2nd Public workshop on Frequency Stability Parameters for Connection Network Code Implementation

Brussels, 20. July 2017

Workshop Agenda

- **Introduction**
  - **Overview of the elaboration process of guidance on frequency related parameters**
  - **Summary of 1rst Workshop on Frequency Stability Parameters and related ESC meeting discussions**
  - **High level outcome of the Public Consultation**
- **First round of draft guidance on frequency related parameters**
  - **Frequency sensitive mode (FSM)**
  - **Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)**
  - **Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)**
  - **Frequency Ranges**
  - **Rate of Change of Frequency (RoCoF) Withstand Capability**
  - **Synthetic Inertia (SI) and Demand Response very fast Active Power Control (DR APC)**
  - **Initial TSO's and stakeholders' view on** Demand Response System Frequency Control (DR SFC), Frequency ranges of automatic connection and gradient of active power increase, Auto reconnection after an incidental disconnection, Admissible active power reduction at low frequencies
- **Wrap-Up and Next Steps**

Introduction

Overview of the elaboration process of guidance on frequency related parameters

Scoping of technical needs and expectations in terms of coordination

- March '17 WS
- March '17 GC ESC

Identification of technological and economic constraints

- Outcome from Public consultation
- Feedback from national discussions with stakeholders

Identification of system needs and risks

- Expert view from each synchronous area
- Feedback from national discussions with stakeholders and authorities

Elaboration of draft guidance

July'17 & End Sept'17 WS

Stakeholder consultation on the draft guidance

Oct-Nov'17

Publication of the final guidance

Exp. Dec'17

Detailed information in ENTSO-e "Roadmap on guidance for frequency stability requirements" published on February 2017
Will be updated shortly

Summary of 1rst Workshop on Frequency Stability Parameters and related ESC meeting discussions

- 39 participants from 20 countries and from manufacturers, producers, consultants, TSO and DSOs
- Output of Breakout Session on Synchronous Generators priority issues
  - Clarification needed on measurement methods for frequency and RoCoF (at least to ease compliance verification)
  - Clarification needed on system risk level and frequency of use (e.g. normal, abnormal or emergency operation)
  - Impact between RoCoF requirement definition and technological limitation extensively described. One proposal could be to define realistic “frequency ride through profile” which the power plant should withstand. This would cover both RoCoF and subsequent frequency values (frequency ranges capabilities).
  - Clarification on the compliance verification
  - Clarification on FSM deadband and/or insensitivity
- Output of Breakout Session on PPM priority issues
  - Application and maturity of synthetic inertia
  - Clarification needed on measurement methods for frequency and RoCoF
  - LFSM - interaction between amplitude of response and response time and initial response delay
- Extract from the MoM for 5th GC ESC meeting (March 2017)
  - Stakeholders request for information sharing ahead of 2nd workshop to facilitate an active contribution, Enhanced stakeholder involvement is foreseen by ENTSO-E
  - Good coordination the GC and SO aspects (especially on system inertia), all agree that things go hand in hand.
- Extract from the MoM for 6th GC ESC meeting (June 2017)
  - Stakeholders request ENTSO-E to provide feedback on how the question on countermeasures and RoCoF is considered in the inertia discussions.

High level outcome of the Public Consultation (1/2)

- 6 responses received:
  - For PPM: 2 responses from manufacturer
  - For SPGM: 3 responses
  - For DSO: 1 response
  - No specific answer received from the demand side.
- General comments and shared issues (blue = ENTSO-e view on this)
  - Interrogation on the process
    - Implementing code vs. drafting of NC. => This is clearly an implementing stage.
    - We share the view that system needs and technical capabilities need to be aligned and that both needs to be factually defined.
    - Some stakeholders request that system needs shall be defined first based on clear assumption and risk level.
    - Some stakeholders request to establish an expert group. => Experts from TSOs are working on the definition of the integrated transmission needs, consulting regularly other expert from DSO and stakeholders to confirm technical feasibility of the requirements. The process is therefore iterative, beginning with system needs.
    - We share the view that some of frequency parameters should be equal in all countries, others should slightly differ depending on the actual electrical mix of each country.
  - Some stakeholders are concerned that the scope was limited to generators. => ENTSO-E focuses on NC requirements requiring coordination between neighboring system, but not exclusively to generator (e.g. DSR-SFC, DSR-APC, frequency ranges)
  - Technical limitations of the distribution grid were not explicitly gathered. => Indeed, feedback from DSOs is often shared during national discussion and will be taken onboard (e.g. discussion on LFSM-U parameters)

High level outcome of the Public Consultation (2/2)

- General comments and shared issues (Cont'd)
  - We share the view that the IGDs should not lower the need for national discussion, cooperation and coordination at national level, including between "relevant system operators" when implementing the codes.
  - We share the view that clarification on frequency and RoCoF measurements is beneficial.
  - Clarification on the level of utilization of the technical capabilities (which can impact design and maintenance is expected => ENTSO-e will clarify in which operational states the capability is needed (Operational States: Normal, Alert, Emergency, Blackout and Restoration)
  - Clarification on the inherent limitation of renewable source in case active power increase unless storage system is added. => It is clearly not the intend of the TSO to request significant storage capability for renewable energy sources

First round of draft guidance on frequency related parameters

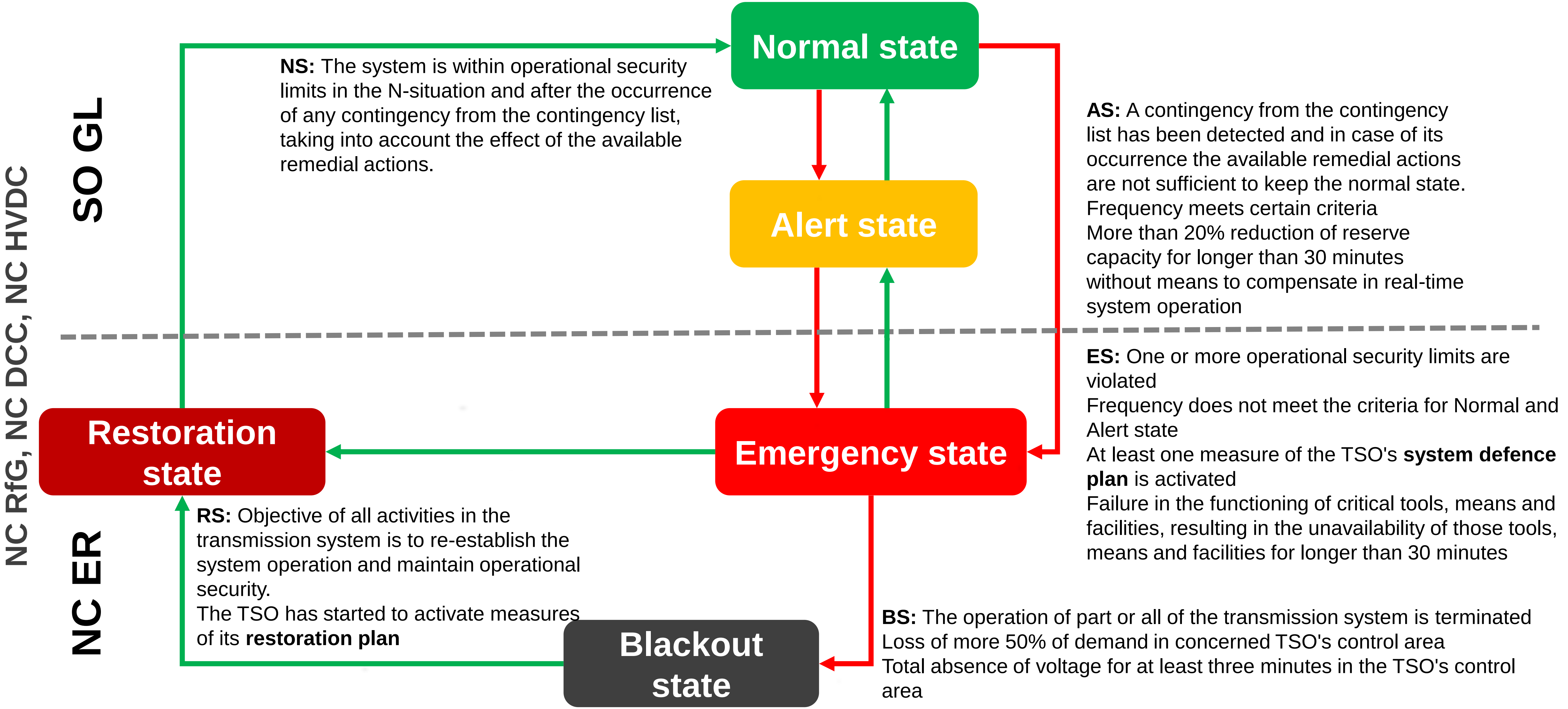
Introduction and structure

- **Frequency sensitive mode (FSM)**
- **Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)**
- **Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)**
- **Frequency Ranges**
- **Rate of Change of Frequency (RoCoF) withstand capability**
- **Synthetic Inertia (SI) and Demand Response very fast Active Power Control (DR APC)**
- **Initial TSOs' and stakeholders' view on**
  - Demand Response System Frequency Control (DR SFC)
  - Frequency ranges of automatic connection and gradient of active power increase
  - Auto reconnection after an incidental disconnection
  - Admissible active power reduction at low frequencies

Introduction and structure

- **For each of the topics, the following structure will be followed:**
  - Part 1: System Needs and Risks
    - Summary of the NC requirement
      - List and range of parameters to be implemented
      - Recall of the objective of the requirement
    - Identification of system needs
      - Expert view, fact and figure about system needs for each synchronous area
      - Risk if not well coordinated
    - Clarification of expected frequency of use of the capability: Normal state (NS), Alert state (AS), Emergency state (ES), Restoration state (RS) - (see next slide for clarification)
  - Part 2: Technological and economic constraints
    - Feedback from stakeholders from public consultation
    - Feedback from stakeholders from discussions at national level
  - Part 3: Current draft proposal for discussion
    - What and why

Introduction and structure



Frequency Stability Requirements

- **Frequency sensitive mode (FSM)**
- **Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)**
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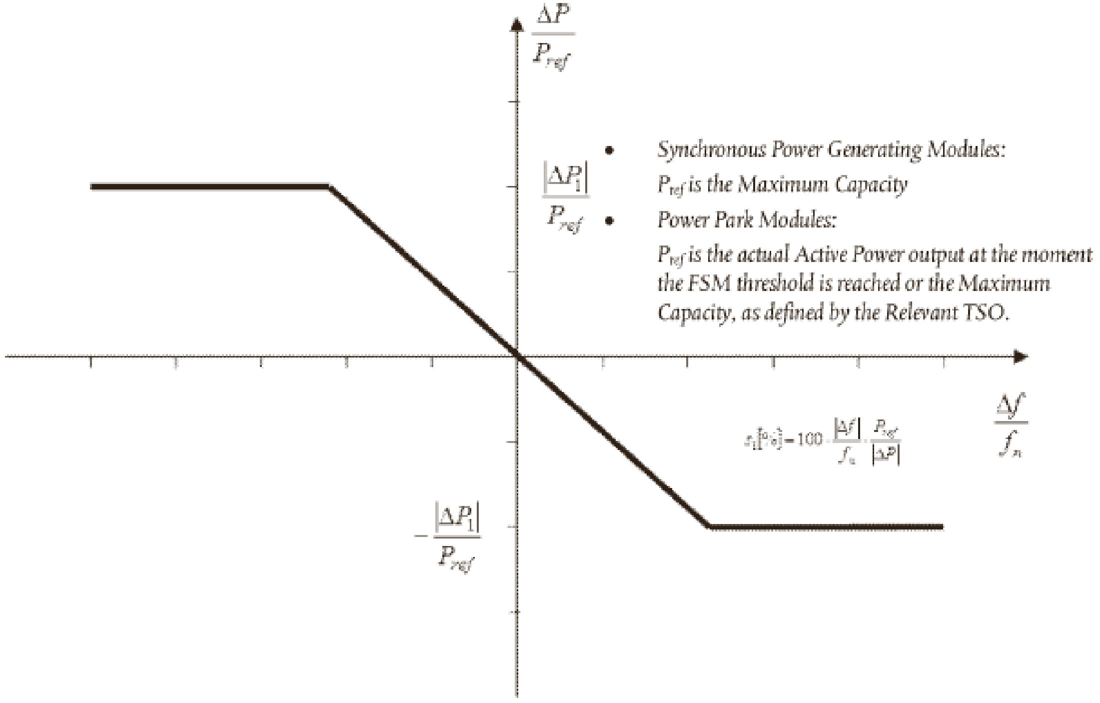
Frequency Sensitive Mode (FSM)

Frequency Sensitive Mode (FSM) RfG requirement: Article 15(2)(d)

Figure 5

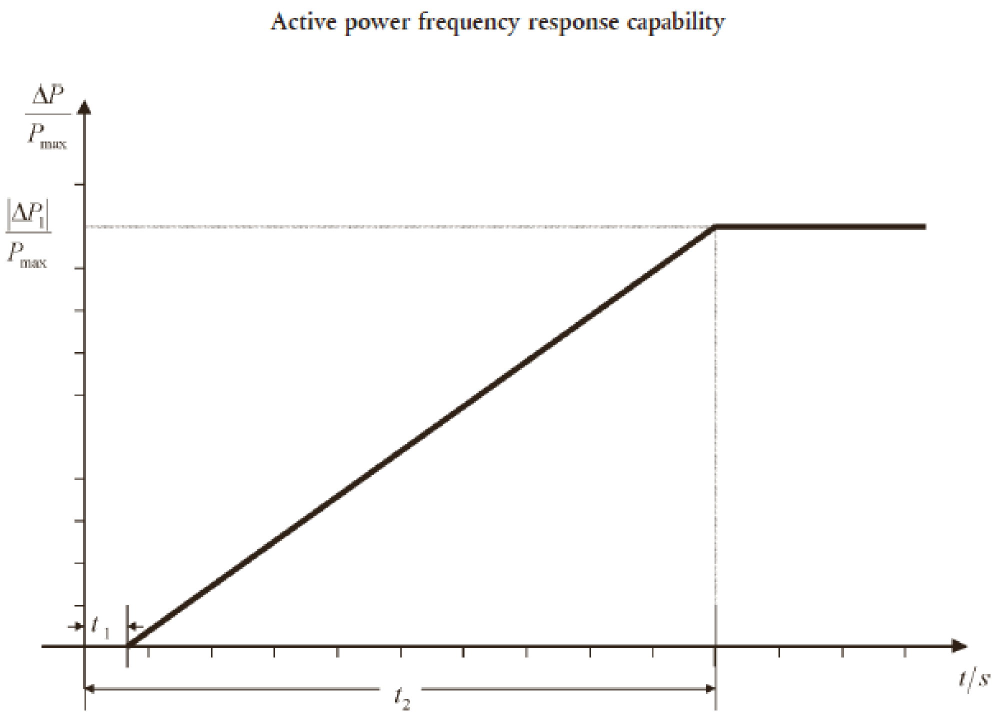
Active power frequency response capability of power-generating modules in FSM illustrating the case of zero deadband and insensitivity



- FSM is to be activated, when the system is in normal state to ensure load-frequency control and restore the frequency after a small frequency deviation.
- After a disturbance like the reference incident, FSM contribute to stabilize the system in order to return to normal state.

