bibliography.

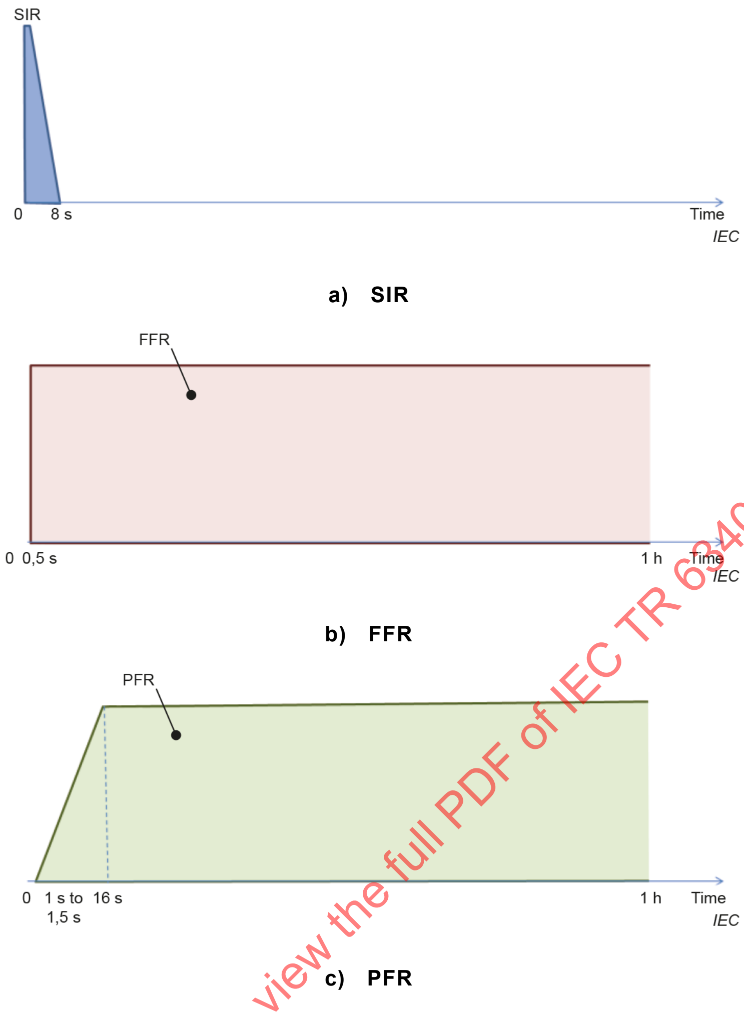


Figure 1 – Proposed response times by ERCOT as of 2014

It can be recognized that the three responses can contribute to mitigate the frequency nadir when the frequency drop event occurs although the contribution levels are different. On the other hand, the secondary frequency response is highly unlikely to contribute to mitigate the frequency nadir because the delivered secondary frequency control signal is regularly updated or renewed every few seconds, e.g. 5 s.

As seen from Figure 1, it is obvious that the initiating time of FFR is not zero. The response time of the fast frequency response consists of five elements and is summarized as Table 1.

1) Measure – Measure and identify frequency deviation and fast frequency decrease.
2) Identify – Identify the occurrence of severe event that involves FFR.
3) Signal – Communicate action to be taken.
4) Activate – Actuate the resource.
5) Activate fully – Full response from the resource.

Table 1 – Frequency response times of FFR

FFR option	Measure and identify	Signal	Activate	Activate fully
Direct detection	≤ 40 ms to 60 ms (approximately 2 to 3 cycles)	~ 20 ms (approximately 1 cycle)		
Detection with PMU	~ 40 ms to 60 ms (approximately 2 to 3 cycles)	~ 20 ms (approximately 1 cycle)		
Local frequency detection	≥ 100 ms (approximately 5 to 6 cycles)	nil		
Wind turbine with IBFFR			40 ms (approximately 2 cycles)	~ 500 ms (approximately 30 cycles)
Lithium batteries, flow batteries, supercapacitor			10 ms to 20 ms (approximately 0,5 to 1 cycle)	
Lead-acid batteries			40 ms (approximately 2 cycles)	
Flywheels (non-inverter)			≤ 4 ms (approximately instantaneously)	
Solar PV			100 ms to 200 ms (approximately 5 to 12 cycles)	
HVDC			50 ms to 500 ms (approximately 2,5 to 30 cycles)	

There are several FFR options which cannot do without external detection and signalling: wind turbines; lithium, flow and lead-acid batteries; flywheel energy storage systems (inverter-interfaced); supercapacitor energy storage systems; solar photovoltaic (PV); and high-voltage DC (HVDC) transmission. Inertia-based FFR (IBFFR, also known as "synthetic inertia") from wind turbines can make a valuable contribution.

There are several FFR options that detect, signal and actuate by themselves such as flywheel energy storage systems (non-inverter interfaced).

There are several FFR options that signal and actuate such as load.

In Figure 2, a simple illustration of the relationship between a frequency event and an FFR response is shown.

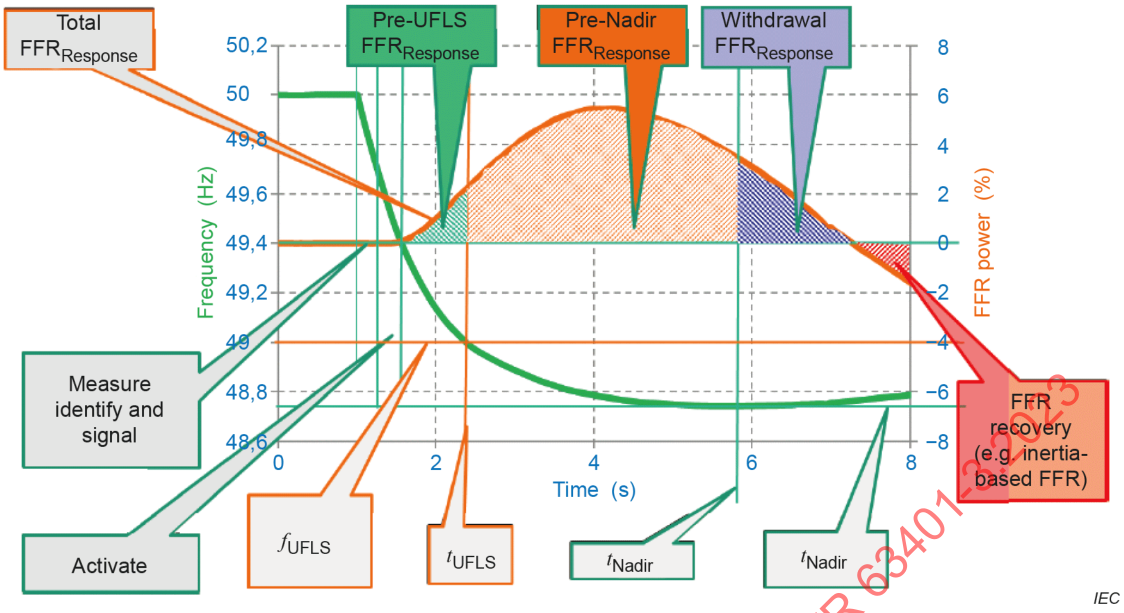


Figure 2 – Time elements of FFR

At the beginning of the event (at 1 s), system frequency begins to drop at a ROCOF (as noted above) that is proportional to the size of the event, and inversely proportional to the system inertia. As the frequency drops until the event has been detected, actions requested from FFR resources respond by providing arresting energy to slow and stop the frequency decline. A primary objective is to ensure ROCOF is sufficiently reduced such that UFLS can operate successfully, so energy delivered before hitting UFLS (green shading) is most valuable. Even if UFLS occurs, FFR continues to arrest until the frequency nadir. This is the energy shaded in orange. After the frequency nadir, the FFR energy complements the restorative energy coming from the primary frequency response. This is shown in blue. As the figure suggests, speed is important to avoid UFLS. However, the power industry has not asked for response times that are as fast as the AEMO values in Table 1. Because of that, technologies will not have been optimized for speeds less than several hundreds of milliseconds in some cases. However, there will be modifications or trade-offs that could reduce response times significantly in some cases. For example, an aggressive response from lithium batteries will be at the expense of increased thermal stress on the battery cells, which could be mitigated by increased parasitic losses from increased cooling capacity, or will reduce lithium battery life expectancy in some cases. Rotating devices like flywheels and wind turbines will see higher torques, etc.

4.2.1.2 The main challenge to achieve FFR

The main challenge to achieve FFR is to quickly and accurately identify a severe event where the FFR is inseparable. Complicating this step is the fact that directly after an event, frequency varies spatially. So, while one part of the grid could perceive a severe event, another part of the grid will not. Additionally, triggering too much FFR will have adverse consequences in some cases. Triggered by local ROCOF measurement and triggered by direct event detection become two options that can be selected according to different conditions.

Another difficulty is that very fast measurements will misinterpret transients to a certain extent, switching operations or other actions that are not severe events as reasons to trigger. Risk of false triggering is mitigated by longer periods for measurement and identification, but this comes at the expense of FFR activation time. So, FFR response time is critical; however, a balance between making high fidelity decisions to act and speed is needed. Fortunately, it turns out that FFR needs to be fast but not incredibly fast. FFR needs to be started well before UFLS or the occurrence of the frequency nadir. Analysis presented suggests that total response times on the order of one quarter to one half second are sufficiently fast. It is non-intuitive, but extremely fast FFR is less effective. If it is too fast, then it interferes with and stifles full PFR response. Part of the planning process can include fine-tuning the response time of FFR, thereby improving the efficacy of the FFR for critical conditions.

4.2.1.3 Response trigger options

There are two ways to detect the need to deploy FFR.

1) Direct event detection – Detect the specific condition of the disruption (e.g. the relay action that results in losing AC link to main grid) and having a direct transfer trip scheme to inform the resource(s). This can be done quickly (on the order of a few cycles) but dedicated, fast communications are inseparable from it and it only addresses the specific contingencies within its design criteria (i.e. if something else causes a frequency event, the FFR won't trigger).
2) Frequency and ROCOF detection – Detect the frequency deviation and high ROCOF. There are promising new technologies that claim to be able to do this very quickly. However, accuracy and, especially, false triggering will still be an issue when attempting to measure frequency and ROCOF very quickly after a major system fault in some cases. Further, this approach has the limitation of only being applicable to frequency events (and not, for example, excess interconnector loading that can cause an island to form or other problems to evolve).

4.2.2 FFR and synthetic inertia in European Network of Transmission System Operators for Electricity (ENTSO-E)

The ENTSO-E has published several documents related to FFR. It is summarized as follows.

- The word "frequency response" is widely used in the published grid code on Requirements for Generators (RfG) [3], but RfG focuses on the performance requirement of the frequency response from a functional perspective rather than details on technical implementation to achieve the objectives. Based on the definitions in Article 2 in NC RfG, "frequency response insensitivity" means the inherent feature of the control system specified as the minimum magnitude of change in the frequency or input signal that results in a change of output power or output signal. It can be speculated that frequency response is more relevant to magnitude of change in the frequency than ROCOF.
- RfG defines synthetic inertia as the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power generating module to a prescribed level of performance. It responds to ROCOF like true inertia inherently provided by synchronous generators [4].
- FFR is not defined as a specific term. It is described as the frequency response that delivers energy in the very first seconds after disturbance. Although FFR qualifies "replace the effect of inertia of a synchronous power generating module to a prescribed level of performance", it is still controversial to be termed as synthetic inertia because it emphasizes an active power block infeed rather than a power increase proportional to ROCOF. FFR will be an alternative or supplement of synthetic inertia as reaching the nadir is likely to take several seconds in some cases [5].

- In the Nordic synchronous area, fast frequency reserve is intended to be a fast, active power support, responding to a frequency deviation [5]. There are three different combinations for frequency activation level and maximum full activation time, that are equally efficient for FFR provision, and the FFR provider can freely choose the most suitable combination for each specific providing entity: 0,7 s maximum full activation time for the activation level 49,5 Hz; 1,0 s maximum full activation time for the activation level 49,6 Hz; 1,3 s maximum full activation time for the activation level 49,7 Hz.

In summary, fast frequency response generally refers to the fast active power support responding to frequency deviation, especially for the controlled contribution of electrical power from a unit which responds quickly to changes in frequency in order to counteract the effect of reduced inertial response. It can react proportionally to the deviation or inject power according to a pre-determined schedule. As a distinction, synthetic inertia is defined as the controlled contribution of electrical power from a unit that is proportional to the ROCOF at the terminals of the unit.

Fast frequency response based on frequency deviation can significantly improve the minimum instantaneous frequency namely nadir. Careful investigation was done in order to ensure that these responses do not cause instability, overshoot or larger frequency deviations shifted in time as released power is restored to supporting units. For wind turbines, the implementation of the speed recovery has a large impact on the system response. The main focus is on the fast response. The duration of the delivery will be highly dependent on the source and other parameters. The duration will be coordinated with other frequency reserves installed in the system.

In addition, the research presents a complete definition of synthetic inertia, which separates it from other fast frequency response [6].

The natural inertial response of a synchronous generator releases torque in direct proportion to the ROCOF it experiences. Generally, the synthetic inertial response therefore correspond to the controlled response from a generating unit to mimic the exchange of rotational energy from a synchronous machine with the power system. And the synthetic inertia is defined as the controlled contribution of electrical torque from a unit that is proportional to the ROCOF at the terminals of the unit.

Synthetic inertia is related to the delivered electrical power in proportion to ROCOF. To decrease the absolute ROCOF of a system, the electrical power from the unit needs to be controlled in response to ROCOF. Simulation studies show that both synthetic inertia and fast frequency response based on frequency deviation can improve the minimum instantaneous frequency after a power imbalance disturbance. It has also been shown that fast frequency response based on frequency deviation can improve the normal operation frequency quality and reduce the absolute ROCOF, while synthetic inertia does not improve the normal operation frequency quality but only reduces the absolute ROCOF.

4.2.3 FFR and synthetic inertia in EirGrid/SONI

4.2.3.1 General

The technology analysis [7] published by DNV GL indicates that all 13 fast frequency response (FFR) type technologies, listed by EirGrid-SONI, have the capability to help prevent high ROCOF events:

1) synchronous compensators;
2) reduction in the minimum MW generation;
3) rotating stabilizers;
4) pumped hydro;
5) flexible thermal power plant;
6) "parking";

7) battery technology;
8) CAES;
9) flywheels;
10) wind turbines;
11) HVDC interconnector;
12) demand side management (DSM);
13) AC interconnectors.

These FFR technologies provide two types of inertia delivery to the power system: synchronous and "synthetic" inertia. Technologies 1) to 6) are all based on synchronous rotating mass (inertia) and without converters; therefore, response is immediate without the need for ROCOF detection. The synthetic inertia FFR type devices have the potential to provide a power response to help prevent high ROCOF events.

The basic differences between the two inertia types are also presented.

4.2.3.2 Synchronous inertia

Synchronous inertia is provided by all machines physically connected to the grid via its electromagnetic field, and therefore its prime-mover is directly connected.

The electromagnetic connection, which naturally exists when using machines directly connected to the grid, without the electrical circuit being interrupted or separated by power electronics, can be explained as follows.

- Motors: For a motor, the electrical energy induces a magnetic field in the stator (rotating field) and rotor (static field). The two magnetic fields interact, creating a rotational mechanical force.
- Generators: For a generator this process is reversed. The machine is rotated by a mechanical force. The rotor (with its static magnetic field) induces a changing magnetic force in the stator which induces electrical energy.

It is for this reason that the effects on the electrical network have a direct impact on the mechanical energy of such machines and vice versa. Thus when a system frequency event occurs, the machine will naturally react to the frequency changes in the electromagnetic field. This in turn results in the mechanical system reacting "instantaneously" and force changes as a result. The amount of power extracted or generated from the rotating mass of a synchronous machine is naturally controlled by the principles of inertia physics. The amount of energy delivered is proportional to the mass of the rotating shaft of the machine and its prime-mover and the change in frequency squared.

4.2.3.3 Synthetic (non-synchronous) inertia

With synthetic inertia, this direct electromagnetic connection between the grid and the machine does not exist. Machines that are connected by means of power electronics to the grid are therefore non-synchronous in principle. As a result, machines connected non-synchronously through power electronics can only provide synthetic inertia in principle, but not synchronous inertia.

The power electronic convertors are responsible for the electromagnetic separation between the machine and its prime-mover, and the grid. The power electronics act effectively as a buffer between the grid and the connected machine. Therefore, frequency changes in the grid do not directly affect the frequency of the machine connected and vice versa.

The reason for the use of power electronics is due to the mismatch in the form of energy between the grid and the machine. The mismatch exists due to frequency differences. This mismatch is one of the main reasons why a direct electromagnetic connection is not possible or not efficient.

Synthetic inertia needs to be established through power electronic controls because of this lack of natural electromagnetic connection and thus response between grid and the machine. However, the power electronics can be used to subtract energy from or add energy to the connected machine.

Take HVDC as an example, as HVDC interconnectors do not explicitly encompass energy storage, and as a result, they are not inherently capable of providing inertia replacement by themselves. They are, however, capable of regulating their power in response to the network frequency at one of the two endpoints. At that endpoint, the interconnector is capable of providing inertia compensation, while at the other endpoint, the interconnector acts like an irregular load, placing part of that demand on the other network's inertia. Furthermore, although HVDC does not explicitly have storage, it is possible to use the DC capacitors to draw short bursts of energy, like other capacitor-based storage technologies.

From that point, any form of fast controlled response can then be termed as fast frequency response. To clarify, synthetic inertial response is also a subset of fast frequency response which contains different responses based on frequency and ROCOF.

4.2.4 The enhanced frequency response and enhanced frequency control capability in the UK

The UK is committed to designing new frequency response balancing service to maintain system frequency stability. There are two main projects – enhanced frequency response (EFR) and enhanced frequency control capability (EFCC), aiming to achieve the FFR target [8], [9].

- The scope of EFR is to achieve 100 % active power output within one second or less when registering a frequency deviation.
- The EFCC project aims to provide a faster coordinated response time (target time of 0,5 s) primarily from inverter-based technologies operating in low inertia systems. In this project, ROCOF-based frequency response is proposed to achieve faster response speed instead of that responding to a deviation in frequency.

The FFR is a general concept for frequency response scheme that can be triggered within 1 s. The ROCOF-based frequency response is one of the means to achieve FFR, so as the regular way of responding to a deviation in frequency.

