European Network of
Transmission System Operators
for Electricity

High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS)

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

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Description	
Code(s) & Article(s)	All Connection Network Codes (RfG, DCC and HVDC) Articles with national options or parameter choices for requirements which affect operability, dealing with challenges potentially threatening system resilience, arising from future operation with high RES penetration focused on new connections of power sources interfaced via power electronics. These articles from NC RfG and NC HVDC include the topics of: • Synthetic Inertia – non-mandatory • HVDC Control System Interactions – not fully specified at European level • Fast Fault Current Contribution (FFCI) - not fully specified at European level Additionally, it covers specific means of dealing with general requirements such as the capability to operate stably over the full operating range. It also provides limited information for interacting requirements associated with the above, which themselves are fully delegated to national level, such as Quality of Supply (QoS, e.g. harmonics & unbalance).
Introduction	This IGD focuses on an overview of resilience issues related to the system technical challenges of operating a power system with high penetration of RES. In particular the focus is on RES power sources interfaced via power electronics, hence forth named High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS) or when appropriate just PEIPS. This document deals with necessary capabilities to manage low Total System Inertia (TSI) and also with other system challenges arising from operation with low overall system strength such as low short-circuit power and low dynamic voltage support. It identifies means of establishing where in future these challenges are greatest and also means which may be considered at national level to overcome the potential problems. The proposals developed in this IGD arise from an Expert Group with widespread stakeholder representation, in particular experts from industry, academia and study tools related to converters and their control systems. This IGD is structured as follows: 1. High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS) without contribution to inertia and system strength – supported with terminology and explanations in Appendix 1 2. Analysis of degree of RES penetration in context of TYNDP future energy scenarios – supported with data in Appendix 2 3. Analysis of Total System Inertia (TSI) in context of future energy scenarios – supported with data in Appendix 3 4. Analysis of possible HPoPEIPS remedial actions – supported in depth in Appendix 4 5. Considerations for implementation of Grid Forming performance for HPoPEIPS in most affected locations - supported in depth in Appendix 5 As a conclusion a process diagram is provided later, under the heading of “Collaboration”, intended to guide national activity on how to manage connection capabilities related to

HPoPEIPSs with the main focus at synchronous area although also with an additional national focus. Further work backed by EC focused on operating at or close to 100% power electronics is in progress under the MIGRATE (Massive InteGRATion of power Electronic devices) project [1].

1. HPoPEIPS without contribution to inertia and system strength

This is known to lower the Total System Inertia (TSI) or in per unit terms H, for specifics sections 2 and 3 below and [2]. Inadequate inertia is already significantly affecting operation of some synchronous areas, notably Ireland & Northern Ireland (EI+ NI) [3] and Great Britain (GB) [4]. In these Synchronous Areas (SAs) costly actions (financially & environmentally, e.g. via RES substitution) are already undertaken to ensure system security is maintained during conditions of high penetration. In other SAs in Europe the immediacy is less under intact system conditions, although for Continental Europe there is already concern about inadequate inertia under high RES production conditions in some parts if a system split should occur [15]. See also [6] regarding the Nordic Area.

Appendix 1 contains terminology associated with this topic, initially this is covered at a high level and then followed by further in depth descriptions/and explanations

HPoPEIPS is known to be associated with general low system strength [7] which has the potential to involve a wide range of operational stability challenges [7], [8], [9] & [10], such as:

Frequency stability

a. Excessive rate of change of frequency when sudden power system imbalances occur while Total System Inertia (TSI) is low within the synchronous area.
b. Inadequate sharing of TSI within a control area / country (in part of a SA) leading to risk of system collapse of a separated network following a rare system split.
c. Inadequate post fault active power recovery.

Voltage stability

d. Inadequate transmission protection performance due to delayed and limited fault current which may also be provided only as a balanced output by PEIPSs.
e. Inadequate support to restore system voltage immediately post fault.
f. Adverse interactions between controllers of converters (connected electrically close). Such interactions may become visible as Sub Synchronous Resonances (SSR) or Super Synchronous Instability (SSI).
g. Possible system voltage collapse before Low Frequency Demand Disconnection can act to cope with major power imbalances such as during system splits.

Power quality (quality of supply)

h. Lack of “sinks” to correct low order system harmonics including inter-harmonics.
i. Lack of “sinks” to correct phase unbalance.

Other low system strength issues relating to fast dynamics

j. Low synchronising torque / power between generation sources, to overcome

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sudden voltage angle disturbances (at the fundamental frequency).

k. SSR in context of interactions with conventional machines.

In addition to the above dynamic phenomena, in context of converter control interactions, models currently used for power system stability analysis to model PEIPSs in system wide studies are inadequate. Hence, limited capacity to confidently predict system dynamic behaviours. This is due to presence of active complex high frequency (super-synchronous) converter control interactions.

In Ireland [3] for several years the upper limit of operation for PEIPS has been 50% in real time, although a start has been made to raise this limit (currently 55%). Costs of associated Ancillary Services (AS) for EI+NI have been predicted by EirGrid, the TSO to rise 5 fold between 2015 and 2020 from 5 to 25% of the total cost of electricity for end users [3].

In GB studies demonstrated in 2013 that by 2030 the potential annual cost of having a PEIPS operability limit as low as 50% could be between £3-4,000M (to constrain RES (PEIPS) off and replace with Synchronous Generation) under the Gone Green scenario [7]. The paper [7] also demonstrated that if this unacceptably high cost and associated environmental loss of opportunity was to be reduced by a full order of magnitude (to about £1-300M annually, to give a more realistic level of constraints regardless of which of the many system technical issues described in [9] is the cause of the limitation on penetration) the PEIPS operability limit (stability tipping point) needs to be raised to 95% (from 50%), if no relief from export was available. If however 10GW of export was possible (capability and market) from the GB SA, then an operability limit of PEIPS of 80-85% could be adequate, to ensure attributable annual AS costs for GB in low £100s of millions.

The three other SAs in Europe (CE, Nordic and Baltic) have so far been less affected by HPoPEIPS challenges, at least in context of total system inertia [5] & [6]. However, some individual countries within these SAs have already faced other RES penetration issues notably related to voltage stability, e.g. in mainland Denmark (the part connected via Germany to CE). Challenges of 100% are already a reality for the offshore HVAC systems connected to shore via HVDC in the North Sea off Germany.

2. Analysis of penetration for future energy scenarios

Appendix 2 contains data on RES penetration (RLPI, included in definitions in Appendix 1) in context of domestic generation, sourced from [2]. The first figure shows the highest occurring % RES in any hour of the year by country in 2025 under the future energy scenario of Vision 4. Eight countries reach an RLPI of 100% on national basis (DE, DK, GB, GR, IE, NI, NL and PT) and 22 countries at least 50% for the most challenging hour, assuming RES unconstrained operation (no substitution).

Further in depth RES penetration analysis is presented in the subsequent figures based on source data from [5] linked to the outcome of the TYNDP 2016 focused on scenarios in 2030. The first one shows hourly % variation in penetration of RES for one year for Continental Europe (CE) for scenario vision 4 (V4). The selection of year 2030 reflects the middle of life time (if 20 years) of the earliest PEIPSs possible commissioning dates of about 2020 for new connections affected by this guidance. This data is then converted for CE into a duration curve. Similar duration curves are also shown for the other SAs in Europe, covering SAs Nordic, Baltic, GB and finally IE+NI. Large variations in penetration can be seen between the highest RES penetration IE+NI and GB (both with significant periods in which penetration is expected to be between 90 and 100 %) and the lowest Nordic (always below 50%), followed in between by Baltic and CE. It should be noted that there can be some small differences between RES penetration and PEIPS penetration, where exceptionally RES is implemented without use of power electronic interfaces, see [5] for underlying assumptions. Such differences may be the case for small hydro and biomass plant, which are likely to use synchronous generators. Also, early wind implementation using Type 1 wind turbine technology, as in Denmark, was without power electronic interface. Overall, this is expected to be a modest correction factor, but analysis at individual synchronous area / national level is suggested.

3. Analysis of system inertia for future energy scenarios

Appendix 3 contains data on the level of inertia associated with the 2030 position of the above scenarios. The national contribution of H for the 50% and 90% duration points **for their SA** are extracted for the energy scenario of Vision 4, based on market data associated with TYNDP 2016 [5]. For respectively 50% and 10% of time (hours in a year) the H is below the values given in the tables. Extremely low values of H can be seen for the high penetration SAs, with 90% points for SAs GB and Ireland/NI both below 0.7s compared to historical values around 5-6s. Therefore for considerable time these two systems are seeing a 5-10 fold reduction in inertia.

Other SAs are also showing reductions in inertia, but nowhere near as dramatic. However, some individual countries within these SAs are at times making only a marginal contribution to their SA inertia. For example the 90% point for Germany is also below 1s, in contrast with France contributing H of 3.4s at the 90% duration point for SA CE.

Please note all these inertia figures are for H, per unit values of TSIs, e.g. contribution per MW. Some countries (e.g. Greece) have a 90% H which is higher than their 50% H. This at first appears to make no sense. It arises however in Greece and some other countries because they have a pattern of variation in H which is different to the variation pattern for their SA as a whole. The national contribution data relates to the 50 and 90% points for the whole SA. The lowest allowable H for each SA and for each country within the SA in real time operation is an issue for System Operation to determine, and hence out of scope here. However, the connection capability to facilitate stable operation is within scope. It is reasonable to expect that operation of a SA with its overall H below 1s is not going to be allowed. Minimum values may vary between SAs, but are more likely to be at least in the range 2-3s (or not allowed to be much more than halved from historical values) to maintain frequency stability during times of HPoPEIPS. Within each SA it will be necessary to have economical means (capabilities) of delivering such inertia. It might also be expected that constraints may be introduced on minimum regional / local inertia value to cope with system splits or black start scenarios. This shall be defined through a coordinated approach.

4. Analysis of possible remedial actions

Alternative means of dealing with the operability challenges to improve resilience:

Conventional approaches

It is possible to initially deal with the resilience / operability challenges in a conventional way by constraining in real time the amount of PEIPS to a certain value (or conversely in reality constraining on plant providing system strength by providing a minimum of synchronous generators) , e.g. as implemented in IE+NI. However, this is both costly and environmentally undesirable. EirGrid has published [3] an anticipated rise in cost of ancillary services, significantly affected by this aspect, from 5% of total electricity cost in 2015 to 25% in 2020. Information on alternative solutions in context of IE+NI to prevent high RoCoF events on the system is assessed in the report [11].

Alternatively, several of the challenges can be reduced / overcome by large scale installation of synchronous compensators (SC, generators with no prime mover) for system strength or in context of inertia simply flywheels. For example [7] suggests that GB could be operated **in respect of super-synchronous instability** up to 100% PEIPS penetration by adding approximately 9,000MVA of rotating SCs. This scale of SCs may not be considered a societal optimal solution.

Denmark was the first nation in Europe to face some of these challenges through its operation with extremely high RES in Jylland (part of Denmark connected to CE via Germany). Energinet.dk (the Danish TSO) has chosen to apply SCs at a time before alternative PE solutions have emerged. For several years an increasing number of hours in the year Jylland has had wind alone exceed the total Jylland electricity demand. Many of the associated system strength / voltage stability dynamic challenges have been tackled with strategic located large SC installations, e.g. adjacent to multiple HVDC converter connections. Jylland is however connected by 400kV to Germany and as such benefits from imported system strength, which is not available to countries of the island synchronous areas, such as IE+NI and GB, nor is it for Offshore HVAC systems which are connected to shore via HVDC (so far mainly in the German sector of North Sea) [8].