Active power range $\Delta P/P_{max}$	Between 1,5 – 10%
Droop	Between 3-12%
Frequency response insensitivity $\lvert\Delta f_1\rvert$ $\lvert\Delta f_1\rvert/f_n$	 Between 10 – 30 mHz Between 0,02 – 0,06%
Frequency response deadband	Between 0 – 500 mHz
Maximum initial delay of FSM activation (t_1)	SPGM : 2s (to be justified if > 2s) PPM : to be specified by the relevant TSO
Maximum delay of FSM full activation (t_2)	30 s

Frequency Sensitive Mode (FSM)
RfG requirement: Article 15(2)(d)



- FSM parameters needs to be defined to cover operational needs, such as FCR minimal technical requirements (SOGL art.154)

Active power range $\Delta P/P_{max}$	Between 1,5 – 10%
Droop	Between 3-12%
Frequency response insensitivity $\lvert\Delta f_1\rvert$ $\lvert\Delta f_1\rvert/f_n$	 Between 10 – 30 mHz Between 0,02 – 0,06%
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Maximum initial delay of FSM activation (t_1)	SPGM : 2s (to be justified if > 2s) PPM : to be specified by the relevant TSO
Maximum delay of FSM full activation (t_2)	30 s

Frequency Sensitive Mode (FSM) stakeholder feedback on technical capabilities

Limitation on frequency step response time (fastest response time, what puts a limit on the response time, differences between increase and decrease P)

- **SPGM: mainly Thermal power plants, gas turbines :** no difference between increase and decrease P, response time depends on desired power step because of a constant ramp rate. Limited by load controller and emission controller. Response time not necessary linear. Response time can be limited due to emission compliance request.
- **PPM - mainly Wind turbines :** Need for requirement on frequency measurement quality performance. Active power decrease fast and easily achievable (response time < 5s). Active power increase more difficult to predict and depending on the active power operating point, proposed to define different operating ranges associated with response time values (faster if P > 50% Pmax – increase of 10% Pmax within 5s - than if P < 50% Pmax - increase of 10% Pmax within 10 to 15s). Limited by mechanical constraints (need for increase rotor speed) => Larger turbines means time response increase.

Activation of frequency step response time at any P operating point

- Step response can be provided from any operating point between minimum technical and maximum power.
- Regarding wind turbines, Pmin = 10% Pmax (below Pmin, mechanical constraints -> damages)

Technological improvements

- **SPGM: mainly Thermal power plants, gas turbines :** increase in the ramp rate within 10 years (cost increase btw 10% and 20% p.u)
- **PPM - mainly Wind turbines :** minor improvement while adapting wind turbine design (with cost implication).More efficient improvement using external solutions (e.g storage), CBA non-profitable for the moment.

Others

- Thermal power plants, gas turbines : lower droop 2% achievable but with huge increase of maintenance costs.
- Industrial plants (embedded in an industrial process) : power variation can strongly affect the industrial process => limitation to provide FSM.
- Harmonisation of settings will help to develop technical and cost effective solutions

Frequency Sensitive Mode (FSM)
stakeholder feedback from national processes or ESC meetings

- The effort to control frequency must be shared fairly across a synchronous area

- Extract from Eurelectric presentation, ESC – 9th December 2016
  - *According to most French stakeholders' analysis**, EURELECTRIC points out the most important parameters that should be 'equal' or strongly 'coordinated' between countries*
    - ➢ ***Equal***
      - ✓ *Performances of measurement system*
      - ✓ *Insensitivity*
      - ✓ *Deadband*
    - ➢ ***Coordinated** (depending on actual parameter of each country)*
      - ✓ *Droop*

- According to discussion in the Spanish national implementation process
  - FSM initial delay: t1 = 500ms deemed acceptable for PPM
  - FSM full activation delay : A faster t2 could facilitate an appropriate system restoration. Due to technology specifics t2 is considered different for PPMs and SPGM. t2=12s deemed acceptable for SPGM (related to the active power range to deliver). An even faster t2 could be deemed acceptable for PPMs.

*see *Position paper 'Setting Frequency-Related Parameters in Europe'*, by French stakeholders with the support of EURELECTRIC

Frequency Sensitive Mode (FSM) proposed parameters according to RfG Article 15(2)(d)

FSM requirements shall ensure that technical capabilities and, where applicable, initial settings of parameters are available to cover operational needs, such as FCR minimal technical requirements (SO GL, Art 154).

- Methodology to define active power range and associated droop :

Parameters	Proposal	Comments
Active power range related to maximum capacity |∆P1| / Pmax	Each TSO shall propose a value, which shall be understood as a minimum technical requirement to ensure that FCR part will be covered by C & D units in the country / TSO control area. Compliance to be tested against the chosen value.	To identify and quantify critical future scenarios with low instantaneous penetration of C & D units
Droop s1	Adjustable droop to cover the active power range |∆P1| / Pmax to be uniformly activated over the maximum admissible frequency deviation for FCR.	To be calculated to be able to increase/decrease power from |DP1| / Pmax for a FCR full activation frequency deviation Typical values : 4-5%

Frequency Sensitive Mode (FSM) proposed parameters according to RfG Article 15(2)(d)

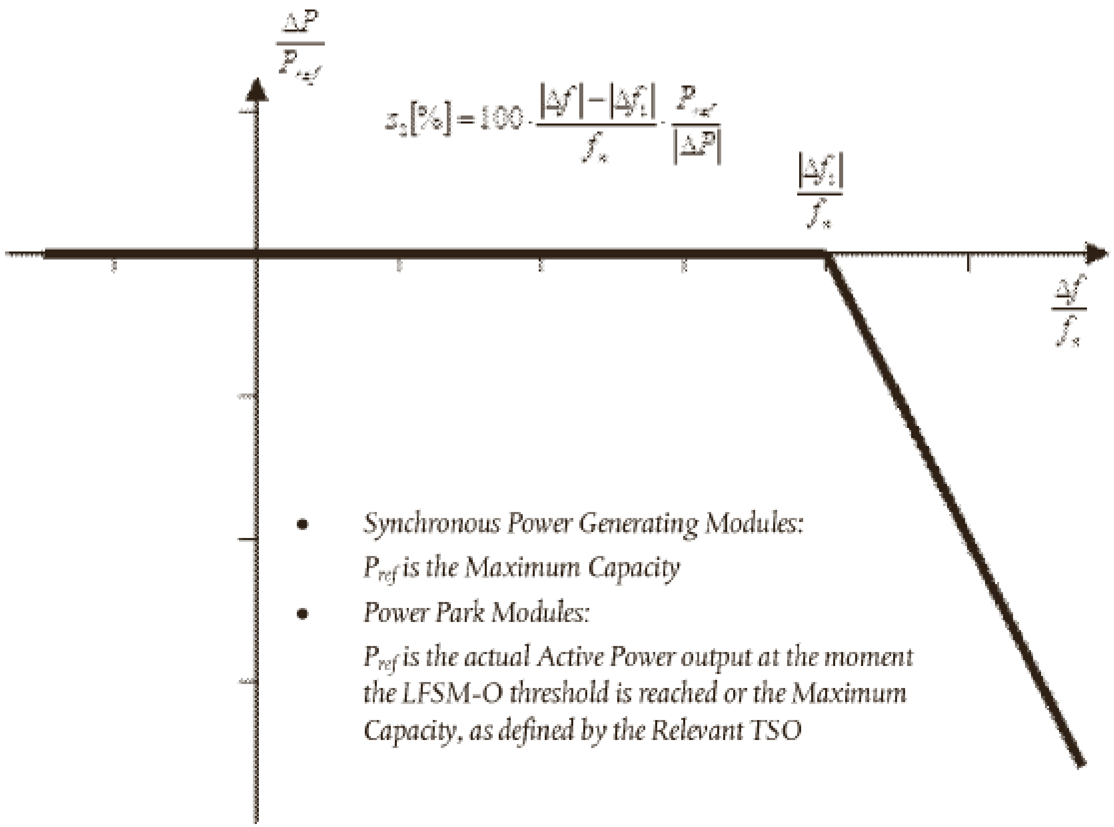
- Proposed settings for parameters

Parameters	Proposal		Comments
Frequency response insensitivity	|Δfi| / fn ≤ 0,02%		Ensure compliance with FCR requirements Note : insensitivity is not accuracy
	|Δfi| ≤ 10 mHz		
Frequency response deadband	Adjustable value in the range of 0 – 500 mHz		
	Default values : • CE, Nordic, GB, IE : 0 mHz • Baltics : n/a		Ensure compliance with FCR requirements. Setting a large deadband may be used to “deactivate” FSM under normal operating conditions but shall not impair LFSM-O/-U function
Initial delay t1	≤ 2s for SPGM ≤ 500 ms for PPM		To use widest possible technical capability of the power-generating module
Response activation (full activation) t2	CE, Nordic :	30s	Default value proposed refers to normal operating conditions across CE. In case of forming local islands accidentally, a faster t2 could be requested by the TSO with the purpose of facilitating an appropriate system restoration. Therefore the generator FSM control must be designed to allow a faster response in case of local needs, taking into consideration technology specifics.
	GB	10s	
	IE/NI	15s	

- ENTSO-E experts are working to recommend a minimum frequency measurement quality performance.

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)

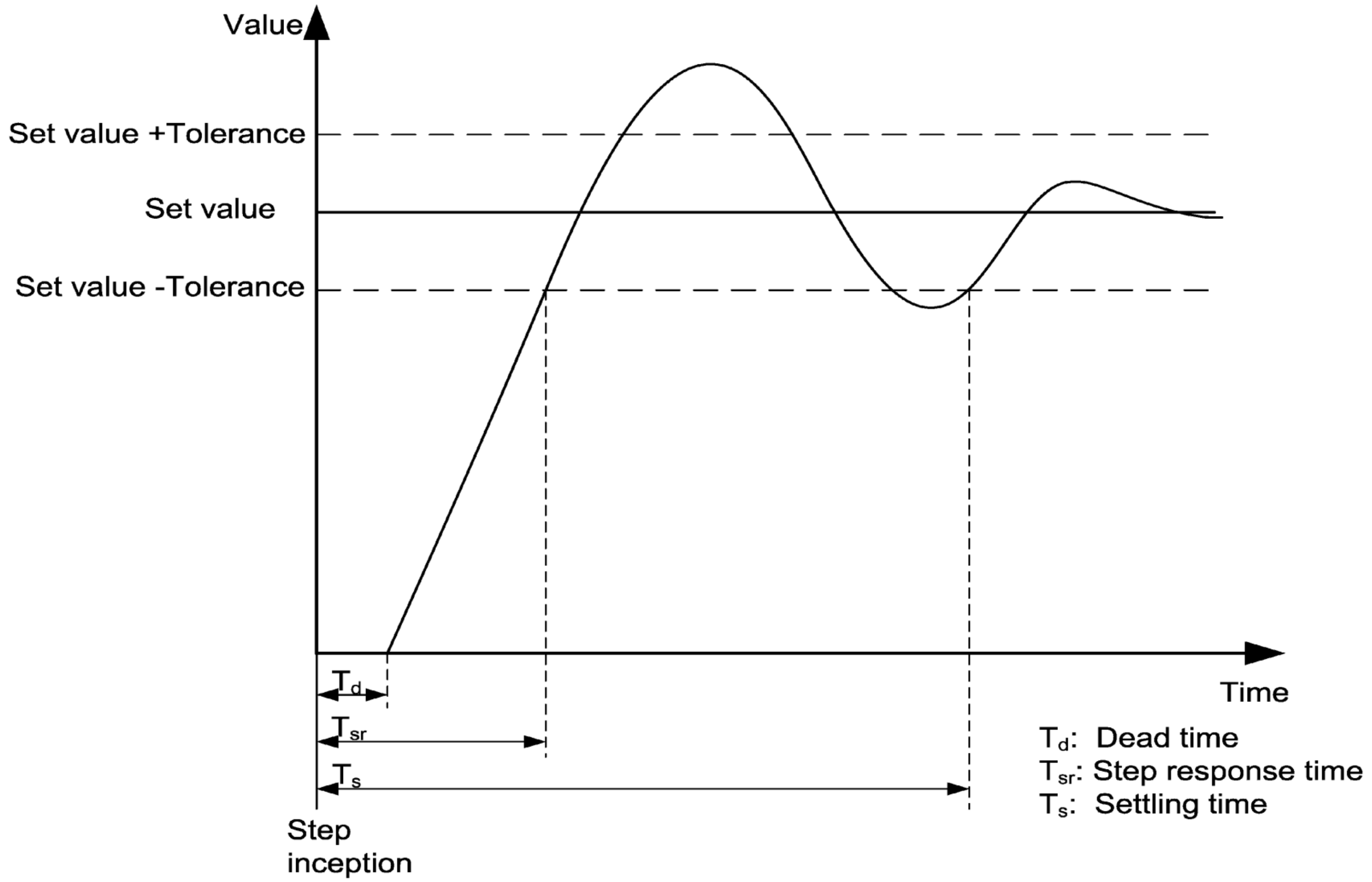
Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) RfG requirement: Article 13(2)



Droop	Adjustable range of 2-12%
Frequency threshold	Between 50.2 – 50.5 Hz
Initial delay of LFSM-O activation	as fast as technically possible, to be justified if > 2s
minimum active power	Minimum regulating level or lower
Priority	Prevalence over other active power setpoint

