European Network of
Transmission System Operators
for Electricity

Need for synthetic inertia (SI) for frequency regulation

ENTSO-E guidance document for national implementation for network codes on grid connection

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DESCRIPTION

Code(s) & Article(s)	**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frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency.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.
Introduction	System inertia is an essential parameter for frequency stability of the electrical power system. It determines the initial rate of change of frequency in case of a sudden imbalance between supply and demand (e.g. trip of a large MW source or demand). A slower rate of change of frequency provides margins for activating automated active power reserves, predominantly via Frequency Sensitive Mode (FSM) (normal state) or Limited Frequency Sensitive Mode (LFSM) (emergency state). Replacement of conventional synchronous power generating modules, whose rotating masses inherently contribute to system inertia, by power park modules largely connected through power electronics results in a decrease in the Total System Inertia (TSI). Increased application of power electronic drives at the demand side also contributes to a decrease in inertia. This decrease in TSI combined with a higher frequency volatility, particularly if no countermeasures are taken, may become an essential aspect in context of frequency stability. The objective of this IGD is to provide guidance on Synthetic Inertia (SI) aspects to be considered when choosing relevant national parameters and opting in or out of non-mandatory requirements. It should be noted that the need for SI is less when the relevant TSO is experiencing or foreseeing modest penetration of RES. The challenge of maintaining frequency stability increases dramatically when total system inertia decreases at synchronous area (SA) level. Exceptionally, during rare system splits, some TSOs normally relying upon adequate inertia from elsewhere in the SA, could experience a lack of inertia for a short critical time. If insufficient inertia is available after a system split, this could result in a major challenge to prevent an immediate system collapse. The IGD on High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS) contains a detailed analysis in its Appendix 2 of the foreseen development of RES penetration (based on an analysis associated with TYNDP2016) and consequential calculated Total System Inertia by 2030 for each Synchronous Area. HPoPEIPS also breaks down the TSI of each SA to inertia contributions from each country. This analysis assumes that new RES is predominantly interfaced with power electronics and that no other sources of inertia (SI) are available.

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The development towards lower TSI with increased RES production is used in HPoPEIPS as an indicator to illustrate the broader potential development towards weaker power system (or lacking in system strength). A number of additional challenges beyond inertia are associated with lack of system strength. For the most extreme levels of penetration in operational timescales, there could be adverse interactions between different remedies for various low system strength challenges. To safeguard such situations, the IGD HPoPEIPS introduces more holistic and effective approaches, including possible adverse interactions like SI's potential to add to other forms of instability. The IGD HPoPEIPS suggests a process for determining where and when actions should be considered to deal with low system strength.

The need for SI applies particularly for smaller synchronous areas with high penetration of non-synchronous generation which tend to have lower total system inertia and greater frequency volatility (such as Ireland and Great Britain). It may also apply to large synchronous areas to prevent total system collapse in case of a system split and subsequent island operation. From a system operation perspective it can therefore be of crucial importance that all generators, HVDC systems are able to provide SI and supported further by fast action from suitable demand units. SI could then facilitate further expansion of RES, which do not naturally contribute to inertia.

However, the topic of SI needs further research and investigation efforts like the major pan European project MIGRATE.

NC frame

RfG defines synthetic inertia as the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power generating module to a prescribed level of performance. Based on Article 21 (2) (b) of RfG, the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO. Hence, RfG focuses on the performance requirement of the SI from a functional perspective rather than details on technical implementation to achieve the objectives.

There are two distinct challenges.

1. Limit the system initial rate of change of frequency (RoCoF) – df/dt

The initial RoCoF after a worst case disturbance shall not exceed the maximum withstand capability of users (demand and power generation units). User limitations include both control system robustness for high df/dt (including existing conventional plant) as well as use of df/dt for island detection and Loss of Mains (LOM) protection for embedded generators. These RoCoF LOM protections typically have a df/dt 500ms rolling measurement window. For these aspects a form of SI contribution virtually without delay (as provided by synchronous generators) may be required. Delivery in a few 100 ms after detection may be too slow. For systems with very high penetration of non-synchronous generation, the IGD HPoPEIPS warns about stability problems.

