EASY-RES

SUMMER SCHOOL
“ENABLING DRES TO OFFER ANCILLARY SERVICES”
20th – 24th SEPTEMBER 2021

BASICS OF GRID STABILITY AND DEFINITIONS

Prof. Charis Demoulias // 20-09-2021

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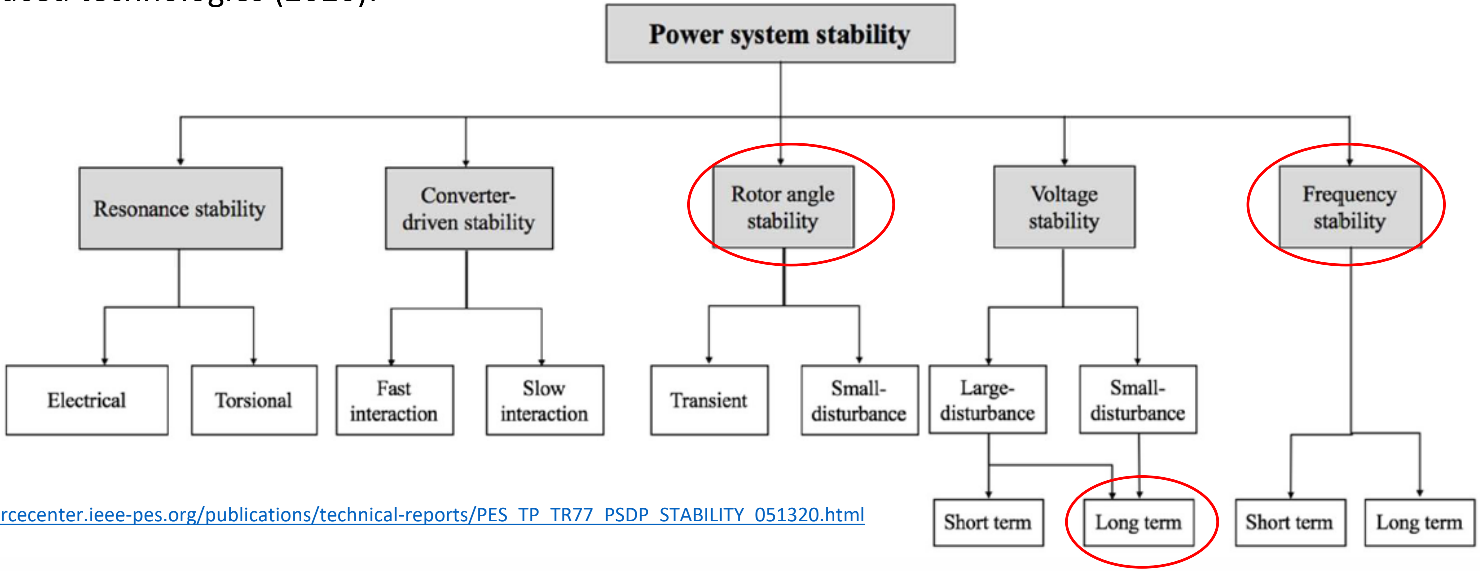
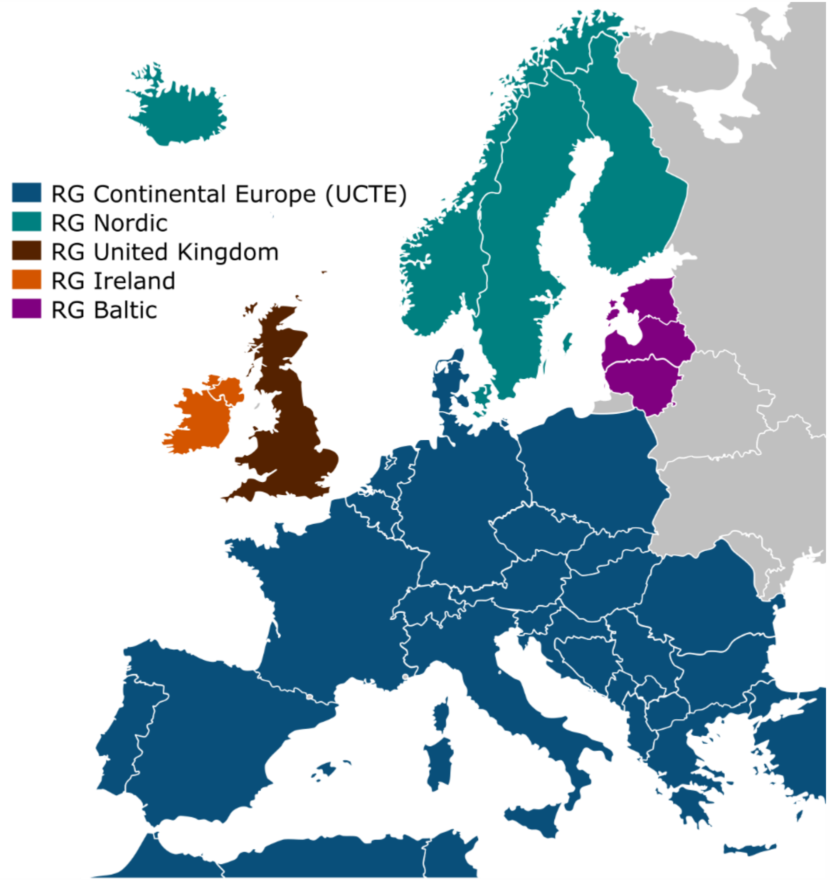
Contents

Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies (2020):



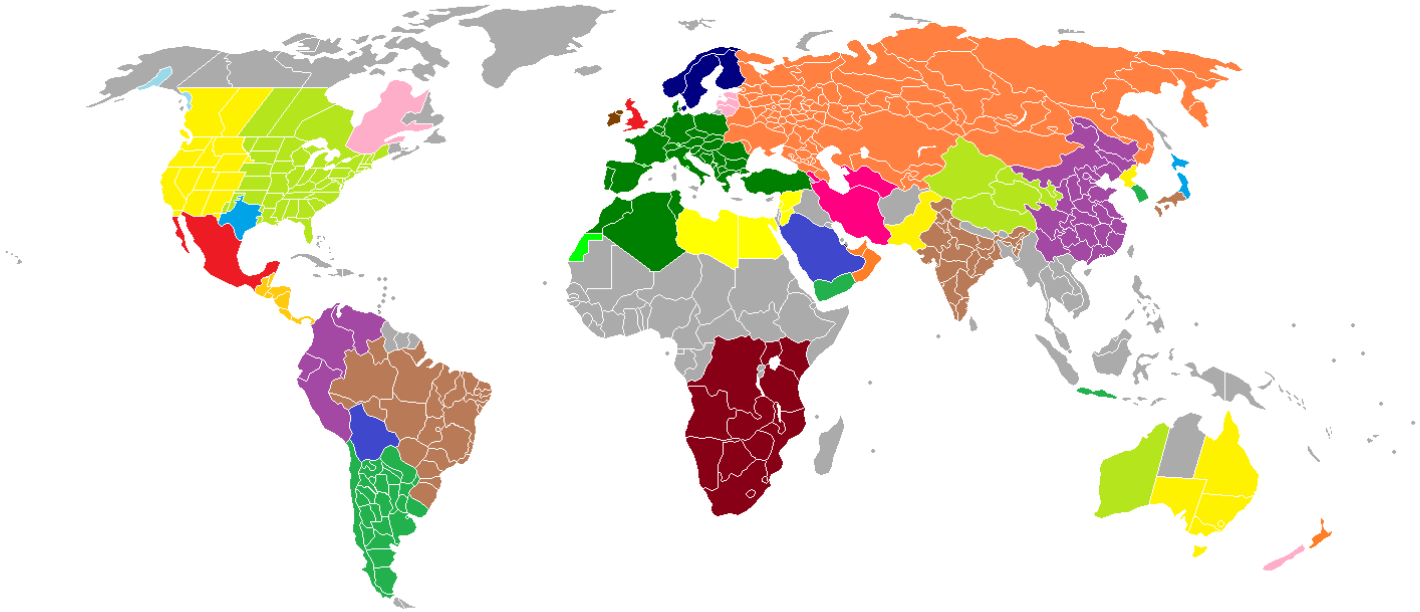
https://resourcecenter.ieee-pes.org/publications/technical-reports/PES_TP_TR77_PSDP_STABILITY_051320.html

- In EASY-RES to improve both **Voltage Stability** and **Frequency Stability** are considered as main objectives.
- Also **Rotor Angle Stability** can be improved by emulating inertia with CIGs
- An extensive work in converters lower level controllers is carried out to avoid Resonance and converter driven instabilities (Part 2).



Europe is divided in 5 synchronous zones.