- LFSM-O is to be activated, when the system is in an emergency state after a severe disturbance, which has resulted in a major load imbalance and the frequency deviation cannot be mitigated by the FCR resources
- LFSM-O shall support stabilizing the system at a frequency < 51.5 Hz after FCR has been exhaustively deployed

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)



Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)

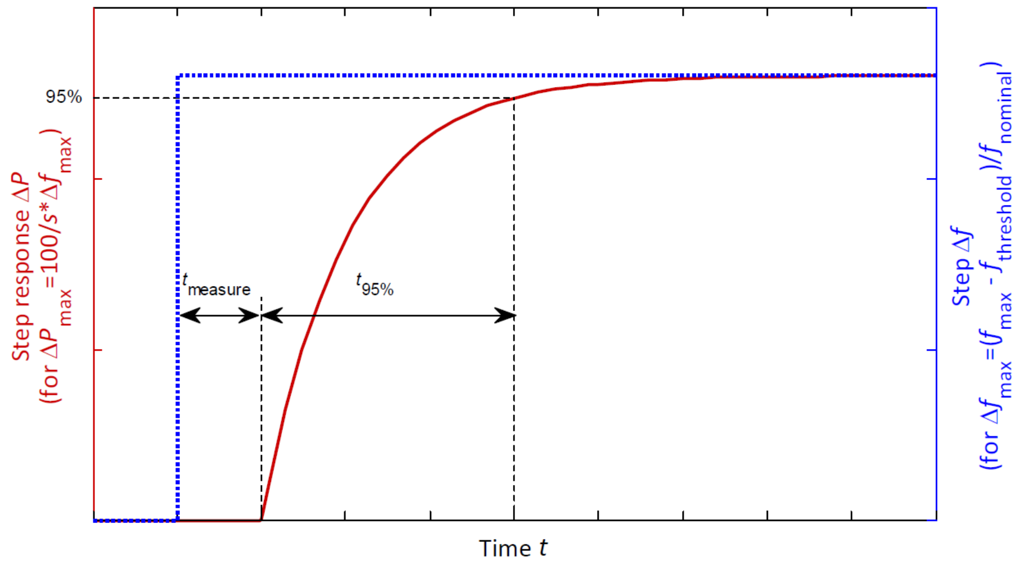


Figure 10: Evaluating the required time behaviour of LFSM-O.

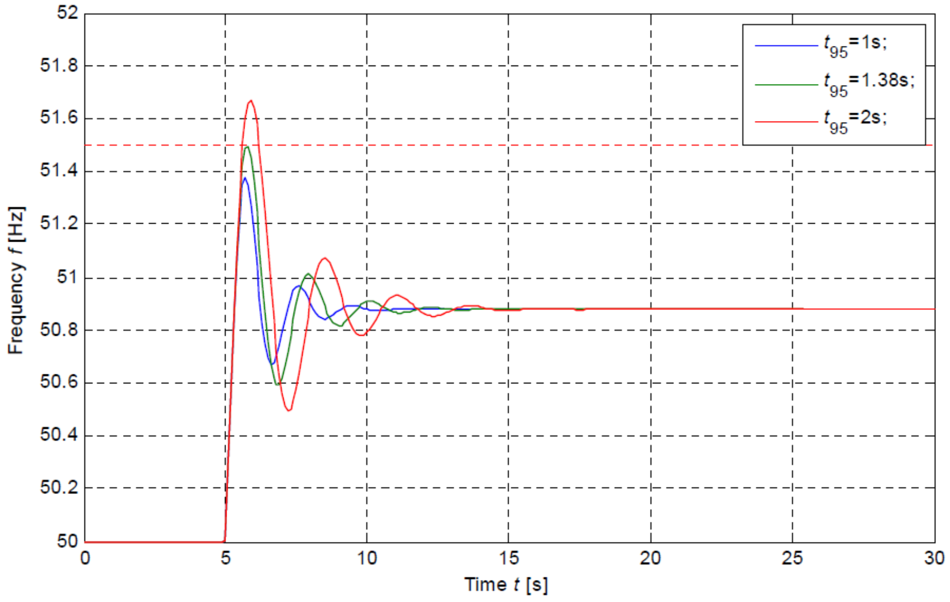


Figure 11: Time domain response for one exemplary scenario with different response times.

Extract from “Frequency Stability Evaluation Criteria for the Synchronous zone of Continental Europe – Requirements and impacting factors”, ENSTO-e RG-CE System Protection & Dynamics Sub Group,
March 2016

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) RfG requirement (II): Article 13(2)

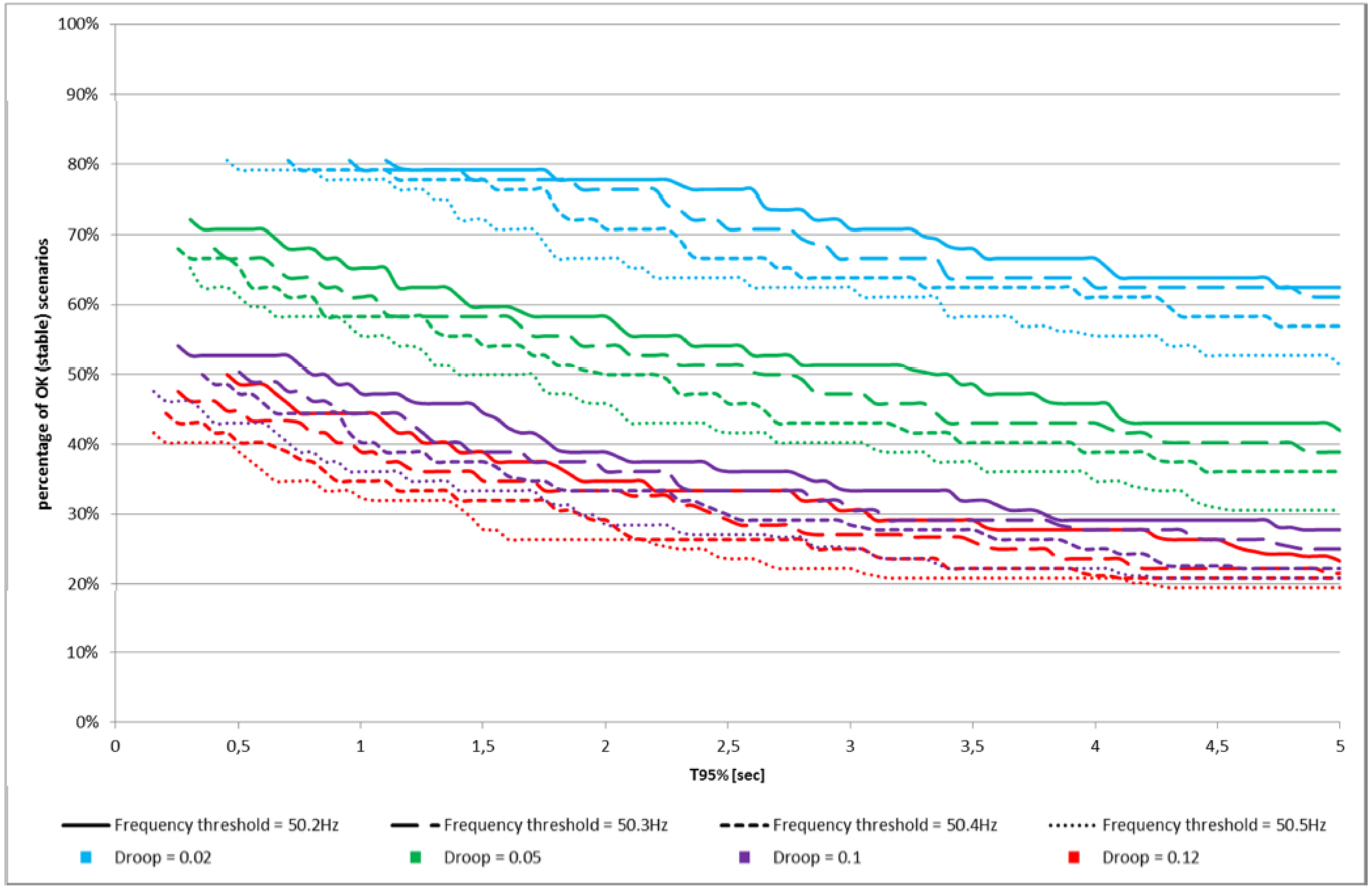


Figure 13: Percentage of stable scenarios depending on responds time and LFSM-O parameters

Extract from "Frequency Stability Evaluation Criteria for the Synchronous zone of Continental Europe – Requirements and impacting factors", ENSTO-e RG-CE System Protection & Dynamics Sub Group, March 2016

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) stakeholder feedback on consultation on technical capabilities

Feasibility of an adjustable droop range and associated costs

- adjustable droop is technically feasible is not a significant cost issue
- a low droop with more frequency sensitive responses could lead to increased maintenance costs

Limitation on frequency step response time (fastest response time, what puts a limit on the response time, differences between increase and decrease P)

- **PPM - wind turbines :** Need for a common frequency measurement method. Active power decrease fast and easily achievable (response time < 5s). Active power increase more difficult to predict and depending on the active power operating point, proposed to define different operating ranges associated with response time values (faster if P > 50% Pmax – increase of 2-5% Pmax/s - than if P < 50% Pmax - increase of 1% Pmax/s). Limited by mechanical constraints (need for increase rotor speed) => Larger turbines means time response increase.
- **SPGM - gas turbines and combustion engines**: response time depends on desired power step because of a constant ramp rate. Limited by load controller and emission controller. Fastest response for combustion engines: 30s.

Activation of frequency step response time at any P operating point

- **PPM - wind turbines :** Wind turbines not controllable below 10%Pmax.
- **SPGM - gas turbines and combustion engines**: from any point between minimum operating level and Pmax

Technological improvements

- **PPM - wind turbines :** minor improvements in turbine technology; use of battery or other storage technologies technically feasible at significant costs
- **SPGM - gas turbines** : products are continuously improved, increased performance through harmonization of settings response times of 5s are conceivable, cost implications difficult to assess
- **SPGM - combustion engines**: double the ramp rate at 10-20% cost increase

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) stakeholder feedback from national processes on technical capabilities

- Step response time needed for CE for a reference system split (see presentation at 09. March 2017 stakeholder workshop): 1 s with a droop of 5%

- According to discussion in the German national implementation process, a step response time achievable currently and in the near future from manufacturers' perspective:
  - active power decrease in case of frequency increasing above the threshold:
    - SPGM: ≤ 8 s for $\Delta P \leq 45\%\ P_{max}$
    - PPM: ≤ 2 s for $\Delta P \leq 50\%\ P_{max}$
    - If ΔP is greater than the given limits, the response time for the part of ΔP exceeding the given limit shall be as fast as possible.

  - active power increase in case of frequency decreasing above the threshold:
    - SPGM: ≤ 5 min for ΔP ≤ 20% Pmax (slow performance not applicable, if the increase follows shortly after the decrease)
    - PPM (except wind): ≤ 10 s for $\Delta P \leq 50\% P_{max}$
    - PPM (wind): ≤ 5 s for $\Delta P \leq 20\%\ P_{max}$ and above $50\%\ P_{max}$
    - If ΔP is greater than the given limits, the response time for the part of ΔP exceeding the given limit shall be as fast as possible.

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) proposed parameters according to RfG Article 13(2) – (I)

- Frequency thresholds:
  - CE: 50,2 Hz
  - Nordic: 50,3 Hz
  - GB: 50,4 Hz
  - IE/NI: tbd
  - Baltic: tbd

- Droop settings:
  - Selectable in a range of 2% - 12%
  - Default settings:
    - CE: 3% (see next slide for justification)
    - Nordic: 4%
    - GB: 3–5 %
    - IE/NI: tbd
    - Baltic: tbd

Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) proposed parameters in addition to RfG Article 13(2) – (II)

- Step response time needed for CE for a reference system split (see presentation at 09. March 2017 stakeholder workshop): 1 s with a droop of 5% (or 2s with a droop of 3%)

- Response time proposal for CE taking into consideration both system needs and plant capabilities:
  - PPM: droop of 3% and response time of 2 s (active power decrease) or 5 s (active power increase)
  - SPGM: droop and response time as fast as currently achievable from manufacturers’ perspective with the selected design (same values for active power increase as for decrease)

- First swing overshoot to be as small as possible and ≤ 10% of the step change

- Settling time:
  - active power decrease in case of frequency increasing above the threshold:
    - SPGM: ≤ 30 s
    - PPM: ≤ 20 s
  - active power increase in case of frequency decreasing above the threshold:
    - SPGM: ≤ 6 min (slow performance not applicable, if the increase follows shortly (within a few seconds) after the decrease)
    - PPM: ≤ 30 s

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)