4.2.5 FFR in North American Electric Reliability Council (NERC) and North America

Fast frequency response: power injected to (or absorbed from) the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency [10].

4.3 Definition of FFR given by CIGRE JWG C2/C4.41

In the technical brochure 'Impact of High Penetration of Inverter-based Generation on System Inertia of Networks' published by CIGRE JWG C2/C4.41 [11], FFR is defined as:

Local and autonomous change in active power from a resource (load, generation storage) to reduce initial rate of change of frequency (ROCOF) after a sudden generation or load loss and allow sufficient time for frequency containment response (FCR) to be deployed. Requirements for response time differ in different systems but typically this is a step or proportional response to a preset frequency trigger or a ROCOF trigger with full response expected between 0,25 s and 2 s once the trigger is reached.

4.4 Recommended definition of fast frequency response (FFR)

4.4.1 Clear definition

Internationally the term FFR has a wide range of interpretations based on its applications in different grids. The recommended definition of FFR from inverter-based resources is given based on its impact mechanism on the system frequency. The distinction between the concept of FFR from inverter-based resources and PFR is clarified from the perspective of the impact mechanism on system frequency.

Definition: Fast frequency response from inverter-based resources is the controlled contribution of active electric power from a generating unit or power plant which responds quickly to the changes in frequency that includes ROCOF and frequency deviation, in order to relieve the torque imbalance of synchronous generators by increasing or subtracting the active electric power injection to the power system, which contributes to arrest the frequency change and settle frequency indirectly. It was noted that system frequency is directly determined mainly by the rotation speeds of synchronous generators in power system.

This definition focuses on the performance requirements more than the details of the technical implementation to achieve the objectives. In this way, any form of fast controlled response can be termed as FFR. To clarify, synthetic inertia response is also a subset of FFR.

The significant characteristics are emphasized as follows:

- contribution to (controlled) electrical power from various sources, instead of contribution to mechanical power of synchronous generators like PFR;
- fast acting response, the response time is faster than PFR and is especially critical under low inertia conditions;
- collection of a variety of controlled responses from inverter-based resources, such as ROCOF-based FFR responding to ROCOF (i.e. synthetic inertia response), deviation-based FFR responding to frequency derivation, fast power injection triggered by event detection, etc.

4.4.2 Impact mechanism on system frequency

The impact mechanism on system frequency by inverter-based resources with FFR function is shown in Figure 3. To simplify the analysis, the frequency response from load is not considered here.

It turns out that both the high ROCOF and low frequency nadir are mitigated with FFR, as shown in Figure 3 a).

It is worth reiterating the note that the control objective of FFR from inverter-based resources is the electrical power injected into the system which is intended to counteract part of the power imbalance acting on the synchronous generators.

FFR achieves the same effect of reducing the imbalance between mechanical power and electrical power acting on the rotor of synchronous generator as PFR, while on different sides. As a distinction, FFR indirectly affects the electrical power acting on the synchronous generator, while PFR directly affects the mechanical power acting on the synchronous generator, as shown in Figure 3 b).

It was noted that the functional orientation of FFR is an alternative or supplement to PFR to help prevent rapid frequency decline, avoiding under-frequency load shedding. It can be designed to withdraw after the frequency nadir. Generally, this was done slowly enough to make sure that the frequency doesn't drop again, as shown in Figure 3 c).

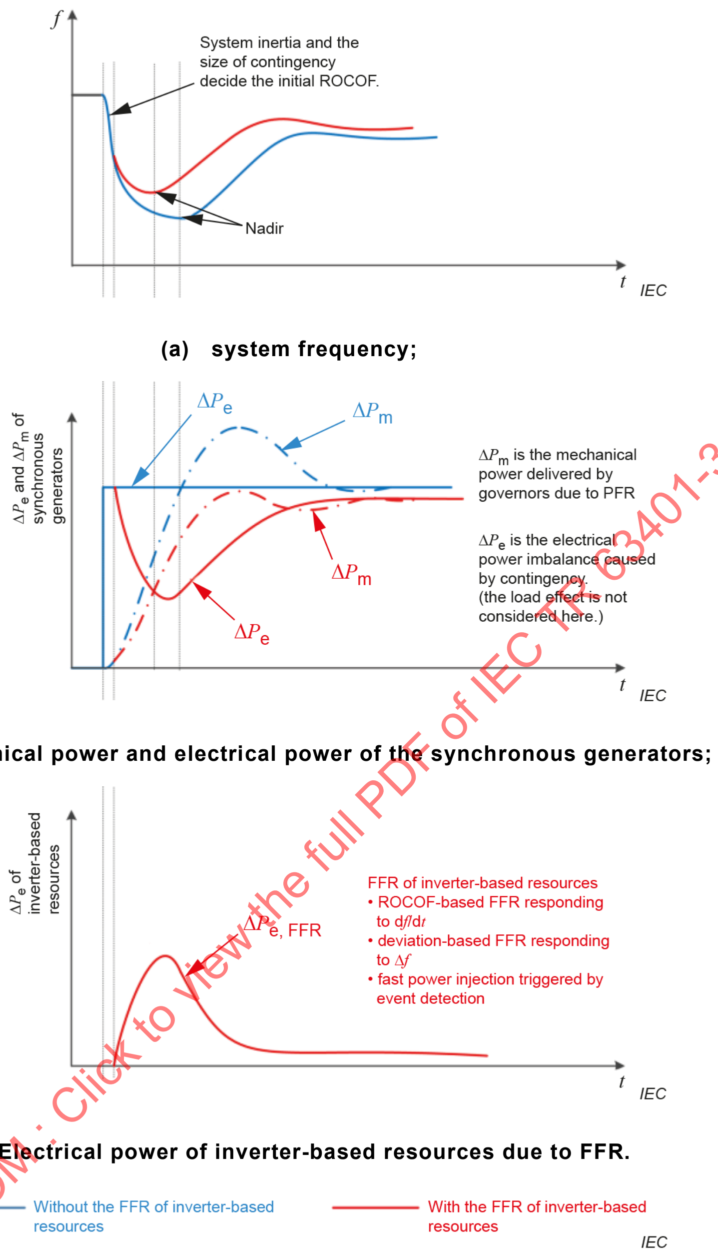


Figure 3 – Impact mechanism on system frequency by FFR

4.5 Description of the relationship among synchronous inertia response, fast frequency response, and primary frequency response

4.5.1 Relationship between synchronous inertia response and fast frequency response

Synchronous inertia response is the inherent response to an imbalanced torque acting on the turbine of synchronous generation ROCOF, enabling enough time for primary frequency response to arrest frequency. The bulk of inertia in power systems is made up of rotating masses in synchronous generators. A momentary imbalance between consumed and produced power results in a change of system frequency where kinetic energy is stored or released in rotating masses in the system.

Fast frequency response is the controlled contribution of electrical power from a unit which responds quickly to changes in frequency. It includes the synthetic inertia response, as well as primary frequency response, as long as it belongs to a fast-acting response: the time from frequency meeting a threshold to full response from the resource is within about 0,5 s.

It is this instantaneous response that distinguishes inertia from fast frequency response (FFR). ROCOF-based FFR (also termed synthetic inertia or inertia-based fast frequency response) is referred to as the contribution of additional electrical power from a source which does not inherently release energy as its terminal frequency varies, but mimics the release of kinetic energy from a rotating mass. Since non-synchronously connected generation units, such as modern wind turbine generators, are connected via power converters, their rotational speed is isolated from the system frequency. They do not therefore, deliver a natural inertial response and do not contribute to the inertia of the system. But with certain control strategies, the inverter-interfaced sources can mimic the release of kinetic energy from a rotating mass.

Both natural synchronous inertia from the synchronous generators and the synthetic inertia from the inverter-interfaced sources with certain control strategies provide an electrical power which is proportional to the rate of change of frequency (ROCOF) and resists changes in frequency.

4.5.2 Relationship between fast frequency response and primary frequency response

Fast frequency response is the contribution of controlled electrical power from a IBR unit which responds quickly to changes in frequency, to reduce the sudden variation of electrical power from the synchronous generators by injecting electrical power from the IBR unit into grid, which contributes to arrest and settle frequency indirectly. It includes the synthetic inertia response (ROCOF-based FFR), as well as the primary frequency response, as long as it belongs to a fast-acting response: the time from frequency meeting a threshold to full response from the resource is within about 0,5 s.

Primary frequency response is the action to arrest and stabilize frequency in response to frequency deviation. Primary frequency response comes from generator governor response, load response (motors) and other devices that provide immediate response based on local (device-level) measurement and control. Generator governor response is within 0 s to 10 s. Generator turbine governors either mechanically or electronically control the primary control valves to the turbine. Steam, water or fuel is what is regulated. Inverter-interfaced power sources response can be quite fast, active time is within 0,5 s, belonging to the category of fast frequency response.

4.5.3 Relationship between synchronous inertia response and primary frequency response

Conventional synchronous inertia response is the inherent response to an imbalanced torque exerted on the turbine of synchronous generation, enabling enough time for primary frequency response to arrest frequency. Synchronous inertia response comes from generator turbine rotational kinetic energy and acts simultaneously to frequency changes with no delay. When a large generating unit is abruptly lost, load exceeds generation, causing an imbalance between the electromagnetic and mechanical torque acting on the synchronous generator rotors. The combined inertia of the generator and prime mover is decelerated by the imbalance in the applied torque following the rotor equation of motion, which reflects in the system performance as system frequency drops. In the perspective of control theory, the synchronous inertia response is like some kind of differential feed-back control.

Primary frequency response is the action to arrest and stabilize frequency in response to frequency deviation. Primary frequency response comes from generator governor response, load response (motors) and other devices that provide immediate response based on their local (device-level) measurement and control. In the perspective of control theory, the primary frequency response is like some kind of proportional feed-back control.

5 System needs and conditions where fast frequency response is warranted

5.1 Higher ROCOF and lower nadir

5.1.1 General

When a large generating unit is abruptly lost, load exceeds generation, so the frequency drops. The speed of the initial decline is related to the number of conventional synchronous generators in the system. More generators mean more inertia, which retards the frequency decline. At several seconds, the frequency nadir or minimum is reached. Frequency nadir is one measure of a system's frequency stability; generally, it was above the highest level of under-frequency load shedding (UFLS). Within several time delays after the frequency meets or drops below a pre-set threshold, the generators with governor controls have begun to act to increase power output, and thus the system frequency begins to recover at the point of time when load equals generation. The typical frequency response to a large generation trip is shown in Figure 4.

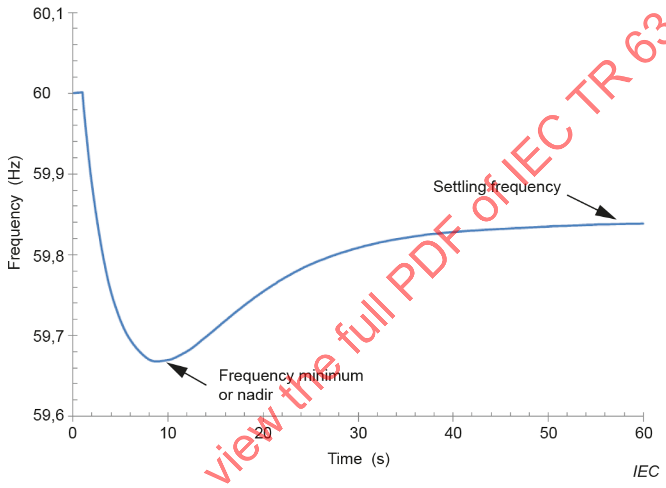


Figure 4 – System frequency in response to a large generation trip

System frequency is naturally determined by the rotating speed of the synchronous generators connected to the grid. As for a synchronous generator in the system, the electromagnetic torque acting on the rotor exceeds the mechanical torque immediately, slowing down the rotating speed of rotor. The inertia, which is one of the inherent physical characteristics, provides synchronous inertial response (SIR) to retard the frequency decline. When the speed deviation exceeds the pre-set dead band, the governor automatic control system provides primary frequency response (PFR) to increase mechanical torque, arresting and restoring the rotating speed of rotor after a period of time. As reflected in the system's electrical parameters, the frequency of voltage and current changes along with the rotating speed of the generators, declining in the first few seconds and rebounding after the nadir.

Frequency nadir is an important index as the UFLS is triggered by the set value of frequency. The initial rate of change of frequency (ROCOF) also can not exceed the maximum withstand capability of power generation units and demand to avoid disconnection. SIR and PFR are two key elements: Inertia decides how fast frequency falls immediately following the disturbance. PFR decides how much the frequency steady-state deviation is. They are both involved in the dynamic frequency response and affect the frequency nadir.

5.1.2 Higher ROCOF

The time derivative of the power system frequency (df/dt) is defined as ROCOF. It is a measure of how rapidly the system frequency declines or increases.

The initial ROCOF is decided by the system inertia and size of the power imbalance. The initial ROCOF is calculated as the following equation:

$$\left.\frac{df}{dt}\right|_{0+} = \frac{1}{2H_{\text{sys}}} \frac{\Delta P}{S_{\text{sys}}} f_0 \tag{1}$$

where f is the instantaneous frequency in Hz, t is the time in seconds, H_{sys} is the per unit system inertia constant, ΔP is the unbalanced power in MW, S_{sys} is the system load capacity in MW, f_0 is the system rated frequency in Hz, 0+ represents the very beginning post-disturbance state at the time when disturbance occurs.

This quantity is conventionally of minor relevance for systems with generation mainly based on synchronous generators because the inertia which inherently counteracts power imbalance is large enough to limit ROCOF.

In comparison to the synchronously connected rotating machines, the inverter-based resources like wind turbines with rotating rotors cannot directly affect the frequency since the kinetic energy of the wind turbine is on the DC side and is released indirectly to the AC system due to the converter. For doubly fed induction generators, which have AC connection to the system, the physical inertia is also negligible compared to the rotational inertia of synchronous generators.

Inertia retards the frequency decline by injecting kinetic energy from the synchronously rotating devices into the system during the power imbalance. The system inertia constant H_{sys} is mainly contributed from synchronously connected rotating generators as the following equation:

$$\begin{aligned} H_{\text{sys}} &= \frac{1}{S_{\text{sys}}} \sum H_{\text{SG}}^{i} S_{\text{SG}}^{i} \\ &= \frac{\sum S_{\text{SG}}^{i}}{S_{\text{sys}}} \frac{\sum H_{\text{SG}}^{i} S_{\text{SG}}^{i}}{\sum S_{\text{SG}}^{i}} \\ &= \frac{\sum S_{\text{SG}}^{i}}{S_{\text{sys}}} \bar{H}_{\text{SG}} \end{aligned} \tag{2}$$

where S_{sys} is the MW system load capacity, $H^{i}{}_{\text{SG}}$ is the per unit inertia constant of the i-th synchronously connected rotating generator, $S^{i}{}_{\text{SG}}$ is the MVA rating capacity of the i-th synchronously connected rotating generator, $\bar{H}_{\text{SG}}$ is the average per unit inertia constant of the synchronously connected rotating generators.

From Formula (2), the system inertia is proportional to the proportion of total capacity of conventional synchronous generators in the total capacity of the whole system. Therefore, generally, more synchronous generators mean more inertia. Typically the per unit inertia $H^{i}{}_{\text{SG}}$ for a large unit is on the order of 3 s to 6 s and varies according to the generation profile.

In the power system the inverter-based resources penetration p_{inv} is calculated as the following equation:

$$p_{\text{inv}} = \frac{P_{\text{inv}}}{S_{\text{sys}}} \tag{3}$$

where P_{inv} is the MW output power of inverter-based resources, S_{sys} is the MW system load capacity.

Since the inverter-based resource is a power substitute for synchronous connecting generators, the output power of synchronous connecting generators will be reduced during operation as p_{inv} grows.

To simplify the analysis, it is supposed that synchronous connecting generators are turned off as p_{inv} grows and there is no spinning reserve in the system. In this condition, the relative inertia decreases as p_{inv} grows, as the following equation:

$$H_{\text{sys}} = (1 - p_{\text{inv}})\bar{H}_{\text{SG}} \tag{4}$$

Based on Formula (1) and Formula (4), the initial speed of frequency drop is given, as the following equation:

$$\left.\frac{\mathrm{d}f}{\mathrm{d}t}\right|_{0+} = \frac{1}{(1 - p_{\text{inv}})} \frac{1}{2\bar{H}_{\text{SG}}} \frac{\Delta P}{S_{\text{sys}}} f_0 \tag{5}$$

In the absence of additional control, inverter-based resources do not possess such inherent characteristics. Therefore, in the high inverter-based resources penetration conditions, the relative inertia decreases, leading to nonlinearly growing ROCOF in power system.

Large ROCOF values will endanger system secure operation because the protection devices triggered by a particular ROCOF threshold value will act to cut the power generation unit off the system in some cases, leading to cascade collapse.

To maintain a given ROCOF level for different amounts of inertia, the unbalanced power needs to be proportional to the inertia. In a system with lower inertia, the system's sustainable power imbalance is smaller. Thus FFR is an effective way to counteract part of the contingency size to limit the unbalanced power acting on the rotors of synchronously connected rotating machines.

5.1.3 Worse nadir

The frequency nadir is the minimum frequency point during frequency dynamic process, which occurs at the first time that the mechanical power acting on the rotor equals the electric power. The increase in the mechanical power is attributed to the PFR of governor automatic control system. PFR helps to arrest frequency and interact with inertia to determine the frequency nadir. It takes seconds to tens of seconds for PFR to respond fully.

In a conventional synchronous generator dominated system, the impact on the nadir brought by PFR is more serious than that brought by the system inertia. With the high penetration of inverter-based resources connected to the grid, the system PFR capability is reduced, leading to worse nadir. Moreover, the high ROCOF due to low inertia can easily lead to a sharp frequency drop below the set value of the UFLS. In this sense, arresting frequency decay within the first few seconds of a significant frequency deviation is very important. While limited by the governor performance, the PFR is not as fast as needed.

FFR is an effective supplement to act before frequency reaches the nadir, by arresting frequency decline and improving nadir.