Synchronous Zone definition: is a three-phase electric power grid that has regional scale or greater and operates at a synchronized utility frequency and is electrically tied together during normal system conditions.



Synchronous Zones in the world

Traditionally, the primary energy source (coal, hydro, nuclear, natural gas, etc) is converted into electricity via a particular type of rotating machine called synchronous.

The name is derived by the fact that the rotor rotates in synchronism with the magnetic field. This is equivalent to saying that the mechanical and electrical power are exactly the same.

Any mismatch between them leads to a change in the rotating speed of the rotor and eventually to the frequency.

This is described by the well known swing equation which, in its simplest form, is

$$J\frac{d\omega}{dt} = \tau_m - \tau_e$$

Where
J is the moment of inertia of the SG and its prime mover, in $kg \cdot m^2$
ω is the rotating speed of the rotor in rad/s
τ_m and τ_e are the instantaneous mechanical and electromagnetic torques respectively in $N \cdot m$

A common approach is to express the swing equation in per unit form and use powers instead of torques. Thus, using

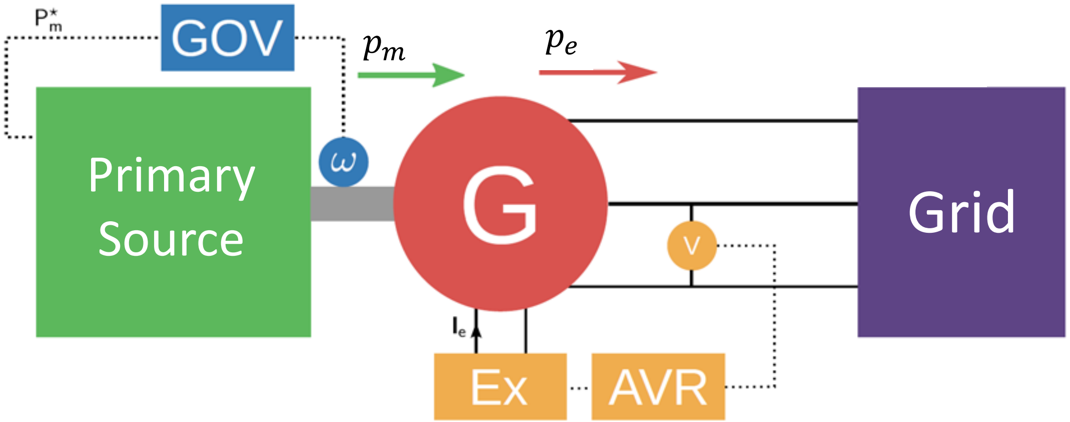
$$\omega = \Omega_b \cdot \omega^{pu}$$

$$p_m = \tau_m \cdot \omega, \quad p_m = S_b \cdot p_m^{pu}$$
$$p_e = \tau_e \cdot \omega, \quad p_e = S_b \cdot p_e^{pu}$$

S_b is the base power, usually the nominal power of the SG

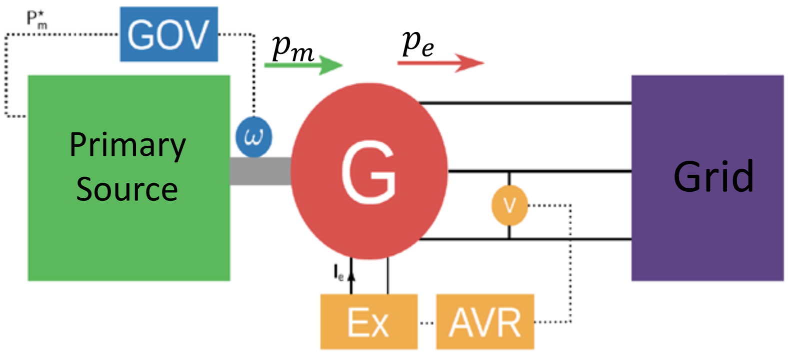
The swing equation can take the form of

$$J \frac{\Omega_b^2}{S_b} \frac{d\omega^{pu}}{dt} = p_m^{pu} - p_e^{pu}$$



In power systems, instead of using the moment of inertia we prefer the use of the Inertia Time Constant, H, defined by

$$H = \frac{\frac{1}{2}J\omega^2}{S_b}$$



The nominator is the kinetic energy stored in the rotating masses of the SG and its prime mover.
The inertia constant, expressed in seconds, practically indicates the time it takes a SG to release all its kinetic energy assuming that the energy is released at a constant rate equal to the SG nominal power.

Using the above definition the swing equation takes the following simple form

$$2 \cdot H \frac{d\omega^{pu}}{dt} = p_m^{pu} - p_e^{pu}$$ or equivalently

$$2 \cdot H \frac{df^{pu}}{dt} = p_m^{pu} - p_e^{pu}$$

An equivalent Inertia Time Constant, H_{eq}, can be defined for a whole synchronous zone based on the total kinetic energy stored in the rotors of all activated SGs,

$$H_{eq} \cdot \sum_{i} S_{b,i} = \sum_{i} H_i \cdot S_{b,i}$$

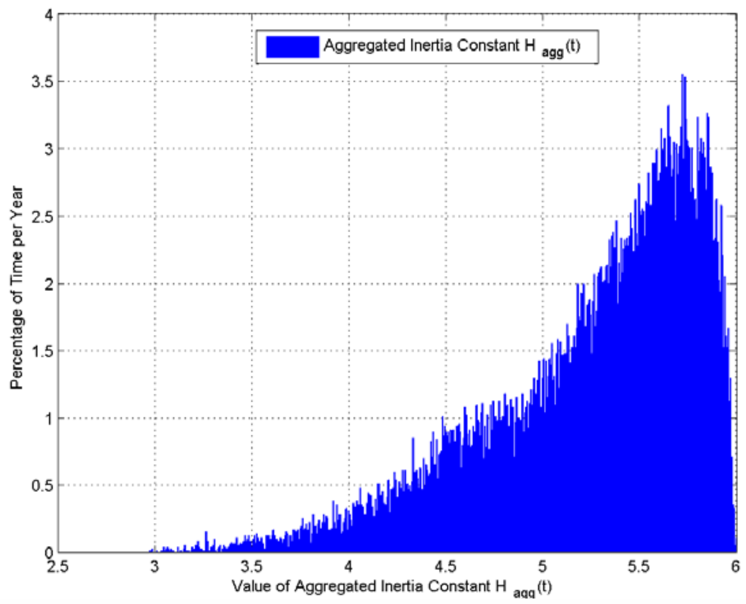
Thus the swing equation can, approximately, be used for the whole synchronous zone

$$2 \cdot H_{eq} \frac{df^{pu}}{dt} = p_m^{pu} - p_e^{pu}$$

Example: Suppose that, in a synchronous zone, the equivalent inertia constant is H_{eq}=5s. In case a sudden power mismatch of
$p_m^{pu} - p_e^{pu} = -0{,}1pu$
appears in the zone, the frequency will start dropping with a rate equal to
$\frac{df^{pu}}{dt} = \frac{-0{,}1}{2 \cdot 5} = -0{,}01\ pu/s$ or 0,5 Hz/s for a 50Hz system.

In case the inertia of the zone is reduced to H_{eq}=2s, then, for the same power mismatch the frequency would drop at a rate of 1,25 Hz/s.

It is evident that the inertia of the system determines the Rate of Change of the Frequency (ROCOF) for a given power mismatch.



Aggregated Rotational Inertia in German Power System (full-year 2012). Extracted from [1]

The equivalent or aggregated inertia in a power system changes as the number and power of SGs committed change.

As shown in the graph, the aggregated inertia may change from 5.7s to 3.5s during various periods in a year.

Therefore, **for the same power imbalance different ROCOFs may be encountered**.

The dotted lines represent the different ROCOFs as function of the total kinetic energy of the system.

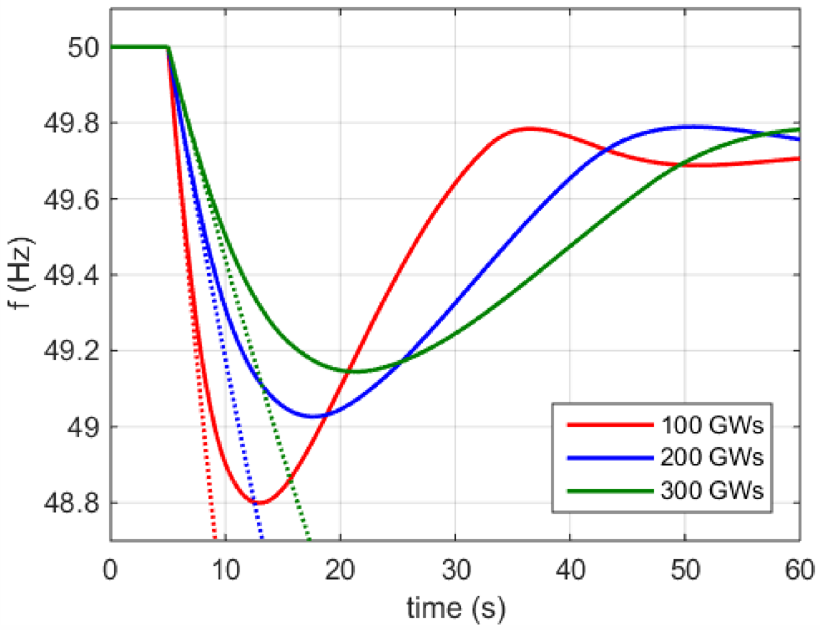


Figure extracted from [2].