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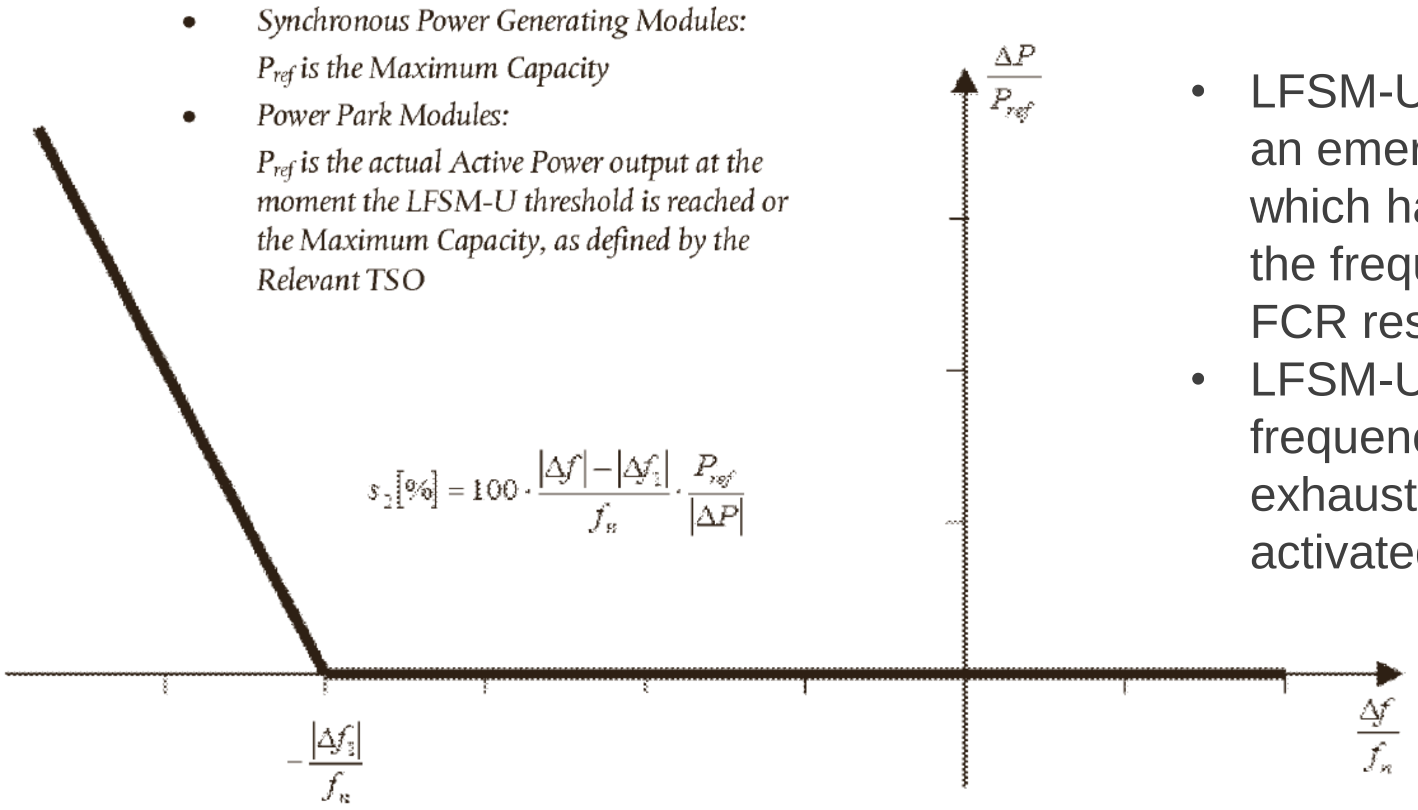
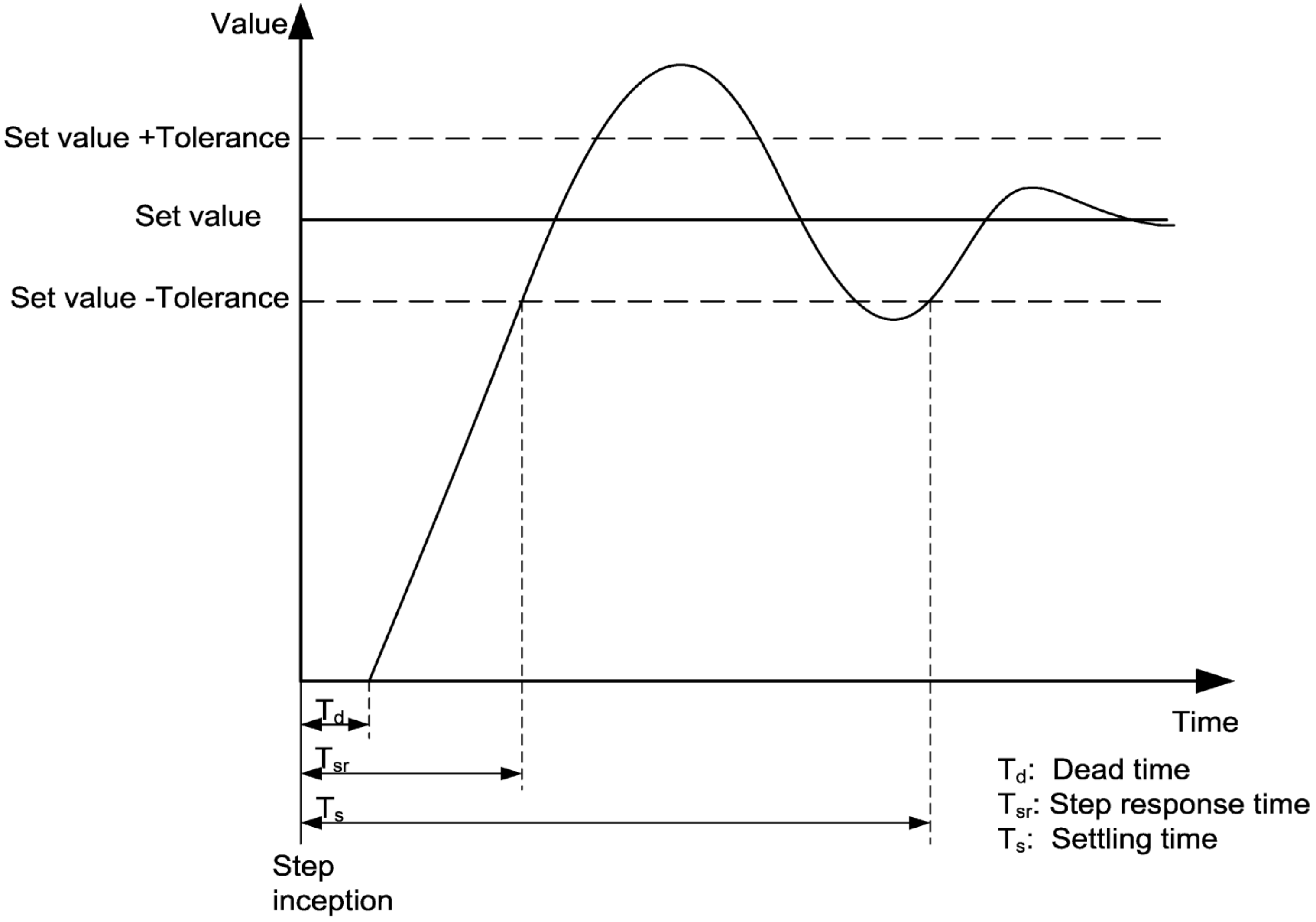
Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)
RfG requirement: Article 15(2)(c)

Droop	Adjustable range of 2-12%
Frequency threshold	Between 49.8 – 49.5 Hz
Initial delay of LFSM-U activation	as fast as technically possible, to be justified if > 2s
Limit for increasing of active power	Up to maximum capacity



- LFSM-U is to be activated, when the system is in an emergency state after a severe disturbance, which has resulted in a major load imbalance and the frequency deviation cannot be mitigated by the FCR resources
- LFSM-U shall support stabilizing the system at a frequency > 49.0 Hz after FCR has been exhaustively deployed and before load shedding is activated

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)



Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) stakeholder feedback on technical capabilities

Q1 Limitation on frequency step response time (fastest response time, what puts a limit on the response time, differences between increase and decrease P)

- **SPGM - gas turbines and combustion engines:** The parameters according NC RfG can be followed. Response time is limited by the load controller and emission controller. Settling time depends on extent frequency change (now: from 0.56%/s to 1.11%/s in each direction up and down). Limitation is given by ambient condition (temperature), emission compliance or generation in CHP cycles and by inherent thermo/mechanical inertia
- **PPM - wind turbines :** The only option to underfrequency response is operating bellow MPP (maximal power point) or using built-in battery storage. Response time depends on rotor speed (higher wind speed --> faster P increase)

Q2 Activation of frequency step response time at any P operating point

- **SPGM - gas turbines and combustion engines:** Step response is achievable in whole active power range. Response time is given by constant ramp rate. Response time is not necessarily linear (depends on *f* deviation, RoCoF) → proportional response
- **PPM - wind turbines :** Activation of frequency step response time above 10% of Pn is without limitation.

Q3 Limiting factor of LFSM-U activation

- **SPGM - gas turbines and combustion engines:** Limiting factors: engine overload and ramp rates limits (engine running in CHP). Maximum step response time could be limited by emission compliance. Time response is limited by slow inertia of conventional boilers in sliding pressure mode
- **PPM - wind turbines :** At very low active power (<20% of PRATED) the synthetic inertia is not available (not enough kinetic energy). Activation depends on current P output (lower levels → slower; higher levels → faster) i.e. P>50%Pn → ΔP of 10% in 5s and P<50%Pn → ΔP of 10% in 10-15s.

Q4 Technological improvements

- **SPGM - gas turbines and combustion engines:** Optimization of the fuel mixture-generation system (but it could cause a worse efficiency) and by optimization of settling time (but need to specify that such an event only happens a few times in the lifetime) and upgrade of gas admission system, additional actuators, modified turbocharger. Increase of ramp rate up to 3%/s (but this could lead to increase of cost up to 20% of p.u.)
- **PPM - wind turbines :** Use battery storages -> ensure a synthetic inertia

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) stakeholder feedback on technical capabilities

DSOs' opinion:

As system operators, they need data from and direct access to grid users to operate their networks safely and efficiently manage distributed energy resources. In several Member States, ***distributed generation is not connected to distribution systems following the N-1 principle****, that means, already the line connecting a set of* ***generators can be overloaded during abnormal but not necessarily extreme situations****. In other words, automatically controlled increase of generators' infeed like foreseen for example for* ***LFSM-U can lead to tripping of lines and other elements of the distribution system****.* ***Such a tripping would result in the loss of the whole generation capacity, having an inverse effect on frequency stability.***

To mitigate this risk, DSOs need the right and capability to block in real time LFSM-U for generators and DSM-APC for loads connected to their systems*, if the necessity arises. Of course, such blocking would only be carried out for single generators and loads feeding on contingencies.*

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) stakeholder feedback from national processes on technical capabilities

- According to discussion in the German national implementation process, a step response time achievable currently and in the near future from manufacturers' perspective:
  - active power decrease in case of frequency increasing below the threshold:
    - SPGM: ≤ 8 s for $\Delta P \leq 45\%\ P_{max}$
    - PPM: ≤ 2 s for $\Delta P \leq 50\%\ P_{max}$
    - If ΔP is greater than the given limits, the response time for the part of ΔP exceeding the given limit shall be as fast as possible.
  - active power increase in case of frequency decreasing below the threshold:
    - SPGM: ≤ 5 min for ΔP ≤ 20% Pmax (slow performance not applicable, if the increase follows shortly after the decrease)
    - PPM (except wind): ≤ 10 s for $\Delta P \leq 50\% P_{max}$
    - PPM (wind): ≤ 5 s for $\Delta P \leq 20\%\ P_{max}$ and above $50\%\ P_{max}$
    - If ΔP is greater than the given limits, the response time for the part of ΔP exceeding the given limit shall be as fast as possible.

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) proposed parameters according to Article 15(2)(c)

- Frequency thresholds:
  - CE: 49,8 Hz
  - Nordic: 49,5 Hz
  - GB: 49,5 Hz
  - IE/NI: tbd
  - Baltic: tbd

- Droop settings:
  - Selectable in a range of 2% - 12%
  - Default settings: ≤ FSM settings

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) proposed parameters according to Article 15(2)(c)

- Response time proposal taking into consideration both system needs and plant capabilities:
  - PPM: droop ≤ FSM settings and response time of 2 s (active power decrease) or 5 s (active power increase)
  - SPGM: droop and response time as fast as currently achievable from manufacturers’ perspective with the selected design (same values for active power increase as for decrease)

- First swing overshoot to be as small as possible and ≤ 10% of the step change

- Settling time:
  - active power decrease in case of frequency increasing below the threshold:
    - SPGM: ≤ 30 s
    - PPM: ≤ 20 s
  - active power increase in case of frequency decreasing below the threshold:
    - SPGM: ≤ 6 min (slow performance not applicable, if the increase follows shortly (within a few seconds) after the decrease)
    - PPM: ≤ 30 s

Frequency Ranges

Frequency Ranges

NC references

Topic:	Frequency ranges specified - essential for the stability of the grid
Code(s) & Article(s)	NC RfG article 13(1)(a) NC DCC article 12(1); 12(2) NC HVDC article 11
Interactions with other NC articles	NC DCC article 19(1)(c)(i) NC DCC article 28(2)(a) NC HVDC article 39(2)(a)

Frequency Ranges

General principles

Tx and Dx lines shall be available longer than generator and demand facilities

Generators facilities shall stay connected longer than demand facilities

Demand facilities shall disconnect before generator facilities

Frequency Ranges
RfG requirement (I): Article 13(1)

(1) Type A power-generating modules shall fulfil the following requirements relating to frequency stability:

(a) With regard to frequency ranges:

(i) a power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Table 2;

(ii) the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power- generating module, if it is required to preserve or to restore system security;

(iii) the power-generating facility owner shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation, taking account of their economic and technical feasibility.

(b) With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.

Frequency Ranges
RfG requirement (II): Article 13(1)

Ranges	Synchronous area				
	GB	IE / NI	Baltic	Nordic	CE
47,0 Hz-47,5 Hz	20 seconds	------------------------	------------------------	------------------------	------------------------
47,5 Hz-48,5 Hz	90 minutes	90 minutes	To be specified by each TSO, but not less than 30 minutes	30 minutes	To be specified by each TSO, but not less than 30 minutes
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 90 minutes	To be specified by each TSO, but not less than 90 minutes	To be specified by each TSO, but not less than the period for 47,5 Hz-48,5 Hz	To be specified by each TSO, but not less than 30 minutes	To be specified by each TSO, but not less than the period for 47,5 Hz-48,5 Hz
49,0 Hz-51,0 Hz	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
51,0 Hz-51,5 Hz	90 minutes	90 minutes	To be specified by each TSO, but not less than 30 minutes	30 minutes	30 minutes
51,5 Hz-52,0 Hz	15 minutes	------------------------	------------------------	------------------------	------------------------

Frequency ranges
stakeholder feedback on technical capabilities

- None received until now.