5.1.4 Simulation study

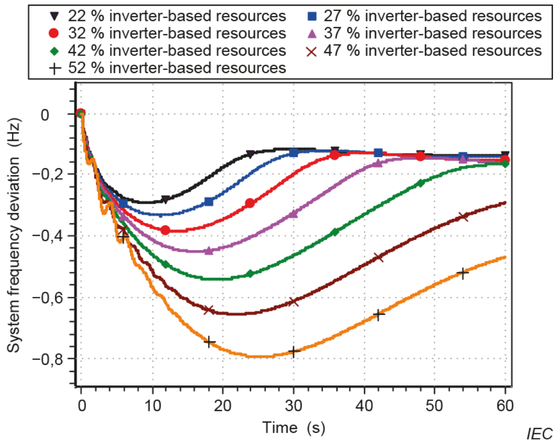
With a simulation case of a bulk receiving end grid of 350 GW load capacity, the frequency characteristics under a serious active power shortage contingency with various penetration of inverter-based resources are compared in Figure 5 a). After the bipolar blocking fault of ultra HVDC, the system bears an active power loss of 12 GW, which is about 3,4 % load capacity. With the increasing inverter-based resources penetration, the dynamic characteristics of system frequency gradually deteriorate, which is manifested by the worse nadir and the higher ROCOF.

As shown in Figure 5 a), the initial ROCOF right after the disturbance is the highest and this initial ROCOF increases with the penetration of inverter-based resources. And then the ROCOF gradually decreases as time goes on with the comprehensive effects of system frequency response against frequency change. The frequency nadir occurs at the first time that ROCOF equals zero. The frequency nadir gets worse with the increase of inverter-based resources penetration.

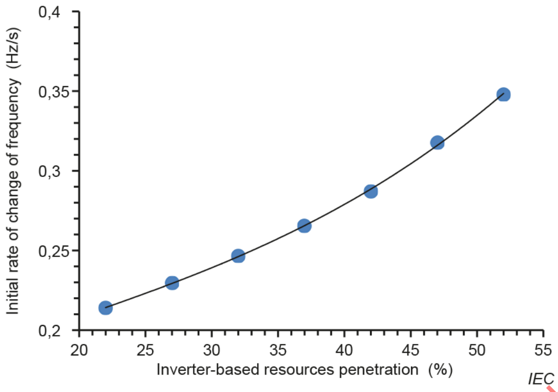
Figure 5 b) shows the non-linear relationship between the initial ROCOF right after the disturbance and the inverter-based resources penetration. The initial ROCOF right after the disturbance is decided by the system inertia.

Figure 5 c) shows the non-linear relationship between the maximum frequency deviation at the nadir and the inverter-based resources penetration. As the penetration increases, the speed of maximum frequency deviation increases faster.

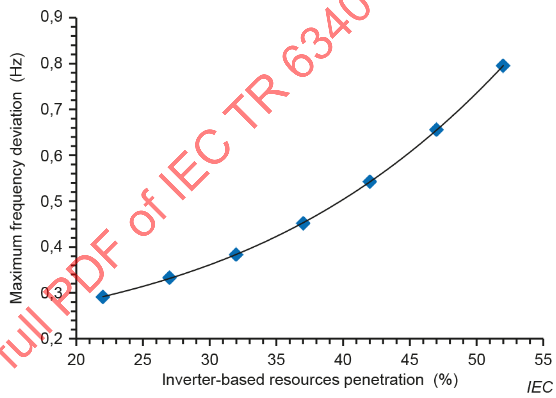
The urgency of system needs for FFR in high inverter-based resources penetration conditions is verified in this simulation case.



(a) frequency deviation



(b) initial rate of change of frequency



(c) maximum frequency deviation

Figure 5 – Frequency characteristics under the same disturbance with various inverter-based resources penetration

5.1.5 Blackout in Great Britain power grid on 9 August 2019

On 9 August 2019, there were a series of events on the electricity system resulting in a large and fast fall in frequency. Over one million customers were without power for between 15 and 50 minutes.

The system conditions prior to the events are listed below.

- Load was 29 GW.
- Around 30 % of the generation was from wind, 10 % from embedded PV, 30 % from gas and 20 % from nuclear and 10 % from DC interconnectors.
- The ESO was keeping automatic "backup" power (response) at that time to cater for the loss of the largest infeed at 1 000 MW.

At 16:52:33 there were a number of lightning strikes on the transmission network north of London. This triggered the transmission line protection to disconnect and clear the disturbance plus initiate its subsequent reconnection. As would be expected in such circumstances, there was the loss of some small embedded distributed generation associated with the transient voltage disturbance caused by the lightning. Almost simultaneously, and unexpectedly, two large transmission connected generators and wind farms reduced their output (totalling approximately 980 MW) onto the system. The subsequent loss of power resulted in a large and fast fall in frequency. This rapid fall in frequency initiated further small power sources on the distribution network to disconnect, increasing the loss of power generation and resulting in the frequency falling even further. The total loss of generation over the first minute of the event was so large that the frequency fell to 48,8 Hz, triggering low frequency demand disconnection (LFDD) relays across the DNOs (Distribution Network Operators). These acted to disconnect approximately 1 GW of demand from the electricity network (approximately 5 % of total demand). This loss of demand arrested the frequency fall as designed and, alongside the response, reserve and rapid dispatch of additional generation, recovered the system security position within five minutes.

The timeline of events in the official report is shown in Figure 6.

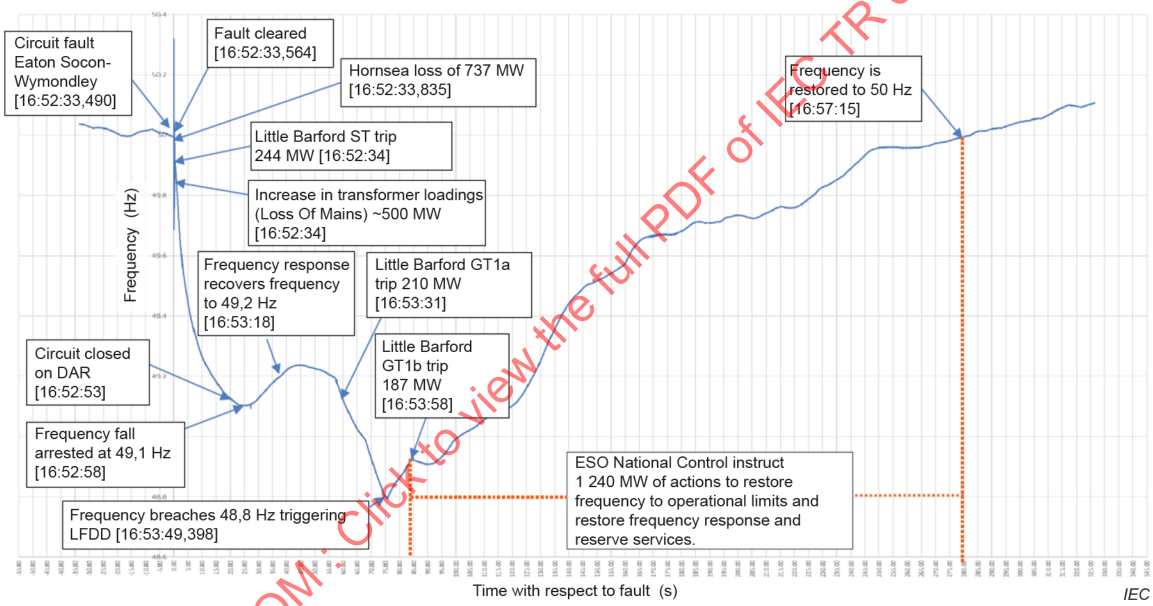


Figure 6 – Frequency response in blackout in Great Britain power grid on 9 August 2019

According to the official report by ESO, while the system quality and security standards (SQSS) are designed to cover for an event such as a lightning strike, the scale of subsequent loss of output from offshore wind farms, gas-fired power plants and embedded distributed generation was beyond the security standards, which is the main reason for the blackout.

The preliminary findings about higher ROCOF and lower nadir based on the analysis are:

- The rapid fall in frequency initiated the operation of loss of mains (LoM) protection on embedded generation. The LoM protections operate in two different modes – rate of change of frequency (ROCOF) and vector shift. Both are designed to ensure the safety of the equipment attached via the protection. Approximately 350 MW of embedded generation tripped due to ROCOF protection and 150 MW of embedded generation disconnected through vector shift.
- The frequency nadir at 48,8 Hz triggered a total of 931 MW of demand disconnection on LFDD. The large fall in frequency reflected the insufficiency of frequency response and reserve available in this event.

The trigger for vector shift protection is not related to system frequency but instead to voltage phase angles being out of alignment (e.g. following a fault). The vector shift protected generation would have therefore been lost co-incident with the transmission system fault.

A ROCOF protection system is designed to disconnect the embedded generation if the ROCOF is greater than a trigger level. As result any ROCOF protected generation would have been lost coincident with the frequency fall and so occurs after the loss of generation due to vector shift.

The system inertia kinetic energy prior to the events is 210 GVA · s. When the accumulative active power loss reaches 1 131 MW within one second after the circuit fault, the ROCOF is

$$\frac{\mathrm{d}f}{\mathrm{d}t} = \frac{\Delta P f_0}{2H} = 0{,}135 \text{Hz} / \text{s} .$$

It is noted that the value is greater than the setting value for ROCOF protection (0,125 Hz/s). As the known protection setting historically specified in the Distribution Code for ROCOF is 0,125 Hz/s, approximately 350 MW of embedded generation tripped due to ROCOF protection.

On one hand, the ROCOF withstand capability standard needs to be modified to ensure frequency ride-through during high ROCOF conditions. On another hand, sufficient system inertia is crucial for maintaining the ROCOF below trigger levels for the larger loss.

As frequency dynamics get faster in power systems with lower inertia, power system operation, particularly frequency control, becomes more challenging.

The ESO procures two main types of low frequency response: primary and secondary.

- Primary response is to contain the fall in frequency following an instantaneous generation loss in addition to the effect from system inertia. Generally, it delivered its output by 10 seconds following the trip and continued to deliver for a further 20 seconds (30 seconds total).
- Secondary response is to help return the frequency back to within operational limits. Generally, it delivered its output by 30 seconds following the change in frequency and continued to deliver for a further 30 minutes.

Both primary and secondary response can be delivered through two different types of provisions: either dynamic or static.

- Dynamic is a continuously provided service to manage the normal fluctuations in the frequency.
- Static is a service to provide frequency response when the system frequency transgresses the low frequency relay setting on site.

These two types of service can be provided from generation and demand, balancing mechanism (BM) and non-BM units.

To ensure the quality of steady-state frequency control, a minimum amount of dynamic response was held. The minimum dynamic response requirement at the time of the incident was set to 550 MW, securing the largest loss of 1 000 MW.

In this incident, about five seconds after the lightning strike, the frequency drops below 49,5 Hz, which is outside of the normal range. The frequency stopped falling after 25 seconds at 48,8 Hz, triggering LFDD. The full frequency response time is almost 30 seconds, which is shown in Table 2.

Table 2 – Frequency response in Great Britain power grid on 9 August 2019

Time elapsed since the short circuit fault	Frequency deviation	Power delivered by frequency response (ESO secures for a loss of power infeed of 1 000 MW)
10 s	0,75 Hz	650 MW
30 s	0,88 Hz	900 MW

The existing frequency containment and regulation methodologies have been designed based on the implicit assumption that a certain level of inertia would be available and that this would provide sufficient time for these control services to ensure frequency quality requirements are met under both normal and contingency conditions. While in the absence of the inertia inherent to synchronous generators, it is important to provide faster frequency response in a power system with high penetrations of inverter-based resources. Besides, the procurement of higher levels of frequency response could secure the system against higher infeed losses (e.g. the loss of multiple units).

5.2 Large fluctuation of system frequency in power system operation

5.2.1 General

In some synchronous grids, steady-frequency fluctuations in the power grid are with a natural period of one minute and amplitude of around 0,05 Hz as shown in Figure 7, and the phenomenon results from relatively large load fluctuation and relatively slow PFR. Under this situation, FFR can play a potential better role to increase the system PFR performance and system frequency quality.

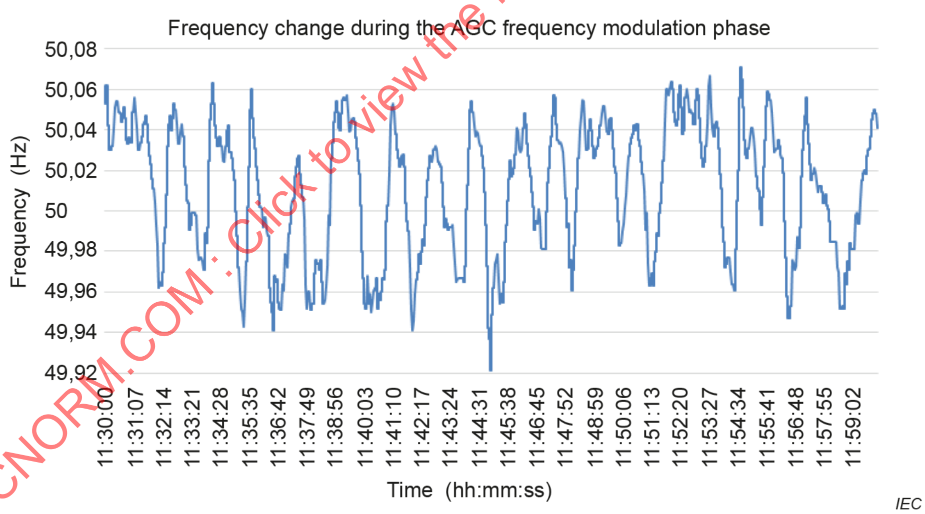
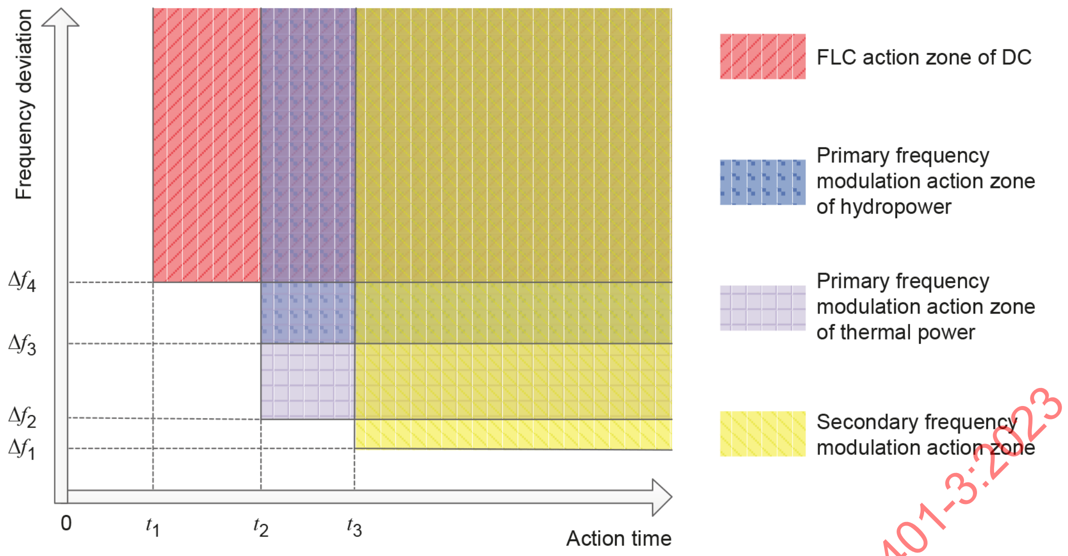


Figure 7 – System frequency fluctuation under secondary frequency regulation due to load fluctuation in a grid

5.2.2 Frequency regulation scheme

In the frequency regulation scheme of this system, the assignment of frequency deviation zone and full-activation time for different frequency modulations is shown in Figure 8.



Δf_1 is the dead zone of secondary frequency modulation

Δf_2 is the dead zone of primary frequency modulation of thermal power

Δf_3 is the dead zone of primary frequency modulation of thermal power

Δf_4 is the dead zone of FLC function of DC

t_1 is the action time of FLC function of DC

t_2 is the action time of primary frequency modulation

t_3 is the action time of secondary frequency modulation

IEC

Figure 8 – Assignment of different modulations for quasi-steady-state frequency fluctuation

As shown above, the assignment is mainly:

- The quasi-steady-state frequency fluctuation within 0,033 Hz is regulated by the secondary frequency modulation from automatic generation control (AGC) system.
- The steady-state frequency fluctuation within 0,03 Hz to 0,07 Hz is stabilized by primary frequency modulation, mainly relying on the governor of hydropower and thermal power.
- Frequency fluctuations above 0,07 Hz are assisted by the modulation of DC interconnector, for larger power imbalance contingencies.

5.2.3 Relatively large load fluctuation

The unbalanced power amplitude that causes the fluctuation is around 300 MW, about 0,3 % of the maximum total load. From a statistical point of view, the random load fluctuation of the power grid presents a 'white noise' characteristic.

5.2.4 Relatively weak and slow PFR

Primary frequency responses are aimed to arrest and stabilize system frequency in response to frequency deviations. And primary frequency response comes from generator governor response, load response (motors) and other devices that provide immediate response based on local (device-level) control. But there are some problems with the governor in this case.

- The dead zone is relatively large: 0,033 Hz to 0,05 Hz (0,05 Hz for hydropower generators), therefore the small frequency deviation does not trigger primary frequency response.
- The failure rate of primary frequency response is high, cannot be called out as needed.
- Primary frequency modulation can suppress the frequency fluctuation within a certain range, but cannot eliminate the fluctuation.

- The response time of primary frequency response is within 0 s to 10s, which is relatively large and mainly due to hydropower generators.
- In this situation, FFR can play a potential better role to remedy the shortcomings described above, which is helpful to make the PFR zones move towards left bottom in Figure 8.

6 Performance objectives for fast frequency response from inverter-based resources

6.1 The response time of FFR

The functional orientation is a contribution to arresting the frequency change and settling frequency before the frequency nadir. Under low inertia conditions, FFR response time is critical.

The summary of response times in different countries and regions is listed in Table 3. The time for which these various FFR conditions varies, but the intent of all of them is that the response last at least until the frequency nadir. Some pilot projects are demonstrating fast response times with various technologies and these will be discussed in the subsequent sections.

Table 3 – Summary of response times in different countries and regions

Region	Response time s
Nordic synchronous area (ENTSO-E)	0,7 to 1,3
Ireland	2
UK	1
Texas	0,5
Australia	0,5 to 1

From the viewpoint of the implementation of FFR, the response time is the total of the control actions including measuring, identifying, signal processing, activating and fully responding. Due to the fast control advantage of power electronics, the response time that can be technically achieved is as fast as hundreds of milliseconds. The summary of response times is listed in Table 4.