Therefore, for the same power imbalance different ROCOFs may be encountered.

High RoCoF level means large transient displacements of voltage angles in different zones of the grid that induce pole slipping on synchronous machines and network splitting, possibly causing distance protection tripping.
Thus conventional generators employee protection relays against high ROCOF.
Also, in many distribution grids, high ROCOF is used a method for Loss of Mains detection and subsequent disconnection of distributed generation. A cascaded disconnection may eventually **lead to black out**.
For this reason ROCOF should be restricted.
However, the increasing DRES penetration displaces conventional SGs, thereby reduces the system inertia and increases the expected ROCOF!

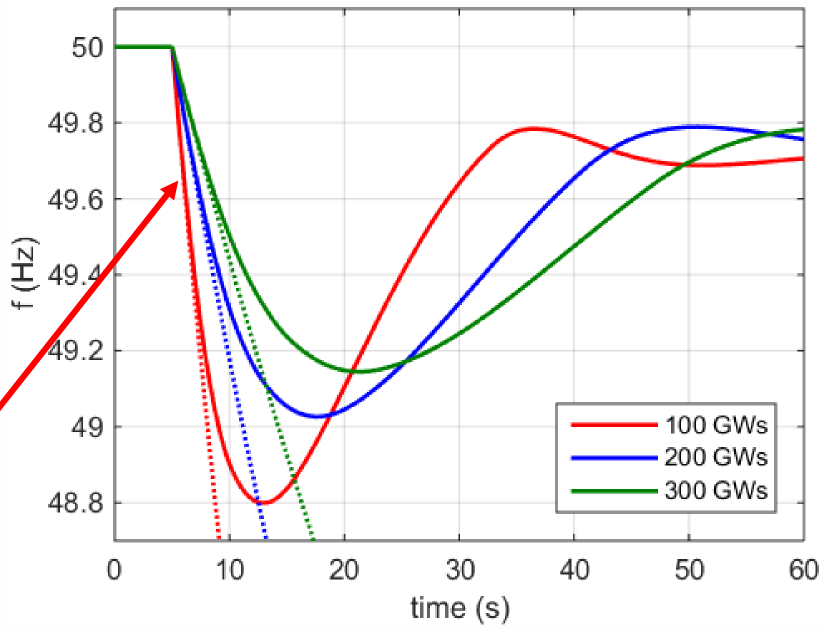
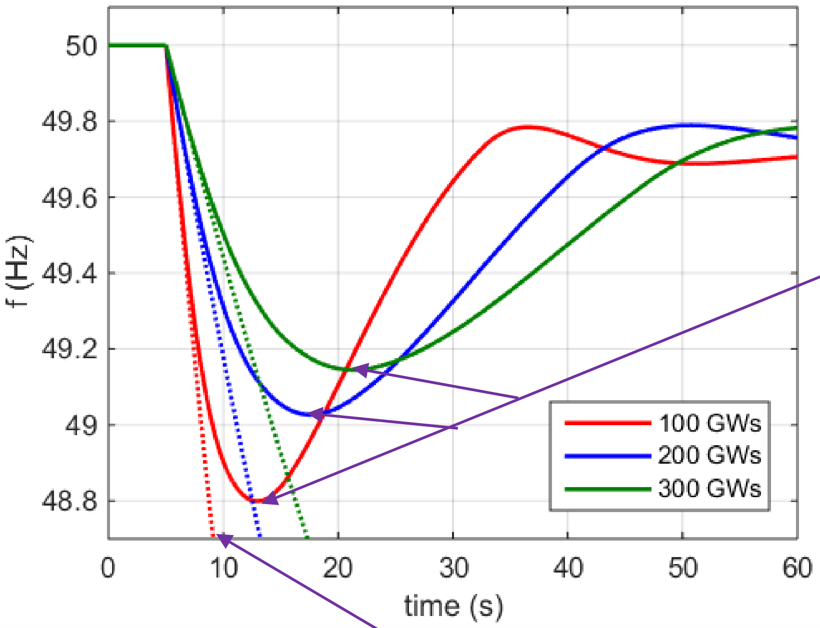


Figure extracted from [2]



How is then frequency **contained**?

The frequency is contained through the action of a number of power plants operating in Frequency Sensitive Mode (FSM).

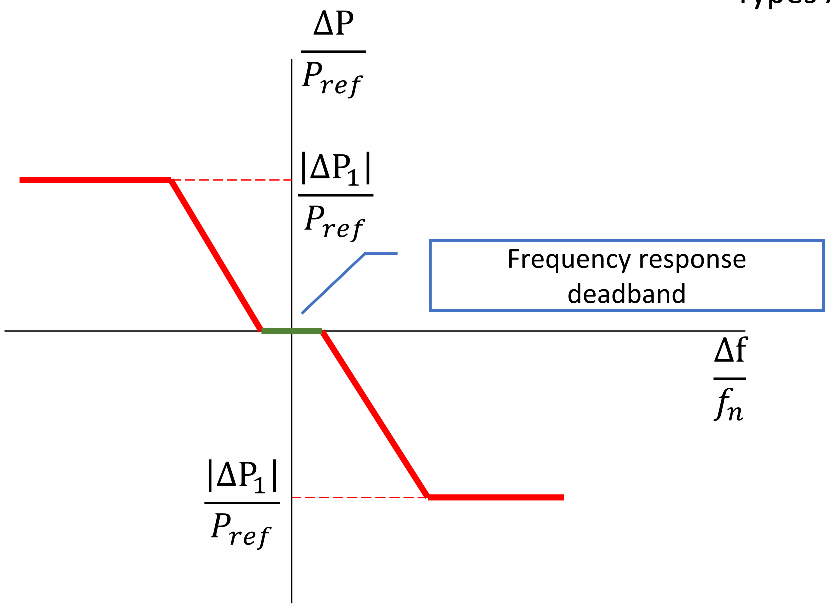
They are called Frequency Containment Reserves (FCR) and the action is called Primary Frequency Regulation.

In case of a power imbalance, the inertia alone cannot prevent the frequency from falling (or increasing).

Table 1. Power Generating Modules according to [3]

	P_{max}			
Synchronous Area	**Type A (power in kW)**	**Type B (power in MW)**	**Type C (power in MW)**	**Type D (power in MW)**
Continental Europe	$0.8 \leq P_{max} < 1000$	$1.0 \leq P_{max} < 50$	$50 \leq P_{max} < 75$	$75 \leq P_{max}$
Nordic	$0.8 \leq P_{max} < 1500$	$1.5 \leq P_{max} < 10$	$10 \leq P_{max} < 30$	$30 \leq P_{max}$
Great Britain	$0.8 \leq P_{max} < 1000$	$1.0 \leq P_{max} < 10$	$10 \leq P_{max} < 30$	$30 \leq P_{max}$
Ireland	$0.8 \leq P_{max} < 100$	$0.1 \leq P_{max} < 5$	$5 \leq P_{max} < 10$	$10 \leq P_{max}$
Baltic	$0.8 \leq P_{max} < 500$	$0.5 \leq P_{max} < 10$	$10 \leq P_{max} < 15$	$15 \leq P_{max}$

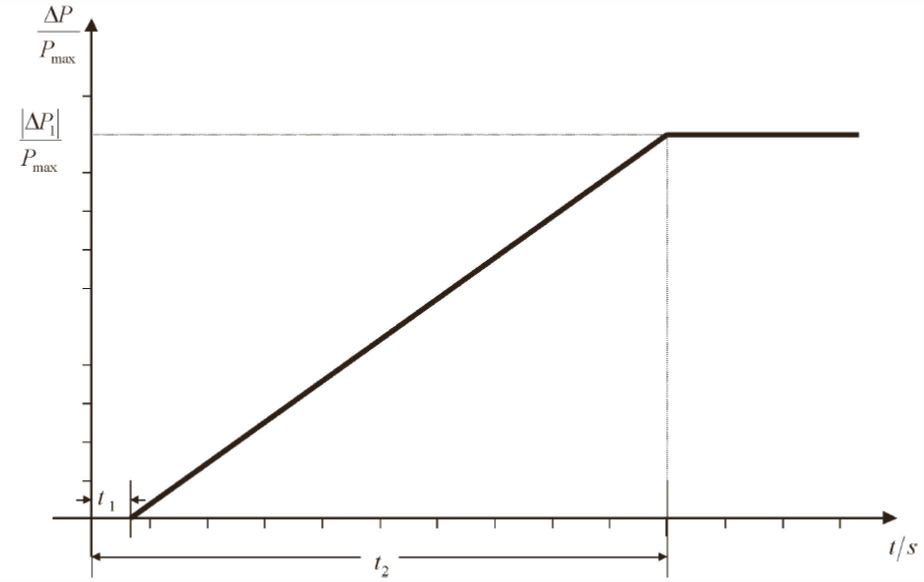
A Power Plant operating in Frequency Sensitive Mode (FSM) follows a Power-Frequency droop.
According to [3], the power plants that are required to operate in both FSM-U an FSM-O belong to the Types C and D.
Types A and B are required to participate only in FSM-O.



