Task Force Overfrequency Control Schemes - Recommendations for the Synchronous Area of Continental Europe

- Final -

RG-CE System Protection & Dynamics Sub Group

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Table of Contents

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1. Introduction

The SPD Task Force Overfrequency Control Schemes (OFCS) only deals with the dynamic aspects related to LFSM-O (Limited Frequency Sensitive Mode Over-frequency) for generators, which are not covered by the activities of the other SPD task forces related to system operation:

- Codes TF
- Critical Fault Clearing Time (CFCT)
- Dynamic Security Analysis (DSA)

The current document mainly addresses generator response and does not deal with HVDC requirements.[1]

Substantial OFCS analysis, calculations and recommendations were performed within previous SPD activities /1-3/. In these reports, details with respect to underfrequency load shedding /2/, impact of dispersed generation /1/ and power system inertia /3/ issues were addressed which all have a strong link to the power system overfrequency response.

The Task Force “scanned” different codes with respect to dynamic issues, namely:

a. Guideline for System Operation
b. Requirement for Generators
c. Demand Connection Code
d. Emergency and Restoration Code
e. HVDC Code

In the European Network Codes, like in RfG code, the OFCS is refered to as LFSM-O (Limited Frequency Sensitive Mode Over-frequency) for generators. This limited frequency sensitive mode is required for all units covered by the code (from type A to D). The objective of this control is not to control the frequency during normal operation. It is instead intended to ensure the system stability when the system is at risk. This is the reason for the large deadband of this control (between 200 mHz and 500 mHz). In the Continental European area, the primary frequency control is performed in such a way that a 200 mHz deviation of frequency leads to a full activation of the FCR (primary control).

Therefore, if the frequency deviation exceeds 200 mHz, there will be no additional participation of units that provide FCR to the system. If the event that leds to this frequency deviation is bigger than the total FCR capacity (3 GW) of the synchronous area, an additional control needs to be deployed to back up the FCR, and this is where OFCS in general and LFSM-O for generators in particular take effect.

The response times for active power increase and active power reduction of different technologies for power system generation are quite different. This is based either on the required time for opening or closing valves for steam, water, fuel or the physical processes behind resulting in challenges for pressure control or thermal limits for power plant material. The achieveable reaction times are relatively slow. This is the case for all conventional generation which is synchronously connected to the grid. On the other hand, these units are providing inertia. New renewable generation units as e.g. power electronic connected PV generation do not provide inertia, but can rapidly change their operation point and, therefore, contribute in principle very fast by compensating the power deficit or surplus.

[1] The DCC requires "Demand response in form of a very fast active power control" which shall be activated within 2 seconds. This is mainly intended for under frequency control, but batteries and electrical boilers could operate as "dump loads" in the over frequency range. However, this subject is not covered in this report.

The tasks shall be shared between the technologies: Whereas synchronous generating modules are unable to provide very fast LFSM-O, they provide inertia. On the other hand, inverter based generation is able to deliver fast LFSM-O, but not inertia.

The shortest power reduction times (reduction of active power infeed by 50 % of the rated power) that seem feasible today, are approximately 1 s for PV, around 2 s for wind and about 8 s for large synchronously connected conventional power generation units (subject to further clarification and stakeholder discussion).

2. System Stability Control – System Protection Schemes

The overfrequency control scheme for each individual generation unit is an integral part of the system-wide system protection scheme. Therefore, it will have to follow a few principles such as selectivity, correct reaction to the rate of changes of the frequency, and coordinated behavior with all other generation within the region and the overall synchronous area. Only by following these principles, subsequent negative dynamic effects during system-wide overfrequnecy situations can be avoided.

One crucial point is that a local frequency measurement at the level of a generation unit might differ a lot with respect to its quality and robustness. It has to be considered that small units (LV, MV connected) are usually not equipped with accurate frequency measurements. The exact requirements for accurate and detailed frequency measurement are beyond the target of this document. However, this subject will have to be addressed more specifically in future activities.

3. Challenge due to New Generation Sources Changes

In the past, when a very low percentage of distributed connected power generation was included in the dedicated disconnection scheme, it was arranged that each such generation unit shall disconnect from the system outside of a very narrow frequency range around rated frequency in order to avoid uncontrolled islanding with uncontrolled infeed etc. Today, as the distributed generation infeed is already significant and contributes in several areas and under favourable infeed conditions with an important amount of active power, the related disconnection settings will have to be coordinated with those of the conventional power plants and the overall system protection. Therefore, a contribution of the new generation units for selective and coordinated power infeed increase or reduction is urgently required.