Table 4 – Summary of response times for inverter-based resources

<table>
<tr><th rowspan="2">Inverter-based resources</th><th colspan="4">Response times
s</th></tr>
<tr><th>Measure and identify</th><th>Signal</th><th>Activate</th><th>Respond fully</th></tr>
<tr><td>wind turbine</td><td rowspan="6">approximately 0,04 to 0,1</td><td rowspan="6">0,02</td><td>0,04</td><td>0,5</td></tr>
<tr><td>solar PV</td><td colspan="2">approximately 0,1 to 0,2</td></tr>
<tr><td>HVDC</td><td colspan="2">approximately 0,05 to 0,5</td></tr>
<tr><td>lithium batteries</td><td colspan="2">approximately 0,01 to 0,02</td></tr>
<tr><td>flow batteries</td><td colspan="2">approximately 0,01 to 0,02</td></tr>
<tr><td>lead-acid batteries</td><td colspan="2">approximately 0,04</td></tr>
</table>

The main challenge is to quickly and accurately measure the frequency or the ROCOF in the transient period when the contingency happens. It takes longer time to ensure the accuracy of measurement. A balance between making high fidelity decisions to act and speed is needed.

Considering the elements above, the response time is advised to be less than 0,5 to 1,5 seconds. Generally, the lower the system inertia is, the shorter the response time needs to be.

6.2 The response characteristics and maximum response capacity of FFR

According to the different implementation means, FFR is categorized into ROCOF-based FFR (synthetic inertia) responding to ROCOF, deviation-based FFR responding to frequency deviation and fast power injection triggered by event detection.

Unlike the other two types, fast power injection triggered by event detection is a preset automatic strategy only applied for specific events. This type of control technology is normally used in power modulation of HVDC and automatic switching of power sources.

The controlled contribution of electrical power provided by ROCOF-based FFR is calculated as the following equation:

$$P_{\text{inertia}} = -T_{\text{J}} \frac{\text{d}f/\text{d}t}{f_0} P_{\text{N}} \tag{6}$$

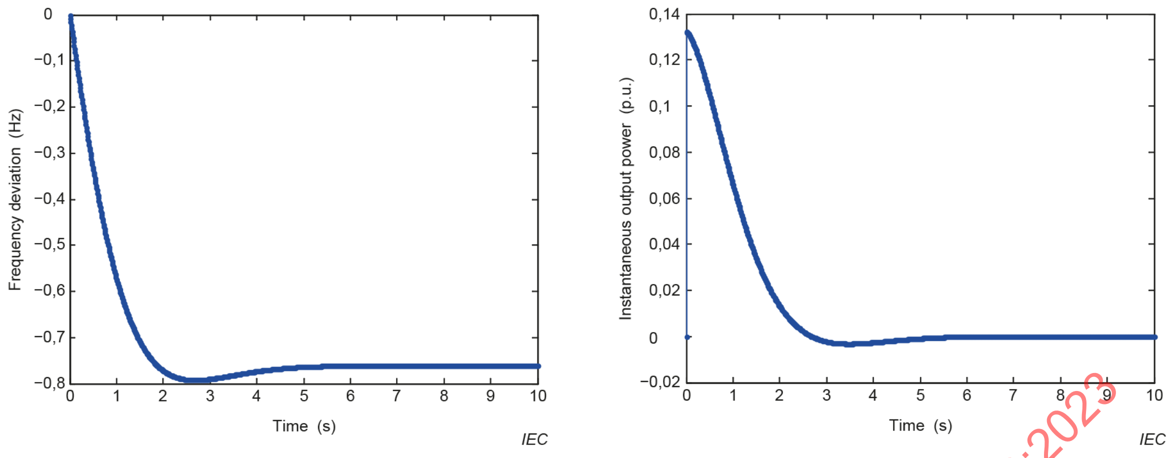
where P_{inertia} is the MW electrical active power provided by ROCOF-based FFR, T_{J} is the equivalent per unit inertia constant of the inverter-based resources due to the control actions, f is the instantaneous frequency in Hz, f_0 is the system rated frequency in Hz, P_{N} is the MVA rating capacity of the inverter-based resources.

The inertia time constant T_{J} is two times the per unit inertia constant H_{eq}, as the following equations:

$$T_{\text{J}} = 2H_{\text{eq}} \tag{7}$$

$$H_{\text{eq}} = \frac{\text{stored energy at rated speed in MW} \cdot \text{s}}{\text{MVA rating}} \tag{8}$$

The ROCOF-based FFR effect is shown in Figure 9.



a) frequency deviation **b) instantaneous output power**

Figure 9 – Controlled contribution of electrical power provided by ROCOF-based FFR

The physical characteristics of the inertia of the synchronous machine are to prevent the rotor motion state from changing. Therefore, it not only prevents the frequency from deviating from the rated frequency, but also prevents the frequency from returning to the rated frequency, just as the negative output power in recovery stage after nadir shown in Figure 9 b).

Taking advantage of the flexible control characteristics of the inverter-based resources, the ROCOF-based FFR can be designed to only operate under the conditions:

$$\Delta f \frac{\mathrm{d}f}{\mathrm{d}t} > 0 \tag{9}$$

Thus the ROCOF-based FFR only plays a positive role in helping to prevent the frequency from deviating from the rated frequency. And when the frequency begins to recover, the inertia response is invalidated so that it will not play a negative role in preventing frequency recovery.

The controlled contribution of electrical power provided by deviation-based FFR shown in Figure 10 is calculated as the following equation:

$$P_\mathrm{f} = -K_\mathrm{f} \frac{\Delta f}{f_0} P_\mathrm{N} \tag{10}$$

where P_f is the MW electrical power provided by deviation-based FFR, f_0 is the system rated frequency in Hz, K_f is the frequency modulation ratio due to the control actions, P_N is the MVA rating capacity of the inverter-based resources, Δf is the frequency deviation as $(f - f_0)$ in Hz.

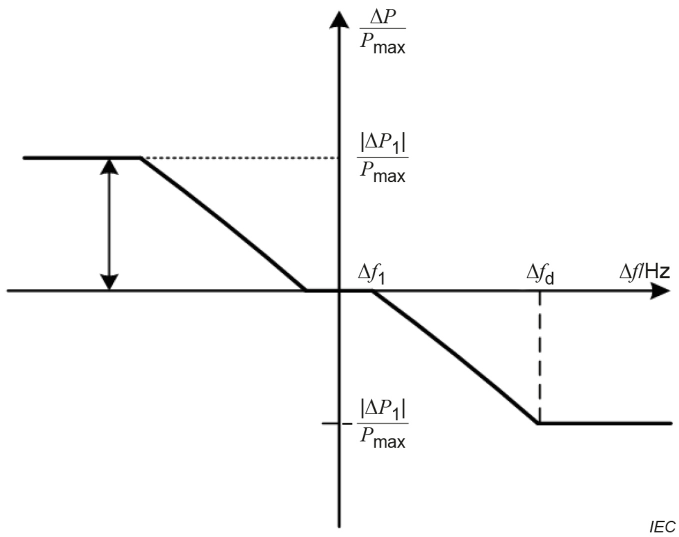


Figure 10 – The controlled contribution of electrical power provided by deviation-based FFR

In order to ensure that FFR actually plays a sufficient role to inject more power to the power system, active power reserve is retained. Generally, the maximum available response capacity was guaranteed above a certain level.

The typical parameters are listed in Table 5.

Table 5 – Typical ranges of control parameters of FFR

Control parameters	Typical values		
	Wind turbine	Solar PV	electrochemical energy storage station
equivalent per unit inertia constant, T_J	4 s to12 s		
frequency modulation ratio, K_f	10 to 50	10 to 50	50 to 200
maximum available response capacity	≥ 6 %	≥ 6 %	≥ 10 %

6.3 Test performance for renewable generator equipped with fast frequency response in China

6.3.1 General

In 2016, the State Grid Corporation of China decided to launch a renewable virtual synchronous generator project based on the Wind-Solar-Storage hybrid renewable power station in the North of Hebei province. This project is built to explore the engineering technology for renewable generator equipped with fast frequency response, which is adapted to Chinese conditions.

6.3.2 Engineering construction

By the end of 2017, 59 wind turbines in the Wind-Solar-Storage hybrid renewable power station have been rebuilt, so that the total capacity of 118 MW wind turbines are able to be equipped with fast frequency response capability. At the same time, there are 24 photovoltaic inverters (12 MW) modified to be equipped with fast frequency response capability. For the 100 MW wind power and photovoltaic units that cannot be modified, two 5 MW energy storage are built to equip the 100 MW renewable generators with fast frequency response feature.

6.3.3 Test practice and performance

The fast frequency response capability of renewable generators was tested by applying a disturbance signal on the control system of the renewable generator. This proposed method solved the problem to balance the efficiency and the safety. And relying on the laboratory, a semi-physical simulation platform based on real-time laboratory (RT-LAB) was built to verify the performance of renewable generators' controllers for inertia response and the fast frequency regulation. The laboratory works compensated for the working conditions which cannot be covered by field tests. A total of more than 1 000 tests on renewable generator inertia response and fast frequency regulation performance were carried out, covering various technical routes such as wind power, photovoltaic and energy storage shown in Table 6.

Table 6 – Inertia response and fast frequency regulation performance

Performance objectives	Wind	PV	Storage
Frequency response dead band	0,05 Hz	0,05 Hz	0,05 Hz
Inertia response time	0,5 s	0,35 s	0,05 s
Fast frequency regulation response time	5 s	1 s	0,1 s
Active power response deviation relative to rated power of DFIG	1 %	1 %	0,5 %

7 Available technologies, controls, and tuning considerations for fast frequency response and primary frequency response

7.1 Available technologies for fast frequency response

7.1.1 Technology capabilities for FFR service

Technology capabilities for FFR service include:

- wind turbine;
- solar PV;
- energy storage systems, including lithium batteries, flow batteries, lead-acid batteries, super capacitor, flywheels (inverter), etc.;
- HVDC.

It was noted that:

- delivery of FFR services by the various technologies will depend on the physics of the technology and on control;
- further, equipment that can act rapidly under ideal grid conditions will not perform as well under weak grid conditions in some cases.

7.1.2 Wind turbines

7.1.2.1 The physics of ROCOF-based FFR from wind turbines

Most modern large-scale (> 1 MW) wind turbine generators (WTGs) rely on sophisticated power electronics to maximize wind power production, control turbine speeds and provide a range of performance functions. In these variable speed machines, the power electronic enabled controls improve energy capture and provide characteristics that are beneficial to the grid. The economics and physics of wind generation demand that the speed of rotation of the blades be adjustable with different wind speeds. The industry has almost unanimously settled on the use of power electronics to allow the generator speed to vary, and this electrically decouples the generator speed from the grid frequency. Consequently, unlike simpler induction-generator based systems, turbine-generators with these controls do not naturally provide inertial response.

Unlike conventional synchronous or induction generators, the delivery of active power from variable speed wind generators is almost entirely controlled by the power electronics. The power electronic controls allow nearly instantaneous adjustment of electrical torque on the generator, and therefore power delivery, which is essentially independent of the terminal bus voltage angle, and rate of change of angle – i.e. frequency. Controlled inertial response is possible because of this extremely fast response. This is a fast, controlled response, rather than the inherent, uncontrollable response of all synchronous machines. This response is transiently decoupled from the mechanical angle of the wind generator rotor. Therefore, it is possible, though not necessarily desirable, to more-or-less instantly change (a few cycles) electrical power delivery. It is worth reiterating that those inverter-based devices, including wind turbines, could be designed to behave as virtual synchronous machines. This presents a possible, even likely, path forward for the industry faced with systems evolving towards occasional operation with zero synchronous inertia.

The language of the industry is confusing and unsettled. Early work talked about 'replacing' the lost synchronous inertia from displaced thermal machines. Further, the available controls generally are enabled by accessing the energy stored in the inertia of the turbine. So, in that sense, these are inertial controls. But, the physics of the behaviour is fundamentally different: the power electronic devices do not mimic Park's equations, i.e. they don't 'look' like synchronous machines. The power injected into the grid is one variety of FFR. Unlike some of the other technologies discussed in subsequent sections, the energy available is relatively limited, so the response cannot be sustained throughout the time period when secondary frequency response returns system frequency to normal.

The discussion at times is becoming heated: some people at the US Federal Energy Regulatory Commission strongly dislike the term 'synthetic inertia', but they also dislike simply calling it FFR, since the inertia-enabled control cannot be sustained. In contrast, what is generally called PFR control from wind turbines is enabled by both the pitch control and the power electronic torque control.

Throughout the balance of this discussion, the notation 'ROCOF-based FFR' is used to capture this specific behaviour.

The power delivery of the wind turbine-generator is limited not only by the available wind, but by the physical limitations of the components of the WTG. Most critical are aero-mechanical ratings and speed limits. The lift of wind turbine blades is a strong function of blade speed relative to wind speed. These well-understood relationships are reflected in the control algorithms of modern, variable speed WTGs. Blade speed and rotational speed are directly proportional, so turbine controllers target optimal rotational speed for power production. The speed of the turbine is dictated by the mechanical torque delivered from the blades and the electrical torque removed by the generator. When in balance, the turbine speed is constant. ROCOF-based FFR controls for wind turbines are based on temporarily making the electric power delivered to the grid exceed the mechanical power being captured from the wind. The source of energy for this extra power is the stored rotational energy in the turbine rotor and drive-train. To extract that energy, the rotor will slow down.

A key point is that slowing the turbine tends to reduce the aerodynamic lift, thereby reducing the delivered mechanical shaft torque and exacerbating the speed decline caused by increased generator electrical torque. This positive feedback tends to push the blade towards aerodynamic stall, which is to be avoided. Generally, the inertial control provides margin above stall, and is consequently limited when the initial rotor speed is low. This means that the energy available response is limited whenever the wind speed is at or below rated. Further, the amount of energy available drops with wind speed (and therefore turbine power). At low wind turbine power levels, the available energy of the inertial response starts to decline rapidly below about 50 % rated power, dropping to zero below about 20 %.

7.1.2.2 Wind turbine FFR

The activation of wind turbine FFR starts with ones of cycles of triggering at the turbine level, and power can rise on the order of 20 % to 30 % per second. The incremental power is generally limited to 10 % of pre-disturbance power.

Below rated wind speed, but near rated power, the maximum available arresting energy is on the order of 1 MW · s/MW; this maximum available arresting energy drops roughly linearly with power level. The ramp rate is limited to 20 % to 30 % per second. Mechanical stresses and aero-mechanical stability determine each of these limits to avoid loss-of-life in turbines.

Various OEMs, including, at least, GE, Senvion, Enercon and Siemens have demonstrated various ROCOF-based FFR controls. Tests have been run in the US and Canada, at least. First generation offerings have been available for several years from selected OEMs. There is considerable interest now and new requirements are emerging rapidly. More options and more field data will almost certainly be available in the near future.

Limitations are mostly systemic. The ability to push extra power into the grid following disturbances is often voltage dependent. In weak grid controls, active power injection is often slowed or suppressed to allow for the grid to recover. This will be a serious concern for this application under conditions when loss of infeed is caused by a fault and trip event. It applies to all FFR technologies. A somewhat separate consideration is how fast the equipment can resume power injection on AC voltage recovery. This is highly dependent on the state of the DC voltage. This is a design consideration for all FFR and will affect all the inverter-based technologies discussed in this document. In general, technologies that resist changes in the DC bus voltage on the inverters (i.e. the DC bus is 'stiff'), like batteries, will tend to be able to recover the fastest.

NOTE This is reflected in the subsequent discussions and in the speed notes in the summary tables.

7.1.3 Solar PV

Solar photovoltaic (PV) generation is enjoying a worldwide explosion in growth. The two most basic components of PV for provision of AC power are common to all applications, in power ratings ranging from a fraction of a watt to utility scale projects approaching (or even exceeding) a Gigawatt. The first component is a collection of photosensitive semiconductor cells that when subjected to photons of appropriate wavelength, produce energetic electrons that will flow, when allowed to do so: that is, they produce direct voltage and current. The product of this DC voltage and current is power, which was converted to 50 Hz AC power by inverters. PV installations consist of one or more of these modules, normally connected in parallel. For projects of utility scale, AC collector systems (sometimes 'reticulation' in Australia) resemble those of wind plant, with a supervisory control providing intelligent interface between the grid and the farm.

For this discussion of possible fast frequency response, a few physical elements of PV are critical:

1) DC Power Rating. Individual photocells typically have voltage rating on the order of 2 V, and current rating is very roughly proportional to the area of the cell. The details of voltage, rating, sensitive wavelength, temperature sensitivity, etc. vary with different cell designs and materials, and are not particularly important here. The DC rating of the collection of cells (i.e. a 'panel') dedicated to a specific inverter is important. The DC rating (for this discussion) is the maximum DC power that can be produced under conditions of maximum insolation (sunlight energy intensity at the panel). DC rating is independent of the inverter.
2) AC Power Rating. The inverter serves the function of converting the DC power to AC. The cost of the inverter is dominated by the AC current rating, although the rating is typically given in kVA at nominal AC voltage. The key point is that there is no fundamental requirement that rating of the inverter 'match' the DC rating of the panel. In practice, this has significant implications for FFR, as will be discussed below.
3) Tracking. The orientation of the panel relative to the sun dictates how much of the available insolation energy is converted. In general, PV installations can be fixed, single axis trackers, or dual axis trackers. Tracking installations physically orient the panels so that they capture more energy over the course of a daily solar transit.

Unlike wind, there is no inherent energy storage available via kinetics (i.e. the rotating mass). Therefore, if a PV resource is to deliver any fast boost in power output, the inverter generally operated at an AC power transfer level that is LOWER than the available DC power from the PV panel at that point in time. Under conditions when the AC inverter (and balance of plant) is not the limiting condition, the power production was expected to be reduced to a level below the available power. This is a nearly perfect analogue to the pre-curtailment of the wind power used to provide sustained FFR or PFR, as described above in the wind section. Note that it is possible to have (battery or supercapacitor) energy storage integrated with the solar PV, but aside from possible savings associated with shared infrastructure (inverters, transformers, balance of plant), there is no intrinsic performance synergy associated with co-location (or hybridization) of the energy storage with PV. Otherwise, the energy storage discussion in the previous sections applies.

The steady-state and short-term overload rating of the PV inverter can play an important role here. While it is natural to think of the rating of the inverter in terms of kW, or kVA, the physical reality is that the rating is dominated by the current carrying capability of the semi-conductor valves.