Specifications set in [3]:

- P_{ref} is the maximum power capacity of Synchronous Power Generating Modules
- P_{ref} is the actual active power at the moment the FSM threshold is reached for Power Park Modules.
- $\frac{|\Delta P_1|}{P_{ref}} \leq 1.5 - 10\%$
- Frequency response insensitivity: 10-30 mHz
- Frequency response deadband: 0-500 mHz
- Droop $s_1(\%) = 100\,\frac{\Delta f}{f_n} \cdot \frac{P_{ref}}{|\Delta P|} = 2 - 12\%$

For generating modules operating in FSM and in case of a frequency step change the following specifications also apply:



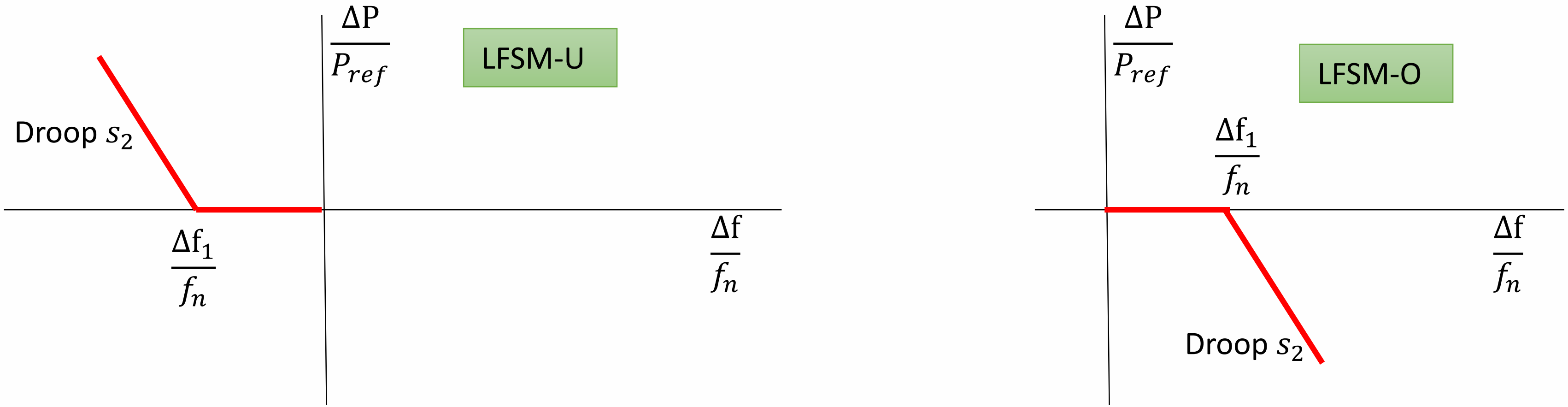
- For power-generating modules with inertia, the maximum admissible initial delay t_1 is 2s.
- For power−generating modules without inertia, the maximum admissible initial delay t_1 is specified by the relavant TSO.
- Maximum admissible choice of full activation time t_2 is 30s.

As an example, in the synchronous area of Continental Europe, the total power of FCR is $\pm 3000\ MW$ i.e. equal to the reference incidence (loss of a large nuclear power plant in France). Those power plants should deploy all their available power when the frequency deviates $\pm 0{,}2 Hz$ $(49{,}8 - 50{,}2\ Hz)$ [4].

The action of the total FCR in continental Europe can be seen in the video captured on 03/09/2021.

The video shows the frequency deviation during normal system operation and the power ups and downs required every second to maintain the frequency within $50\ Hz \pm 10 mHz$.

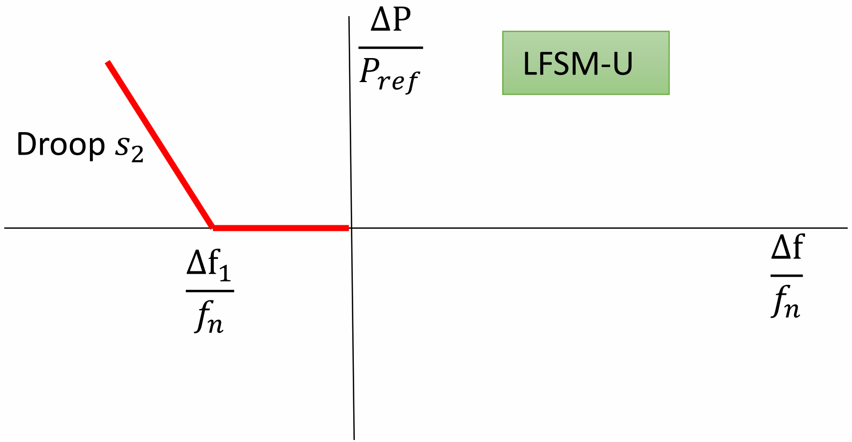
In case the frequency deviates more than $\pm 0{,}2Hz$ $(49{,}8 - 50{,}2\ Hz)$ due to a major active power imbalance, the next "defense line" is the automatic activation of FCRs operating in Limited Frequency Sensitive Mode (LFSM), either for overfrequency events (LFSM-O) or underfrequency events (LFSM-U).

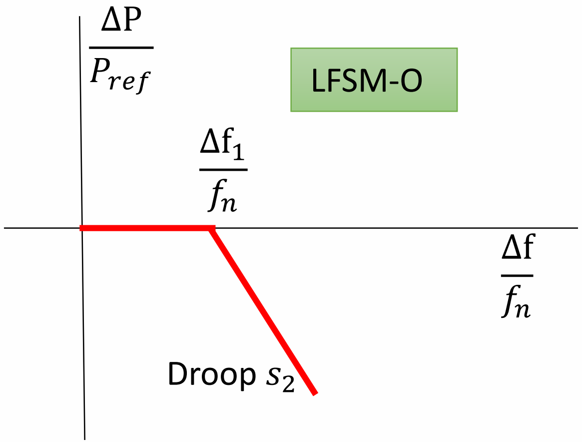


Mandatory only for Types C and D of generating modules [4]

$$s_2(\%) = 100\frac{|\Delta f| - |\Delta f_1|}{f_n} \cdot \frac{P_{ref}}{|\Delta P|} = 2 - 12\%$$

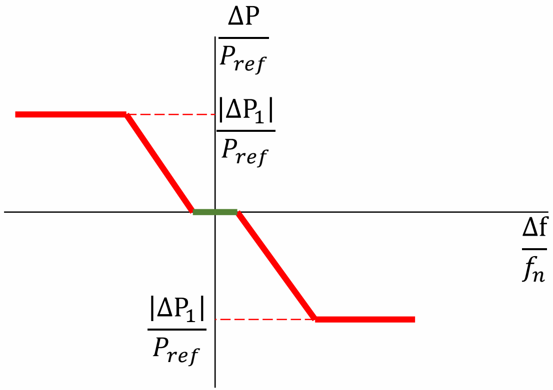
Mandatory for all types of generating modules [4]





LFSM-U is to be activated, after a severe disturbance, which has resulted in a major generation shortfall and the frequency deviation cannot be mitigated by the FCR resources only.
In such cases FCR resources are fully deployed, but system frequency cannot be stabilized and decreases further. The slow activation of FCR resources (due to high RoCoF) can also contribute to low frequencies.
The active power increase of all generating modules **type C and D** shall support stabilizing the system at a frequency **> 49.0 Hz** after FCR has been exhaustively deployed and **before load shedding is activated**.
In case of LFSM-U activation and decreasing frequency the power generating modules shall continuously increase the active power towards to the highest achievable output (taking into account a reduced maximum capacity at low frequencies, if applicable) at that moment according to the selected droop.