Frequency Ranges
proposed parameters according to RfG Article 13(1) (1/5)

Ranges	Synchronous area	
	CE	Proposal of WG CNC
47,0 Hz-47,5 Hz	------------------------	------------------------
47,5 Hz-48,5 Hz	To be specified by each TSO, but not less than 30 minutes	30 minutes, but longer minimum time periods may be required for countries, which are exposed to a higher risk of islanding (e.g. peninsular area) to allow for an extended period of time for system restoration
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz-48,5 Hz	30 minutes, but longer minimum time periods may be required for countries, which are exposed to a higher risk of islanding (e.g. peninsular area) to allow for an extended period of time for system restoration
49,0 Hz-51,0 Hz	Unlimited	Unlimited
51,0 Hz-51,5 Hz	30 minutes	30 minutes
51,5 Hz-52,0 Hz	------------------------	------------------------

Frequency Ranges
proposed parameters according to RfG Article 13(1) (2/5)

Ranges	Synchronous area	
	Nordic	**Proposal of WG CNC**
47,0 Hz-47,5 Hz	------------------------	------------------------
47,5 Hz-48,5 Hz	30 minutes	30 minutes
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 30 minutes	30 minutes
49,0 Hz-51,0 Hz	Unlimited	Unlimited
51,0 Hz-51,5 Hz	30 minutes	30 minutes
51,5 Hz-52,0 Hz	------------------------	------------------------

Frequency Ranges
proposed parameters according to RfG Article 13(1) (3/5)

Ranges	Synchronous area	
	Baltic	Proposal of WG CNC
47,0 Hz-47,5 Hz	------------------------	------------------------
47,5 Hz-48,5 Hz	To be specified by each TSO, but not less than 30 minutes	30 minutes
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than the period for 47,5 Hz-48,5 Hz	To be specified by each TSO, but not less than 30 minutes
49,0 Hz-51,0 Hz	Unlimited	Unlimited
51,0 Hz-51,5 Hz	To be specified by each TSO, but not less than 30 minutes	30 minutes
51,5 Hz-52,0 Hz	------------------------	------------------------

Frequency Ranges
proposed parameters according to RfG Article 13(1) (4/5)

Ranges	Synchronous area	
	IE /NI	Proposal of WG CNC
47,0 Hz-47,5 Hz	------------------------	---------------------
47,5 Hz-48,5 Hz	90 minutes	90 minutes
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 90 minutes	90 minutes
49,0 Hz-51,0 Hz	Unlimited	Unlimited
51,0 Hz-51,5 Hz	90 minutes	90 minutes
51,5 Hz-52,0 Hz	------------------------	---------------------

Frequency Ranges
proposed parameters according to RfG Article 13(1) (5/5)

Ranges	Synchronous area	
	GB	Proposal of WG CNC
47,0 Hz-47,5 Hz	20 seconds	20 seconds
47,5 Hz-48,5 Hz	90 minutes	90 minutes
48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 90 minutes	90 minutes
49,0 Hz-51,0 Hz	Unlimited	Unlimited
51,0 Hz-51,5 Hz	90 minutes	90 minutes
51,5 Hz-52,0 Hz	15 minutes	15 minutes

Rate of Change of Frequency (RoCoF) Withstand Capability

Rate of Change of Frequency (RoCoF) Withstand Capability
RfG: Article 13(1)(b); DCC: Article 28(2)(k); HVDC: Articles 12, 39(3)

The requirement aims at ensuring that power generating modules (NC RfG), demand units offering Demand Response (DR) services (DCC), HVDC systems and DC-connected power park modules shall not disconnect from the network up to a maximum rate of change of frequency (df/dt).

While defining the RoCoF withstand capability, each TSO should take the following concerns and issues into account:

- Transition from existing to future generation mix, in particular instantaneous penetration of non-synchronous generation (PPMs)
- Disconnection of users due to own instability (e.g. pole slip)
- High df/dt may reduce generators’ lifetime (physical damages to the shaft)
- Different users have different inherent capabilities (e.g. wind turbines can easily withstand RoCoFs up to 4Hz/s)
- The measurement time window and technique for verification of compliance

Furthermore, the TSO may conduct following studies before implementing the requirement:

- ✓ Possibility of requiring dissimilar requirements for different technologies (e.g. thermal power plant and power electronic connected modules)
- ✓ Whether to define a single RoCoF value or set of frequency-against-time profiles

The resulting RoCoF withstand capability value will be an important input to calculate the essential minimum inertia (provided by the synchronous PGM with inherent inertia and by PPMs with synthetic inertia) for system stability in case of outage or system split, incl. asynchronous operation of control block. Therefore **there is a direct link between RoCoF and inertia related requirements**.

Part 1: system needs and risks

Rate of Change of Frequency (RoCoF) Withstand Capability
RfG: Article 13(1)(b); DCC: Article 28(2)(k); HVDC: Articles 12, 39(3)

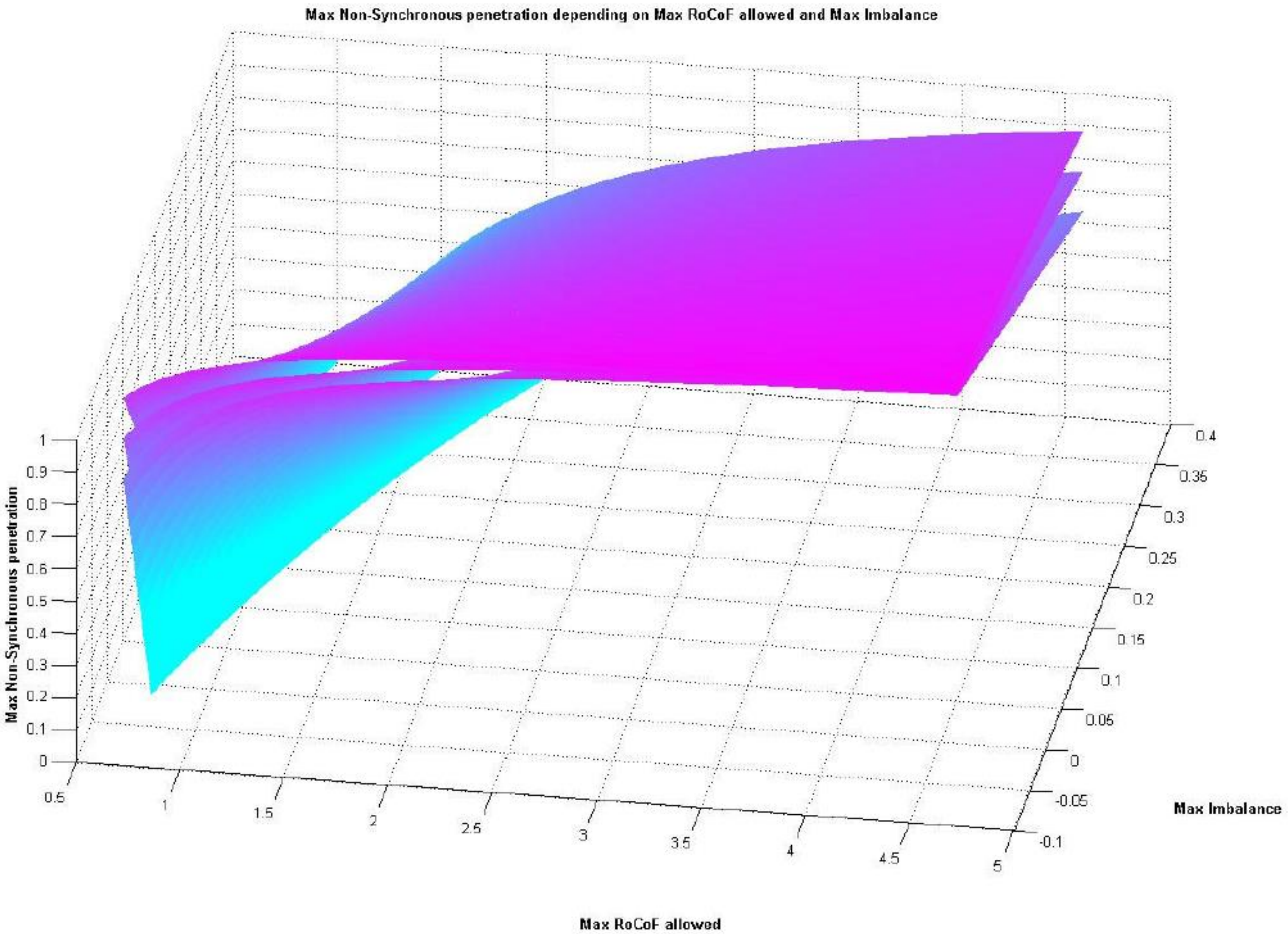


Figure 5: Maximum system penetration with reference to RoCoF and system imbalance for the synchronous generation operating at 50%, 75% and 100% of rated output.

Extract from "Frequency Stability Evaluation Criteria for the Synchronous zone of Continental Europe – Requirements and impacting factors", ENSTO-e RG-CE System Protection & Dynamics Sub Group, March 2016

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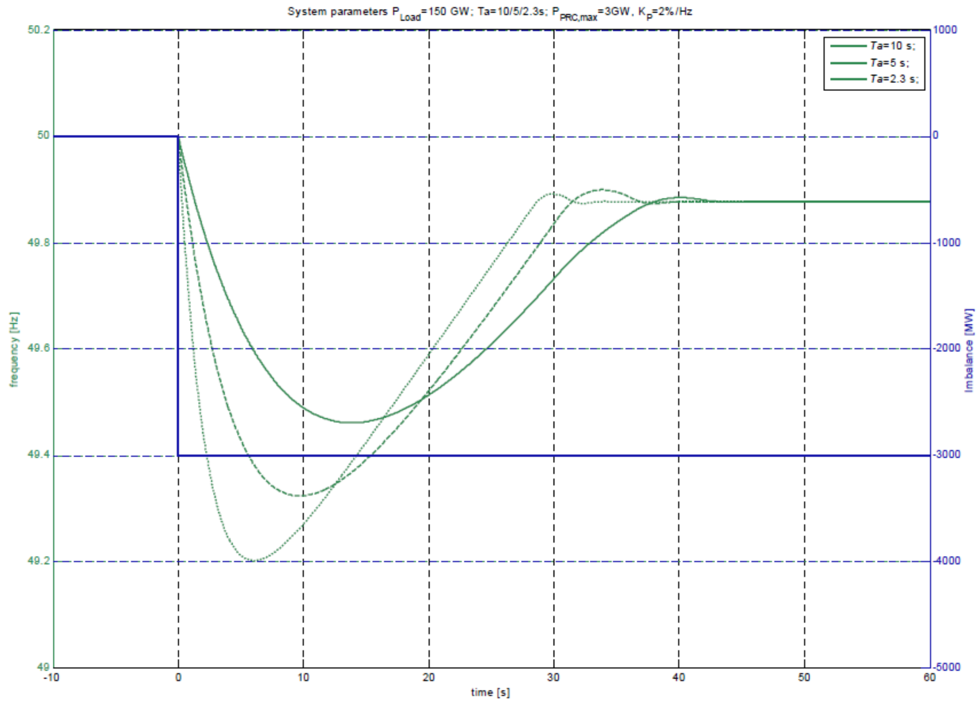
Rate of Change of Frequency (RoCoF) Withstand Capability
RfG: Article 13(1)(b); DCC: Article 28(2)(k); HVDC: Articles 12, 39(3)



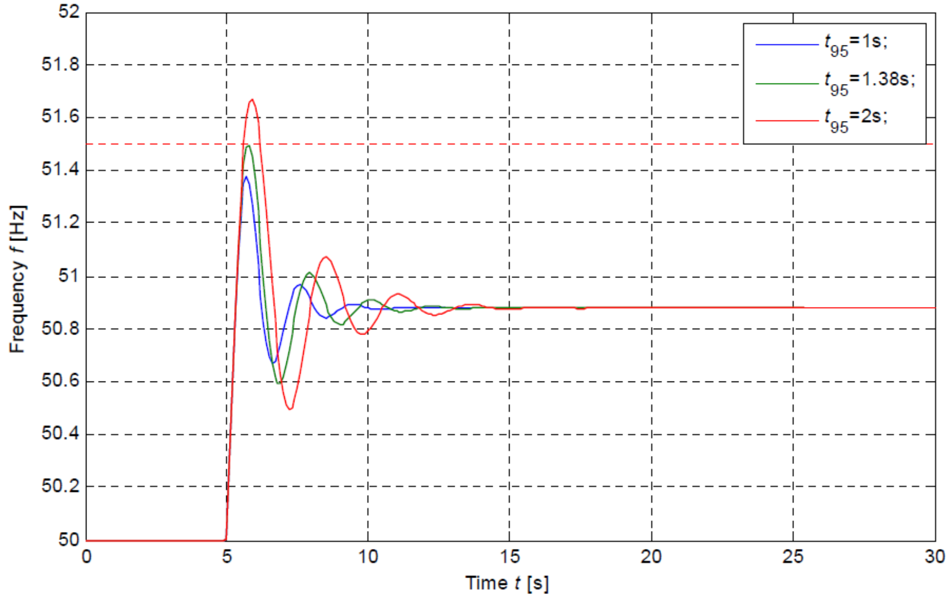


Figure 11: Time domain response for one exemplary scenario with different response times.

Extract from “Frequency Stability Evaluation Criteria for the Synchronous zone of Continental Europe – Requirements and impacting factors”, ENSTO-e RG-CE System Protection & Dynamics Sub Group,
March 2016

Rate of Change of Frequency (RoCoF) Withstand Capability

Outcome of Consultation of Stakeholders on Guidance for Connection Code implementation of frequency related parameters

What is your assumed or calculated value for maximum df/dt withstand capability in your basic design?

- **SPGM :**
  - GT can withstand 2.5 Hz/s with 100 ms (5 cycles @ 50 Hz) window
- **PPM - Wind Farm mainly full converter**
  - 6Hz per second has been observed and runs stable. 4Hz/s we guarantee.
- **PPM - Wind Farm mainly DFIG:**
  - 4Hz/s for current injection control mode (grid-forming control not yet investigated)

Important concerns /issues which are not mentioned in the previous slides:

SPGM

- rigidity of the connection point
- repetition of high df/dt can overstress both electrical and mechanical equipment
- the stability of controllers
- stability of the plant’s auxiliary machines

PPM - Wind Farm

- control instabilities

Rate of Change of Frequency (RoCoF) Withstand Capability

Outcome of Consultation of Stakeholders on Guidance for Connection Code implementation of frequency related parameters

Noteworthy comments:

None of the responding stakeholders use df/dt as an input to any protection for their plant (SPGM related stakeholders have indicated that in some cases it is used along other inputs for split detection). Therefore, their main concern about high df/dt is the high risk of instability and possible damages to their equipment.