PEIPS contributing system strength

Why a holistic approach?

The TSO analysis [8], [10], [12] & [13] indicates that the varied challenges of fast dynamics (voltage, frequency and other stability aspects as defined) associated with low and particularly extremely low System Strength have strong inter relations. It is important to highlight that in order for synthetic inertia to be fully useful, the time constant of the control loop, including time for measurement, control and actuation, must be lower than the natural behaviour of the system. Therefore, a response based on $\Delta P \sim df/dt$ such as the SEBIR approach illustrated in appendix 1B has been found to have adverse impact on system stability if it contains even minor delays in measurement and control actions [10]. This is illustrated in Appendix 4 under the sub-heading “Causes in more depth – the evidence collated so far”.

Management of one HPoPEIPS issue is bound to affect management of several others. There are further examples of this. It is therefore desirable to apply a holistic approach to prepare a path towards possible full RES or PEIPS penetration.

It is also clear that, when average penetration is still relatively modest, the most challenging hour of the year which the System Operators need to concern themselves with sees a very much higher penetration under which the SO still has to deliver the expected high level of security of supply. Typically for one country the highest hourly penetration is 4-5 times greater than the average penetration. This was demonstrated in about 2008 when Jylland (mainland Denmark, the part connected via Germany to SA CE) first reached 100% of demand covered by wind alone while the Danish average RES penetration was a more modest 20%.

In November 2016 National Grid published [4] its System Operability Framework (SOF2016) containing this holistic principle for GB in its Chapter 5 “Whole System Coordination” on pages 142 to 173.

One implementation of a combined synthetic inertia and fast fault current injection could be achieved by carefully applying Grid Forming (Class 1) control strategy for PPMs and HVDC Converter Systems (HCSs). Such an approach is described next and in Appendix 5.

5. Considerations for national implementation of Grid Forming performance for PEIPSs

This approach is delivered by PPMs and HVDC Converter Systems (HCSs). So far, this Grid Forming performance of converters has only been experienced in context of small isolated systems, such as marine environment (e.g. very large ships with electrical propulsion). Its application on a broader scale to full countries or main synchronous areas would be new. Grid Forming (or Class 1) PPMs and HCSs deliver their performance in a holistic way tackling the range of challenges together in an inherent and hence simple response which is without dependency on details of the control algorithms. In context of application to larger SAs, this has so far only been investigated in a research environment and by analysis of a TSO for the full GB synchronous area. It has been subject to publication, and associated discussion by a wide range of world leading experts on the topic. The TSO demonstrated that such a holistic Grid Forming approach, if applied to about 30% of the total installed capacity of PEIPSs, the operational limit (stability tipping point) could be raised up to the ultimate 100% penetration.

In principle, the required characteristics could be delivered by very large HVDC converters, or by middle size wind generation converters or by small scale PV converters. Storage from batteries (although the connection of this latter source is currently outside the scope of the Connection Network Codes and therefore need consideration for application purely on a national basis) could also contribute to this holistic Grid Forming approach. Great care is needed to ensure that the mix of sources contributing is appropriate taking account of their different characteristics, their interactions and their limitations (e.g. stored energy and current carrying capabilities).

In considering implementation of Grid Forming performance, further discussions should be held to determine when its introduction is to be made. To give reasonable opportunity for manufacturers to get ready, this is likely to mean further years beyond the earliest year of Connection Code implementation (effectively commissioning in 2019). So far the implementation has been discussed at a European level at an Expert Group with a number of manufacturers' experts on converters and their associated controls.

In terms of when & how the desired capabilities are brought on stream each synchronous area and country may consider using the context of the overall process diagram to be found under the heading "Collaboration", which focuses on expected penetration and inertia at their SA and also on specifics within each country of the synchronous area.

The final decision of implementation of the Connection Code remains at national level and each country may further consider its contribution to the TSI for its regional area or for the full synchronous area.

Countries and regional areas outside EI+NI and GB may in the short term (unless or until their SA penetration becomes a concern) focus on the local distribution of inertia and other aspects of local inadequate system strength (e.g. short-circuit power) and on the need to introduce a minimum regional value to cope with system splits or black start scenarios. This activity is best undertaken through a coordinated approach. Examples of

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	consequences of an inadequate distribution of inertia include: • potentially unacceptable transient power flows in cases of loss of largest power infeed (e.g. 3000MW in CE) with risk of corridor tripping and inter-area power oscillations. • inability to survive a system split with the core power system still operable (e.g. as investigated in [9] for the split between Scotland and England which required the support of significant volume of Grid Forming converters). This IGD is not intended to provide the fully detailed way forward for each technical issue neither to constrain research and development to pre-defined system service (i.e. grid forming converters is mentioned in this IGD as one alternative), but point to the initial high level process and need case with references to further specific guidance (IGDs) provided / to be provided elsewhere on narrower topics. Further information / guidance is available on topics covered by other IGDs. including: • Fast Fault Current Contribution for PPMs and HVDC converters • Need for Synthetic Inertia • RoCof withstand capability In these cases specific HPoPEIPS guidance has been added. Other related topics include: • Interactions between HVDC controllers • Post fault active power recovery • Parameters related to frequency stability • Special issues for Type A generators For these latter IGDs, reference back to this HPoPEIPS IGD is suggested in cases of application to high penetration scenarios, even if this advice has not been specifically added to these further IGDs.
NC frame	The following articles from NC RfG and NC HVDC contains the most significant non-mandatory requirements & or non- exhaustively defined parameters which are affected by the scope of this IGD: • <u>Synthetic Inertia – non-mandatory in NCs RfG and HVDC</u>: RfG Article 21.2 (a) and (b) states: Type C power park modules shall fulfil the following additional requirements in relation to frequency stability: (a) the relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast

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	frequency deviations; (b) the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO. HVDC Article 14 states: 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. The requirement shall at least take account of the results of the studies undertaken by TSOs to identify if there is a need to set out minimum inertia. 2. The principle of this control system and the associated performance parameters shall be agreed between the relevant TSO and the HVDC system owner. Other linked articles relating to frequency stability include RfG Article 13.1 (a) (i) on frequency ranges and 13.1 (b) relating to Rate of Change of Frequency (RoCoF) withstand to be specified by the relevant TSO. For HVDC, the equivalent withstand capability is fixed at +-2 Hz/s. • <u>HVDC Control System Interactions – not fully specified at European level</u> NC HVDC Article 29.1 states: *Interaction between HVDC systems or other plants and equipment* 1. When several HVDC converter stations or other plants and equipment are within close electrical proximity, the relevant TSO may specify that a study is required, and the scope and extent of that study, to demonstrate that no adverse interaction will occur. If adverse interaction is identified, the studies shall identify possible mitigating actions to be implemented to ensure compliance with the requirements of this Regulation. • <u>Fast Fault Current Contribution (FFCI) - not fully specified</u> – see other IGD on Fast Fault Current Contribution related to RfG and HVDC (for the latter, see also Article 19.1, 2 and 3).
Further info	Further information is available here: [1] Massive InteGRATion of power Electronic devices (MIGRATE). Report on deliverable 3.1 “Description of system needs and test cases”. https://www.h2020-migrate.eu/_Resources/Persistent/22c94a052537329a9812b5ccbb5bb5f2f3c7994f/System%20needs%20and%20test%20cases.pdf [2] “Scenario Outlook&Adequacy Forecast 2015”; ENTSO-E; June 2015 [3] DS3 Programme – Ireland and Northern Ireland Experience. 30th November 2015. By Robbie Aherne. Slides 39-56 from System Operability Framework (SOF) 2015 launch. See National Grid website: SOF 2015 launch.

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Interdependencies	
Between the CNCs	Many aspects are shared between the three CNCs RfG, DCC and HVDC, i.e. technical capabilities of the entities addressed by each of these CNCs have the same objective, for example maintaining frequency, voltage and rotor angle stability. Therefore introducing mandatory measures to overcome challenges should be consistent across the three CNCs bearing in mind the different scope of application of these Codes.
With other NCs	There are many links to the implementation of those codes, which shall apply the connection capabilities in both system and market operation (SOC and MC topics), which need to be taken into account during national implementation of the connection network codes. In some cases these topics will at national level be contained in combined documents (e.g. broader content Grid Codes). Consistency needs to be maintained in these cases and it may be necessary to coordinate the application of these requirements with system and market operation codes.
System charac-teristics	System characteristics are expected to change continuously, e.g. from major changes in generation technologies and their electrical characteristics, such as greater proportion delivered via power electronics with consequent implications on system strength. The speed of such change may be different between countries, e.g. due to differing ambitions of political objectives like levels of penetration of renewable energy sources. In this context, it is recommended to consider for national implementation the expected changes in network needs over the next 15-20 years, the likely minimum life time of new connections. As an example, studies have been undertaken in GB [7] & [13].
Technology characteristics	Converters and their controls have traditionally been primarily focused on self preservation during major system disturbances. As the dominance of converters and their performance increases this has to gradually shift to maintain security of supply. Initially the focus has been done on ability to stay connected during and following faults (FRT requirements). This has been followed by remaining connected for the full operating ranges of voltage and frequency, including under extreme conditions. Then gradually contributions to dynamic voltage and frequency controls have been introduced. In context of the high penetration (e.g. RLPI >50%), even when all the above has been implemented, further contributions are needed from RES to deal with the characteristics of the operability challenges (see above) to ensure resilience. R&D (see references) suggests the key to progress is the basic converter control strategy. The most common existing control strategy applied to VSC converters is Direct Quadrature Current Injection (DQCI) with Phase Locked Loop (PLL) type controls. These converters have an inner control strategy based on current control, and therefore rather shows a current source behaviour in the fundamental frequency (although confusingly they are most commonly called Voltage-Sourced Converter). Ref [10] identifies the shortcomings of this control strategy for high penetration even if the synthetic inertia described as Swing Equation Based Inertial Response (SEBIR) is added. Therefore this approach to inertia may have limited value, as the need for inertia contribution is itself closely linked to high penetration. This reference also introduces alternative control strategy to overcome many stability problems related to DQCI converters with PLL controls. Significant further capabilities are introduced in [12] & [13] with the Virtual Synchronous Machine (VSM) strategy where instead of following the