LFSM-O is to be activated, when the system is in an emergency state after a severe disturbance, which has resulted in a major generation surplus and the frequency deviation cannot be mitigated by the FCR resources only.
In such cases FCR resources are fully deployed, but system frequency cannot be stabilized and increases further. The slow activation of FCR resources (due to high RoCoF) can also contribute to high frequencies.
The active power decrease of all power generation modules according the LFSM-O specifications shall support stabilizing the system at a frequency **< 51.5 Hz** after FCR has been exhaustively deployed to avoid a system collapse and gain time for further operational measures for frequency reduction.
In case of LFSM-O activation and increasing frequency power generating modules shall continuously decrease the active power towards the minimum regulating level according to the selected droop.

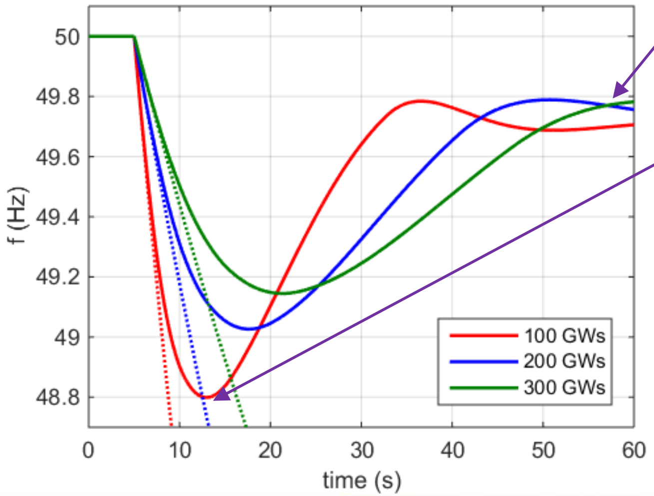


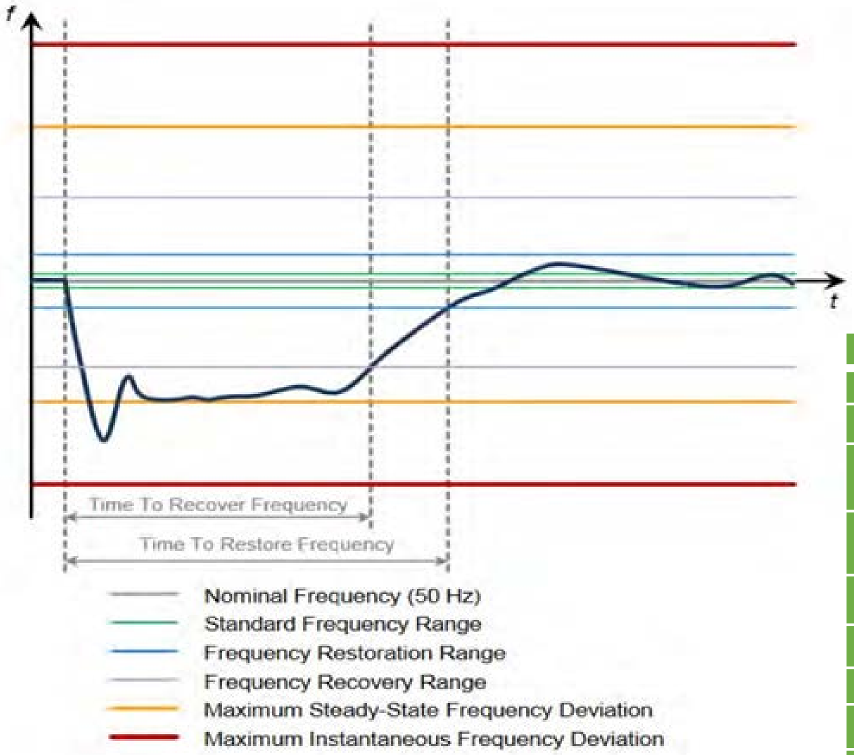
FCRs act through their governors and change their active power according to the droop. The goal is to arrest the frequency deviation within the specified limits.

The response time of the governors, the ROCOF, and the magnitude of the power imbalance determine the:

New settling frequency

Frequency nadir





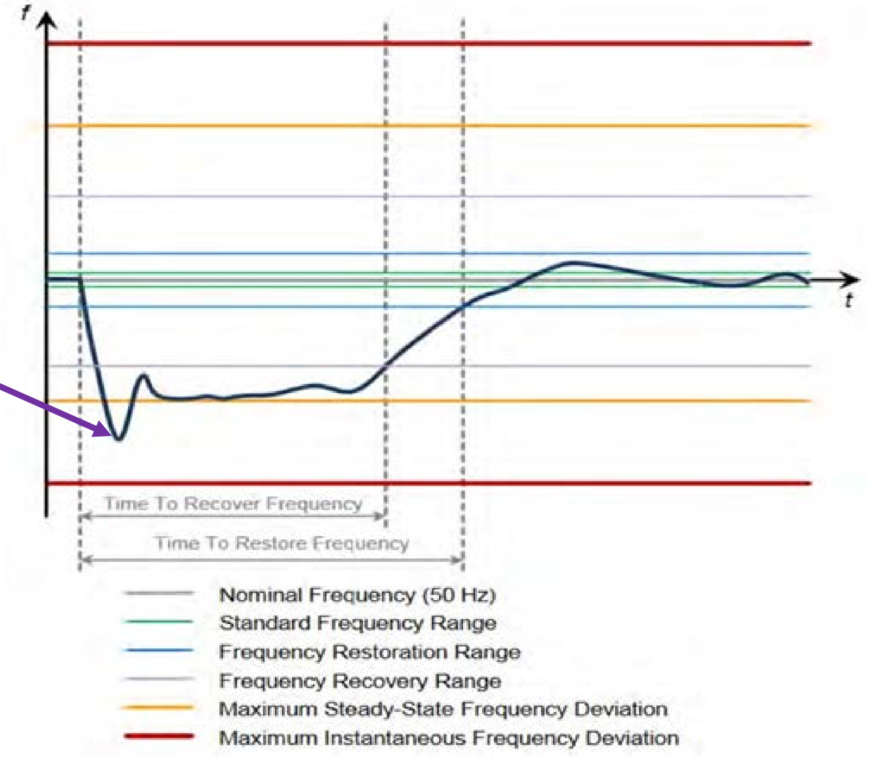
To ensure the frequency stability of the synchronous zone, ENTSO-E (and all other similar TSO unions worldwide) specify some quality criteria for the frequency response under a major reference incidence. The major incidence in Continental Europe (CE) is the sudden loss of 3000MW of generating plants.
The quality of frequency response is specified by a number of parameters shown in the figure and presented in Table 2.

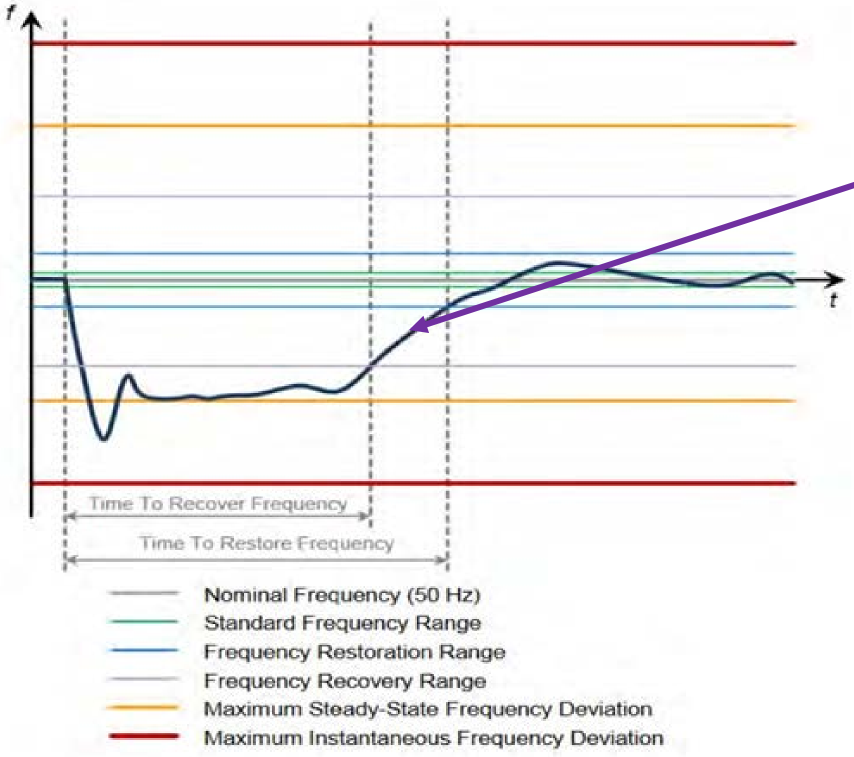
Table 2. Parameters for quality of frequency response in Europe

	CE	GB	IRE	NE
Standard Frequency Range	±50 mHz	±200 mHz	±200 mHz	±100 mHz
Maximum Instantaneous Frequency Deviation	800 mHz	800 mHz	1000 mHz	1000 mHz
Maximum Steady-state Frequency Deviation	200 mHz	500 mHz	500 mHz	500 mHz
Time to Recover Frequency	not used	1 minute	1 minute	not used
Frequency Recovery Range	not used	±500 mHz	±500 mHz	not used
Time to Restore Frequency	15 minutes	10 minutes	20 minutes	15 minutes
Frequency Restoration Range	not used	±200 mHz	±200 mHz	±100 mHz
Alert State Trigger Time	5 minutes	10 minutes	10 minutes	5 minutes

In case the frequency nadir (49,2 Hz in CE and GB, 49,5 Hz in the other European zones) is exceeded, emergency mechanisms like Underfrequency Load Shedding is activated in order to prevent the system blackout.