2. Limit the lower/higher nadir of the frequency to avoid demand/generation disconnection.

A fast activated active power contribution can help to raise the frequency and keep it above the first stage of demand disconnection.
The urgency is less than in challenge 1 above and therefore consideration can be given to reduce reliance on the difficulty of making a refined fast df/dt measurement. Canadians

have done this for more than a decade and initiated an active power block infeed rather than a power increase proportional to df/dt. Fast frequency response (delivered in the very first seconds) may be an alternative or supplement as reaching the nadir is likely to take several seconds. This has generally been shown to be within the capability of existing PPMs. As these services may not fall within the category often termed "true inertia" (dP=k df/dt), using the term SI for these services is controversial although at least for some to an extent qualify in RfG terminology "to replace the effect of inertia of a synchronous power generating module to a prescribed level of performance".

These two aspects are illustrated in the following figure (extracted from the National Grid Electricity Ten Year Statement 2014)[1].

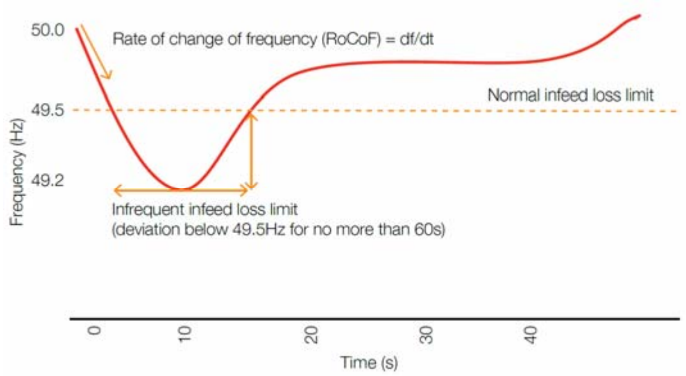

FIGURE 1. SYSTEM FREQUENCY LIMITS AND CONCEPT OF ROCOF REF.[1]

Further info	1. IGD on High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS) 2. IGD on Rate of Change of Frequency (ROCOF) withstand capability 3. DNV-GL, EirGrid, *RoCoF Alternative Solutions Technology Assessment (Phase 1 and Phase 2)* 4. EirGrid, Soni, *Delivering a Secure, Sustainable Electricity System (DS3) Program* 5. DNV-KEMA and COWI for European Commission, *Technical report on ENTSOE Network Code: Requirements for generators* 6. General Electric, *California ISO (CAISO) Frequency Response Study* 7. Aalborg Universitet, *Dynamic Frequency Response of Wind Power Plants* 8. NREL, *Understanding Inertial and Frequency Response of Wind Power Plants* 9. National Grid, *Grid Code Frequency Response Working Group, Requirements for System Inertia* 10. NREL, *Tutorial of Wind Turbine Control for Supporting Grid Frequency through Active Power Control* 11. NERC, *Frequency Response Initiative report* 12. ENTSO-E WG-SPD, *Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe* 13. Andrew J. Roscoe et al, *A VSM (Virtual Synchronous Machine) Convertor Control Model Suitable for RMS Studies for Resolving System Operator / Owner Challenges*", WIW 2016 14. Richard Ierna et al, Effects of VSM Convertor Control on Penetration Limits of Non_ Synchronous Generation in the GB Power System, WIW 2016 15. Richard Ierna and Andrew Roscoe, National Grid, *From Zero to 100% NSG using a reduced GB model*

[1] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=37790

	16. SMA Solar Technology AG, *Low Voltage Ride Through with high current injection* 17. NationalGrid, [GC0100 EU Connection Codes GB Implementation]() Please refer to the comprehensive reference list of IGD on HPoPEIPS for more information