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system voltage, this control strategy is leading. Other research activities are promoting other approaches to overcome the limitation of too slow contribution to synthetic inertia. Broad based activity is in progress under the EU supported MIGRATE project [1].
Manufacturers of wind, solar and HVDC converters are invited to develop solutions which provide effective holistic solutions for weak systems, including delivery of synthetic inertia. Controls should be well designed to meet the challenge of the wider system dynamics, as outlined in the appendixes and associated references. For the design of the dominant existing VSC applications, this may involve only a modest change, primarily focused on changes to the controls. However, for some aspects such as contribution to system inertia either a small stored energy source will be required (e.g. connected to the dc bus) or a reserve on the available active power might be needed. Ref [14] shows a grid forming converter proposal from the view point of solar PV.
Manufacturers’ views on style of specification of this broad control philosophy have been invited initially at an international conference (WIW2016 in Vienna in November 2016), as well as on the time needed to deliver the change in performance. This engagement has been intensified with stakeholder expert contributions to this document in context of an Expert Group (EG) initially focused on “Fast Fault Current Contribution from PPMs & HVDC”. This EG includes seven converter experts from manufacturer of HVDC, of wind turbines and of solar PV systems. Their input supported further by two experts from academia and by one expert from power system analysis tools over phase one of the EG activity covering 8 meetings (during Dec 2016 and Jan 2017) has been incorporated.
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<tr><td colspan="2">Collaboration</td></tr>
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The following steps are suggested for each synchronous area, regional area and for each country. Each step is triggers by indicative system characteristics.
Step 1 - Define extent of the challenge, by starting data collection on penetration at the appropriate level . Establish penetration of PEIPS in relevant area at least to 2030. Data for RES penetration for 2030 is provided in Appendix 2 and in the source data [5].
Step 2A - If PEIPS > 75% for the area under consideration (indicative value, this limit could be in the range 60-85%) for your SA for more than 10% (indicatively again) of the hours in the year, establish a strategy to make improvements to contributions from PEIPS.
If for the area with a defined challenge from Step 1 the inertia is < 1s for more than 10% of time, see [5], consider urgently the possibilities to implement the capabilities defined as Grid Forming.
If 2A conditions do not apply:
Step 2B - If PEIPS>50% for your country, regardless of SA penetration, discuss with other countries in SA. If your country inertia <1s for more than 10% of time [5] consider with your Control Area countries and SA if your limited inertia contribution is acceptable, and your resilience for system splits is adequate. Consider the possibility of implementing Grid Forming capabilities.
Step 3 - work out detailed requirements including parameters for the implementation and associated need for models to study the effectiveness as well as compliance tests. => introduce new requirements at national level
</td></tr>
</table>

	Regarding resilience for system splits in general (step 2B), further analysis is available in [15] focused on Continental Europe.
TSO – TSO	Collaboration between neighbouring countries will be valuable and an overview for each synchronous area will have great benefit. A key aspect, particularly for Continental Europe, is a regional/national/local ambition to survive system splits with the main system in place, even if disconnected from many other countries. The percentage power imbalance to survive for such a system split is a further key parameter (e.g. 30% or 40%). Collaboration on consistent application of requirements will not necessarily result in equal values and/or parameters to be applied, but may reasonably focus on the use of consistent criteria.
TSO – DSO	Collaboration of connection network codes requirements between TSOs and DSOs, in particular within the TSO’s control area is important. However, this is subject to DSO involvement in national implementation. It is recommended to TSOs and DSOs to engage with each other at an early stage of national implementation already to explore interdependencies and possible impacts on transmission and distribution systems. This applies particularly to the application to deeply embedded generation such as solar PV.
RSO – Grid User	Collaboration on connection network codes requirements between system operators and grid users is crucial. In context of this IGD, an important aspect is to provide reasoned arguments, why a non-mandatory requirement has been selected for implementation. Such justification shall explain the rationale behind the choice, i.e. the technical background and possible options to solve the issue, in a transparent manner. This is subject to grid users’ involvement, typically through respective associations in national implementation procedures. It is recommended to system operators to engage with grid users at an early stage of national implementation already to raise awareness on system engineering aspects and inform about system challenges. Early involvement supports transparency of the implementation processes and helps to mitigate concerns about discretionary decisions during implementation. It enables stakeholders to contribute actively to solutions and to make use of their expertise, e.g. manufacturers’ knowledge about technical capabilities and constraints of certain technologies. Factual discussions on technical / procedural challenges based on expertise and best practice are thus facilitated.

Appendix 1 Terminology

Appendix 1 : Terminology (Brief)

The list in this section very briefly summarises the commonly used abbreviations and terms used in this IGD and other relevant literature. For longer explanations and more detail, also see "Appendix 1 B : More detailed background to the terminology "

DQCI
A "VSC" in which the control software actually follows the existing system voltage with defined sinusoidal (and normally balanced) current targets to produce target active and reactive power outputs. The control algorithm is usually based upon a phased-locked-loop and dq-axis control loops in a rotating or stationary reference frame. This is the most common type of grid-connected converter control algorithm used for existing renewables, storage and HVDC schemes at the time of writing (2017).

PWM Pulse Width Modulation. Describes the signals applied to IGBTs, MOSFETs etc. within a VSC so that the desired voltage or current is synthesised at the switching bridge.

RLPI RES Load Penetration Index is defined as the maximum hourly variable RES coverage of load, e.g. for a country. As this is based on RES (Renewable Energy Sources), although mainly consisting of PEIPS, it may contain a component of synchronous generation (usually small) from sources such as small hydro (large hydro is not classified as RES) or and from biomass.

ROCOF
Rate of Change of Frequency. The measured value of the d/dt of frequency, which itself is the d/dt of the voltage phase angle, at some point on a network. To obtain a usable value within a real single-phase or three-phase power system, rolling windows (0.5s in NC DCC and 1.0s in NC HVDC)/filters must be used to reject noise and other power-quality phenomena, so that the wanted ROCOF measure is observable with time delay. Use of Fourier techniques, rotor models, and zero-crossings all have different responses and behaviours, and abilities to reject unwanted disturbances.

SEBIR Swing Equation Based Inertial Response. A scheme in which a response is provided, by forming an estimate of ROCOF from system measurements, and then computing a modified active-power setpoint target through the equation $\Delta P_{pu}=-2H(df/dt)/f_0$

SI Synthetic Inertia means 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; Due to ROCOF measurement delays, a true inertial (TI) response may be complicated to deliver. As of today, the response is then better thought of as "Fast Frequency Response". An example of such a "Fast Frequency Response" scheme is SEBIR. However, R&D activities are needed to enhance the speed of the response and to deliver true inertia.

SPGM Synchronous Power Generating Model as defined in the NC RfG

SSI Super Synchronous Instability describes a condition of system wide instability at frequencies above the fundamental system frequency of 50 Hz (e.g. a few hundred Hz).

TI True Inertia. Power response from a SPGM or VSM that is a direct consequence of network phase/frequency perturbations.

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VSC A "Voltage-Sourced Converter", made with self-commutated devices such as IGBTs, IGCTs or MOSFETs, coupled to a DC bus which is held at a roughly constant voltage. This explains the origin of the term "Voltage-Sourced" in this context, because by defining the PWM patterns at the switching bridge, one defines the voltage which is "created" there, as a proportion of the DC bus value. This compares to an LCC device using thyristors, with an inductor on the DC bus so that the DC bus current is roughly constant, which is known as "Current-Sourced". However, the term "Voltage-Sourced Converter" needs to be considered very carefully. The behaviour of VSCs is defined by the software which produces the PWM patterns. Most grid-connected converters today are controlled using DQCI algorithms. The DQCI algorithm control bandwidth might be ~250Hz. Therefore a DQCI -controlled converter might appear to be truly "Voltage Source" (note the lack of hyphen) with respect to harmonics above 250 Hz. However, when considering the fundamental, and dynamics below 250 Hz, the converter will effectively act as a current source. However, other control scheme of VSC are being developed which could be much faster. One of these schemes is the VSM where the control of the VSC aims at behaving as a true voltage source.

VSM A Virtual Synchronous Machine. A converter controlled to behave as a true voltage source, with a virtual rotor model, tuneable values of inertia constant H and damping, and tunable governor control loops to suit the energy source/sink to which the converter is connected. The performance of this device is closely aligned with that of a real SPGM, although the magnitude of the fault currents available is capped by the short-term current overload rating of the converter hardware. VSMs make no (or very limited) responses to unbalanced current or harmonic voltages. The converter behaves as a "balanced positive-sequence fundamental-only" voltage set behind a "transient impedance" (i.e. the filter impedance). Since the magnitude and phase of this voltage set is changed only slowly, a VSM mitigates unbalance, harmonics etc. on the voltages at the connection point, by sinking or sourcing currents as required.

Appendix 1 B : More detailed background to the terminology of "Voltage-Sourced Converters", "Synthetic Inertia" and "Rate of Change of Frequency"

Current source converters disguised as "Voltage-Sourced Converter" (DQCI)

Most modern converters using self-commutated devices (IGBTs, IGCTs, MMC HVDC, etc.) are described as "VSC"s ("Voltage-Sourced Converters"). This is a name given to them historically, to differentiate them from converters based on thyristor technology, which are Line Commutated Converter (LCC) devices and known as "Current-Sourced Converters". The term "VSC" refers to the fact that the DC bus sits at a nominally constant voltage, and so at any instant the converter bridge can apply a controlled proportion of that voltage to the AC system, via the filter impedance.

However, most grid-connected converters using "VSC" technology do NOT behave as voltage sources. Inside the control software there are a pair of set-points for active (P) and reactive (Q) power, which are translated into "Id and Iq" axis current references. The inner control loop within the converter software is a current-control loop whose primary goal is to source/sink balanced, positive-sequence sinusoidal currents matching the Id/Iq references, and thereby the P&Q setpoints. The controller must have a bandwidth well above 50 Hz, since the aim is to control the currents to be balanced and sinusoidal, even when the terminal voltages are not. This requires rapid modifications to the switching patterns (PWM) (i.e. the voltages being applied) in the presence of voltage unbalance and harmonics. Many controllers also include negative-sequence control paths which help to derive the rapid 2*f voltage modulations required to ride through unbalanced faults, while continuing to sink/source balanced, sinusoidal currents. Therefore, the converter acts as a controlled CURRENT SOURCE, with a high control bandwidth. The converter, due to its control, presents a high impedance to unbalanced voltage, and harmonic voltages. Such a converter is generally unable to provide unbalanced current to loads, or to mitigate voltage harmonics on the grid. Converters such as this may slightly improve, or may slightly degrade, power quality at the point of connection. Any unbalanced loads, or loads drawing non-linear harmonic currents, must have the bulk of their unbalanced and non-linear load currents provided by other devices on the network which behave as true voltage sources, such as synchronous machines, and converters specifically controlled in a different manner.

Because the currents are controlled to be balanced, positive-sequence and sinusoidal, the active power flow is generally constant during the cycle, thereby keeping DC bus power ripple to a low value, unless voltage unbalance or voltage THD becomes very large. Some proposed control schemes actively adjust the currents to achieve a constant DC bus power flow even under high levels of unbalanced voltage. Such schemes can be beneficial to the converter, but are not helpful for the network.

Converter control schemes which behave in this "current source" manner usually include a PLL (phased locked loop), and are classified with names like "d-q axis Vector Current Control" or DQCI (d-q axis Current Injection), etc. Sometimes a "rotating dq frame" is used, and sometimes a "stationary rotating frame with resonant controllers" is used. Unless you know otherwise, you should assume that a grid-connected "VSC" converter uses a "current source" controller based on DQCI/VCC.

DQCI controllers do not allow converters to operate islanded [16], operate reliably at the highest penetrations (above ~65-70%) [13], or operate in weak parts of the network at SCRs (Short Circuit Ratios) of less than 2-3. Partly, it is due to couplings between the d and q axis control loops, which become closely coupled with each other when the SCR becomes low. Partly, this is to do with the inability of the DQCI converter to deal with unbalanced and harmonic loads.