The FCR are designed and controlled in each synchronous area, so that, in the case of the reference incident, the frequency is stabilized within the Maximum Steady-State Frequency Deviation (yellow lines, 49,8-50,2 Hz in CE).

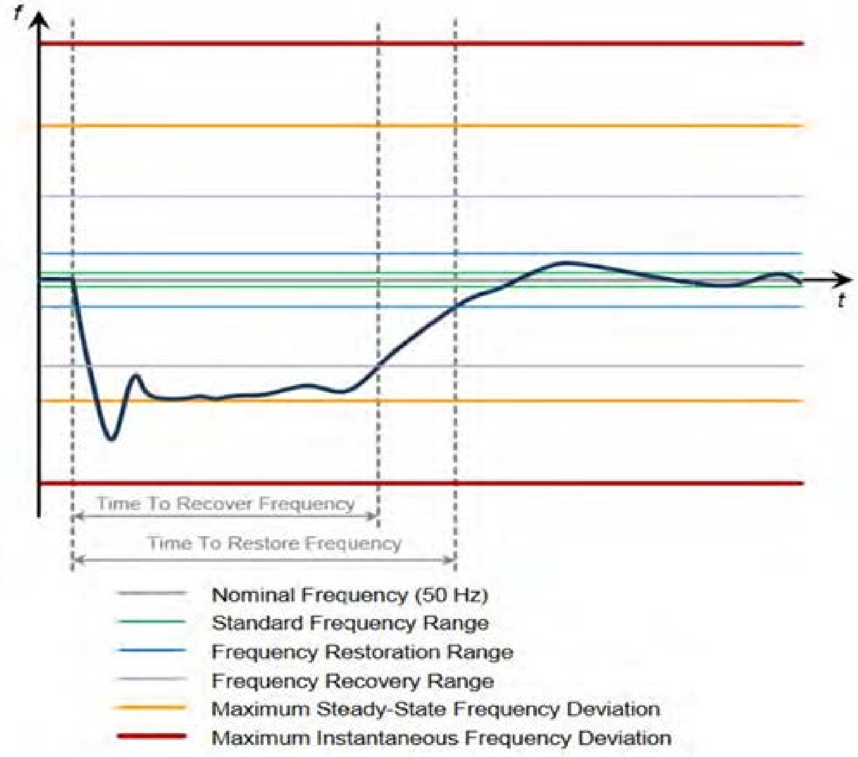




The restoration of the frequency back to the Frequency Restoration Range is made through the action of the so-called Frequency Restoration Reserves (FRR). This action was also called Secondary Frequency Regulation.

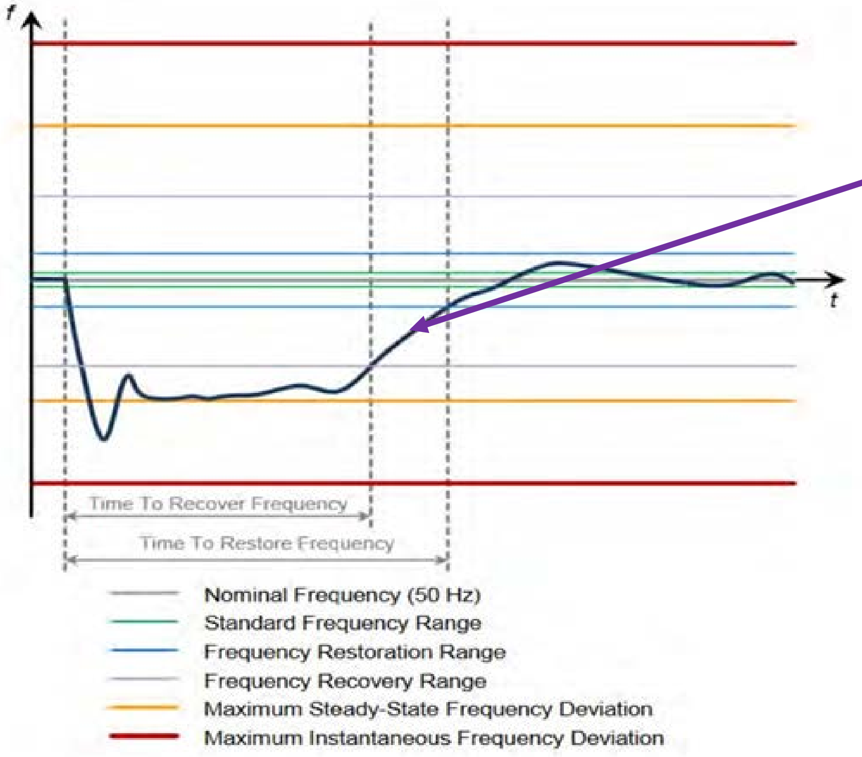
Contrary to FCR, the FRR are activated only within the area/block in a synchronous zone where the major imbalance occurred.
Their activation takes place when the frequency deviation lasts longer than 30s and they should be able to provide (or reduce in case of over-frequencies) the required power within 15min after their activation.
Actually, the role of FRR is to bring the Area Control Error (ACE_i) in the i^{th} area to zero.

$$ACE_i = \sum_j \Delta P_{i,j} + \beta_i \cdot \Delta f$$



$$\boxed{ACE_i = \sum_j \Delta P_{i,j} + \beta_i \cdot \Delta f} \quad [5]$$

$\mathbf{\Delta P_{i,j}}$ is the power interchanged between areas i and j.
$\boldsymbol{\beta_i}$ is the frequency polarization coefficient of the area-actually it is a function of the combined droop characteristics of the area FCR plus the load sensitivity in frequency for area i.



FRR is distinguished in automatic (aFRR) and manually (mFRR) activated. The mixture of aFRR/mFRR is determined by each TSO for his control area/block so that the frequency quality criteria are fulfilled.

After a major frequency event, the FRR not only restores the frequency within the restoration range but also restores the FCR that have exhausted and finally restores the cross-border power flows of the relevant control area to its pre-fault values.
This is depicted in the two terms of the ACE.

$$ACE_i = \sum_j \Delta P_{i,j} + \beta_i \cdot \Delta f$$

During steady-state operation within a synchronous area, Δf is practically zero. Therefore, the ACE (thereby the FRR) has to do with the restoration of the power interchanges among areas to predefined and agreed values.

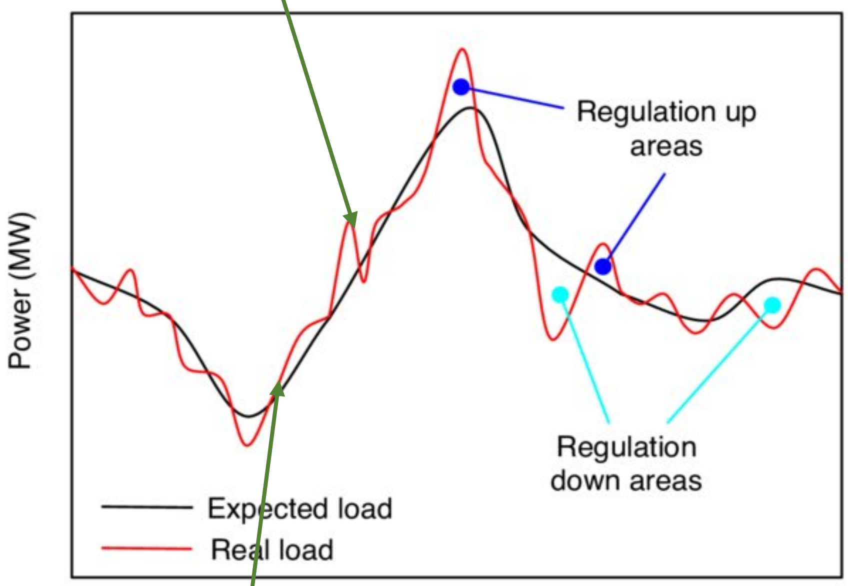
The power interchanges deviate due to errors in forecasting of