The definition of RoCoF and measurement time window has also been a concern by the SPGM related stakeholders

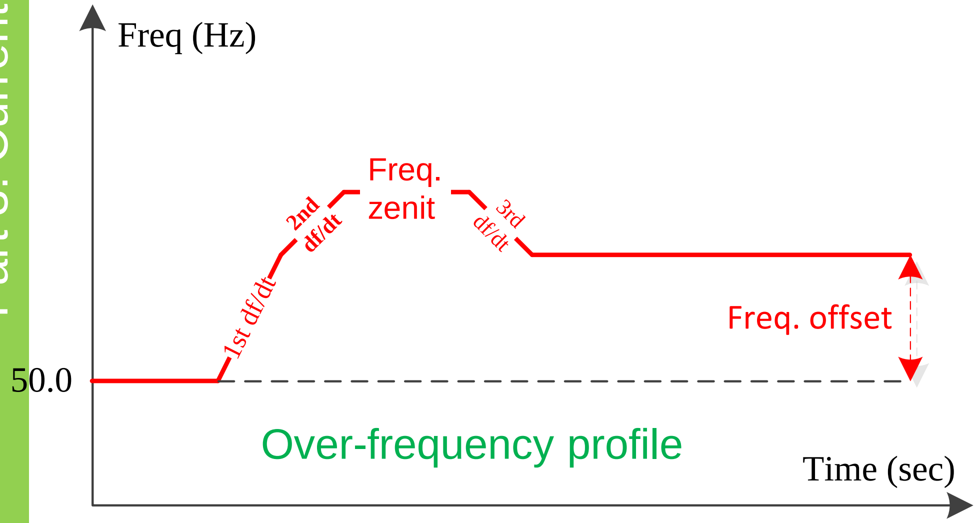
- **the RoCoF value shall be tied to other information**, such as frequency versus time profile, measuring method (including rolling average), operating condition (active power, PF) and grid status (grid topology, impedance, voltage profile) and possibly different profiles for over-frequency and under-frequency.
- **RoCoF stakes and df/dt capability have not been historically explicitly part of design requirement**.
- Analysis to understand RoCoF stakes, study and verify could be of a minimum of 10% of plant CAPEX and can exponentially increase depending on the outcome and the complexity of the system.
- This shall be considered a very conservative estimation, since costs can quickly increase even for the control and related instrumentations and actuators are to be considered.
- If mechanical/electrical integrity (shaft line torsional fatigue…) or system stability (generator stability, excitation voltage surge, compressor surge...) is involved, the cost could be tremendous and just put at stake the plant's viability.

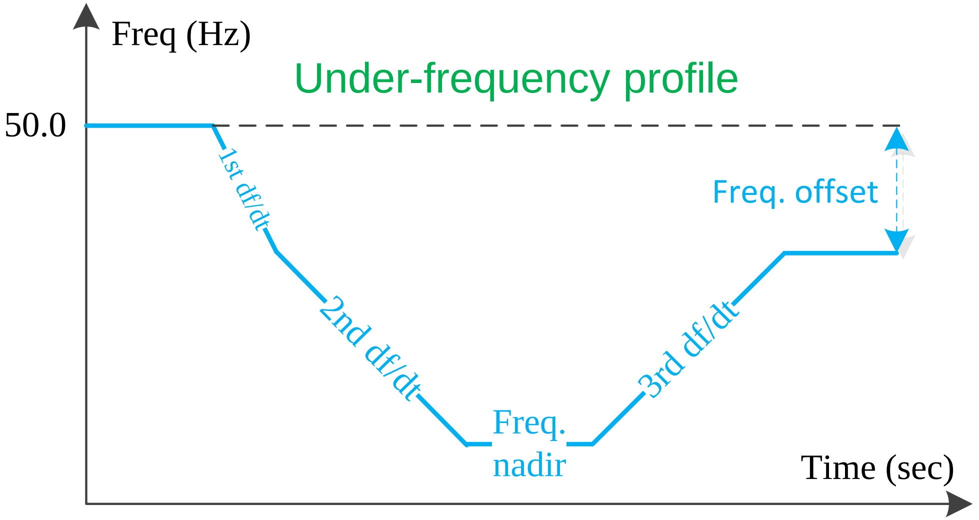
Rate of Change of Frequency (RoCoF) Withstand Capability frequency-against-time profiles

The TSO may define the withstand capability requirements as set of frequency-against-time profiles. The frequency-against-time-profiles shall express lower limits for under-frequency and upper limits for over-frequency of the actual course of the frequency deviation in the network as a function of time before, during and after the frequency event. Such profile should include:

- frequency nadir
- steady state frequency offset
- the duration that the user has to stay connected
- and consecutive *df/dt* ramps

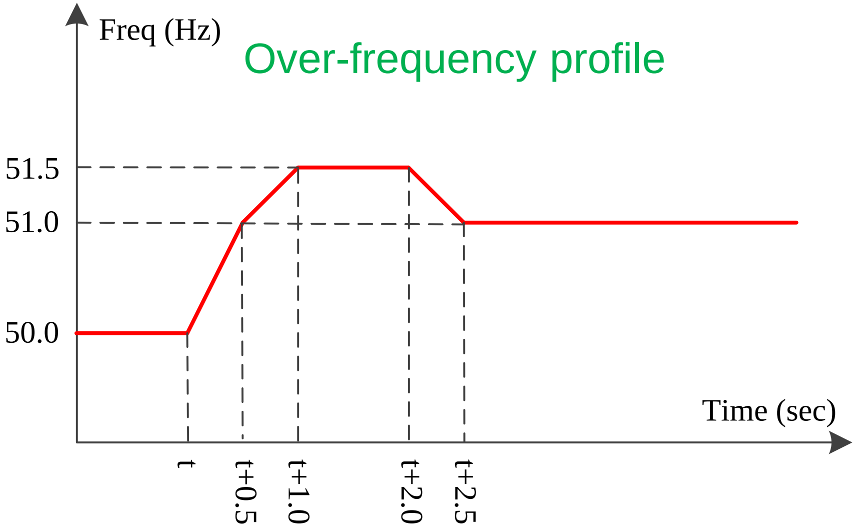
The following profiles are given as an example for both over-frequency and under-frequency profiles:

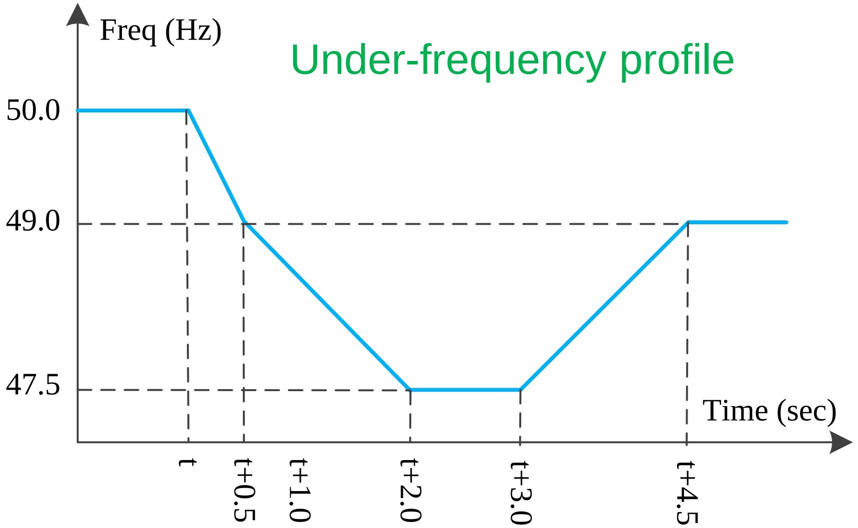




Rate of Change of Frequency (RoCoF) Withstand Capability WG CNC proposals for performance criteria

Based on results from studies and better harmonization between the connection codes, RoCoF measured at any point in time as an average of the previous 500 ms, is the most reasonable proposal for the minimum RoCoF withstand capability. This capability is to be verified with a specific /predefined frequency profile and explicit measuring technique. Following profiles are hence the WG CNC recommended profiles taking 2.0 Hz/s for duration of 500ms as the minimum RoCoF to be withstood.





Coordination on synchronous area level on RoCoF value to be withstood. Minimum RoCoF is to be defined on synchronous level without the prejudice to define by each TSO higher RoCoF on national level if needed to ensure safety of the system in case of asynchronous operation or islanding.

Synthetic Inertia (SI) and Demand Response very fast Active Power Control (DR APC)

Synthetic Inertia & demand response (DR) very fast active power control (APC).

NC RfG - Article 21.2(a): The relevant TSO shall have the right to specify that power park modules [of type C and D] be capable of providing synthetic inertia during very fast frequency deviations.

NC HVDC - Article 14.1: If specified by a relevant TSO, an HVDC system shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency.

NC DCC – Article 30.1: The relevant TSO in coordination with the relevant system operator may agree with a demand facility owner or a closed distribution system operator (CDSO) (including, but not restricted to, through a third party) on a contract for the delivery of demand response very fast active power control.

Synthetic Inertia & demand response (DR) very fast active power control (APC). Proposed parameters.

Minimum Inertia Contribution (from PGM, HVDC and DSR with very fast APC):

Based on

- System studies results for scenarios for horizon 2030 (see IGD HPoPEIPS)
- IGD recommended decision flow chart

Then, recommendation for national implementation of article NC RfG - Article 21.2(a) and NC HVDC - Article 14.1:

- Synthetic Inertia could be true inertia without delay or some form with an inbuilt short delay to allow for active controls. IGD HPoPEIPS concludes that true inertia provided through **Grid Forming converter control capability** seems to be a solid solution for systems with very low inherent inertia.
- **Synthetic inertia with control delays** can support system frequency stability when moving from a synchronous generation based system towards a higher penetration of non-synchronous generation, but entails a risk of other forms of system instabilities for very high penetration of this type of generation, In addition, synthetic inertia with control delays is impractical, if active control features responding within 20ms are needed (measurement alone need > 20ms).

Synthetic Inertia & demand response (DR) very fast active power control (APC). Stakeholder feedback on technical capabilities - SPGMs

- **SPGM**
  - Depending on the turbine size, technologies and arrangements (GT or ST gen only + generator, single, dual or tri-shaft with GT/ST/Gen coupled, etc...), H could be ranging from circa 5 to 15s. H could be marginally modified via the selection of larger generators in portfolio (if available). The related cost depends on many different factors; a minimum of 5% CAPEX impact can be expected when considering the least complex solution. Economic impact will be much higher for other units, if, for example, the generator frame is changed, affecting the overall product design. The cost impact estimated above can be relevant also for existing units, when it is possible to implement modifications. Arrangements for operation in synchronous condensing mode are available (clutch most common). The costs of this modification can vary so much from a generating unit to the other that a case-by-case evaluation shall be carried out.

  - More dedicated for smaller size modules:
    - The typical inertia constant is dependent from the inertia of the engine and the generator. The typical inertia constant (H) is between 0.4 and 0.8. It is possible to add additional inertia by putting some additional mass to the genset, for example a flywheel. The additional mass has disadvantages in other areas. For example, it reduces the energy efficiency and leads to additional costs.

Synthetic Inertia & demand response (DR) very fast active power control (APC). Stakeholder feedback on technical capabilities - NSGs

- **PPM - Wind Farm mainly full converter**
  - The synthetic inertia feature we have implemented works very well, it doesn't bring additional instabilities. Please contact Hydro Quebec for more details. {Comment: Different objective. HQ requires a rectangular block of power injected to deal with specific hydro aspects, not SI or a kdf/dt contribution} Certainly the recovery period and further details can be improved, but this is not a fundamental drawback. We use so far inverters that are (no purpose) not "grid forming", I prefer to call them "the typical VSCs with basically a current-source behavior to the grid". Please specify what you mean by "Grid Forming". So far this is not a meaningful term. All devices with power electronics have to respect current limits at the end (hardware limitations). Even if I perform with my inverter like a voltage source under normal steady state operation, under certain grid events (transients) my current will reach the maximum in few ms , and then I cant perform like a voltage source any more. I can then only adjust my current injection (to whatever phase angle, DC component...) the power system would like to have. But I can never exceed the current limits of the semiconductors. The term "Grid Forming" is way too general and unclear so far. So far the cost for synthetic inertia is very low, as it has to cover only the development and certification cost. Up to now there was no hardware modification included. As soon as the requirements (or markets) impose to built in (battery-) storages the cost can explode. The final cost then mainly depends on how much energy has to be stored.

Synthetic Inertia & demand response (DR) very fast active power control (APC). Stakeholder feedback on technical capabilities - NSGs

- **PPM - Wind Farm mainly DFIG**
  - Currently synthetic inertia is not available to 50Hz wind turbines. It has been developed and already in operation for 60Hz grids in Canada. {Comment: Again this is not considered SI, it is a solution for initial hydro reversal}.The synthetic inertia contribution for 50Hz wind turbines in currently under investigation but it may be expected to be similar to the 60Hz performance – maximum 10% of Pn boost for maximum of 10 seconds with recovery period of 60 seconds after the boost and active power loss of maximum 20% of Pn. The minimum performance values will vary across the wind turbine types mainly according to their mechanical design, rotor diameter and aerodynamical characteristics of the blades.
  - There are currently no plans to implement a grid forming control, since this seems to be a research topic with several unanswered questions and an unclear business case. These include:
    - Where does the dynamic active power come from?
    - Due to mechanical rating and fundamental aerodynamic limitations it will not be possible to use the wind turbine rotor mass as a mechanical dynamic energy storage for these purposes.
    - The only feasible solution seems to be some other fast storage (like batteries) that is decoupled from the “wind” part of the generation.
    - Who will pay for this storage and how large should it be?
    - Is it more economic to put this dynamic storage into generation sites, in the grid or near load centers?
    - How much will the dynamic component rating (especially converter rating) have to be increased?
    - Who will pay for this increased rating? Will this be an ancillary service?
    - If a voltage source type control (VSM) is used, how big would the choke in front of the converter have to be to provide a useful response?
    - Does this choke size lead to an increase in component voltage rating or losses?