INTERDEPENDENCIES

Between the CNCs	All CNCs allow introducing synthetic inertia (RfG and HVDC) or very fast active power response (DCC).
With other NCs	**COMMISSION REGULATION (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation**, adopted by the EC on 04.05.2016, Article 39 ("Dynamic stability management "). The objective is to enable TSOs to determine TSI under current operating conditions and consequently having a greater ability to manage consequences.
System characteristics	<u>Consideration on limiting initial df/dt</u> Use of RoCoF as a Loss-of-Mains (LOM) protection is the largest concern in respect of high initial df/dt, because of potential tripping of embedded generators through mal operation of the protection when the embedded generation is not islanded, but simply subject to a system wide fast frequency movement. A significant further challenge for some control units is stability aspects of control systems of power generating modules during high RoCoF (see second example below concerning R&D early evidence of possible adverse effects related to the converter control type of control associated with implementation of SI). Traditional per unit system inertia H for a synchronous generator dominated system is of the order of 5-6 sec (or $T = 2 \cdot H = 10\text{-}12$ sec). This varies from country to country according to the generation profile. Future system design considerations may need to establish the lowest allowable per unit system inertia at synchronous area level under the most challenging conditions, which may be defined by a normative incident. Each TSO is responsible for establishing its minimum necessary inertia for secure operation in case of relevant incidents with regard to its area of responsibility (loss of generation or system split). It is also necessary that each TSO establishes its maximum load imbalance to be withstood after a system split or loss of generation. Selection of the maximum load imbalance robustness target value and its consequences is extensively covered in the ENTSO-E report "Frequency stability evaluation criteria for the synchronous zone of Continental Europe – Requirements and impacting factors" with a suggested conclusion of a desired capability of robustness up to 40% load imbalance. In this regard, each TSO/control block should consider its capability to provide the necessary inertia in case of system split for its individual stability in addition to contribution to overall synchronous area inertia. The expected initial df/dt should be calculated and it may be managed actively in operational timescales in context of existing df/dt robustness. One extreme legacy case of low RoCoF in Great Britain (GB) is the widespread use of settings at 0.125 Hz/s. To avoid operational limitations (e.g. redispatch and renewable energy curtailment) measures shall be considered to secure total system inertia under

	normative conditions. These shall include:
	• SI contribution from future Power Park Modules (PPMs), e.g. to require minimum contribution such as H=3s.
	• SI contribution from HVDC links.
	    • If the energy is drawn from another system consideration of the impact on that system is needed.
	    • Alternatively, a short burst of active power for the purpose of limiting the initial df/dt can be drawn from the capacitive energy on the DC link. This applies also to the DC links of PPMs. However, the stability/dynamic effects and consequences/performance of such method should be carefully studied/considered.
	• Demand Response (DR) very fast system frequency control (autonomous).
	
	Aggressive SI might lead to second frequency swing which should not be immediately treated as a negative reaction. If reduction of df/dt is the main concern of a TSO, SI over-react might be useful if relevant TSO can manage the second swing via other measures (e.g. by delivery of frequency sensitive mode (FSM)). However, such approaches require accurate models and comprehensive system studies. Also, parameters such as wind speed or solar radiation, demand size and available SI needs to be taken account of to determine the need and the scale of SI.
	
	Considerations on limiting the frequency nadir.
	
	After withstanding the initial RoCoF (limited by either inherent inertia alone or combined by SI) after an outage or system split, the next challenge is to minimize the deviation of frequency nadir from reference frequency. Different studies (e.g. [12]) show that in such cases, the primary frequency response can be too little and too slow to be able to reduce the frequency nadir. Meanwhile, SI can be very effective, benefiting from the speed and controllability of power electronic links.
	
	Frequency response from wind farms has been common in several countries for more than 10 years. See examples of existing grid codes and regulation drafts at the end of this document.

Technology characteristics	Many patents and studies have investigated the measures and technical aspects of providing SI via power park modules and HVDCs. This includes the ability to charge/discharge energy into/from wind turbine blades, magnetic fields of machines and also DC link capacitors using different control schemes. Hence, the technical feasibility of SI is not an issue by principle (although may it be not mature enough presently and need more time for further technical enhancement).
	
	Based on the Dynamic Stability Assessment findings, each TSO choosing to apply SI shall define at least the following requirements for the relevant elements:
	    • Frequency or df/dt measurement criteria:
	        o time window (speed)
	        o accuracy, and
	        o total delay time
	    • Function characteristics (e.g. df/dt vs. Δf, deadband and droop)
	    • TSO input signal for activation and access to alter settings such as droop

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The above considerations require a well-founded strategy to deal with:

- potential measurement limitations such as fast transient movements of “frequency” (local angular movements),
- technical and operational limit of SI exploitation,
- the possibility to increase the size of DC-Link capacitors for storing more energy, and
- DR capabilities and likelihood of participation (technical limits).