True "Voltage Source Converter" control methods

By taking the same "VSC" converter hardware, but completely changing the lower-level control software, the converter can be reprogrammed to operate as a true "Voltage Source". The goal of the converter can be

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to achieve P and Q setpoints, or to achieve frequency and voltage (F & V) setpoints, or a P&V pair, or an F&Q pair. In this mode, the controller synthesises only balanced, positive-sequence sinusoidal voltages at the switching bridge. This is done by controlling the magnitude and angle of the "rotor" voltage compared to the magnitude and angle of the voltage which exists at the point-of-common-coupling (PCC) with the grid. Between the bridge and the PCC is the filter inductor, and this can be thought of as an exact analogy of X' in a synchronous machine. P and Q flow in or out of the machine, based on the relative magnitudes and angles of the voltages at the bridge and at the PCC. The controller software which determines the rotor voltage, must have a bandwidth of less than 50Hz, and often it is significantly less, for example <5 Hz. This ensures that the synthesised voltage set contains only a slowly changing, balanced, positive-sequence, sinusoidal set of components.

Since a converter controlled in this way behaves as a balanced positive-sequence sinusoidal voltage, behind a filter impedance X', it has many of the same beneficial properties of a synchronous machine (SM). It has a low impedance X' to negative sequence voltages at the PCC. It has a finite impedance X'n to harmonics of order n. Therefore, it assists particularly in mitigating against unbalanced voltage on the network, and also mitigates well against low-order harmonic voltages [17]. The mitigation of unbalance and harmonics is a "passive system", in that there is no active "detect-calculate-act" cycle. The unbalance and harmonic voltages are mitigated passively, and proportionately to the converter's rating (which essentially defines X'). [Note, one of the most effective methods of dealing with network voltage harmonics is linear load. Modern trends in loads, moving from linear to non-linear, is an independent cause but also an important factor in determining the power quality and stability of networks with high penetrations of converters.]

A converter which is controlled by a true "voltage source" algorithm can be operated in islanded mode, take part in blackstarts, and operate grid-connected in penetrations up to 100%, because it can be operated stably in an "F&V" control mode, or one of the other modes such as P&V, with appropriate F/P and Q/V droop slopes and set-points so that it power-shares with other generators [13].

Set-points, droop slopes and other parameters such as inertia H, can be changed in real-time in reaction to real-time constraints on power and energy ability. However, parameter adjustments should not be made at bandwidths approaching or greater than 50 Hz, or the "true voltage source" property of the converter will be lost.

During faults, such a converter will naturally (and "instantly", i.e. within 10-20ms) provide fault current on the faulted phases (in an unbalanced manner if the fault impedance requires it), and at the appropriate phase angles depending on the exact nature of the fault impedance (inductive of resistive). This ability to provide fault current to only the faulted phase(s), and not to the un-faulted phases, could be critical in an islanded, small, or high-penetration-of-converter power system.

The biggest issue with such control schemes is protecting the solid-state devices during faults, as 8-10pu current could naturally flow during the deepest faults. However, methods to do this have been presented in literature, and tested in the lab (very short-term overload limited to ~1.5pu, multi-cycle overload limited to ~1.25pu) [18]. The use of IGCT's also allows the possibility of short-term overloads to several pu, even if the converter is designed for a steady-state maximum current of only just above 1pu.

Another issue to be considered by designers is that the DC bus will ripple at multiples of the fundamental frequency, as the converter "mops up" network voltage unbalance and harmonics. In terms of total energy exchanged, it is small due to the small time periods involved. However, long term dV/dt ratings of DC bus capacitor should be considered, and converter control algorithms should expect the DC bus voltage to be rippling with time [17].

A final consideration for this type of converter control scheme is DC current. Low-bandwidth control loops need to be added to ensure that small asymmetries in solid-state component properties and/or PWM patterns do not lead to large DC currents flowing into the nearest transformer (which has almost zero impedance at DC). These DC-current control loops play no part in the fundamental AC power interactions.

Synthetic Inertia and "Virtual Synchronous Machines" (VSM)

A device in an AC power network which possesses True Inertia (TI) has a very specific behaviour. The behaviour must be correctly capture while defining the implementation of "Synthetic Inertia". Something which has True Inertia genuinely provides a power response proportional to ROCOF, where the ROCOF is determined "instantly", or over a very short timeframe such as a measurement window of 1 cycle or less. The power response must also be applied "instantly".

$$\Delta P_{pu} = -\frac{2H}{f_0}\frac{df}{dt} = -\frac{2Hs}{f_0} f \quad \text{where } f \text{ must be assessed over a maximum of 1 cycle} \qquad (1)$$

More commonly, inside machines and converters which closely emulate synchronous machines ("Virtual Synchronous Machines", or VSM), the analysis is reversed and a "virtual rotor" frequency is obtained by:

$$f = -f_0 \frac{\Delta P_{pu}}{2Hs} \quad \text{where } \Delta P_{pu} \text{ must be assessed over a maximum of 1 cycle} \qquad (2)$$

Either way, the fact that no (or almost no) filtering is applied, is crucial if TI is to be provided. TI has a very distinct behaviour, whereby the power output response to a changing frequency is 90 degrees advanced from the changing frequency, due to the relationship between ΔP and the derivative df/dt. This property is explored through the use of "Network Frequency Perturbation" (NFP) plots in [19], and a presentation that accompanied [10] and included the diagram:

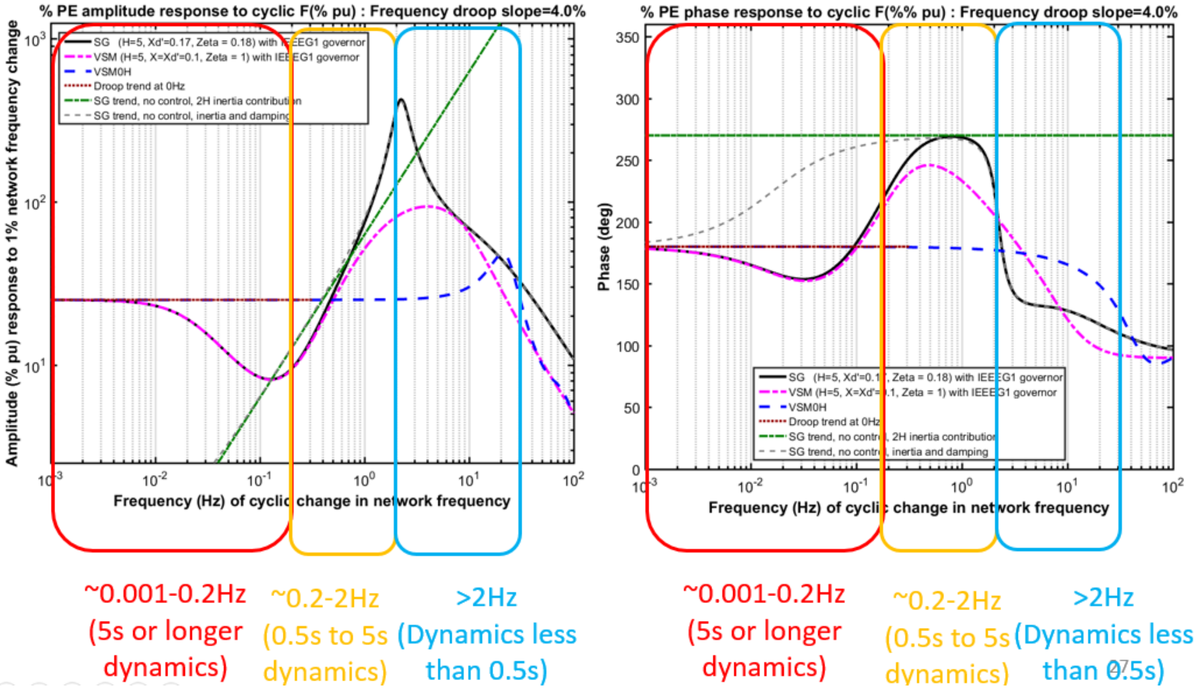

Figure 1 : Network Frequency Perturbation (NFP) plots for real Synchronous Machine (SM, black) and Virtual Synchronous Machine (VSM, pink dashes), both with H=5. The VSM has been configured with critical rotor damping that clearly reduces the rotor oscillation magnitude peak at 2 Hz (left plot). In the region of critical inertial contribution (0.2-2 Hz), the response of SPGM and VSM has a clear 90-degree phase advance due to the 's' term in equation (1), although excessive damping clearly has an impact on this, and the final effect of that still needs to be understood.

The NFP plot allows a visualisation of the response of a device to variations in network frequency, at a range of dynamic frequencies. The x axis is the dynamic frequency of a network perturbation that is applied to the device. In this case, the perturbation which is applied is a sinusoidal variation of network frequency. So, on the x axis is shown the dynamic frequency of a frequency perturbation. This means that at the far left of the diagram represents a steady state frequency offset. On the y axis is shown the ΔP magnitude (left plot) and phase (right plot) which the device responds with. For the steady-state frequency offset at the far left of the diagram, the expected value is the drooped amount (0.25pu for a 1% change in frequency, for the 4% droop slope configured), with a phase of 180° since power goes down if frequency goes up.
At higher frequencies on the x axis, the plots reveal the combined effect of Frequency/Power droop slope, together with governor and prime-mover response (in the dynamic frequency range 0-0.2 Hz on the x axis). A device offering “Fast Frequency Response” can do so through response at the ~0.1 Hz dynamic, representing an approximately 10 s response time.

Crucially, the effects in the dynamic frequency (x axis) range of 0.2-2 Hz represent rotor dynamics and everything which would be encompassed in any device claiming to provide TI. One key point about TI is that by definition, rotor angle has a 2nd-order transfer function relationship with active power, due to the finite value of H. The analogy with a mass-on-a-spring is that H is the mass, (1/X’) represents the spring constant, and damping is damping. The resonance must be damped to avoid sustained oscillations, just as in a real SPGM. The appearance of a resonant frequency on the NPF plot of any real SPGM or VSM is unavoidable in any device which provides TI. However, in a VSM the damping is a freely variable parameter and damping coefficients of 1 (critical damping) can be selected, for example. Therefore, VSM’s can be created which have much better damping than real SMs. An example is shown in the pink dashed trace of Figure 1, showing a VSM designed with critical damping, but the same H=5 as the comparable real SPGM which appears as a solid black trace. Note, however, that there is an effect on the phase response which does not quite reach 90° advance over the dynamic frequency range of 0.2-2 Hz. The real-world effect of this needs further analysis.

One important bi-product of the 2nd-order transfer function relationship in a real SPGM is that there is an upper bandwidth (in terms of modulations of network frequency) at which the relationship ΔP=kdf/dt is applicable. This upper bandwidth is bounded by the rotor resonant frequency, generally in the 2-5 Hz region for normal values of H (2-10 s) and X’ (≈ 0.1 pu). Meanwhile, for low (< 0.1 - 0.2 Hz) modulation frequencies of network frequency, the inertial contribution drops towards zero, and instead the effect of droop settings and governor (or virtual governor) response become dominant. Understanding this, with the help of the NFP plots [18], can help with understanding the relative contributions of TI, SI and a drooped response via a governor.

Beware in literature of thinking every “VSM” provides TI. The term “VSM” is misused by some authors and in some cases, although they present “VSM” solutions, they are actually referring to a DQCI solution providing SI response, i.e. some kind of “Fast Frequency Response”, but which provides no TI.