Due to the fact that all generation connected to the grid via power electronics (non-synchronous generation) do not contribute to system inertia, the rate of change of the frequency (ROCOF) of the synchronous area will increase and, therefore, a faster response in overfrequency condition is required.

When RoCoF increases, measuring the frequency gets more and more challenging. By definition, the frequency is only defined for a stationary signal. However, when the frequency of a signal has to be evaluated in a short time window some “tricks” must be used. Different methods exist to extract the frequency of a time limited signal, but they all make assumptions on the signal, and with higher RoCoF these methods might need to be adapted. Several working groups in CIGRE, IEC, CENELEC are currently investigating this.

4. Critical Parameter Impact

To set up the Overfrequency Control Schemes the following approach is recommended.

In a first step, the possible maximum active power imbalances $\Delta P_{\mathrm{imbalance,max}}$ of a potential over-frequency island has to be analysed for all relevant scenarios. $\Delta P_{\mathrm{imbalance,max}}$ typically corresponds to the active power import over the AC-network of the potential over-frequency island before a system split. Thus, the maximum reduction of active power generation based on LFSM–O $\Delta P_{\mathrm{LFSM-O,max}}$ has to be at least equal to $\Delta P_{\mathrm{imbalance,max}}$

to be able to balance the generation surplus after the system split. In reality, the self-regulating effect of loads reduces the required amount of $\Delta P_{\mathrm{LFSM-O}}$, but this can be seen as safety margin. According to formula 1, $\Delta P_{\mathrm{LFSM-O,max}}$ depends on the droop s of the active power control as well as on $\Delta f_{\mathrm{LFSM\text{-}O,max}}$.

$$\Delta P_{LFSM-O,max} = \frac{100\%}{s} * \Delta f_{LFSM-O,max} \tag{1}$$

Due to the fact that $\Delta f_{\mathrm{LFSM\text{-}O,max}}$ depends on the frequency threshold $f_{\mathrm{threshold}}$ (between 50.2 and 50.5 Hz [NC RfG]) which defines the starting point of LFSM–O (formula 2), the required droop s varies for different values of $f_{\mathrm{threshold}}$. Typical values for the droop in power-frequency controllers are values not less than 5 %.

$$\Delta f_{LFSM-O,max} = 51.5\ Hz - f_{threshold} \tag{2}$$

But, not only the frequency threshold $f_{\mathrm{threshold}}$ and the droop s have to be taken into account. Attention has also to be paid to the time response of LFSM–O. If the overall time behavior of LFSM–O is not fast enough to balance the imbalance before overshooting the maximum frequency $f_{\max}$ of 51.5 Hz, it will not be possible to prevent the island from blackout, because generation units are allowed or even obliged to disconnect at that frequency level. Hence, from a power system stability point of view it is advantageous to concede to LFSM-O as much time as possible to reduce the active power generation. Therefore, especially in over-frequency islands with high potential imbalances, it is of outmost importance that the frequency threshold $f_{\mathrm{threshold}}$ is set to the minimum value of 50.2 Hz. On the other hand, the time response of LFSM–O for 50 % active power reduction has to be maximum 1 second in order to avoid the frequency overshooting 51.5 Hz. **Fig. 1** shows the impact of different reaction times with respect to overfrequency control.

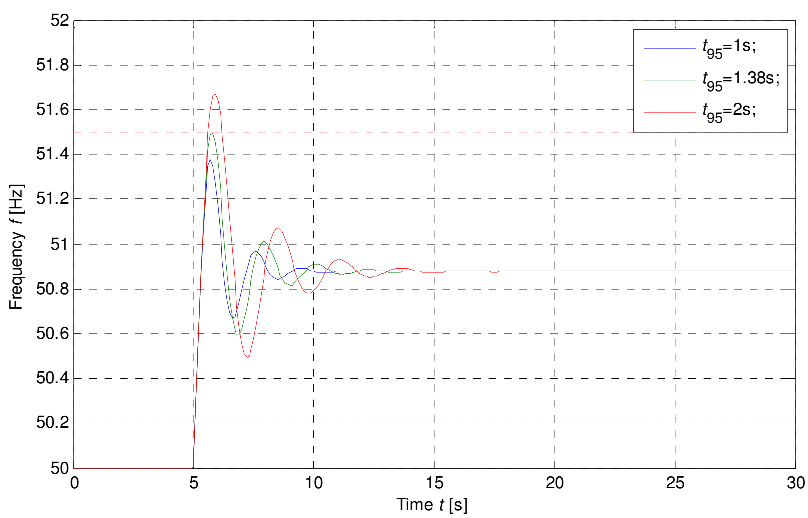

Fig. 1: Time domain response of 95% of full power activation for one exemplary scenario with different response times /3/.