Synthetic Inertia & demand response (DR) very fast active power control (APC). Proposed parameters – continued - The suggested outcomes are:

- Synchronous areas Ireland and GB are likely to face in the near future times of very high penetration and at times extremely low inertia.
  - Recommendation for a national choice of a requirement for a **minimum inertia contribution H in the range 2-7 MWs/MVA** as soon as possible after 2020.
  - Recommendation to take into account available technical capability for new generation as well as headroom or storage.
  - Inertia contribution to be assessed from a holistic perspective to avoid adverse system impacts.
  - Alternatives could be considered, including dispatch constraints for connections not equipped to provide inertia.

  - *GB initial national proposal to cope with a range of High Penetration challenges follows in subsequent slides*

- For Other synchronous areas (CE, Nordic and Baltic),
  - **No minimum requirement for inertia contribution** is considered necessary for the SA as of today
  - However, if a country (as defined in HPoPEIPS) foresees extremely low inertia contribution (e.g. at times H < 1 MWs/MVA for >10% of time) to **cover cases of severe disturbances, such as becoming part of an island with inadequate inertia**, the need for the same requirements as above should be considered in collaboration with adjacent TSOs.

- DR with very fast APC
  - In addition to synthetic inertia which limits RoCoF, frequency stability can be supported (to avoid too low nadir) by other resources faster than FSM. This is the objective of **DR with very fast APC** as covered by NC DCC – Article 30.1.
  - For this to be effective, DR with very fast APC would require the delivery of 90% of the available active power change within 1s or 2s and be sustained for 5s or 10s to **bridge a possible resource gap between inertia and FSM**.

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High Convertor Penetration - Options

With current technology/models, the system may become unstable when more than 65% of generation is Non-Synchronous

For the FES 2Degrees, Consumer Power and Slow Progression scenarios, it is currently forecast this level could be exceeded for 800-1800Hrs p.a. in 2023/24 and for 2100-2750Hrs p.a.in 2026/27.

Key

No	Doesn't Resolve Issue
P I	Potential Improves
Yes	Resolves Issue

Solution	Estimated Cost	RoCoF	Sync Torque/Power (Voltage Stability/Ref)	Prevent Voltage Collapse	Prevent Sub-Sync Osc. / SG Compitable	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance	System Level Maturity	Notes
Constrain Asyncronous Generation	Hgh	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	These technologies are or have the potential to be Grid Forming / Option 1
Syncronous Compensation	High	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	
VSM	Medium	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	P	Modelled	
VSM0H	Low	No	Yes	Yes	No	P	P	P	Yes	P	Modelled	Has the potential to contribute but relies on the above Solutions
Synthetic Inertia	Medium	Yes	No	No	P	No	No	No	No	No	Modelled	
Other NG Projects	Low	Yes	P	Yes	No	No	No	P	P	No	Theoretical	

Timescale (Based on work by SOF team)	RoCoF	Sync Torque/Power	Prevent Voltage Collapse	Prevent Sub-Sync Osc.	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance
	Now	2019	2019	Now	2020	Now	Now	2025	2025

Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

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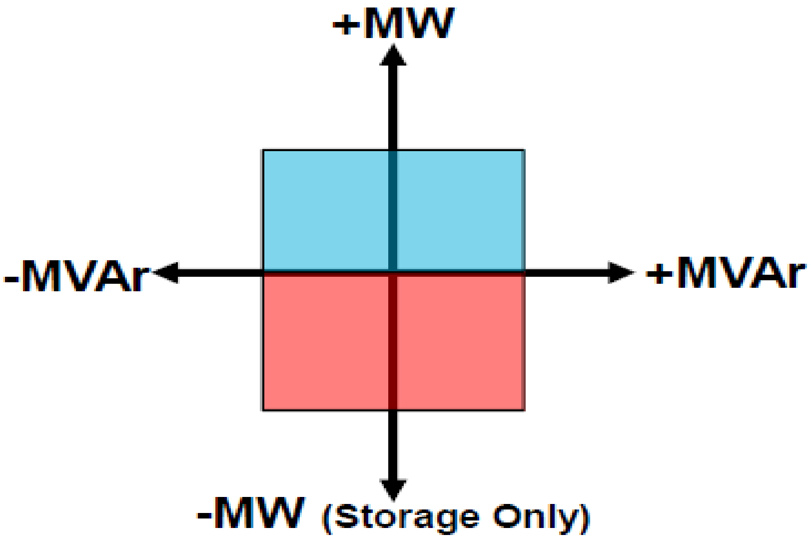
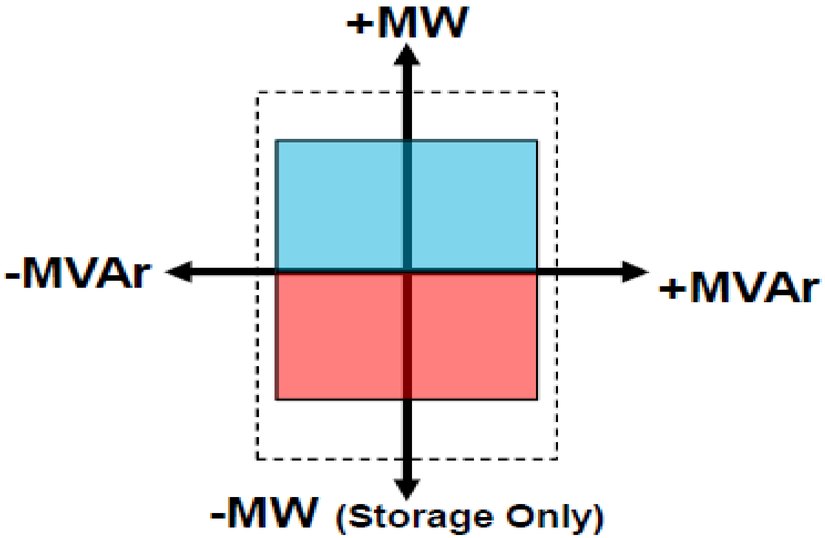
Steady State Capability

- +0.95 Lead/Lag at 100% Rated Power
- Red region applicable to storage and HVDC only
- Many requirements in this region taking from existing Class 1 requirements



Extended Capability

- Available for 20Secs
- Harmonics & Imbalance as GBGC CC6.1.5, CC6.1.6 & CC6.1.7
- 1.33pu Rated Power (33% on rated power > current operating point)
- 1.5pu current (on rated MW)



Please Note: Values (e.g. 1.33pu) quoted in these or the following slides are based on the preliminary studies presented here but maybe subject to change if further studies indicate changes are required.

Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

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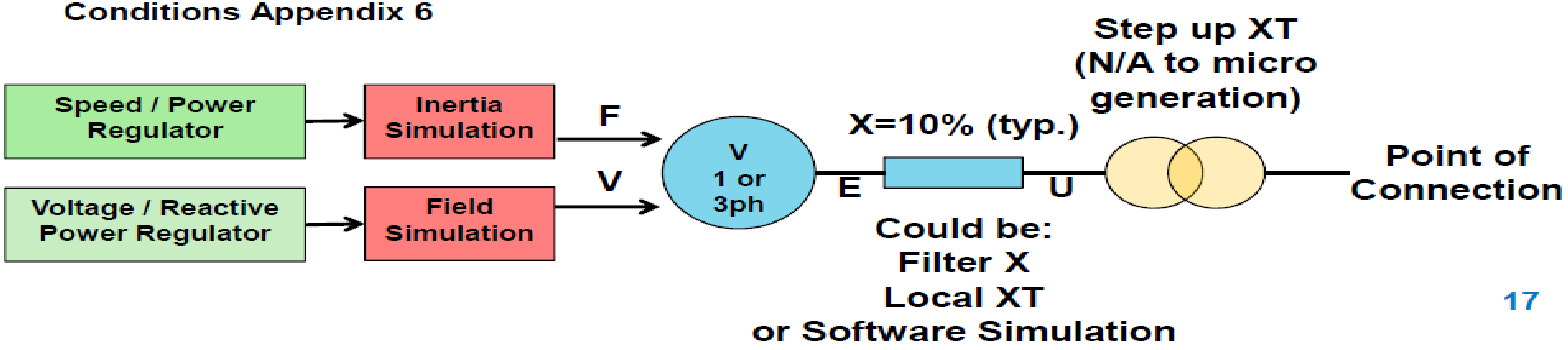
- Should *behave* like a balanced 3ph voltage source behind a constant impedance over the 5Hz to 1kHz band
- Rate of change of frequency should be limited by an equivalent inertia of H=2 to 7s on rated power
- Rapid change to the phase voltages (V), frequency (F) and phase angle in the >5Hz Band are not permitted whilst the operating point remains within the extended capability zone
- Harmonics and / or unbalanced currents will be as GB Grid Code CC6.1.5, CC6.1.6 and CC6.1.7. If the levels stated are exceeded they may be reduced by adjusting the wave shape or phase voltages. The speed at which this occurs may depend on the level.
- Dynamic performance requirements similar to those for GB Grid Code Connection Conditions Appendix 6



Requirement Proposal for Option 1 (Grid Forming Convertors - Initial Thoughts)

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Operation Outside Extended Zone

- If the extended capability zone is breached the device may rapidly reduce real or reactive power, volts or current by reducing pulse width, phase angle, frequency, volts etc. to bring the device back within but not below the extended rating (for 20secs) then normal rating.
- It is anticipated that operation within the extended rating would be followed by operation at less than the previous rating allowing recharging of storage and cooling of power components and that extended rating would be available again after this period. Subsequent cycles would be available on a continuous on going basis provided that on average the device has only operated at full rating.
- Fast Fault Current Injection and Fault Ride Through for Convertors is currently being discussed in Grid Code (GC0048 / GC100) RfG / HVDC Implementation formal working group and can be followed through that forum.

FFCI Option 1 for RfG implementation

Under GB RfG adoption, it is necessary to augment the existing Grid Code definition of current injection. EU RfG requirements drive more robust specification of NSG to address the trends described in the SOF:-

- SOF (System Operability Framework – see National Grid website) illustrates extent of short circuit level decline and its impact upon stability, the ability of generation to ride through faults and for network protection to operate.
- Our studies illustrate the importance of new forms of replacement fault injection to support proposed fault ride through curves which address the issue today. This can be delivered by traditional convertor design choices, to ensure current injection is maximised and not out of phase but relies on a population of Grid Forming Generation.
- However, our studies also illustrate that in order to ensure that across the next 8 years the capability to support fault ride through and voltage against time performance does not degrade, grid forming capability is required from 1st January 2021 onwards. This is the "**FFCI Option 1**" requirement - requiring a short term 1.5p.u. capability and an equivalent inertia of at least 2-7MWs/MVA (for 20s) operating against the principles of VSM as discussed.

Initial TSO's and stakeholders' view on Demand Response System Frequency Control (DR SFC)

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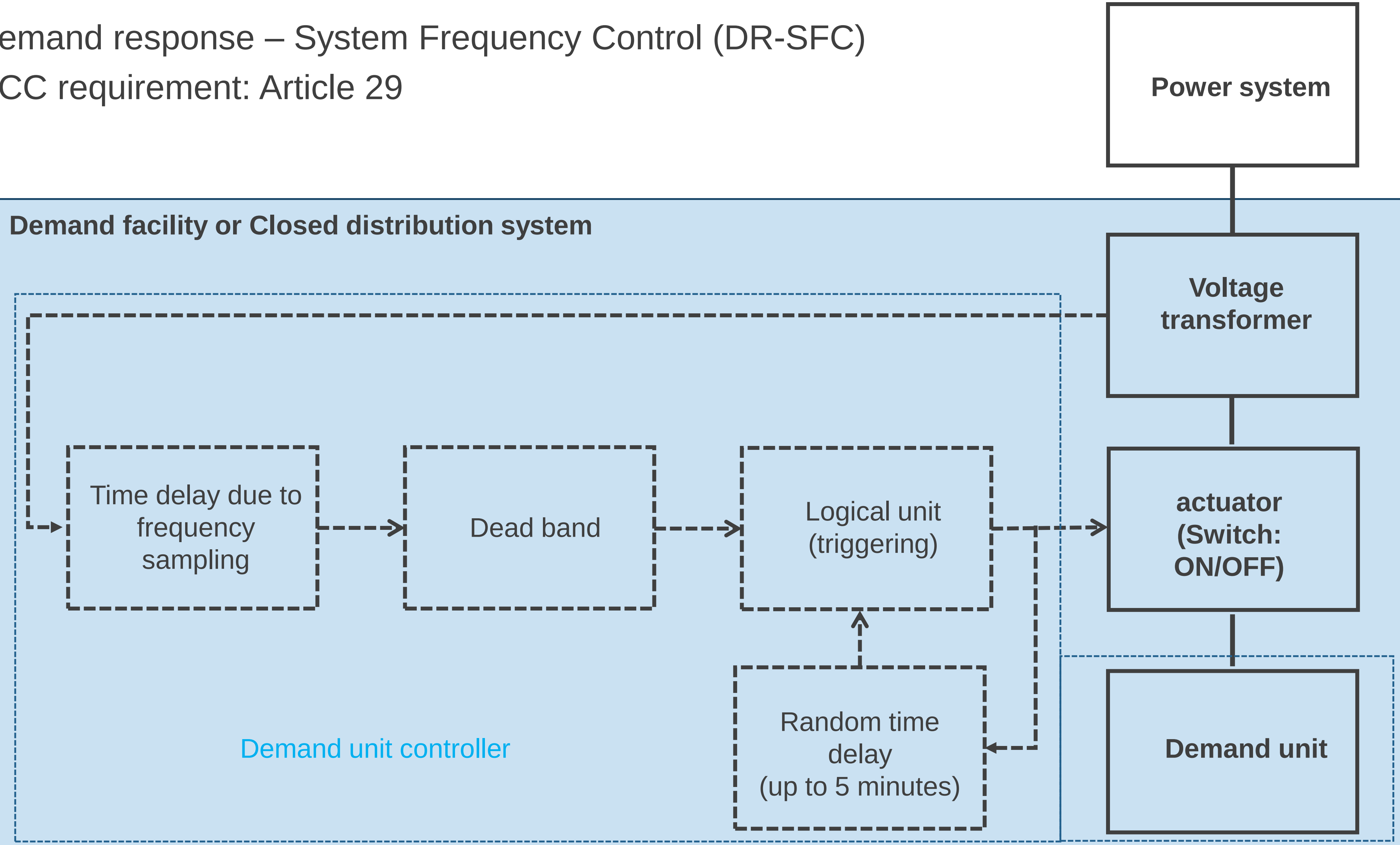
Demand response – System Frequency Control (DR-SFC)
DCC requirement: Article 29

1. Demand facilities and closed distribution systems may offer *demand response system frequency control* to relevant system operators and relevant TSOs.
2. Demand units with demand response system frequency control shall comply with the following requirements, either individually or, where it is not part of a transmission-connected demand facility, collectively as part of demand aggregation through a third party:
   a) be capable of operating across the *frequency ranges* specified in Article 12(1) and the extended range specified in Article 12(2);
   b) be capable of operating across the *voltage ranges* specified in Article 13 if connected at a voltage level at or above 110 kV;
   c) be capable of operating across the *normal operational voltage range of the system at the connection point*, specified by the relevant system operator, if connected at a voltage level below 110 kV. This range shall take into account existing standards, and shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);
   d) be equipped with a control system that is insensitive within a **dead band** around the nominal system frequency of 50,00 Hz, of a **width** to be ***specified by the relevant TSO in consultation with the TSOs in the synchronous area***. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1);
   e) be capable of, upon return to frequency within the dead band specified in paragraph 2(d), initiating a random time delay of up to 5 minutes before resuming normal operation. The **maximum frequency deviation** from nominal value of 50,00 Hz **to respond** to shall be ***specified by the relevant TSO in coordination with the TSOs in the synchronous area***. For demand units connected at a voltage level below 110 kV, these specifications shall, prior to approval in accordance with Article 6, be subject to consultation with the relevant stakeholders in accordance with Article 9(1). The demand shall be increased or decreased for a system frequency above or below the dead band of nominal (50,00 Hz) respectively;
   f) be equipped with a controller that measures the actual system frequency. Measurements shall be updated at least every 0,2 seconds;
   g) be able to detect a change in system frequency of 0,01 Hz, in order to give **overall linear proportional system response**, with regard to the demand response system frequency control's sensitivity and accuracy of the frequency measurement and the consequent modification of the demand. The demand unit shall be capable of a **rapid detection** and **response to changes in system frequency**, to be ***specified by the relevant TSO in coordination with the TSOs in the synchronous area***. An offset in the steady-state measurement of frequency shall be acceptable up to 0,05 Hz.