Synthetic Inertia (SI)

The RFG [6] refers to SI as: “*‘synthetic inertia’ means 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; … the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO..”*

SI, within DQCI converters controlled as current sources, is usually proposed to be implemented as:

$$\Delta P_{pu} = -R(s)F(s)M(s)\frac{2H}{f_0}\frac{df}{dt} = -\frac{2Hs}{f_0}f \qquad (3)$$

Here, M(s) represents a measurement window/filter for df/dt, F(s) represents post-filtering applied to the measurement of df/dt, and R(s) represents the response of the actual converter power control. These all cumulate to make the response significantly different to TI. In [20] this scheme for SI is referred to as SEBIR (Swing Equation Based Inertia Response). In this inadequate provision of "synthetic inertia", any total time lag caused by R(s)F(s)M(s), or more than approximately 1 cycle delay, leads to a quite different response than TI. The time/phase lags mean that although the power response may be "useful" in terms of dealing with frequency nadir, the phase of the response can be quite different to the 90 degree phase advance that TI possesses (ΔP response to df/dt). If the delays are too long, then the SI will provide no mitigation of the initial ROCOF during an event. If the delay happens to lead to a phase lag that is 180 degrees different to the equivalent TI response, then the output power modulation provided by the SI can operate in complete anti-phase to the rotor swings of real SPGM and VSM, encouraging classical SSO rotor oscillations, and thereby degrading network stability.

One of the key problems of this form of inertia is in determining df/dt (ROCOF). ROCOF assessment is notoriously susceptible to large errors and ripples in the presence of noise, and various power quality imperfections, especially following large network events like faults and/or disconnections. DQCI converter designers like to present smooth power targets to their inner current-control loops, and to achieve this, long measurement windows and long filter time constants are applied to the df/dt perception chain. If the total measurement window and response lag becomes too great, however, it makes SI worthless as a tool to mitigate ROCOF, and there would be good arguments to instead just apply a drooped response.

Essentially, once the measurement window is too long, it is better to think of the response as "Fast Frequency Response" instead of an inertial response [21]. Also, if one attempts to use a very short window to assess ROCOF, it can lead to internal stability difficulties within the converter controller. This led to a minimum filter time constant of 1s being applied for "robust stability" in [16]. Such a time delay means that the response cannot be an "inertia" and is a "Fast Frequency Response".

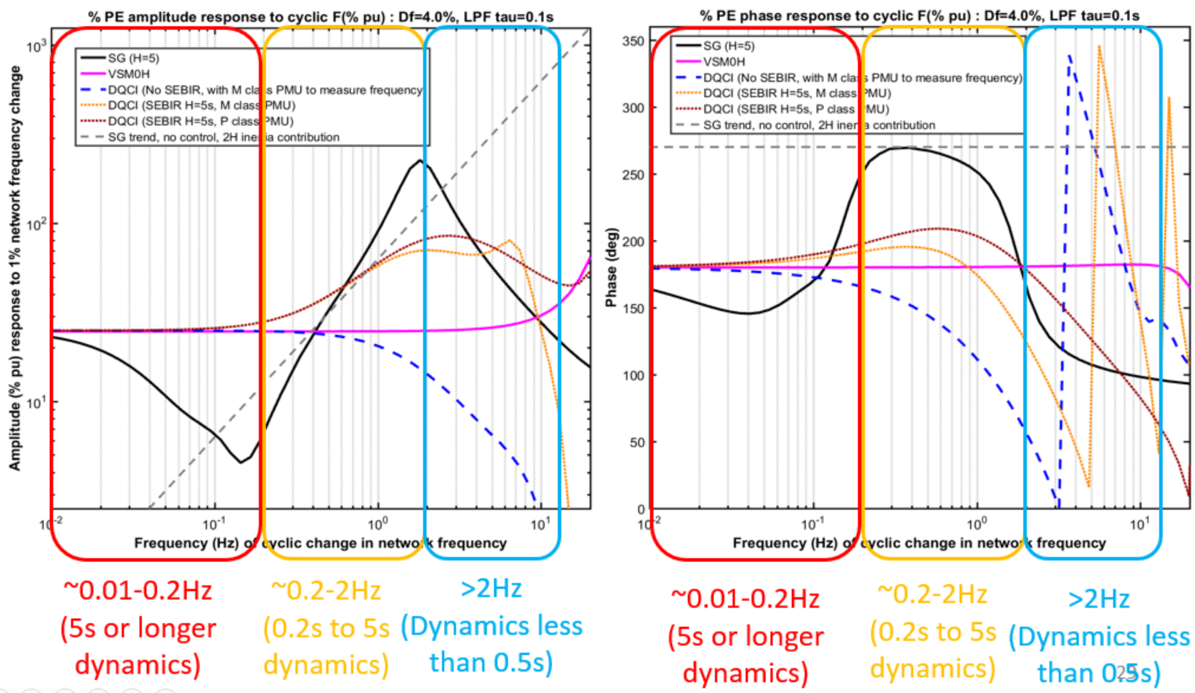

Figure 2 : Network Frequency Perturbation (NFP) plots for real Synchronous Machine (SM, black), DQCI-controlled converter (blue dashes), and DQCI-controlled converter augmented with Synthetic Inertia (SI) (yellow and orange dotted traces, labelled "SEBIR"). H=5 for the SPGM and SI. Clearly the "SEBIR" (SI) response is different to that of the real SM, particularly with respect to the phase of the response. The response is good in terms of the low-frequency dynamics, but is quite different to a real SPGM in terms of modulation frequencies above 0.2 Hz. The "VSM0H" trace shows the response of a "true" voltage source

converter, with a fast-acting power response, but in a purely drooped manner, with H=0. Both VSM and VSM0H are stable in islanded systems, and at 100% penetration. By contrast, neither DQCI or DQCI with SI can achieve 100% penetration or islanded operation, without the stabilising influence of ~30% penetration of SM (generators or synchronous condensers) or VSM.

Rate of Change of Frequency

The potential for excessive rates of change of frequency is an area of concern for power systems with high instantaneous penetration of PE / RES. In this context, several terms are of interest.

- Rate of change of frequency (ROCOF): The time derivative of the power system frequency (df/dt). This quantity is typically not of interest during normal system operation, where it assumes very low values. It becomes of interest during significant load-generation imbalances (caused by disconnection of either large loads or generators, or by system splits), when larger ROCOF values may be observed. Synchronous machines respond to any change in their speed and therefore to non-zero ROCOF by injecting or consuming active power in a manner that reduces existing load-generation imbalances. In the absence of any control, inverter-based generation does not possess such characteristics and high inverter penetration without any countermeasures could therefore lead to higher ROCOF in a power system. The relationship between inverter penetration and ROCOF is, however, not straightforward, and countermeasures – mostly in the form of control algorithms – exist. Large ROCOF values are problematic in some power systems because of mechanical limitations of synchronous machines, protection devices triggered by a particular ROCOF threshold value or timing issues related to load shedding schemes.
- Initial ROCOF**:** The instantaneous ROCOF just after the disconnection of either a generator or load from a power system, before any controls become active. This is theoretically the highest system ROCOF. Its average for an interconnection of *N* synchronous loads and generators can be computed as follows:
$$\left.\frac{d\Delta f}{dt}\right|_{t=0^+} = \frac{f^0 P_k}{2\sum_{i=1,i\neq k}^{N} H_i S_i}$$
wherein Δf is the deviation of the frequency f from its nominal value f^0, 0^+ is the moment just after disconnection of the load/generation P_k is the lost generation/load (the machine carrying the index k), and H_i and S_i are the inertial constant and apparent power rating of synchronous machine *i*, with i ranging from 1 to *N* (Definition from [22], derived from [23]). Additional frequency oscillations may occur locally on top of the average behavior. It should be noted that any system that relies on measuring frequency and ROCOF will most likely not detect a ROCOF as high as the theoretical maximum. This is due to the inevitable filtering involved in frequency estimation [24]. As a result, ROCOF relays with measurement windows of several hundred ms may not be triggered if the initial ROCOF breaches their threshold, but ROCOF is lower subsequently.
- ROCOF relay / Loss of mains protection**:** In some power systems, distributed generation resources are protected against unintentional islanding (loss of mains) through relays based on ROCOF. An example of such protections is the Irish distribution system, where a significant proportion of distributed generation has such protection installed. The threshold there is 0.55 Hz/s (under investigation to be raised a little further). This type of protection is not applied in all power systems (e.g. not commonly used in Continental Europe where f rather than df/dt has been used), although widely used also in GB, with thresholds as low as 0.125Hz/s in vast numbers of installations (actions to raise the thresholds are in progress, in GB initially focused on the modest number of units larger than 5MW).

- Load shedding schemes**:** In many power systems, load shedding schemes are the ultimate defense mechanism designed to prevent a blackout. They are typically staggered schemes, with each stage triggered by a particular under-frequency threshold. In order to guarantee sufficient reaction time for each stage, ROCOF must be limited at the point when the under-frequency threshold is breached.

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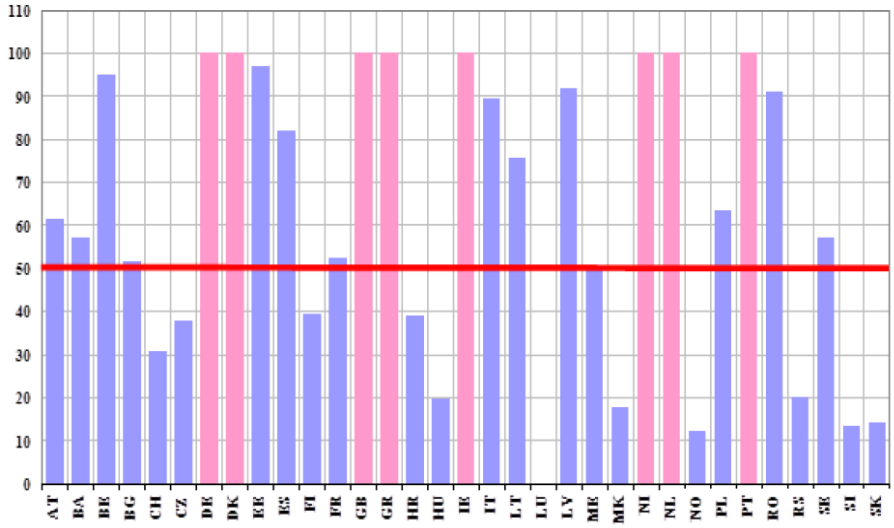
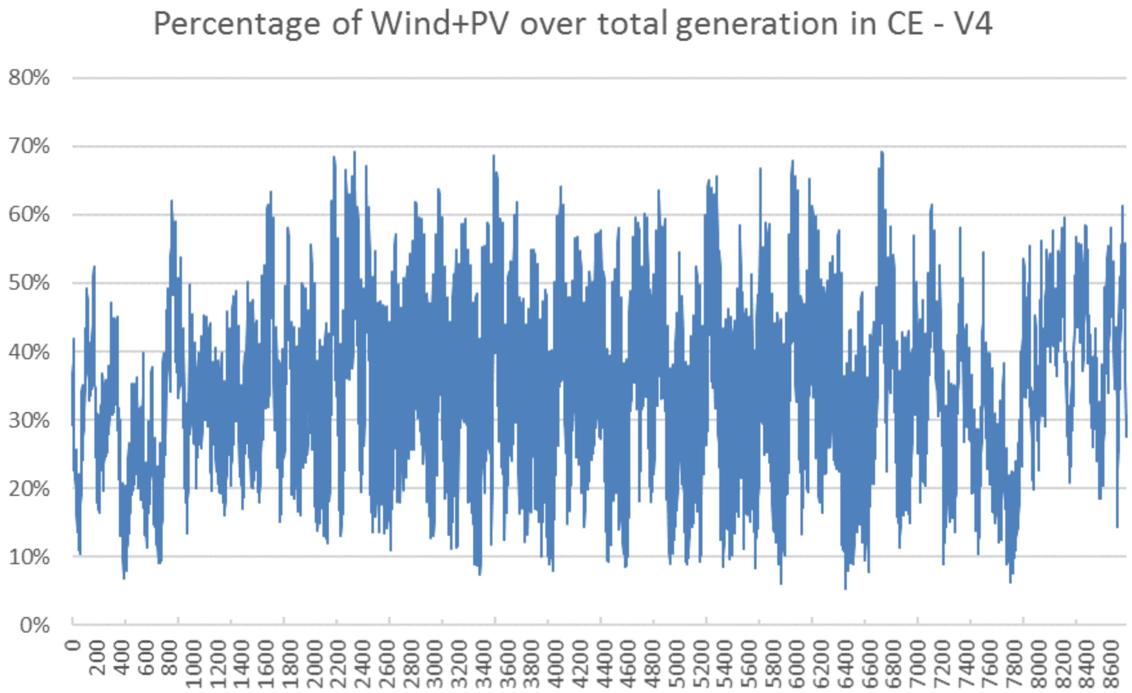
Appendix 2: Data on the degree of penetration in context of future energy scenarios