7.1.4 Battery energy storage

Batteries convert chemical energy into electrical energy. An electrolyte allows ions to flow between the anode and cathode, while a DC electrical current feeds an external circuit. Batteries and hybrid battery systems (e.g. battery/supercapacitors) have the potential to provide a useful fast frequency response to mitigate high ROCOF. Some batteries have an extremely fast response time (e.g. lithium and advanced lead acid) and the technologies range from extremely mature (lead-acid) to less mature (flow). This document focuses on three promising technologies for FFR: lithium ion, flow, and advanced lead-acid.

In the last several years, batteries have been increasingly deployed in utility applications, through subsidies, mandates, and especially as demonstration projects for utilities and governments to better understand the capabilities and limitations of the technology. Applications include the provision of energy, capacity, ancillary services, transmission and distribution upgrade deferral, demand charge reduction and backup power. Depending on the application, different characteristics of energy, power, duration, speed, etc. will be needed to a certain extent. Batteries can provide value to participants across the power system spectrum. For example, storage can support the grid to provide capacity to meet system peak, while demand charge management will allow an individual customer to reduce their individual demand peak in some cases. Today, there are commercial opportunities for batteries in providing fast regulating (secondary) reserve in markets that pay for performance (e.g. PJM in the US). Batteries are also commercially viable in some applications and rate structures where it makes sense to help manage energy bills with existing demand charges and time-of-use rates. In 2013 SBC reported about 750 MW of large batteries deployed in the utility sector. Today the US Department of Energy (DOE) Energy Storage Database lists over 731 battery energy storage systems (BESS) projects (including lithium, lead-acid, flow, and sodium technologies) with 1 720 MW of total capacity world-wide.

BESSs comprise a power conversion system (PCS) and a battery. Battery cells are stacked to make up battery modules of the appropriate voltage. These modules will be controlled with a battery management system (BMS) to protect the battery from overcharging to a certain extent, over-discharging, and thermal damage. The PCS has a bidirectional inverter that converts DC output from one or more strings of batteries to AC output and vice versa. For example, in an 8 MW (32 MWh) BESS in Tehachapi in Southern California Edison, 56 battery cells (60 Wh, 3,7 V) make up each 3,2 kWh module (52 V). Eighteen modules are in each rack and there are 151 racks in each string of the BESS. Charging/discharging voltages of the strings are at 760 V DC to 1 050 V DC. Each 2 MW (8 MWH) string has eight BMSs and one controller. There are two inverter lineups in each 4 MW PCS, which then connects to a 12,47 kV AC grid. The two PCSs are operated by a master controller which will send real and reactive power commands and will provide different modes of operation to a certain extent.

Batteries are not limited by the chemical response time (mass transfer dynamics of ion migration and depletion), but by the inverter and control response times. Additionally, the location of the fast controls, critical sensors, and actuators will have the largest impact on time because plant level control loops are slow compared to the PCS. The plant level response time consists of plant level sensing, communication and dispatch to individual inverters.

Depending on when the event occurs during the control cycle, battery engineers conservatively estimate that the response is between 150 ms and 400 ms [1]. Because of this, an extremely fast frequency response is better implemented directly on the inverters. The PCS regulator control loop will have tens of milliseconds response time in some cases. For example, in Hawaii in the US, requirements for extremely fast response have led to frequency droop implemented directly on the inverters so that the system begins corrective action within 10 ms, with a full response within 50 ms. There are drawbacks of PCSs: PCSs that respond within 20 ms are maintained in a hot standby condition that has parasitic losses (2 % of rated power).

In addition to the BESS response time, total response time for a BESS FFR would include ROCOF detection/communication time. Whether a direct event detection scheme or a local ROCOF detection is used, the fastest options for this detection/communication time appear to be on the order of two cycles. The BESS options discussed in detail below have activation and full response time on the order of cycles, making this a potential option for providing arresting energy within the 250 ms needed.

7.1.5 HVDC

HVDC power transfer is regulated by power electronics and programmable controls which are able to respond in a small fraction of a second. This capability can be used in a few different ways to respond to a power-load imbalance (either under-frequency or over-frequency) [11]:

- Fast ramp down in HVDC power (runback): This is a commonly applied control feature where power is rapidly reduced in response to an over-frequency event. For voltage source converter (VSC) systems, AC bus voltage is regulated by the HVDC control system. For conventional line commutated converter (LCC) systems, power reductions can produce AC over-voltages if there is an excess of reactive compensation, so some reactive power banks will need to be tripped in some cases. This is a mature technology.
- Fast ramp up in HVDC power: This control feature is less commonly applied and it is significantly more challenging than runbacks. The speed and performance of a ramp-up scheme depend on the strength of the AC system. That is, the AC grid was able to support higher power flow from the HVDC terminal without significant depression of the AC bus voltage. For VSC systems, the HVDC converters can contribute reactive power support within the ratings of the converters. For LCC systems, increased HVDC power results in increased reactive power consumption by the converters, which can cause significant depression of the AC voltage unless additional reactive power can be supplied from other devices (e.g. SVC).
- Fast ramp up with short-term HVDC overload: This scheme would temporarily increase the HVDC power transfer above the normal system rating and then return to rated power transfer after a few seconds. This type of scheme could be helpful in arresting the frequency decline during an under-frequency event, during the critical period when generator governors are beginning to respond but have not yet achieved their full response.

Similarly to other inverter-based technologies, HVDC frequency control can be implemented in a number of ways: proportional or droop control in response to frequency or ROCOF, step response in response to frequency or ROCOF.

Several factors affect the speed of response for rapid changes in HVDC power, especially for increases in HVDC power.

- The design of the HVDC system. Back-to-back HVDC systems with strong AC systems can respond in 50 ms. Long HVDC cables connected to weak AC systems have response times in the range of 200 ms to 500 ms.
- The type of initiating event. If the grid event does not involve an AC fault near the HVDC terminal, HVDC response time is very fast, in the range of 50 ms to 100 ms. If the grid event includes an AC system fault that discharges the HVDC line or cable, then the response time includes the fault recovery time of the HVDC system, which is in the range of 100 ms to 500 ms, depending on the strength of the AC system.

The response can sustain indefinitely for any power level within the HVDC converter ratings. Short term overloads are limited by the thermal time constants of the semiconductor devices, which are typically in the range of two to five seconds.

In summary, the preponderance of industry experience suggests that the most effective and secure approach for HVDC to contribute to FFR is a remedial action scheme (RAS) that detects the most critical events via breaker status, transmits a triggering signal to the HVDC terminal, and initiates a pre-programmed action designed for the specific event. With this approach, event detection and signal transmission happen in parallel with the AC and HVDC system fault recovery, and by the time the HVDC converter is recovered and able to respond, the communicated signal arrives and triggers a specific open-loop action. This scheme enables a large response in a very short time, and avoids the significant risk of widespread oscillatory instabilities associated with frequency-input HVDC power modulation schemes.

7.2 Available controls for fast frequency response

7.2.1 General

Power converters can be classified as either grid-following or grid-forming, depending on their control and operation in the AC power system. They are analysed in 7.2.2 and 7.2.3, respectively.

7.2.2 Additional FFR control for grid-following converter

Currently, almost all of the converter connected generation units that are used to convert the energy from wind turbines or PV panels to the grid apply grid-following converters. A grid following control layout of a converter uses a cascaded control structure, in which the inner loops control the converter currents and the outer loops control power and voltage. The converter control is developed in a synchronously rotating frame of which the frequency is tracked by a phase-locked loop (PLL). The dq-frame is typically oriented alongside the voltage at the point of common coupling (PCC). The PLL then aligns the d-axis of the rotating dq-frame to this grid side voltage.

Controlling the converter in this way allows for an independent and direct control of the AC active power by aligning the d-component of the current with the PCC voltage. Therefore deviation-based FFR control in a standard grid-following control can be achieved for instance by adding a droop control action of the (measured) system frequency to the active power set point. Similarly, ROCOF-based FFR can be included by a derivative control action of the (measured) system frequency.

With respect to the behaviour during frequency transients, a further classification can be made. Inherently, those grid-following converters do not alter their power set point as a function of the frequency and can therefore be considered inertia-less from a power system point of view (H_V = 0). However, the grid-following converter with additional FFR control can vary the energy exchange with the grid in a controlled way. As such, they can provide virtual inertia ($0 \le H_V \le \infty$) and supporting power for frequency.

For grid-following converters, the additional FFR control mainly includes ROCOF-based FFR responding to ROCOF (i.e. synthetic inertia response), and deviation-based FFR responding to frequency derivate, fast power injection triggered by event detection.

The ROCOF-based FFR has been modelled to mimic the rotor equation of synchronous generator. And it can be deduced from Figure 11 that for the case of T_J = 8 s and the system frequency shown in Figure 9, the transient output inertia support power can reach to 15 % of rated power of the generator at the moment of sharp frequency drop, which will be a severe torque imbalance for wind turbine generator. Therefore, the design of inertia support usually adopts a first-order inertia link with a time constant of T (adjustable) to buffer the imbalance. The transfer function is illustrated in Figure 11.

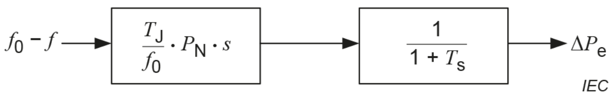


Figure 11 – Scheme of the transfer function of ROCOF-based FFR for grid-following converters

The model of primary frequency regulation is relatively simple, as illustrated in Figure 12.

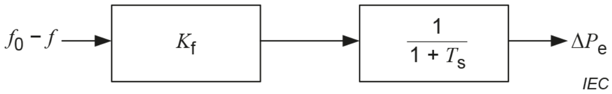


Figure 12 – Scheme of the transfer function of deviation-based FFR for grid-following converters

However, it was noted that the wind turbine with primary frequency regulation needs to reserve its output margin if there are no energy storage devices. Generally, the maximum power point tracking (MPPT) pattern gives wind turbine no power margin. Only in the case of high wind speed, in order to prevent the speed of wind power turbines from breaking the upper limit, does it need to operate in the range of constant power pattern through pitch angle control. At this time, the backup power is reserved naturally. Otherwise, with the MPPT and the constant speed pattern corresponding to the middle and low wind speed, the backup power is obtained by actively adjusting the pitch.

7.2.3 Grid-forming converter control

7.2.3.1 General

For grid-forming converter control, it was pointed out that not only is the electrical active power delivered into grid to impact the system frequency indirectly like grid following converters, but also its internal voltage and frequency have the direct influence on system frequency like synchronous generators.

Grid-forming converters operate as an ideal voltage source as they set the local voltage and frequency of the system.

A purely grid-forming converter keeps the frequency (and voltage) at their terminals constant and can be considered in that way to provide an infinite amount of (virtual) inertia ($H_V = \infty$). In order to allow parallel operation and to offer frequency and voltage regulation with grid-forming converters, a self-synchronizing (droop) based power controller is often included in the model.

As the active and reactive power exchange of the converter is a function of the AC grid voltage and frequency in this case, it is inherently the better way to have a flexible amount of energy (i.e. access to some form of energy storage) available to provide the power and energy almost instantaneously. Otherwise, the self-synchronizing capability is lost. Therefore, standard wind and PV units are mostly not eligible for this type of control.

7.2.3.2 Droop control

Grid-forming converters with $H_V = \infty$ are controlled to keep the frequency (and voltage) at the converter or filter bus constant in time. When $0 \leq H_V \leq \infty$ on the other hand, those converters will vary their frequency depending on the measured active power by means of a droop control action for instance in some cases.

Similar to the synchronous generators, Q and u on the one hand and P and on the other hand are strongly coupled. Hence, changing δ (or ω_e) mainly alters the active power flow; the reactive power is predominantly influenced by the voltage difference and vice versa. Therefore, the simplest and commonly implemented control technique for these kinds of converters to regulate the reactive and active power is based on standard droop control. The control expressions can therefore be defined as the following equations:

$$\omega_e^* = R_P \left(P^* - P\right) + \omega_{e,0} \tag{11}$$

$$e^{*} = R_{\mathrm{Q}}\left(Q^{*} - Q\right) + u_{0} \tag{12}$$

with R_{P} and R_{Q} as the droop gains for the active and reactive power. Using this control principle, the self-regulation capability of synchronous machines is mimicked. When, for instance, the grid frequency is suddenly increased, the exchanged/measured power P decreases. This in turn results in a higher frequency set point (represented as ω_e^{*}) for the droop controller, automatically tracking the frequency of the external system. A PLL or another synchronization system is therefore not a good option.

For example, the control scheme of the converter is given in Figure 13. The outer loop consists of the droop-based active and reactive power controller as presented above. The reference angle/frequency (ω_e^{*}) and voltage (e^{*}) can be used as a direct input for the PWM converter (u_{cv}^{*}) in Figure 13, or an additional cascade current and voltage controller can be implemented as shown in the scheme. Hence, the voltage over the filter capacitance is regulated instead, which allows to explicitly limit the converter currents.

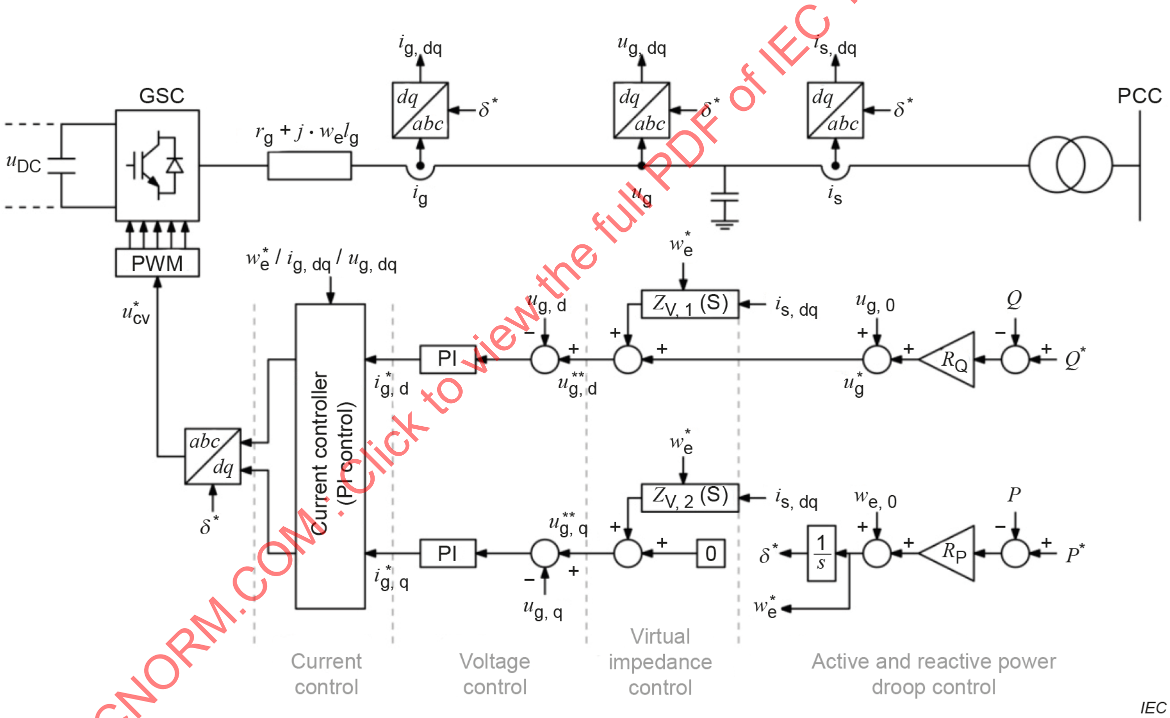


Figure 13 – Schematic of the droop control of deviation-based FFR for grid-forming converters

7.2.3.3 Virtual synchronous machine(VSM)

The control of a virtual synchronous machine (VSM or sometimes also denoted by VISMA or synchronverter) aims at mimicking the dynamic behaviour of a synchronous machine. The most basic controller emulates only the swing equation of the synchronous machine and can be seen as an extension of the droop control. In such control approach, the reference frequency (ω_e') is determined by the following equation:

$$2H_{\mathrm{V}}\frac{\mathrm{d}\omega_e^{*}}{\mathrm{d}t} = P^{*} - P - \frac{1}{R_{\mathrm{P}}}\left(\omega_e^{*} - \omega_{e,0}\right) - K_{\mathrm{D}}\left(\omega_e^{*} - \omega_{e,\mathrm{PLL}}\right) \tag{13}$$

where K_D denotes the damping constant used to represent the damping effect of a synchronous machine which acts here on the difference between the reference frequency and the actual frequency at the PCC, which is measured by a PLL at the filter bus. Using this approach, the converter can be considered to emulate the electromechanical behaviour of a synchronous machine, in terms of damping and inertia, which is equipped with a governor having a droop constant equal to R_P and a very small total time constant (turbine and governor) of the primary control action depending on the control bandwidth.

The implementation of the VSM is similar to the one presented in Figure 13 where ω_e^* and u_g^* are calculated from the electro-mechanical equations of the mimicked synchronous machine. Numerous variations exist depending on the level of detail of the machine model as well as the way additional control loops are included to increase the performance and/or stability of the VSM. For instance, an additional lead-lag filter is added to the power measurement (P) to enhance the stability of the VSM controller mimicking the swing equation.

7.3 Tuning considerations for fast frequency response and primary frequency response

For discussion of tuning considerations for fast frequency response and primary frequency response, the whole frequency response process is reviewed as shown in Figure 14.

In Figure 14, the total power signature of a resource providing FFR is broken into four distinct regions. The energy delivered before reaching UFLS is noted in green. The only arresting energy that is useful for avoiding involuntary UFLS generally was delivered before the system frequency reaches that threshold. Arresting energy delivered after that time, shown in orange, is still useful in managing the depth and timing of the frequency nadir. In systems with staged UFLS, the distinction between the green and orange becomes less distinct. Ultimately, the modelling presented here is based upon the objective to avoid involuntary UFLS, and the results presented here are based on the concept of keeping the frequency nadir above a known threshold. The third area, in blue, represents the period during which the FFR is replaced by PFR. Generally, this was done slowly enough that the frequency doesn't drop again. And finally, for some resources, most notably wind ROCOF-based FFR, the arresting energy provided generally recovered by reducing the total power delivered to a level below pre-disturbance.