Demand response – System Frequency Control (DR-SFC)

DCC requirement: Article 29



Demand response – System Frequency Control (DR-SFC) stakeholder feedback on technical capabilities

Q1 on DR-SFC usage of wind turbines including battery storage for DR-SFC.

A: Wind turbines including battery storage are not part of NC DCC (acc. to article 3 (2)(b))):

„2. This Regulation shall not apply to:
… (b) storage devices except for pump-storage power generating modules in accordance with Article 5(2).“

Initial TSO’s and stakeholders’ view on Frequency ranges of automatic connection and gradient of active power increase

Frequency ranges of automatic connection and gradient of active power increase

NC references

Topic:	**Frequency ranges of automatic connection and gradient of active power increase**
Code(s) & Article(s)	NC RfG Article 13.7
Expected implicit and explicit interactions with other NCs articles	NC DCC Article 19.4 NC RFG Article 14.4
Issues to be considered when providing implementation guidance (covering system and technology characteristics)	*Automatic connection of power generating units* • Definition of frequency and voltage limits were connection is allowed – typically the "normal operational" range. • Coordination between frequency and voltage parameters for reconnection of generating units and reconnection of demand facilities and DSOs *Gradient of active power increase* • Gradient of active power increase may depend on the primary energy source or on the prime mover characteristics Gradient of active power decrease (not covered by codes) may depend on the system characteristics

Frequency ranges of automatic connection and gradient of active power increase

Automatic connection:

Frequency ranges of automatic connection is typically named as “normal operational” range.

Report with recommended parameters: ENTSO-E “Dispersed Generation Impact on RG CE region security”, 2014.

Automatic connection shall be coordinated with protection setting.

Gradient of active power increase:

Essential requirement for handling system stability during rapid wind fronts and sharp cloud edges.

Typically value in DK is max. ramp up/down 10% of nominal capacity/sec – for Type A and B facilities typically ramp up/down is max. 50 kW/sec.

Frequency ranges of automatic connection and gradient of active power increase

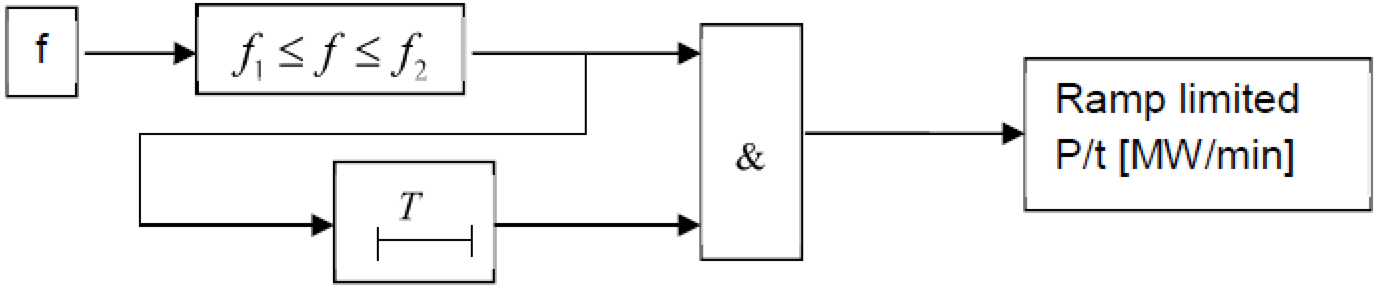


Figure 13: Block scheme for automatic reconnection

Extract from ENTSO-e, “DISPERSED GENERATION IMPACT ON CE REGION SECURITY DYNAMIC STUDY - 2014 REPORT UPDATE”

Initial 2014 recommendation for CE (To be updated):

- Frequency stable in the range between 49.9 (f1) Hz and 50.1 (f2) Hz
- Delay time T: from 60 to 300 s, established by single TSO
- Maximum gradient of ramp limited delivered power: < 20% of maximum power / min

Frequency ranges of automatic connection and gradient of active power increase - stakeholder feedback on technical capabilities

No specific question raised by ENTSO-e

- Network codes on grid connection foresee coordination with “relevant system operators”. This includes DSOs for all aspects relevant to the DSOs.

Initial TSO's and stakeholders' view on Auto reconnection after an incidental disconnection

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Auto reconnection after an incidental disconnection

NC references

Topic:	Automatic reconnection after incidenctial disconnection
Code(s) & Article(s)	NC RfG article 14(4)(b) NC DCC article 19(4)(a)
Expected implicit and explicit interactions with other NCs articles	NC RfG Preamble 20,
Issues to be considered when providing implementation guidance (covering system and technology characteristics)	Principle and motivation for the automatic reconnection functionality. Recommendation on the time and frequency interval for automatic reconnection.

Auto reconnection after an incidental disconnection

Automatic reconnection:

System frequency for allowing automatic reconnection shall be within the "normal operational" range.

Ramp up rate shall be controlled after reconnection – a default value defined by operation.

Automatic reconnection shall be coordinated with protection setting.

DK parameter for auto reconnection after an incidental disconnection is a latency period of minimum 3 min.

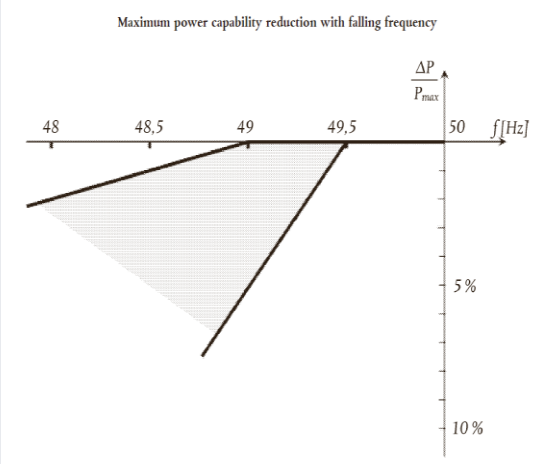
Auto reconnection after an incidental disconnection - stakeholder feedback on technical capabilities

No specific question raised by ENTSO-e

- Network codes on grid connection foresee coordination with “relevant system operators”. This includes DSOs for all aspects relevant to the DSOs.

Initial TSO's and stakeholders' view on Admissible active power reduction at low frequencies

Admissible active power reduction at low frequencies (1/3)

Code(s) & Article(s)	NC RfG Article 13 (4)
Expected implicit and explicit interactions with other NCs articles	The implementation of the requirement of this article has an impact on • GLOS related to the sizing of synchronous area FCR, FRR and UFLS schemes. • other frequency parameters in the connection codes (LFSM-U, RoCoF, …) The implementation of the requirement of this article is impacted by • Synchronous area characteristic about RoCoF and as well related capabilities tackled in articles of NC RfG, DCC and HVDC
Issues to be considered when providing implementation guidance (covering system and technology characteristics)	 Frequency-dependent admissible active power reduction taking into account technology limitations: Requirement could be split per technology depending on their capabilities. Pmax(f)-characteristic is expected to be provided in line with the requirement of the NC RfG. Eventually, multiple Pmax(f)-characteristics could be considered for different time frames. Harmonization of the requirement at synchronous area level could make sense, especially for the system needs driven part of the requirement (mainly faster time frames). Ambient conditions in which the characteristic is defined should be recommended. It could make sense to harmonize ambient conditions at EU level and maybe further harmonization with existing standards

Admissible active power reduction at low frequencies (2/3) - Stakeholder feedback on technical capabilities

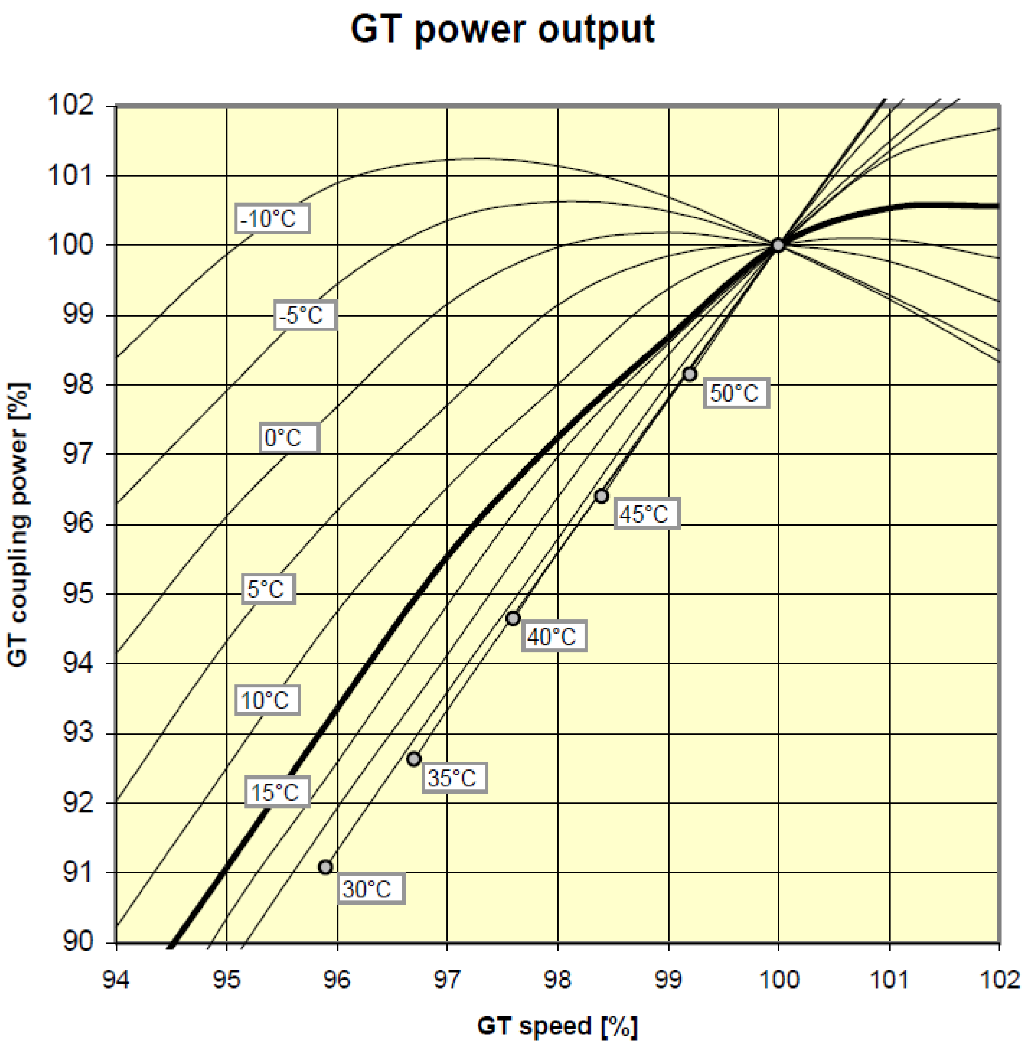
- **PPM - Wind Farm mainly full converter**
  - Steady state operation with rated frequency with plus or minus 7Hz is ok.

- **PPM - Wind Farm mainly DFIG**
  - Within the current NC RfG frequency ranges, wind turbines does not need to reduce active power at low frequencies.

- **SPGM**
  - Upper profile as in RfG is a major concern for gas turbines. The power reduction can be present already when the frequency drops from the 50 Hz.
  - The hotter the ambient temperature, the lower the capability to maintain power output at falling frequency. For GT, the decrease of active power is extremely limited when at low temperature. The GT output is typically specified at ISO condition.

  - Power reduction must be performed below 49 Hz in order to avoid overloading of the engine. The engines start derating with a rate of 10 % /Hz and operate for unlimited time.
  - Mainly critical for gas engine
  - Maintain active power output constant at low frequencies is only possible when engines are over-sized.
  - All ambient conditions (temperature, air pressure and humidity) have an impact. The reference conditions are 400 m to 500 m, 25 to 35-degrees Celsius ambient temperature and 15 to 20 g H_2O/1 kg of air. The operating ambient conditions are considered for each installation site.

Admissible active power reduction at low frequencies (3/3) - Stakeholder feedback on technical capabilities



Wrap-Up and Next Steps

2nd Public workshop on Frequency Stability Parameters for Connection Network Code Implementation

Brussels, 20. July 2017

Thank you for your participation