The figure below shows the highest % RES occurring in any hour in the year by country in 2025 under the future energy scenario of Vision 4. Eight countries reach 100% and 22 countries at least 50% for the most challenging hour, assuming no substitution, source [2]



Further in depth RES penetration data from [2] and TYNDP 2016 is shown below, based on source information in [5] providing details of assumptions. This shows first hourly variation for one year for Continental Europe (CE) for scenario V4, the % degree of penetration of RES. Then this data is converted into a duration curve for CE. Similar duration curves are then shown for the other SAs in Europe, covering SAs Nordic, Baltic, GB and finally Ireland/Northern Ireland (IE+NI). Large variations in penetration can be seen between the highest RES penetration IE+NI and GB and the lowest Nordic, followed in between by Baltic and CE.


Percentage of Wind+PV over total generation in CE - V4
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
4200
4400
4600
4800
5000
5200
5400
5600
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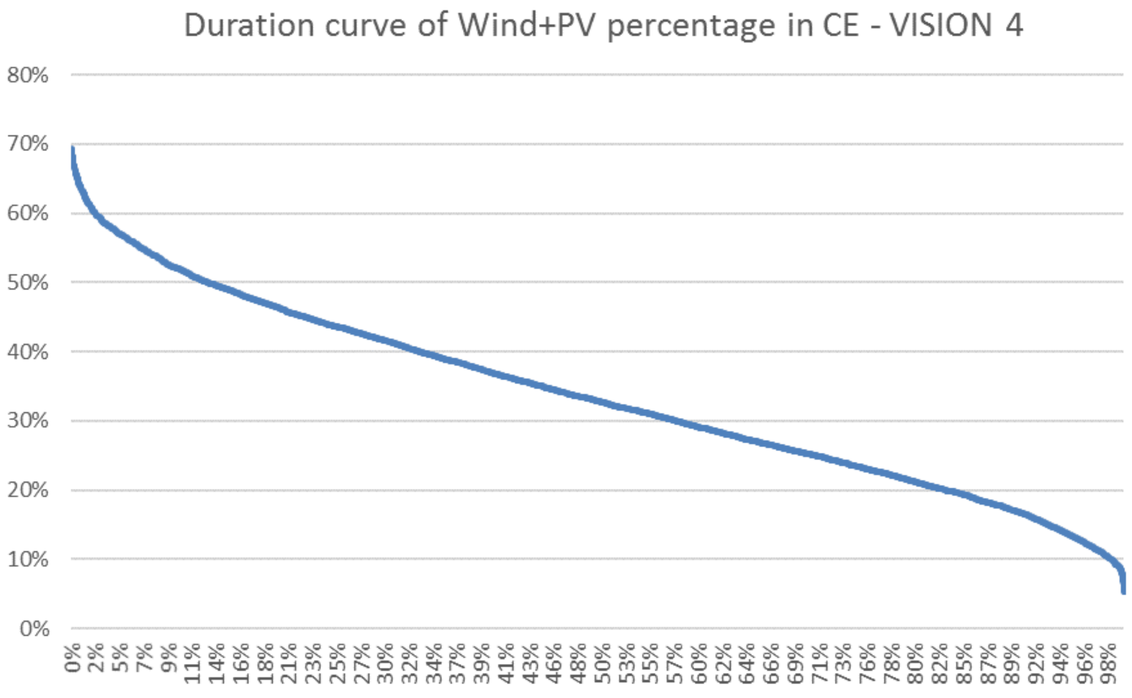
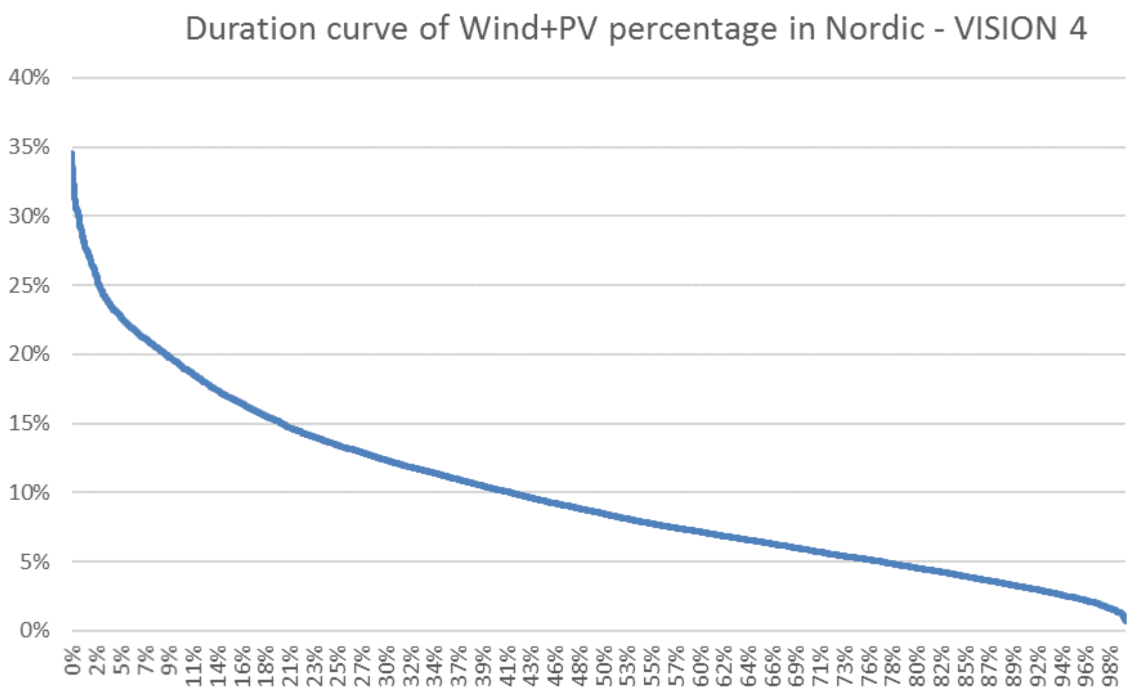
7800
8000
8200
8400
8600


Duration curve of Wind+PV percentage in CE - VISION 4
80%
70%
60%
50%
40%
30%
20%
10%
0%


Duration curve of Wind+PV percentage in Nordic - VISION 4
40%
35%
30%
25%
20%
15%
10%
5%
0%
0%
2%
5%
7%
9%
11%
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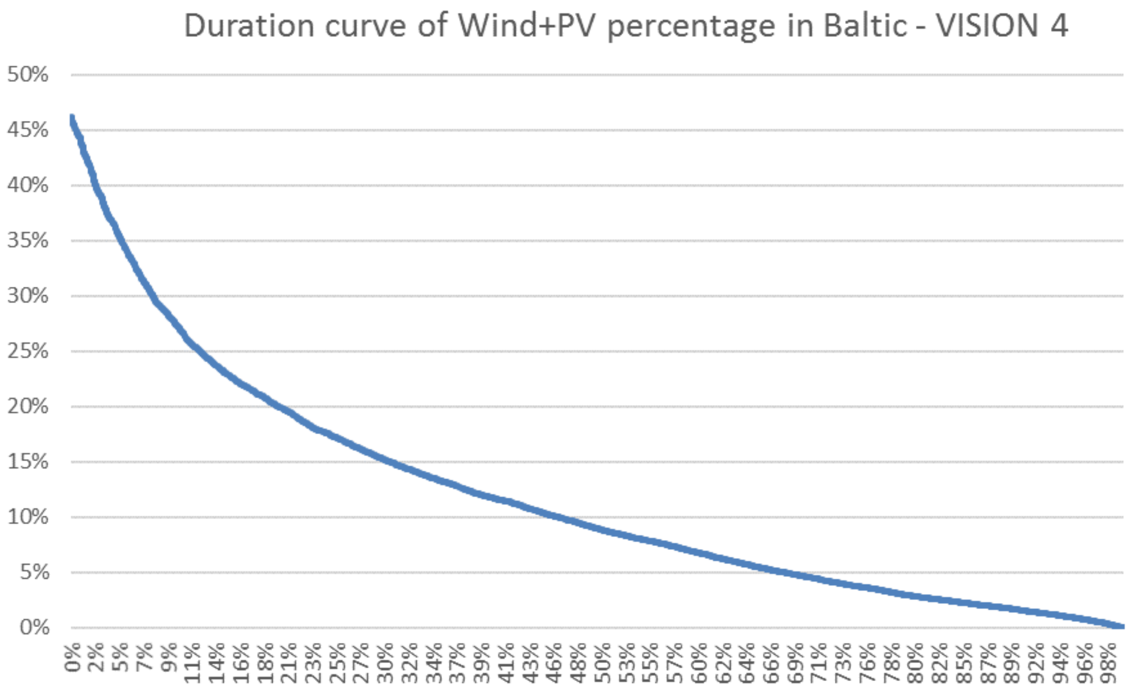
Duration curve of Wind+PV percentage in Baltic - VISION 4
50%
45%
40%
35%
30%
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20%
15%
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5%
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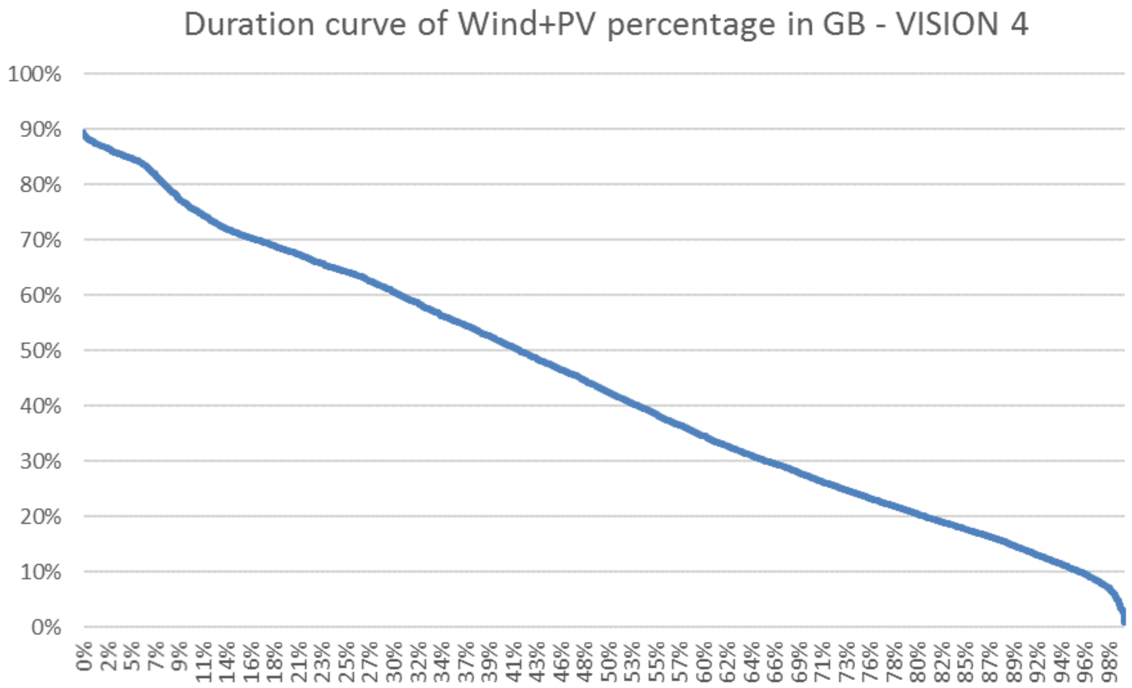