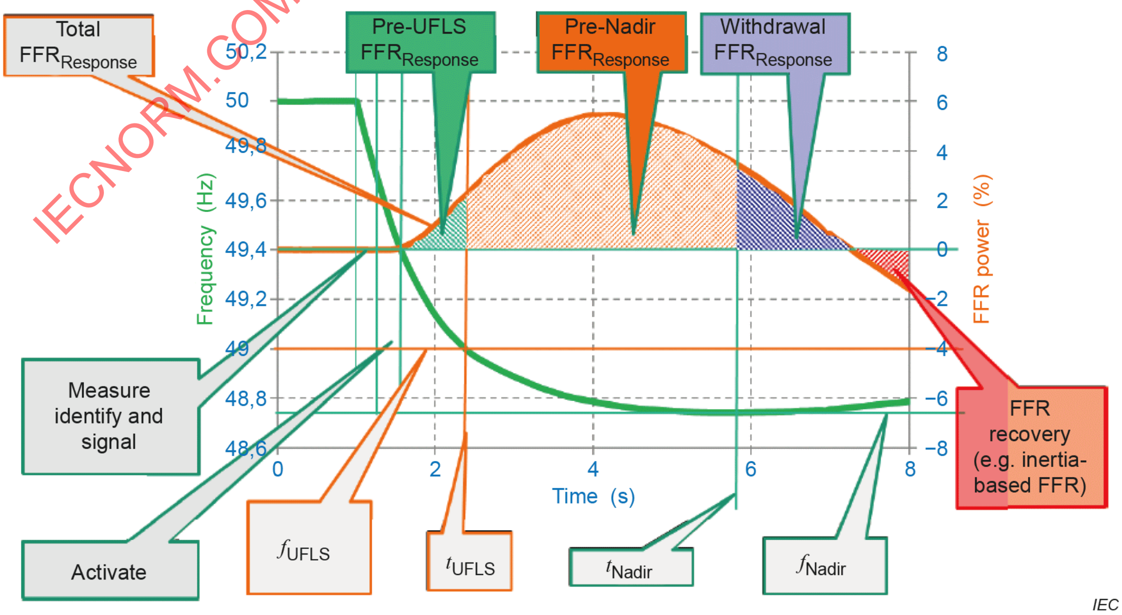


Figure 14 – Time elements of FFR

It is possible to create or tune the dynamic response of generation such that the ability of the unit to reasonably follow the PFR droop characteristic is degraded or defeated. For example,

functionality that focuses on achieving specific power ramp rates or fast response to certain signals can conflict with droop control. Poorly tuned controls can result in frequency correction overshoots, or in sustained frequency errors. For example, in the US, generator load controls that defeat ('withdraw') PFR are presently in widespread use. These cause poor frequency response, especially in the US Eastern Interconnection. For any system to evaluate FFR properly, dynamic models of PFR need to correctly capture all these effects.

8 Test methods for verifying turbine-level or plant-level fast frequency response capability

8.1 General

The Northwest Power Grid in China has taken the nationwide lead in launching the promotion and application of fast frequency response function of IBR.

The fast frequency response test method for renewable energy power plants in sending-end large power grid is proposed. Through frequency step disturbance test, simulating actual frequency disturbance test, anti-disturbance performance test and AGC coordination test, the fast frequency response function test of renewable energy power plant is completed, and the on-site feasibility verification is completed for the first time in China. At present, this method has been used to guide the access detection of fast frequency response function of renewable energy power plants in Northwest Power Grid, and has the significance of popularization and application.

8.2 Selection of test equipment

In order to ensure the authenticity and effectiveness of the signals collected by the test, the data recording analyser and frequency signal generating device selected for the test need to meet the following conditions:

1) Data record analyser

   The accuracy of the voltage transformer and current transformer used by the data recording analyser used in the test to collect the grid voltage and current needs to not be less than 0,2, the sampling frequency of the selected data analyser needs to not be less than 20 kHz, and the bandwidth needs not to be less than 2,5 kHz.

2) Frequency signal generating device

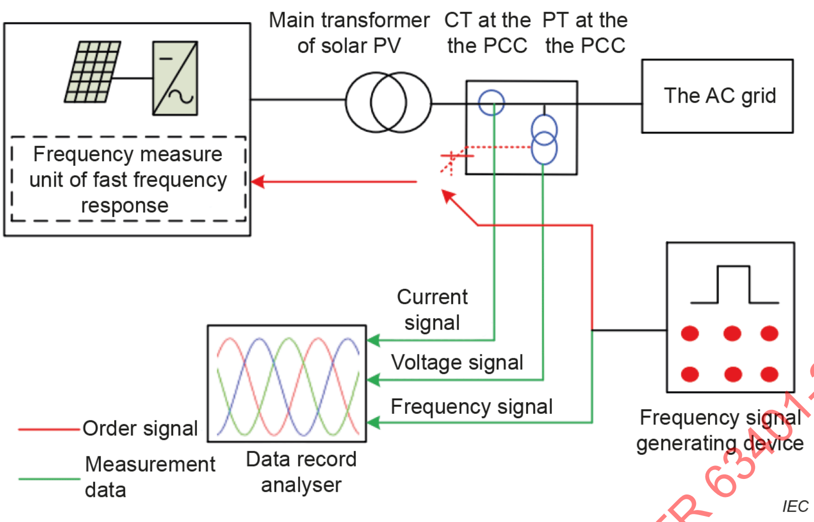
   Frequency signal generating device is three-phase four-wire output, voltage output range is wider than 0 V to 130 V, output voltage error is not more than ±0,1 %, frequency output range is wider than 1 Hz to 100 Hz, frequency error is not more than 0,002 Hz, phase output range is 0° to 360°, the phase output error does not exceed ±0,1°, the signal generation period does not exceed 100 ms, and the voltage and frequency curve can be edited.

The signal generating device and the data recording analyser will pass the calibration of the relevant calibration qualification institution, and the test report will include the calibration report of the signal generating device and the data recording analyser.

8.3 Test wiring method

The plant-level fast frequency response function is verified by the field test at the grid connection point of the station that has the fast frequency response function.

The test uses a frequency signal generating device to simulate the secondary side signal of the grid connection point PT (potential transformer) of the station, give the frequency test signal, and send it to the frequency measurement unit of the renewable energy power plant frequency response control system to test the frequency response performance. As shown in Figure 15 and Table 7.



Key

CT current transformer

PT potential transformer

Figure 15 – Test wiring diagram

Table 7 – Input and output of a data collection point

Data collection point	Collected data
PCC	the current, voltage signal for the active power calculating
frequency signal generating device	the 0 V to130 V voltage signal output of frequency signal generating device

The measurement unit of the fast frequency response control system of the renewable energy power plant is expected to support the signal access of the signal generating device. Before connecting the analogue signal (three-phase four-wire) of the frequency signal generating device, the renewable energy power plant needs to disconnect the electrical connection between the original grid-side PT signal and the fast frequency response control system to ensure correctly receiving the test signal from the frequency signal generator.

8.4 Selection of measuring conditions

Before the test, the capacity ratio of the wind turbines and photovoltaic power generation units that are shut down is generally not exceed 5 % of the whole station capacity.

There are various test items which are shown in Table 8.

Table 8 – Test conditions for fast frequency response of renewable energy power plant

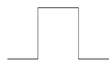
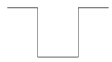
Output power range/P_n	Limited power	Unlimited power
20 % to 30 %	working condition 1	working condition 2
50 % to 90 %	working condition 3	working condition 4

In order to test the fast frequency response capability of the renewable energy power plant to the greatest extent and make the test as executable as possible, the test conditions can be divided according to the new energy primary frequency modulation test. P_n is the rated power of the renewable energy power plant. When the power is limited, in order to ensure the active power and upward adjustment ability of the renewable energy power plant, it is important to ensure the limited power is not less than 15 % of P_n, and to select different test conditions for different test projects.

8.5 Step frequency disturbance test

Referring to the primary frequency modulation test of conventional hydropower and thermal power generators, the response characteristics of the renewable energy power plant underfrequency step disturbance are tested in the case of frequency step disturbance according to Table 9.

Table 9 – Stepped frequency disturbance test

Disturbance type	Frequency change	Duration	Test conditions	Frequency disturbance waveform
upward frequency step disturbance	from 50 Hz to 50,1 Hz	≥ 30 s	working condition 1 to 4	
	from 50 Hz to 50,2 Hz			
	from 50 Hz to 50,4 Hz			
	from 50 Hz to 51,0 Hz			
downward frequency step disturbance	from 50 Hz to 49,9 Hz	≥ 30 s	working condition 1, 3	
	from 50 Hz to 49,8 Hz			
	from 50 Hz to 49,5 Hz			
	from 50 Hz to 48,5 Hz			

The upward frequency step disturbance test needs to be done under the working conditions 1 to 4. The downward frequency step disturbance test is done under the working conditions 1 and 3 because under the condition of unlimited power (working conditions 2, 4), the wind turbine and the photovoltaic power generation unit can barely release more output in a short time. But if the renewable energy power plant is configured with electrochemical energy storage or other backup power generation units, the downward frequency step disturbance can be carried out under the working conditions 2 and 4.

By detecting the pick-up time, response time, and settling time, the rapid frequency response capability is evaluated.

8.6 Slope frequency disturbance test

For example, the performance for ROCOF-based FFR is tested under the output frequency of the frequency signal generating devices varying according to the frequency slope curve in Figure 16. The ROCOF within t_0 to t_1, t_2 to t_3, t_4 to t_5, t_6 to t_7 is settled at 0,5 Hz/s, $t_4 - t_3 \geq 2$ min, $t_6 - t_5 = t_2 - t_1 = 1$ min.

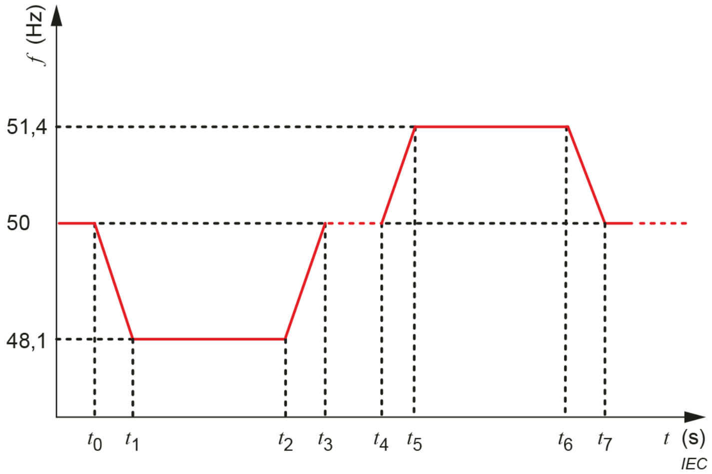
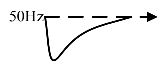


Figure 16 – Test slope curve for ROCOF-based FFR

8.7 Actual frequency disturbance simulation test

According to the content in Table 10, the actual frequency disturbances of the power grid are simulated and the response characteristics of the renewable energy power plant are tested. The frequency curve is simulated according to the historical frequency disturbance data. Two tests will be performed for each test condition in Table 10. The renewable energy power plant maintains stable operation during the test, and the collected test data will cover the frequency fluctuation range. The next test can not be carried out until the power regulation of the station becomes stable.

Table 10 – Test conditions for actual frequency disturbance simulation

Disturbance type	Test conditions	Frequency disturbance waveform
upward frequency disturbance	working conditions 1 to 4	
downward frequency disturbance	working conditions 1, 3	

8.8 Actual frequency disturbance simulation test

The fast frequency response function of renewable energy power plant needs to avoid the instantaneous frequency mutation caused by single short circuit fault. The high-precision signal generator is used as the signal source, the anti-disturbance performance verification was carried out under the condition of working condition 1, and the signal generator was adjusted to output two kinds of calibration signals.

Signal 1: Voltage amplitude drops to (0 %, 20 %, 40 %, 60 %, 80 %) rated voltage instantaneously, duration ≥ 150 ms, and two phase shifts are completed during voltage drop and recovery, each phase shift is generally ≥ 60 degrees.

Signal 2: Voltage amplitude step to 130 % rated voltage instantaneously, duration ≥ 500 ms, and complete two phase shifts during voltage step and recovery, each phase shift ≥ 60 degrees.

9 Rate-of-change-of-frequency (ROCOF) definition and withstand capability for high ROCOF conditions

9.1 Definition of rate of change of frequency (ROCOF)

Rate of change of frequency (ROCOF) is the time derivative of the power system frequency ($\mathrm{d}f/\mathrm{d}t$). It is a measure of how quickly frequency changes following a sudden imbalance between generation and load.

ROCOF is most commonly expressed in hertz per second (Hz/s). ROCOF is fundamentally the tangential line for any given point on a frequency response curve; however, this is typically estimated by using two frequency measurements within a short period of time (i.e. 0,1 s to 0,5 s). As the following equation:

$$\mathrm{ROCOF}_{t_0+\Delta t} = \frac{\mathrm{d}f}{\mathrm{d}t} = \frac{f_{t_0+\Delta t} - f_{t_0}}{\Delta t} \tag{14}$$

Initial ROCOF is the rate of change of frequency immediately after the system is unbalanced by a disturbance like loss of generation or islanding, before any controls become active. This is theoretically the highest system ROCOF. Initial ROCOF is related to synchronous system inertia and the size of the contingency according to the following equation (assuming load dampening to be zero):

$$\mathrm{ROCOF}_{t=0^+} = \frac{\mathrm{d}f}{\mathrm{d}t} = \frac{\Delta P}{2H} \times f_0 \tag{15}$$

where

ΔP is size of contingency (MW lost);

H is system inertia (MW·s/MVA rating);

f_0 is the frequency at the time of disturbance (Hz);

$\frac{\mathrm{d}f}{\mathrm{d}t}$ is the rate of change of frequency (Hz/s).

In the instant following the disturbance, no control actions take part. Notice that the equation does not include any terms other than the size of the event and the inertia. Therefore, for systems where high ROCOF can drive adverse behaviour, such as tripping of generators and loads, high system inertia is desirable. There are two ways to manage frequency response:

1) Slow ROCOF down:

   Synchronous generators provide inertia that decreases ROCOF. Governors on conventional generators act fairly slowly (in the time frame of seconds to minutes) to increase output to arrest and recover frequency. A conventional enhancement would be to increase grid inertia using synchronous machines (e.g. synchronous condensers) to slow ROCOF to allow time for other responses to activate. Synchronous machines do this autonomously and with no need for 'detection' or 'communication'. This is how the power system is managed at present, but this is not the focus of this document.

2) Respond more quickly:

   Another option is to mitigate the effects of fast initial ROCOF by rapidly injecting arresting energy into the grid. Note that arresting energy could be provided by increasing generation or decreasing load. Both provide the same function of bringing system generation and load into balance. The objective of this study is to examine what kind of very fast frequency response can be achieved using advanced features from new inverter-based technologies such as (but not exclusive to) wind, solar, batteries, flywheels. This option can be implemented by measuring frequency and identifying the problem, communicating to the resource and activating the resource. This approach is the focus of this document.

This quantity of ROCOF was traditionally of minor relevance for systems with generation mainly based on synchronous generators, because of the inertia of these generators, which inherently counteract load imbalances and thus limit ROCOF in these cases. It however becomes relevant now during significant load-generation imbalances (caused by disconnection of either large loads or generators, or by system splits), when larger ROCOF values will be observed because of low system inertia caused by (amongst others) disposal of synchronous generation in case of high instantaneous penetration of non-synchronously connected generation facilities in some cases.

In the absence of any control, inverter-based generation does not possess such inherent characteristics and high inverter penetration could therefore lead to higher ROCOF in a power system. The relationship between inverter penetration and ROCOF is, however, not straightforward, and countermeasures – mostly in the form of control algorithms – need to be implemented carefully.

Large ROCOF values will endanger secure system operation to a certain extent because of mechanical limitations of individual synchronous machines (inherent capability), protection devices triggered by a particular ROCOF threshold value or timing issues related to load shedding schemes.

In the new global generation mix where the loss of traditional fossil and nuclear generation plants is being replaced by renewables, as shown in Figure 17, there is an increased rate of change of frequency (ROCOF) where grid disturbances cause load shedding, system tripping, and an increased risk for unintended short- and longer-term power drop-outs.

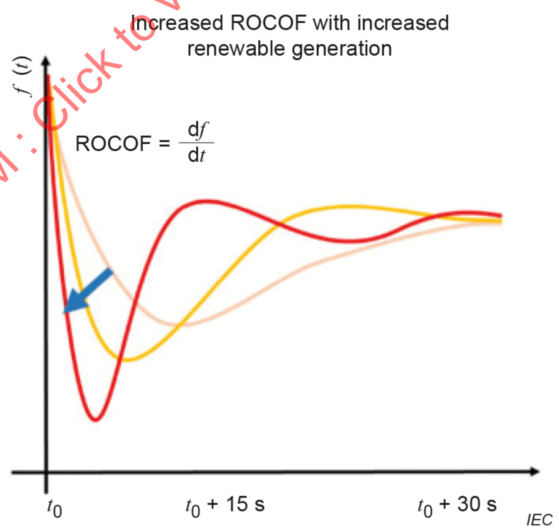


Figure 17 – Schematic of increased ROCOF with increased renewable generation

Energy storage technologies, including ultra-capacitors (supercapacitors), provide synthetic inertia to utility grids and micro-grids to ensure frequency and power system stability. During frequency deviations away from utility set points, ultra-capacitors provide ultra-fast synthetic inertia (with a response rate measured in cycles) to the system by rapidly injecting power thus mitigating fast ROCOF events and out-of-limits frequency deviations.

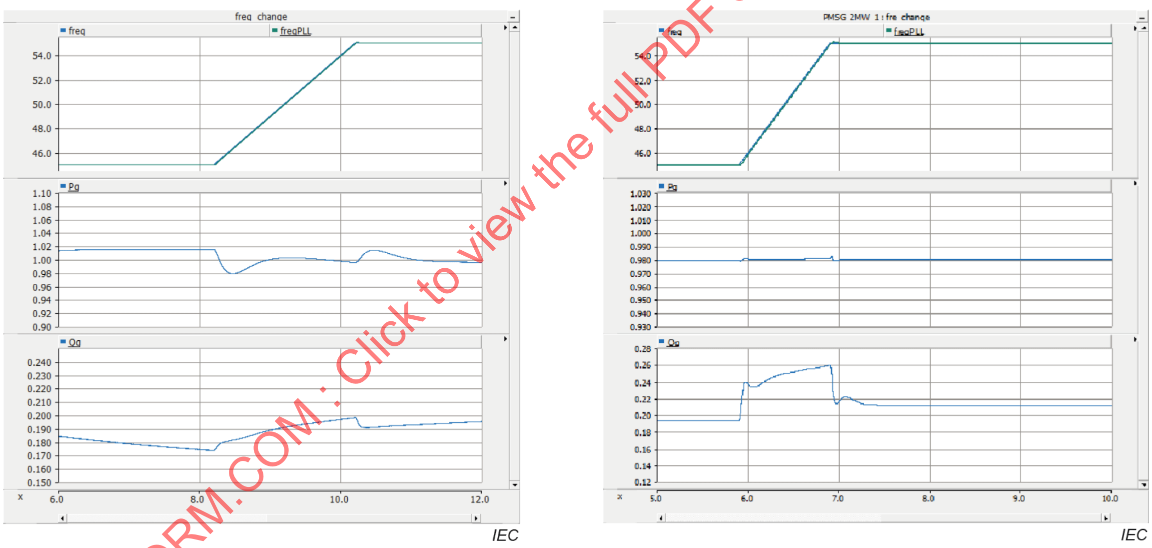
Ultracapacitors and fast responding inverters set in frequency sensitive mode can stabilize frequency excursions in grids and micro-grids by rapidly injecting or absorbing power in the milliseconds timeframe, with continuous power delivery scalable to traditional primary response time durations. This provides immediate response to the imbalance before slower assets can react.