- Load
- Power generated by RES

and also by probable faults like loss of a local generating unit, or of a tie line.

$$\boxed{ACE_i = \sum_j \Delta P_{i,j} + \cancel{\beta_i \cdot \Delta f}}$$

aFRR is used to deal with the fast variations in the scheduled load/generation

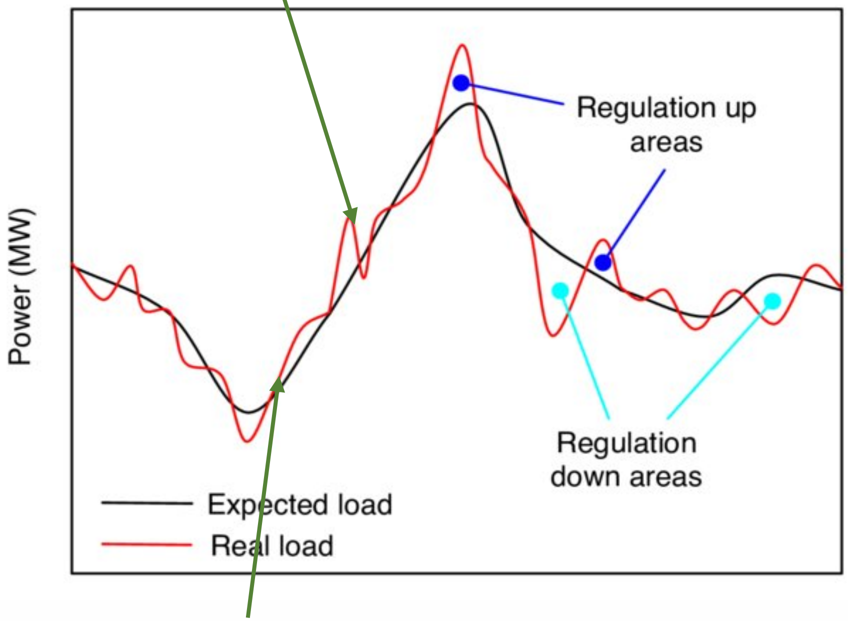


mFRR is used to deal with the slower variations in the scheduled load/generation

Some TSOs use the mFRR also for restoration of the aFRR.

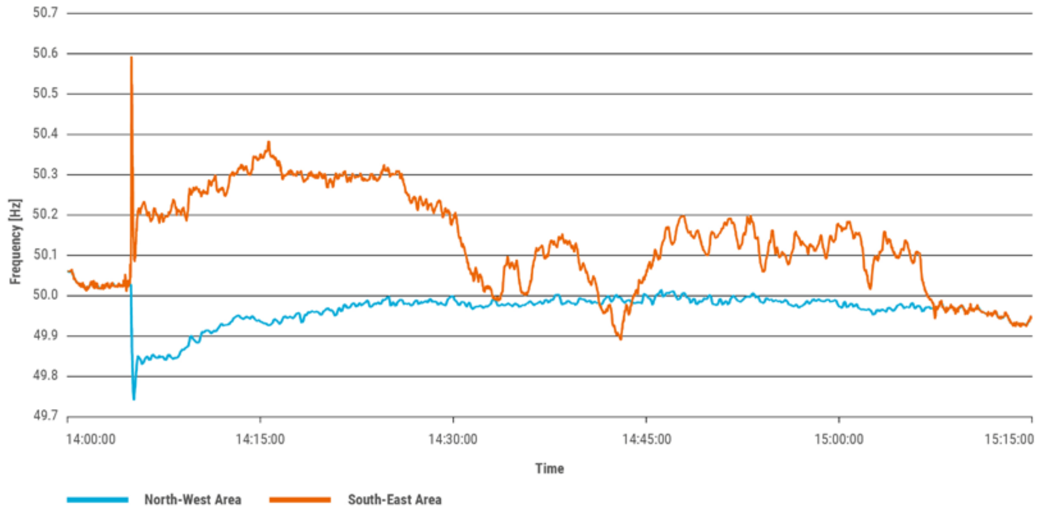
Other TSOs use the **Replacement Reserves (RR)** to restore the FRR.
RRs are also used as α means to redispatch the generation in an optimized way.

aFRR is used to deal with the fast variations in the scheduled load/generation



mFRR is used to deal with the slower variations in the scheduled load/generation

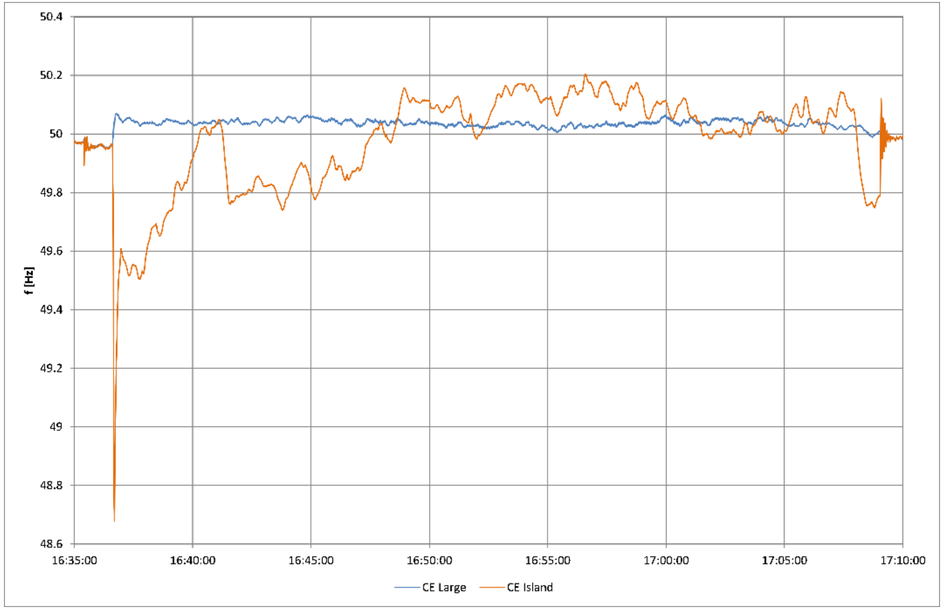
Example 1 of major frequency deviation.

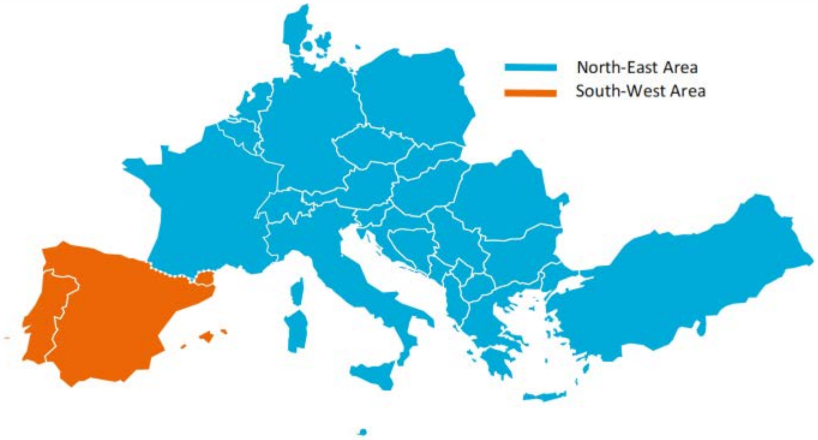


Frequency deviations after the incident in a 400kV substation in Croatia on 08/01/2021. The CE zone was split into sub-zones before resynchronization. A power imbalance of $\pm 6{,}3\ GW$ was observed the two zones. Power surplus in the South East are led to overfrequency. Power deficit in the North-West area led to underfrequency.