5. Conclusion and Recommendations

The LFSM-O function, implemented in power generating modules and in HVDC links connecting different synchronous zones, is the only scheme that prevents an overfrequency island from blacking out after a system split. In this context, an island is meant as a relatively large part of the transmission grid, together with its underlaying distribution grids. The LFSM-O scheme reduces the power production to the amount equal to the load in the suddenly formed isolated island. In the meantime, between system split and reaction of the LFSM-O scheme, the power surplus in the island accelerates the rotating masses. The less inertia in the island is, the steeper the frequency gradient (ROCOF) will be. Therefore, the first parameter which has to be defined is the steepest ROCOF for which a blackout of the whole island shall be avoided.

This maximum ROCOF to be defined has three important aspects:

1. For all grid users (loads as well as generation modules), this maximum value of ROCOF defines their withstand capability: No grid user shall disconnect or be damaged because of this ROCOF. Because this is required from all grid users, it is not a requirement of the LFSM-O scheme.
2. The following formula, see /3/ :

$$T_{\mathrm{N,min}} = \frac{\Delta P_{\mathrm{Imbalance}}}{P_{\mathrm{Load}}} * \frac{f_0}{\mathrm{RoCoF_{max}}}$$

   determines the minimum inertia that has to be in operation in the island given a certain imbalance in it.
3. The steeper the maximum ROCOF is, the less time remains for the activation of the LFSM-O scheme. Therefore, it indirectly defines the maximum reaction time of the LFSM-O scheme.

Recommendation:
For the maximum ROCOF, a value of 2 Hz/s is recommended.

Reasons:

- On the one hand, a low value would be desirable in order to allow the LFSM-O scheme to react slowly. On the other hand, a low maximum ROCOF would require a large amount of interita in the system. 2 Hz/s seems to be a good compromise between these two aspects.
- In discussions with manufacturers, 2 Hz/s seems to be a realistic value for withstand capability.
- In the HVDC connection code, 2.5 Hz/s is required for HVDC converters. An HVDC link shall stay in operation longer than all other grid users. So, the withstand capability for generating modules and demand facilities must be lower than 2.5 Hz. 2 Hz/s for the grid users leaves a reasonable margin.

Droop settings:
Starting frequency:
The LFSM-O shall not interfere with the FCR (primary control). Therefore, the starting frequency cannot be lower than 50.2 Hz. Because the LFSM-O scheme must be effective in scenarios with high ROCOF, it is essential not to lose time for the mitigation of the power surplus. Therefore, LFSM-O has to be activated at the lowest frequency threshold that is possible. As stated above, the lowest possible threshold is 50.2 Hz. This is why 50.2 Hz is recommended as starting frequency for LFSM-O. By this, the whole frequency range up to 51.5 Hz can be used for mitigating the overfrequency problem. This way, it is avoided that the frequency rises and no mitigation measure is in operation.
If a TSO can justify a higher starting frequency because of particularities of its network, it can define a higher starting frequency.

Droop steepness:
The TSO shall select a droop between 2% and 12%. If a TSO does not choose a specific value, a droop of 5% is recommended .

Disconnection
When the LFSM-O is fully activated it is also necessary to consider that the generator stays connected at minimum output until the maximum operating frequency is reached (51.5 Hz for typically 30 minutes).

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Although automatic disconnection would help restoring the normal operationg frequency this is not recommended as this could delay the restoration process.

Droop Characteristic
The exact droop characteristic can be realised in different ways according to dynamic studies provided by the TSO.

Speed:
System need:
As shown in chapter 4, t_{95} = maximum 1 s for a load reduction of 50 % is required for being able to cope with system split scenarios. This definition is independent from the steepness of the droop and reflects the technical limits in facilities (power gradient).

The following table summarises the propsed settings for LFSM-O

Maximum **RoCoF** that can be withstood by the grid users	envisaged 2 Hz/s; currently 1 Hz/s
The **starting point** of the **LFSM-O** droop ($\mathbf{f}_{\mathbf{threshold}}$)	recommended 50.2 Hz
Droop of the **LFSM-O**	recommended 5%
The required **response time** (measurement delay $\mathbf{t}_{\mathbf{measure}}$ plus the time until 95% of units are fully activated to provide active power frequency response $\mathbf{t}_{\mathbf{95\%}}$) for LFSM-O	max. 1 s

The above reflects the approach to use the capability of the power electronic connected generation units for a very fast response in combination with the slightly delayed reaction of the conventional units which, on the other hand, also deliver a significant contribution to the system inertia. Therefore, the common understanding is that the maximum response time of 1 sec. is only related to power electronic-connected generation units.

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