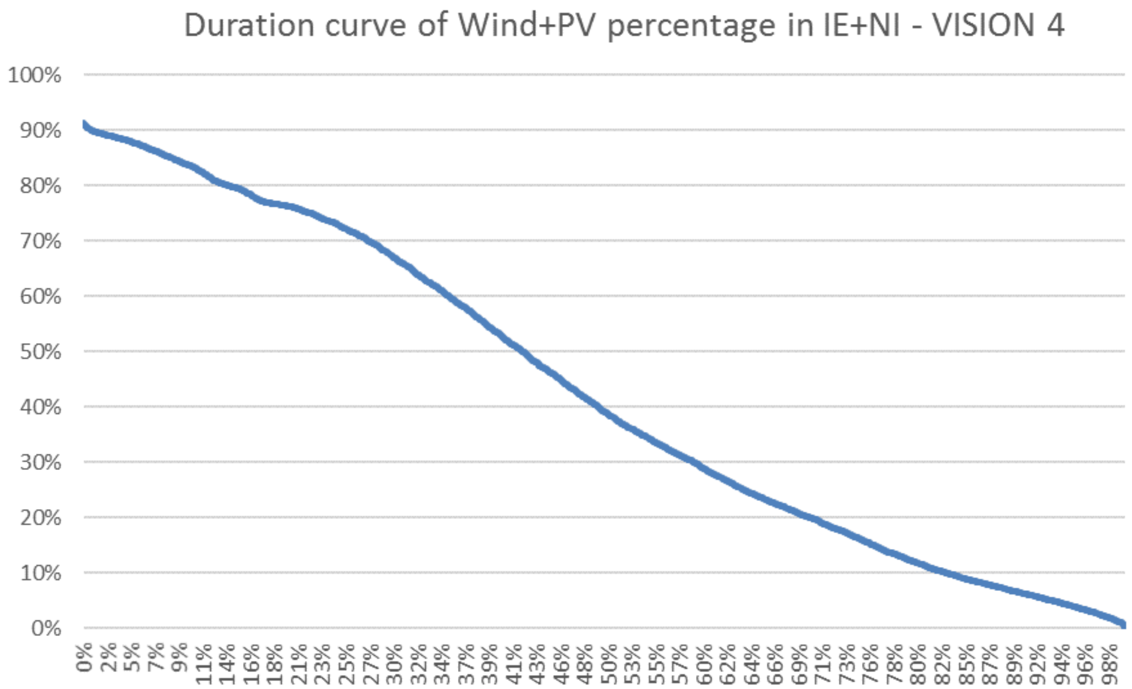

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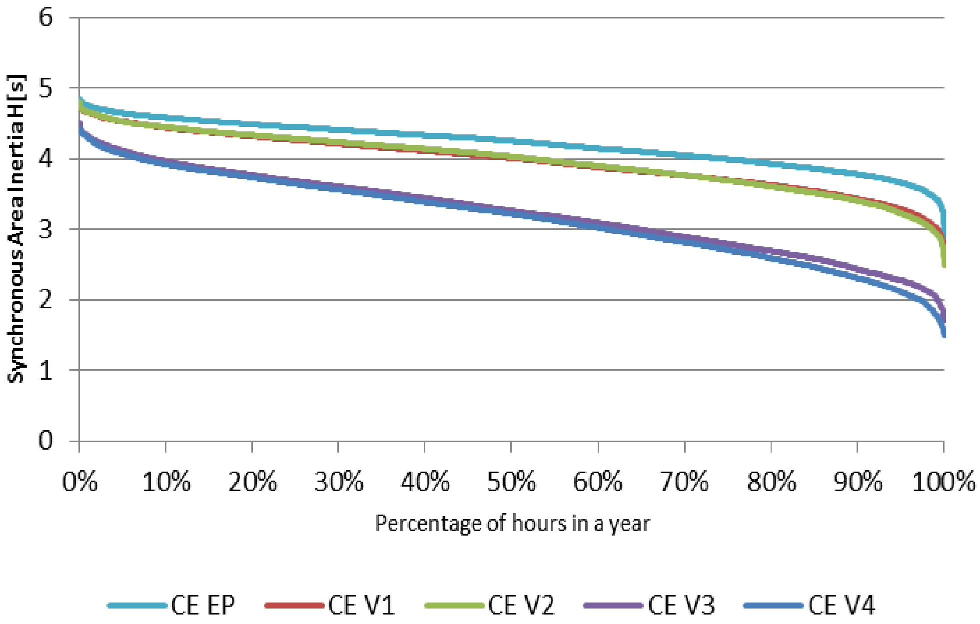
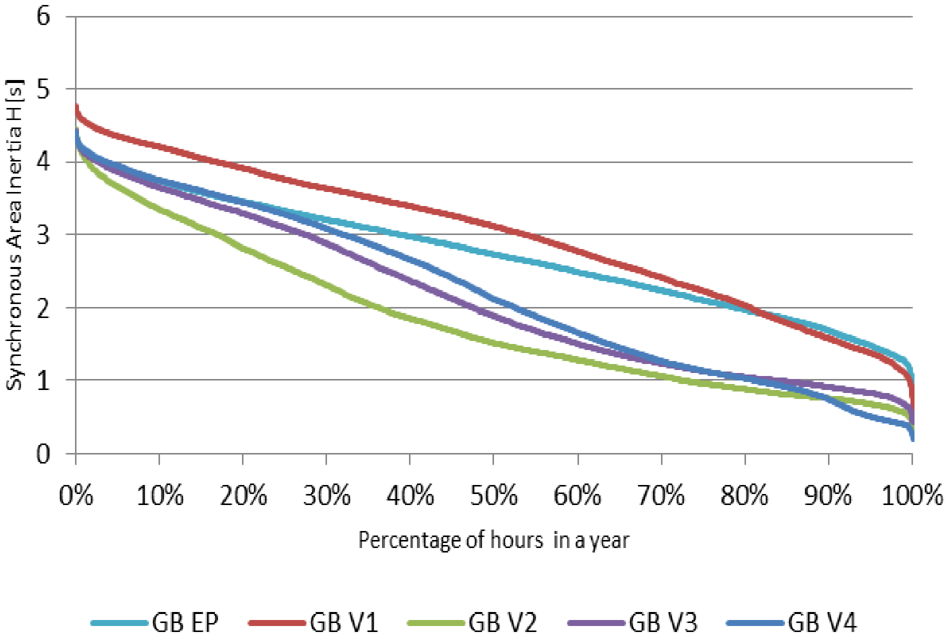
Appendix 3: Data on Total System Inertia (TSI) in context of the full range of 2016 ENTSO-E future energy scenarios

Estimation of the evolution of system inertia for different 2016 TYNDP visions for 2030 for CE and GB SAs. This assumes the PEIPSs do not make any contribute to inertia. The 90% point for CE for V4 has an H significantly above 2s, while in contrast GB has an equivalent H well below 1s., about 2.5 times lower.





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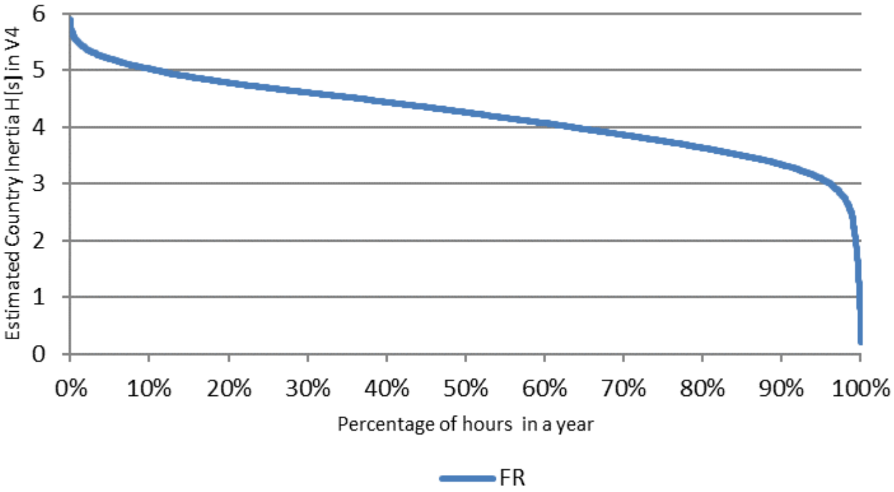
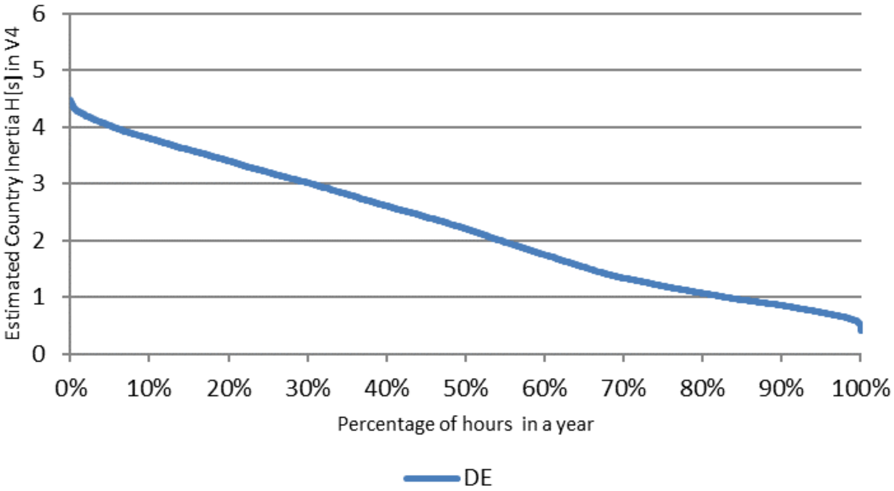
Estimation of the evolution of system inertia for Vision 4 differences within CE – Germany & France. This illustrates the large variation in national contributions (per unit) to TSI during high RES within CE, covering the two largest countries, e.g. the 90% points are H=3.4s for France compared to H=0.9s for Germany.