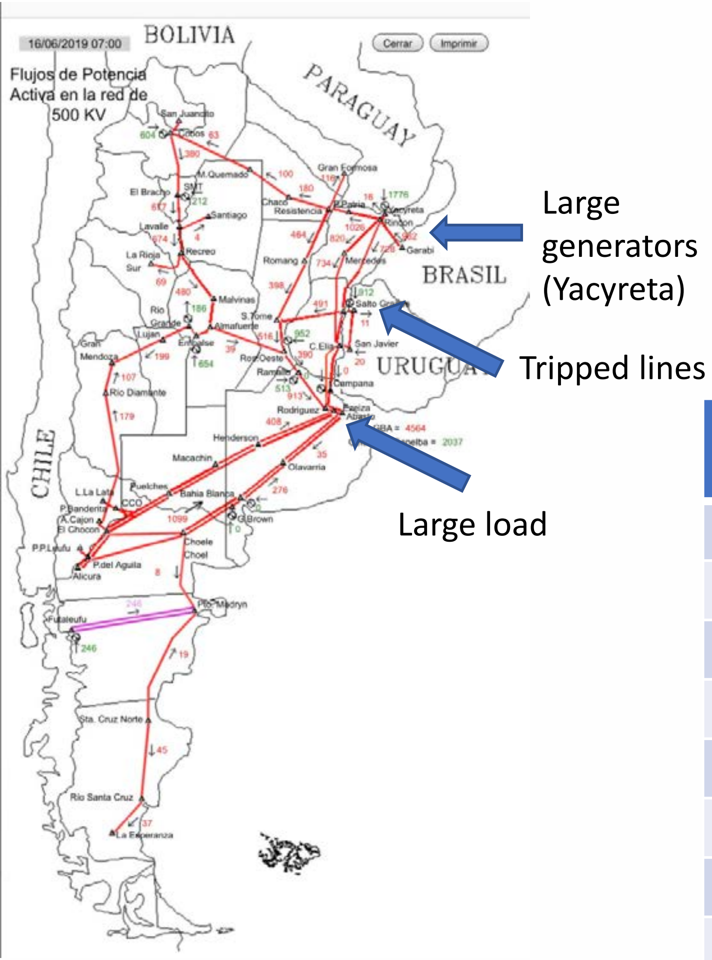
FCR were activated in both sides to restore the frequency. FCR were followed by load shedding in the NW area and by switching off of generation in SE area.

Example 2 of major frequency deviation.





Frequency deviations after the incident close to the Spain-France border on 24/07/2021. The CE zone was split into sub-zones before resynchronization. A deficit of 2,5GW was observed in Iberian peninsula leading to a drop in frequency to 48,65Hz.
As this was below the permissible nadir, load shedding was employed to arrest the frequency.
The North-East area experienced an overfrequency of small magnitude.



One of the largest frequency collapses in history (13 GW).

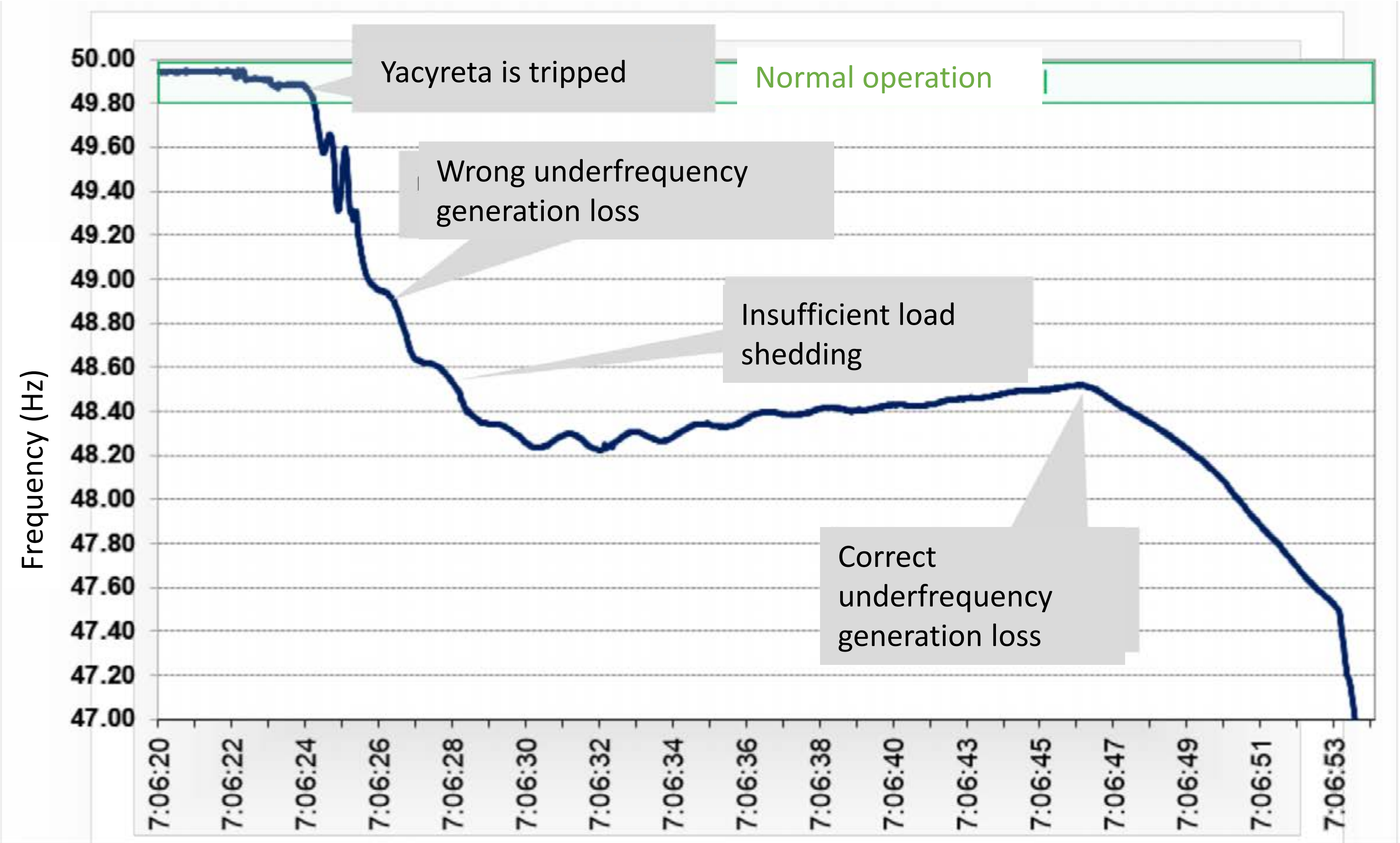
Failure in the Automatic Generation Disconnection (Yacyreta)

Cascaded trip of supporting generators

Insufficient load shedding

Take from 7 am to 9:30 pm to recover the system.

Year	Zone	Load shedding (MW)	People affected (Millons)	Restoration time
1977	New York	6000	9	26h
1982	West Coast USA	12000	5	
1996	West Coast USA	12000	2	
1996	West Coast USA	28000	7	9h
2003	Northeast USA	62000	50	3 days
2003	Italy	24000	57	24h
2009	Brazil	25000		8 days
2012	India	30000	350	21h


Yacyreta is tripped
Normal operation
Wrong underfrequency generation loss
Insufficient load shedding
Correct underfrequency generation loss
Frequency (Hz)
50.00
49.80
49.60
49.40
49.20
49.00
48.80
48.60
48.40
48.20
48.00
47.80
47.60
47.40
47.20
47.00
7:06:20
7:06:22
7:06:24
7:06:26
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7:06:43
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7:06:51
7:06:53

Summary and discussion

Maintaining Frequency stability is a delicate and complex action and is present every single moment.

- Firstly it relies on the system inertia in order to limit the ROCOF and indirectly provide some time (ms to one second) to the governors of FCR to start acting. Currently, inertia is provided inherently by the rotating masses of SGs of large conventional power plants.
- Secondly, the FCR which operate in FSM adjust their power to mitigate the power imbalance. Currently, most of the FCR are also SGs driven by conventional power plants. This is the case, not only for historical reasons, but also because a certain power headroom can be set to conventional power plants in order to deal with underfrequency events.
- Thirdly, the FRRs restore the frequency to the normal value, re-establish the power interchanges in neighbouring areas and restore the exhausted FCRs. Again, FRRs currently consist of conventional power plants because their power can be accurately set and measured.
- Finally, the RRs restore the FRRs and optimize the power flow in an area. Also RRs currently consist of conventional power plants because their power can be accurately set and measured.

Summary and discussion

Inertia is a vital service but it is not treated as an Ancillary Service (it is not remunerated) since it is provided inherently.
The FCR, FRR and RR are treated as AS in the transmission system. They are traded daily in the respective AS markets of each country.

As the DRES penetration increases, theoretically the conventional power plants should be decommissioned in proportion.

However, this is not happening!

The reason is that the AS associated with the SGs are still needed to maintain the grid stability which is further jeopardised by the intermittent nature of the wind and solar power plants.

Summary and discussion

In this summer school a solution this problem is presented.
Firstly, a method for making the DRES exhibit functionalities like the SGs:

1. provide true inertia,
2. act as FCR,
3. smooth the electric power,
4. exchange reactive power,
5. inject controllable currents during faults and
6. act as harmonic filters

is presented.

Secondly, methodologies for aggregating those services in the distribution grid are presented. In this way, a whole active distribution grid can be represented as a Virtual Power Plant able to offer controllable inertia and act as FCR.

Finally, some of the above functionalities can be used as AS within the distribution grids in future relevant local markets. This is feasible since the methods for their measurement and quantification have been developed.

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Thank you!

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