9.2 Ride-through (withstand) capability for high ROCOF conditions

Inverter-based resources do not have an equipment limitation or need to trip on high ROCOF.

Some studies focus on regional higher ROCOF in interconnected systems – where large disturbances in regions with very high penetrations of IBR will experience much higher ROCOFs than the rest of the system to a certain extent. In the relatively weak grids of these regions, the significant voltage phase shift and magnitude change will occur near IBRs in some cases. And during the voltage phase shift and magnitude change, there is the risk that a false change in frequency will be measured and hence a false rate of change of frequency will be measured to a certain extent. In particular, a positive/negative phase shift can be seen by the frequency function as a transient increase/decrease in frequency, which will lead to higher ROCOF to a certain extent.

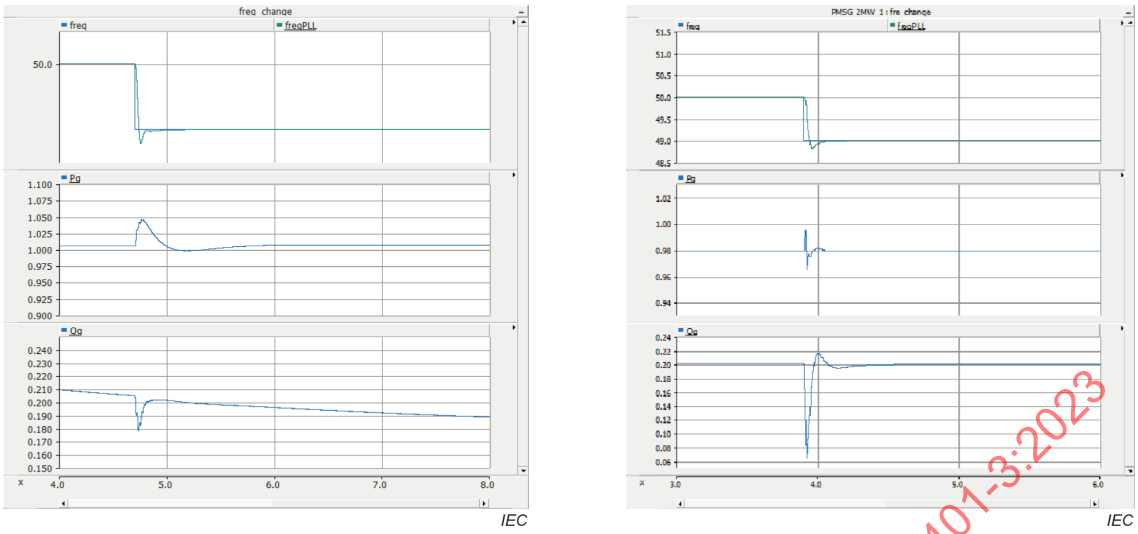
As for the adaptability of the control system of the IBR unit itself, studies have shown that it can adapt to at least ±5 Hz frequency range and ±1 Hz frequency step change, which are shown in Figure 18 and Figure 19.



a) Doubly fed induction generator (DFIG)-based wind turbine generator

b) Permanent magnet synchronous generator (PMSG)-based wind turbine generator

Figure 18 – The response of IBRs for frequency slope change (change from 45 Hz to 55 Hz in 1 s)



a) **Doubly fed induction generator (DFIG)-based wind turbine generator**

b) **Permanent magnet synchronous generator (PMSG)-based wind turbine generator**

Figure 19 – The response of IBRs for frequency step change of 1 Hz

However, ROCOF protection has been used in certain grid code requirements around the world, particularly for small island systems, and for passive islanding detection for DER installations.

In the blackout event in the Great Britain power grid on 9 August 2019, the embedded generation disconnected from the system under rate of change of frequency (ROCOF) protection. In Great Britain, the standard setting for ROCOF protection is 0,125 Hz/s. It indicates that ROCOF relays, if not set correctly, can be responsible for accidental trips.

So the standard setting needs to be modified to ensure frequency ride-through during high ROCOF conditions.

In Belgium and Denmark, the typical settings of ROCOF relays are in excess of 1 Hz/s.

The current ROCOF standard in Ireland as specified in the Grid Code is 0,5 Hz/s: generators are obliged to stay synchronized for ROCOF values up to this level. In the Northern Ireland Grid Code there is no specific mention of ROCOF.

While with system non-synchronous penetration (SNSP) increasing , SONI expect conventional generation to have the capability to continue operating through ROCOF values greater than 1 Hz/s. An appropriate time frame to calculate ROCOF is 500 ms.

However, NERC suggested not to use ROCOF relays for inverter-based resources connected to the BPS and make it disabled in the inverter [12].

Measured frequency changes at the inverter are either caused by phase shifts on the BPS (due to faults, line switching, or other normally occurring fast transient events) or by a generation-load imbalance in the system. Phase shifts from fault events, for example, cause an instantaneous change in phase angle that results in a very high instantaneously calculated ROCOF value. Inverter-based resources are expected to ride through these events, regardless of the ROCOF, using advanced controls to maintain PLL synchronism during the high ROCOF and potential momentary (cycles) loss of PLL lock. On the other hand, the BPS will experience a relatively high system-wide ROCOF during a large generation load imbalance situation in some cases. However, these conditions are significantly slower than the instantaneous phase jumps caused by faults, and riding through these events and continuing to provide active and reactive current are important for inverter-based resources. In either case, a BPS-connected inverter-based resource was hoped to maintain ROCOF protection disabled and to be able to ride through phase jumps and high system-wide ROCOF events. PLL controls which are robust enough to ride through these events will be the development direction. Tripping due to high ROCOF is not acceptable ride through performance.

10 Test specifications for high ROCOF conditions

10.1 Performance specification

10.1.1 Effective and operating ranges

Table 11 and Table 12 show examples on how the effective range and operating range can be declared by the manufacturer for ROCOF protections. Depending on the frequency function technology, the range can differ from the given table, where the values are given as an example to indicate the format of the data. The effective and operating ranges will be declared by the manufacturer and the data will be published in accordance with the format shown in Table 11 and Table 12. When effective and operating ranges are expressed according to rated voltage or nominal frequency, the values of rated voltages or nominal frequencies authorized by the protection function will be declared by the manufacturer.

Table 11 – Example of effective and operating ranges for over- and under-frequency protection

Quantity	Effective range	Operating range
Voltage	5 % to 150 % of rated voltage	2 % to 200 % of rated voltage
Power frequency	0,95 to 1,05 of nominal frequency	0,9 to 1,1 of nominal frequency

Table 12 – Example of effective and operating ranges for ROCOF protection

Quantity	Effective range	Operating range
Voltage	5 % to 150 % of rated voltage	2 % to 200 % of rated voltage
Power frequency	0,95 to 1,05 of nominal frequency	0,9 to 1,1 of nominal frequency
ROCOF	−5 Hz/s to +5 Hz/s	−10 Hz/s to +10 Hz/s

10.1.2 Accuracy related to the characteristic quantity

For a ROCOF function, the accuracy will be declared with a relative value with respect to the setting value (G_S) or an absolute df/dt value or the combination of both values (for example, '±5 % or ±15 mHz/s, whichever is the greater'). The manufacturer can declare variable accuracies over the ROCOF setting range.

10.1.3 Start time for rate of change of frequency (ROCOF) function

The start time of ROCOF functions depends on different factors, similar to under-/over-frequency functions. The start time will be published by the manufacturer as a result of tests based on different slopes with constant frequency rate of change between the initial test frequency value and the end test frequency value.

10.1.4 Accuracy related to the operate time delay setting

The operate time delay is the time interval from the instant when the start (pick-up) signal is activated, to the instant when the operate signal is activated.

The operate time of the frequency protection function is the sum of the start time (pick-up time) and the operate time delay setting. The difference between operate time and operate time delay setting is specified in Figure 20.

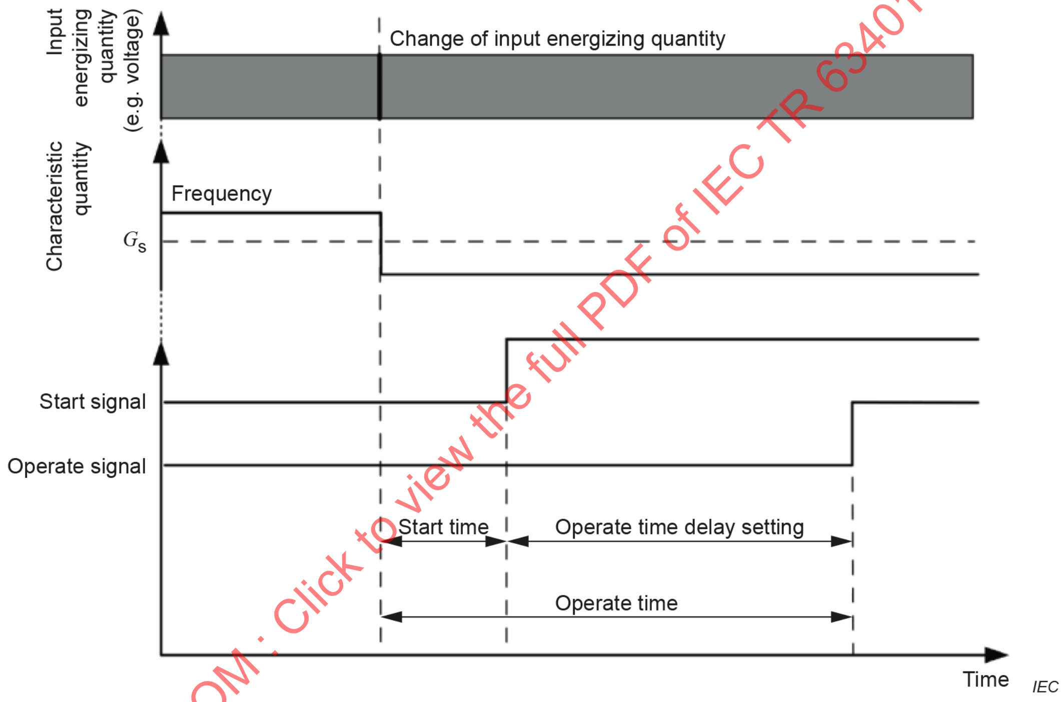


Figure 20 – Operate time and operate time delay setting

The maximum permissible error of the operate time delay setting can be expressed as either:

- a percentage of the time setting value, together with a fixed maximum time error (where this will exceed the percentage value in some cases), whichever is greater (for example, ±5 % or ±20 ms, whichever is greater); or
- a fixed maximum time error (for example, ±20 ms).

10.1.5 Voltage input

If voltage instrument transformers are used, the type of voltage transformers generally was declared by the manufacturer to maintain the claimed performance levels of frequency protections.

If direct low voltage connections are used, the rated voltage range will be defined by the declared effective and operating voltage ranges.

10.2 Functional test methodology

10.2.1 General

10.2 gives a detailed description of the tests to be performed to verify the frequency function accuracy and performance specification described in 10.1.

These tests are designed in such a way to exercise all aspects of the hardware and firmware (if applicable) of the frequency function. This means that the injection of voltage (or current) will be at the interface to the device, either directly into the conventional voltage transformer input terminals, or an equivalent digital signal with the appropriate protocol at the appropriate interface. Similarly, operation will be taken from output contacts wherever possible or equivalent signals at an appropriate interface.

In order to determine the accuracy of the frequency functions under steady-state conditions, the injected characteristic quantity will be a sinusoid of rated voltage amplitude and its frequency will be varied according to the test requirements. During transitions, the injected signal will be continuous, with no step change in its phase angle or magnitude, except in its frequency, unless otherwise specified. It is allowed to adjust the voltage level to keep within the withstand requirements of voltage inputs related to the rated volt/hertz level. If the frequency functions are based on phase current, the same test methodology will be followed, and the test conditions will be fully described in the type test report.

Several functional tests described in 10.2 are based on waveform signals with a constant frequency slope. When the test signal is based on a COMTRADE file (or other binary format test files) and replayed using a test device, the sampling frequency of the test waveform will be at least 4 800 Hz. The sampling rate will meet the Nyquist criteria depending on frequency content of tested signals.

For ROCOF functions, the actual setting to be used can be calculated using the following formula:

$$G_{\mathrm{s}} = (G_{\mathrm{s\_max}} - G_{\mathrm{s\_min}}) \times X + G_{\mathrm{s\_min}}$$

where

G_{s}	is the setting value; the tested value can be rounded according to the step size of the frequency function;
$G_{\mathrm{s\_max}}$	is the maximum available setting value;
$G_{\mathrm{s\_min}}$	is the minimum available setting value;
X	is the test point percentage value divided by 100 expressed in test methodology.

For example, based on the ROCOF setting defined in Table 13, and assuming the setting range is 0,1 Hz to 10 Hz/s, the actual ROCOF settings to be used would be: 0,1 Hz/s, 0,595 Hz/s, 1,09 Hz/s, 3,07 Hz/s, 6,04 Hz/s, 10 Hz/s. The rounded values can be used according to the setting step size.

10.2.2 Determination of steady-state errors related to the characteristic quantity

10.2.2.1 Accuracy of the start value

10.2.2.1.1 Description of the generated frequency ramp

The accuracy of the ROCOF setting (G_{s}) is assessed with a sequence of frequency ramps where the frequency increases or decreases from the nominal value depending on the sign of the frequency derivative ('+' or '−'). The test method is illustrated in Figure 21, applicable for a positive ROCOF function.

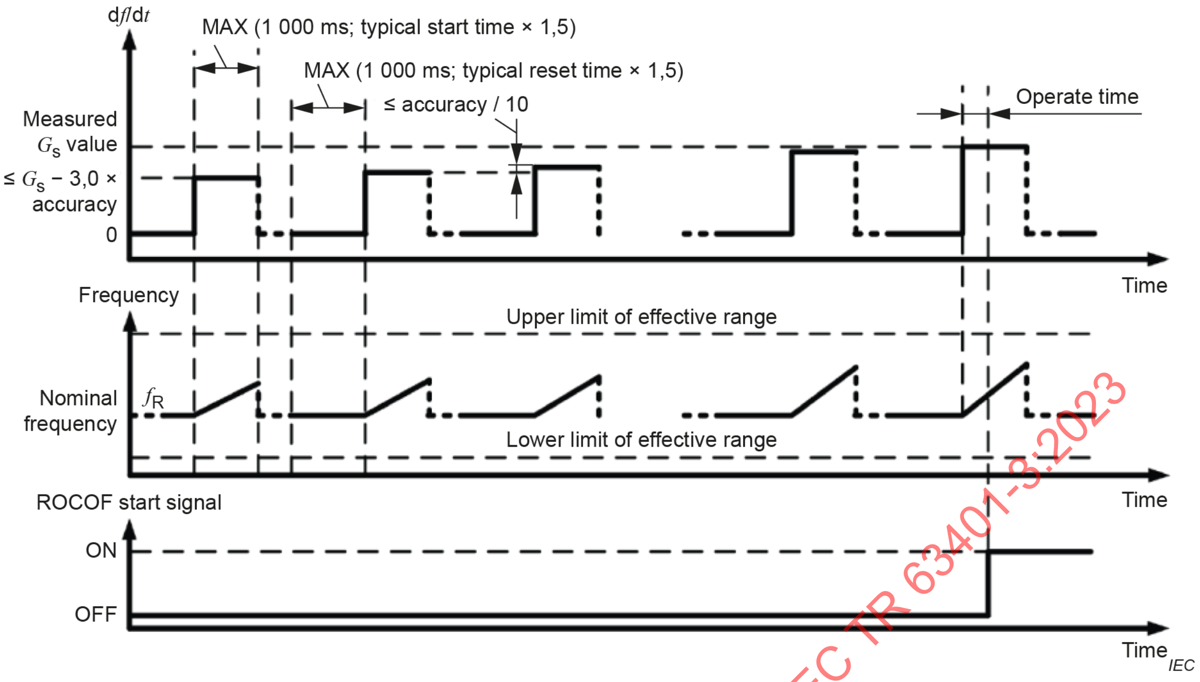


Figure 21 – Example of test method for positive ROCOF function

The ramp commences at the nominal frequency f_R and stops when the protection START signal operates or when the ramp terminates without the protection start being asserted. The ramp duration to assess if the protection has started or not during the injection is:

MAX (1 000 ms; typical start time × 1,5)

According to relevant regulations and requirements, the injected frequency will always be within the effective range of the protection function, if an effective frequency range is declared for the ROCOF function. This condition will be dependent on a limited duration of the frequency ramp to a certain extent. If the duration of the frequency ramp needs to be shorter than the maximum start time for the ROCOF function, the function cannot be tested for that setting based on the standardized test conditions. In that case, this information and the appropriate test method to be used to check the accuracy of these start value settings will be declared by the manufacturer .

The first ramp has a frequency derivative much lower than the absolute value of the protection setting G_S.

If the protection does not start within the ramp duration, the next ramp will be injected with a new frequency derivative value with a start point always equal to the nominal frequency value.

MAX (1 000 ms; typical disengaging time × 1,5)

Then, the frequency is changed in a linear way away from its nominal value. During this transition, the injected signal will be continuous, with no step change in its phase angle or magnitude except its frequency.

At the end of each ramp, the frequency returns to its nominal value to get ready for the next ramp. During this transition, the injected signal is not defined in this document. Any start (pick-up) or operation during this period will be ignored.