COLLABORATION

TSO – TSO	Based on the System Operation Guideline (SO GL), article 39.3(a) (Dynamic stability management): In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level, all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of SO GL, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years.
TSO – DSO	Interaction between Loss-of-Mains protection based on RoCoF where these are applied (i.e. GB and Ireland) and df/dt in system incidents needs to be considered. In particular, RfG requires the relevant system operator to collaborate with the relevant TSO the specification of RoCoF-type loss of mains protection, which also interacts with the necessary system inertia.
RSO – Grid User	

Examples and final considerations:

<u>Conventional frequency response for wind farms in existing grid codes</u>

Low frequency capability is in the main preparation for longer term future with very high non-synchronous generation (NSG) penetration (with diminished FSM from synchronous generators (SGs)). However, at an earlier stage high frequency response delivered without head room is of particular value for high frequency control under low demand. This is when many of the SGs providing frequency response are operating at minimum generation (unable to respond to a high frequency excursion). Additional features have more recently been added to FSM for PPMs to virtually avoid all loss of energy capture while selected to deliver just a high frequency FSM response service.

In Canada, wind farms of nominal size greater than 10 MW, if frequency deviation is greater than 500 mHz, the PPM should be able to emulate an inertia of minimum H = 3.5 sec for 10 seconds (see Hydro Quebec - technical requirements for connecting generation). It should be noted that this block of power provision (still described as SI) was introduced to cope with specific shortcomings of hydro governors when sudden frequency changes takes place. The governor response is initially in reverse direction, for about 2 s, from what is needed. Wind is used to counter synchronous hydro generators shortcomings, rather than dealing with issues arising from non-synchronous RES.

<u>Potential adverse effects from certain types of SI control strategies.</u>

R&D (see [13] and [14]) has demonstrated that power systems with high % instantaneous Power Electronic Interfaced Power Sources (PEIPS), above the order of 65%, may be at risk of high frequency instability, as discussed in IGD HPoPEIPS.

Many factors influence the tipping point at which steady state stability is at risk at a given level of PEIPS%. Most noticeable is the selection of control strategy for the converters.

In context of frequency stability, high % PEIPS is also associated with challenges of high RoCoF when the power balance is suddenly subject to a large disturbance. This is due to diminished total system inertia. Possible solutions to this aspect include consideration of synthetic inertia (SI). Research has shown that some forms of SI may make the steady state stability worse. This appears to include dq-axis controllers with current injection (DQCI controllers) with Swing-Equation-Based-Inertial-Response (SEBIR). The negative impact of SEBIR on steady state stability is heavily dependent upon measurement of df/dt or RoCoF. Early results applying measurements of ROCOF using an M-class Phasor Measurement Unit (PMU) window (11 cycles) seems to provide higher system stability than using P-class PMU windows (3 cycles), although there are many variables and parameters which concurrently affect the results and this is not a firm conclusion at this stage. See the report Use of an Inertia-less Virtual Synchronous Machine within Future Power Networks with High Penetrations. See also IGD RoCoF withstand capability.

<u>A Proposal for Introduction by 2021 of Grid Forming Converter Capability with SI</u>

In GB the TSO has proposed to the Grid Code Panel WG 3 July 2017 that Grid Forming (GF) capability as described in IGD HPoPEIPS is required by 2021 for converters to deal with a number of weak power system / lack of system strength issues. This control strategy (described as Option 1 is optional before 2021). It is based on the holistic approach described in HPoPEIPS, dealing with a string of challenges. For each of them a date is defined in the documentation (iii) with a date when each is estimated to become critical. In context of SI the equivalent inertia is described so far rather openly as at least 2-7 MWs/MVA on rated power (for 20 s) operating against the principles of VSM. A key part of the VSM description is “Should behave like a balanced 3ph voltage source behind a constant impedance over the 5 Hz to 1 kHz band”. This proposal is available as 3 July 2017 Working Group presentation document on National Grid website for Grid Code WG GC0100[17].

<u>Risk management considerations</u>

It is recommended that TSOs in a SA conduct a collaborative study/procedure to define the possibility and risks of different system split scenarios to conclude/determine:

- the range of circumstances that one TSO wishes to withstand
- how much each TSO/country shall contribute to total min SA inertia
- how large % of time does each country have to contribute their share

to ensure that nominative split event (e.g. 40% power imbalance) can be coped with.