The next ramp has an increment (step) of frequency derivative equal to or smaller than:

(frequency rate of change accuracy / 10) Hz/s

When the protection start signal operates, the injection can be interrupted and the measured rate of change of frequency is the value of the frequency derivative for the last ramp.

The activation of the start signal will be a 'solid activation', this means no chattering of the signal with several transitions high–low–high during the injection of the ramp. The only chattering allowed in the signal is by the output contact, which has a reasonable bouncing time of less than 4 ms. If the start signal oscillates for more than 4 ms, the start activation is not considered and the ramp will continue with the next step. For other output media, no chattering at all will be present in the transition of the start signal, in order to be considered valid.

10.2.2.1.2 Function settings

Start ROCOF settings will be varied in the setting range as shown in Table 13.

Table 13 – Test points for ROCOF function

Test point value X[a] %	ROCOF setting (start threshold, G_s)[a] Hz/s	Voltage magnitude[b]	Test 1 Hz/s	Test 2 Hz/s	Test 3 Hz/s	Test 4 Hz/s	Test 5 Hz/s	Acceptance criteria Hz/s
0 (minimum)		min. U						$G_s \pm f'_{accuracy}$
0		max. U						$G_s \pm f'_{accuracy}$
0		U_n						$G_s \pm f'_{accuracy}$
5		U_n						$G_s \pm f'_{accuracy}$
10		U_n						$G_s \pm f'_{accuracy}$
30		U_n						$G_s \pm f'_{accuracy}$
60		U_n						$G_s \pm f'_{accuracy}$
100		U_n						$G_s \pm f'_{accuracy}$
100		min. U						$G_s \pm f'_{accuracy}$
100 (maximum)		max. U						$G_s \pm f'_{accuracy}$

[a] Test points are expressed as a percentage to compute the ROCOF settings (threshold G_s) according to the common rules defined in 10.2.1.

[b] U_n is the nominal voltage, and min. U and max. U are the minimum and maximum values of the declared voltage effective range.

If some protection functions have a setting for the definition of the window length to measure the frequency rate of change, the setting value will be the default value, unless the manufacturer has a special recommendation for the window length as a function of the rate of change setting (G_s). In this case, the manufacturer's recommendation will be followed.

10.2.2.1.3 Test points and calculation of ROCOF accuracy

The tests are repeated for each nominal power frequency value of the protection function (typically 50 Hz and 60 Hz).

The ROCOF accuracy is measured for the following test points (Table 13). Each test is repeated five times and the test results are reported as shown in Table 13.

All test points are carried out at nominal voltage. In addition, the first test (0 % − min. setting) and the last test (100 % − max. setting) points are repeated at the maximum and the minimum voltage of the effective range. The results of the test points at minimum and maximum effective range of the voltage are documented in line with the other test points at nominal voltage.

When the function is based on an absolute df/dt value, each test line defined in Table 7 will be performed with a positive and a negative ROCOF.

For each test, the measured rate of change of frequency will be within the declared accuracy. The accepted values are calculated for each measured value as described below.

The start of the protection function occurs within the error band around the expected start value (G_s). The band has the following borders:

higher accepted value = (G_s + declared frequency rate of change accuracy);

lower accepted value = (G_s − declared frequency rate of change accuracy).

10.2.2.1.4 Reporting of the ROCOF accuracy

The accuracy of the ROCOF is reported as a measurement error, as per the example shown in Table 14.

Table 14 – Reporting of ROCOF accuracy

ROCOF protection	
Rate of change of frequency accuracy	±5 % (of G_s) or ±15 mHz/s, whichever is greater

10.2.2.2 Reset hysteresis or reset ratio determination

10.2.2.2.1 Description of the test

10.2.2.2.1.1 General

The tests to assess the reset value for ROCOF functions are based on sequences of frequency ramps that are driven by the condition of the protection start signal which is monitored.

The tests are carried out according to the following procedure.

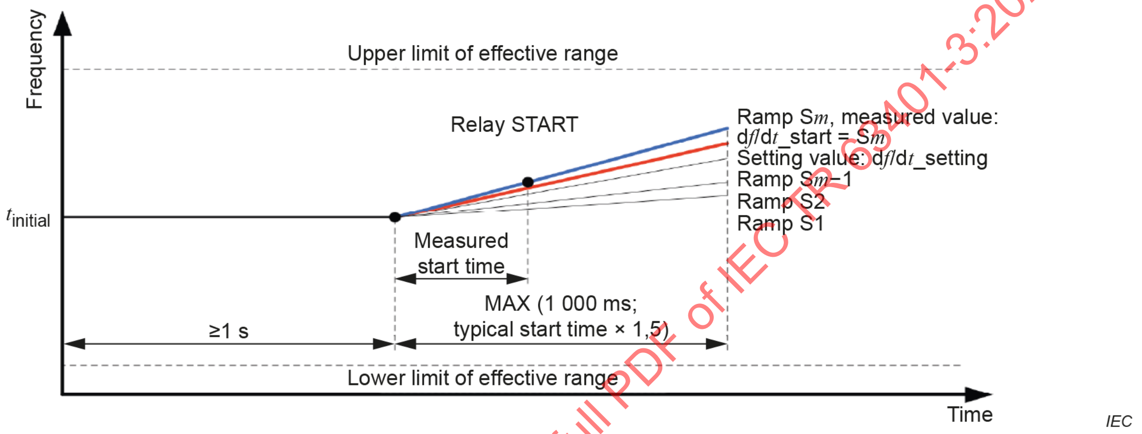
- The start value for df/dt (associated with the protection function setting G_s, indicated also as df/dt_setting) is detected with a succession of frequency ramps with increasing value of the frequency slope for positive ROCOF (for negative ROCOF the ramps will have a decreasing frequency slope). The detected ROCOF start value is associated with the value df/dt_start. See ramps S1, S2, …, Sm−1 and Sm in Figure 22 a), where the start operation is detected with the ramp Sm in the case of a positive error on start value.
- A frequency ramp with the value 1,2 × df/dt_start is generated, causing a definite start operation. At the end of this frequency ramp, a frequency ramp with a lower frequency slope is generated (df/dt_1, illustrated by ramp R1 in Figure 22 b)). During this ramp, the protection function will or will not reset to a certain extent:
  – if the function does not reset, then the initial ramp at 1,2 × df/dt_start is generated again, following this, a ramp with an even lower frequency slope is generated (df/dt_2, illustrated by ramp R2 in Figure 22 b));

– this process continues until the protection function resets, which occurs at the ramp with the frequency derivative value of d*f*/d*t*_reset. See ramps R1, R2, …, R*n*−1 and R*n* in Figure 22 b), where the reset operation is detected with ramp R*n*−1 in the case of a positive error on reset value or with ramp R*n* in the case of a negative error on reset value. When the protection function resets, the reset value can be calculated.

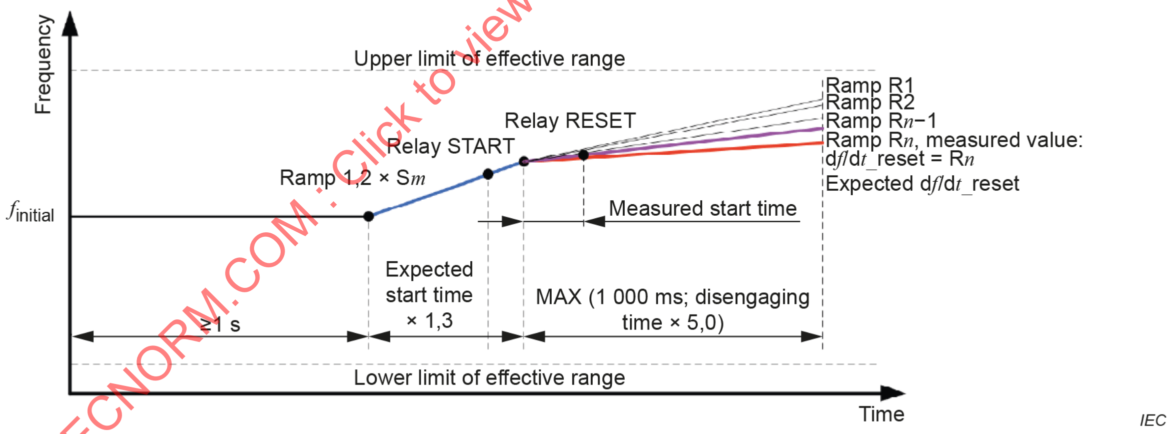
- The reset value is calculated based on the values d*f*/d*t*_start and d*f*/d*t*_reset.

NOTE According to the declared accuracy of the start value, if the frequency ramp with value 1,2 × d*f*/d*t*_start is not sufficient to ensure a definite start operation, the frequency ramp can be fixed to (1 + 2 × ε) × d*f*/d*t*_start, where ε is the declared accuracy of the start value. This particular test condition can be used for lower threshold values, if the declared accuracy is close to or above 20 %.

Figure 22 shows the test method for a ROCOF function.



a) Test to determine d*f*/d*t*_start



b) Test to determine d*f*/d*t*_reset

Figure 22 – Test method for measurement of reset value for ROCOF functions: example for positive ROCOF function

10.2.2.2.1.2 Test to determine d*f*/d*t*_start (see Figure 22 a)).

The first sequence of frequency ramps (increasing ramp for positive ROCOF function and decreasing ramp negative ROCOF function) will start from the frequency value f_{initial} within the frequency effective range of the protection.

At the beginning of each ramp, the frequency at f_{initial} at least for the duration of 1 s. If the duration of 1 s is not sufficient, in the type test report the time duration to be used for this test will be declared by the manufacturer .

Then, the frequency is changed in a linear way, away from its initial value. During this transition, the injected signal will be continuous, with no step change in its phase angle or magnitude, except in its frequency.

The frequency ramp will have a time duration of:

MAX (1 000 ms; typical start time × 1,5)

The injected frequency will always be within the effective range of the protection function, if a frequency effective range has been declared for the ROCOF function. This condition will be dependent on a limited duration for the frequency ramp to a certain extent.

The frequency value f_{initial} will be equal to the nominal frequency. If during these tests, the frequency value exceeds the effective range, the frequency value f_{initial} can be chosen to the minimum or maximum value of the declared frequency effective range. The initial frequency value will be declared in the type test report.

The START signal of the protection function is monitored and when the START signal operates, the value of the rate of change of the injected frequency is registered as df/dt_start value.

The activation of the start signal will be a 'solid activation'; this means no chattering of the signal with several transitions high–low–high during the injection of the ramp. The only chattering allowed in the signal is by the output contact, which has a reasonable bouncing time of less than 4 ms. If the start signal oscillates for more than 4 ms, the start activation will not be considered valid, and the ramp will continue with the next step. For other output media, no chattering at all will be present in the transition of the start signal, in order to be considered valid.

If the protection function does not start, the frequency ramp will continue until its end; the frequency value f_{initial} is applied for a minimum time duration of 1 s and a new ramp will be generated with a new frequency slope. The increment for the new frequency slope is:

(frequency rate of change accuracy / 10) Hz/s

To reduce the length of the test, the frequency increment can be higher at the beginning of the test, with the following rules:

– For the overfrequency function, this increment can be equal to G_{s} minus three times the declared frequency accuracy.
– For the underfrequency function, this increment can be equal to G_{s} plus three times the declared frequency accuracy.

The declared frequency rate of change accuracy is based on the procedures specified in 10.1.2.

Once the above value is reached, the increment of the rate of change of frequency will be less than or equal to 10 % of the declared frequency rate of change accuracy until the end of the ramps caused by the operation of the start signal.

At this point, the start value of the function has been determined, df/dt_start, and the sequence of ramps for determining the reset value will initiate.

10.2.2.2.1.3 Test to determine d*f*/d*t*_reset (see Figure 22 b)).

Each ramp of the sequence of ramps is actually formed by two ramps: a first ramp with a frequency slope of 1,2 × d*f*/d*t*_start, and a second ramp with a variable frequency slope. The first slope at 1,2 × d*f*/d*t*_start has a duration of:

$$\text{expected start time} \times 1{,}3$$

The ramp starts at frequency f_{initial}, with the recommended value to be the minimum value of the frequency effective range for positive ROCOF and the maximum value of the frequency effective range for negative ROCOF.

At the beginning of each ramp, frequency will be at f_{initial} at least for the duration of 1 s. If the duration of 1 s is not sufficient, the manufacturer will declare in the type test report the time duration to be used for this test.

Then, the frequency is changed in a linear way, away from its initial value. During this transition, the injected signal will be continuous, with no step change in its phase angle or magnitude, except in its frequency.

When this ramp ends, a new ramp begins. The transition between the first ramp and the second one will be 'smooth'. This means that the injected signal will be continuous, with no step change in its phase angle or magnitude, except in its frequency.

The second ramp has a duration of:

$$\text{MAX (1 000 ms; expected disengaging time} \times 5)$$

and a frequency slope of:

$$\mathrm{d}f/\mathrm{d}t = (\mathrm{d}f/\mathrm{d}t\_\text{previous}) - (\text{frequency rate of change accuracy} / 10)\ \text{Hz/s}$$

where d*f*/d*t*_previous is:

- d*f*/d*t*_start, if the ramp is the first shot of the sequence to determine the reset value d*f*/d*t*_reset (ramp R1);
- the frequency derivative of the previous ramp, if the ramp is not the first shot of the sequence to determine the reset value d*f*/d*t* _reset (ramp R2, R3, ...).

If, during this second ramp, the ROCOF function does not reset, at the end of the ramp a new set of frequency ramps is generated. The frequency value f_{initial} is applied for a minimum time duration of 1 s, followed by the first ramp to ensure a start and a second ramp with the new d*f*/d*t* value. If the function resets instead, the frequency derivative of the generated ramp is recorded as d*f*/d*t*_reset.

The reset of the start signal is considered valid if there is no chattering at all, regardless of whether the output media is a contact.

The reset ratio is calculated with the formula:

$$\text{reset ratio} = (\mathrm{d}f/\mathrm{d}t\_\text{reset} / \mathrm{d}f/\mathrm{d}t\_\text{start}) \times 100\ \%$$

If a minimum absolute reset hysteresis is declared, the reset hysteresis is calculated with the formula:

reset hysteresis = df/dt_start − df/dt_reset

10.2.2.2.2 Function settings

Start ROCOF settings will be varied in the setting range as shown in Table 15.

If some protection functions have a setting for the definition of the window length to measure the frequency, the setting value will be the default value, unless the manufacturer has a special recommendation for the window length as function of the ROCOF setting (G_s) that is tested. In this case, the manufacturer's recommendation will be followed.

The reset value is measured for the test points indicated in Table 15.

All test points are carried out at nominal voltage. In addition, the first test (0 % – min. setting) and the last test (100 % – max. setting) points are repeated at the maximum and the minimum voltage of the effective range. The results of the test points at minimum and maximum effective range of the voltage are documented in line with the other test points at nominal voltage.

Each test is repeated five times, and for each of the five tests, the result will be below the declared reset value according to relevant regulations and requirements.

Table 15 – Test points of reset value for ROCOF function

Test point value, X[a] %	**ROCOF setting (start threshold, G_s)[a]** Hz/s	**Voltage magnitude[b]**	**Test 1 result**	**Test 2 result**	**Test 3 result**	**Test 4 result**	**Test 5 result**	**Acceptance criteria**
0 (minimum)		min. U						≤ reset ratio (or hysteresis)
		max. U						≤ reset ratio (or hysteresis)
0		U_n						≤ reset ratio (or hysteresis)
5		U_n						≤ reset ratio (or hysteresis)
10		U_n						≤ reset ratio (or hysteresis)
30		U_n						≤ reset ratio (or hysteresis)
60		U_n						≤ reset ratio (or hysteresis)
100		U_n						≤ reset ratio (or hysteresis)
100		min. U						≤ reset ratio (or hysteresis)
100 (maximum)		max. U						≤ reset ratio (or hysteresis)

[a] Test points are expressed as a percentage to compute ROCOF settings (threshold G_s) according to the common rules defined in 10.1.

[b] U_n is the nominal voltage, and min. U and max. U are the minimum and maximum values of the declared voltage effective range.

10.2.2.2.3 Reporting of the reset value

The reset value for ROCOF functions is reported by the manufacturer with a reset ratio expressed as a percentage, with or without a minimum reset hysteresis, as per the example shown in Table 16.

Table 16 – Reporting of the reset value for ROCOF function

ROCOF protection reset value	
Reset ratio	98 %
(alternative solution) **Reset ratio with minimum reset hysteresis**	98 % or 40 mHz/s

10.2.3 Determination of the start time

10.2.3.1.1 Description of the generated waveform

The start time measurement is assessed using a test method based upon a constant frequency slope. The method is illustrated in Figure 23 (for positive ROCOF function). During the transition in the frequency change, the injected signal will be managed without discontinuity in the voltage waveform, except in its frequency.

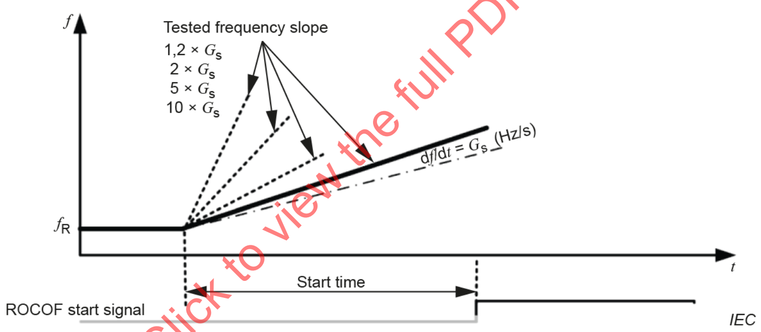


Figure 23 – Start time measurement of positive ROCOF function

Each test shot is determined by the test points defined in Table 17.

- The initial test frequency value is always equal to the tested nominal power frequency.
- The frequency is increased with different values of frequency slope, to measure the start time with different test conditions.
- The injection can be interrupted when the protection start signal operates.
- The start time measurement is initiated when the frequency variation starts and stops when the protection start signal operates.

The injected frequency will always be within the operating range of the protection function, if an operating frequency range is declared for the ROCOF function. This condition will be dependent on a limited duration of the frequency ramp to a certain extent. For higher ROCOF settings, if the injected frequency is outside the declared operating range before the start signal operation, the function cannot be tested for that setting based on the standardized test conditions. In that case, the manufacturer will declare this information and the appropriate test method to be used to measure the start time for these settings.

10.2.3.1.2 Function settings

Start ROCOF settings will be varied in the setting range as shown in Table 17.