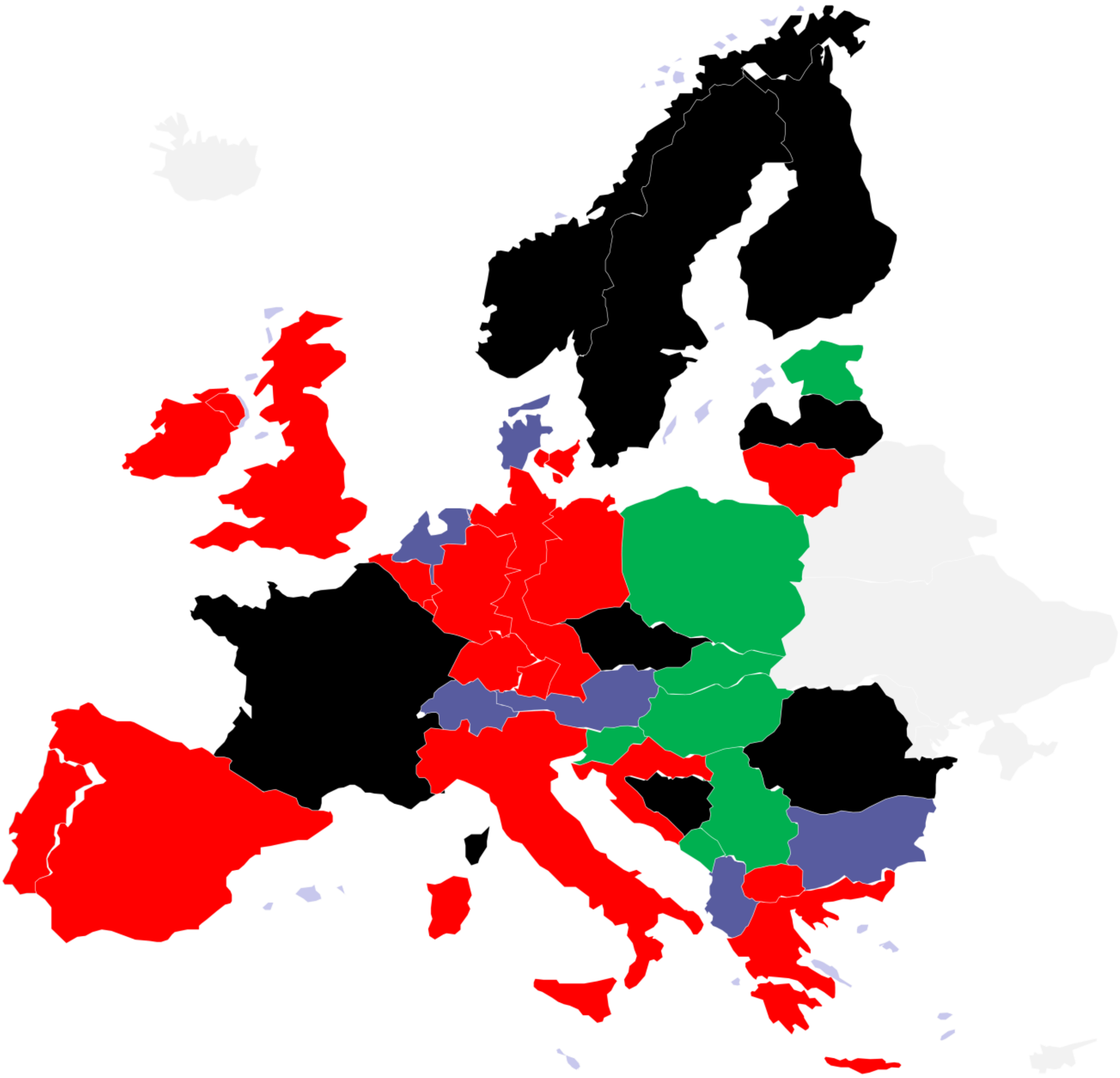


Values of national inertia contribution (in per unit) to their SA calculated for each country at the 50% and 90% duration points arranged by synchronous areas for 2030 V4. As expected most countries follows the SA profile with higher inertia at the 50% point than the 90% point. Please note however, that a few countries have inertia changes with time different from the overall SA changes of inertia with time, such as Greece with much higher H at the CE 90% point for CE (1.4s) than at the 50% point for CE (0.5s), i.e. very different pattern of variation. Therefore, these figures may not contain the most challenging conditions for each country. These countries are banded **indicatively** in the diagram below (based on figures from tables further down) in terms of concern or not about adequacy of inertia contribution and hence indicatively about general system strength. The below colouring is narrowly based **(indicatively only)** and in context of the single points, the hour at which their SA is at the 90% point. The national minimum point for the most challenging hour in the year may be different from the most challenging point for the SA as a whole. More details on inertia is available in [5] for each country. The concern indicator below assumes that contribution by every country to the resilience of their SA is needed at all times. This may not be the case, as it may be deemed adequate due to sharing. Resilience for possible system splits is also needed. The system splits do not necessarily coincide with national boundaries.

The single point data create in some cases (e.g. Denmark) a strange result.

Inertia contribution colouring code:

- Green H>4s Very good contribution
- Black 3s<H<4s Good contribution
- Purple 2s<H <3s Marginal contribution
- Red H<2s Limited contribution. Action needed?



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CE	AL	AT	BA	BE	BG	CH	CZ	DE	DKw	ES
50%	3,6 s	3,3 s	3,9 s	3,3 s	3,5 s	3,2 s	3,6 s	2,4 s	3,1 s	2,9 s
90%	2,5 s	2,2 s	3,9 s	1,5 s	2,9 s	2,4 s	3,0 s	0,9 s	2,5 s	1,7 s
CE	**FR**	**GR**	**HR**	**HU**	**IT**	**LU**	**ME**	**MK**	**NL**	**PL**
50%	4,4 s	0,6 s	3,8 s	4,8 s	2,6 s	4,2 s	3,9 s	3,0 s	4,0 s	4,3 s
90%	3,4 s	1,4 s	1,7 s	5,4 s	1,6 s	1,7 s	4,2 s	1,2 s	2,7 s	4,4 s
CE	**PT**	**RO**	**RS**	**SI**	**SK**					
50%	2,9 s	2,6 s	4,0 s	4,6 s	4,9 s					
90%	2,0 s	3,2 s	4,0 s	5,0 s	5,0 s					

Nordic	DKe	FI	NO	SE
50%	1,1 s	3,9 s	3,4 s	3,7 s
90%	1,1 s	3,3 s	3,3 s	3,1 s

Baltic	EE	LT	LV
50%	3,5 s	4,0 s	3,9 s
90%	4,1 s	1,4 s	3,3 s

IE+NI	IE	NI
50%	2,9 s	0,7 s
90%	0,6 s	0,4 s

GB	GB
50%	2,1 s
90%	0,7 s

Appendix 4: Possible remedial actions – for high penetration of PEIPS

Alternative means of dealing with the operability challenges to improve resilience

Conventional approaches

It is possible to initially deal with the resilience / operability challenges in a conventional way by constraining in real time the amount of power electronic interfaced RES to a certain value, e.g. as implemented in Ireland. However, this is both costly and environmentally undesirable. EirGrid has published [3] an anticipated rise in cost of ancillary services, significantly affected by this aspect, from 5% of total electricity cost in 2015 to 25% in 2020.

Alternatively, several of the challenges can be reduced / overcome by large scale installation of synchronous compensators (SC, generators with no prime mover). For example [4] suggests that GB could be stabilised for high frequency instability up to 100% penetration with approximately 9,000MVA of rotating SCs. This scale of SCs may not be considered a societal optimal solution.

However, Denmark as the first nation in Europe to face these challenges has chosen this route, at a time before alternative PE solutions have emerged. For several years an increasing number of hours in the year Jylland (the mainland part connected to SA CE) has had wind alone exceed the total Jylland electricity demand. Many of the associated dynamic challenges have been tackled with strategic large SC installations, e.g. adjacent to locations of converter connections. Jylland is connected by 400kV to Germany and as such benefits from imported system strength, which is not available to countries of the island synchronous areas, such as Ireland and GB and Offshore HVAC systems.

Causes in more depth – the evidence collated so far

HPoPEIPS Tipping points / limit of aspects of voltage stability

In GB in 2012/13 studies were undertaken under the heading "System strength considerations in a converter dominated power system". Initially these were published in October 2013 at WIW2013 in London and then made more accessible by IET in the publication Renewable Power Generation (RPG) in January 2015. This work indicated a possible high frequency instability, indicatively around 65% NSG/PE penetration for the SA of GB.

This finding together with the potential future massive constraint cost or ceiling on RES developments (both unacceptable) lead to commissioning by the TSO (NGET) of R&D to establish

A The physical causes of the indicated loss of stability for the SA

B Practical means for the TSO to analyse & manage the issues (i.e. in dynamic studies)

C Which other stability aspects could be of concern at high PE penetration

D The limit of operation / tipping point for each stability challenge

E Demonstrate a practical & economic range of solutions to allow unrestricted PEIPS penetration (80-100%) suitable for only requiring modest RES substitution by SGs.

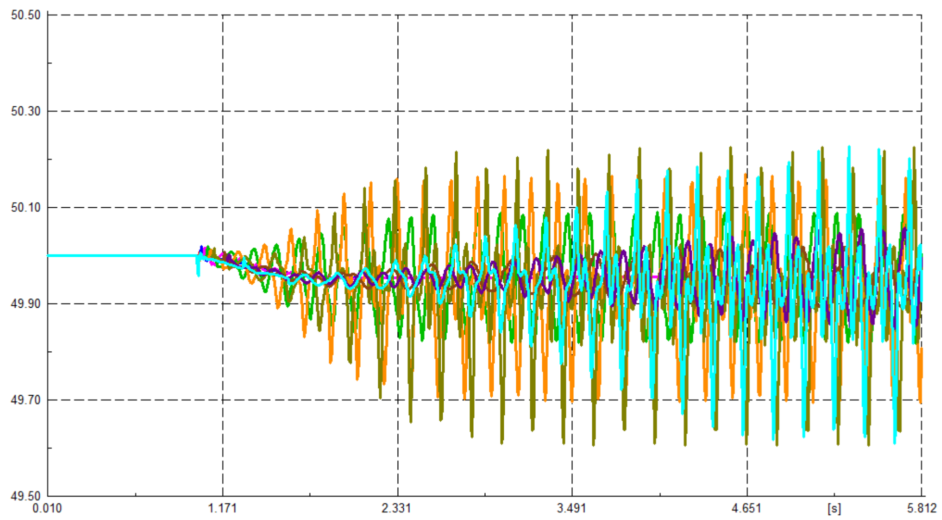
In 2015 and 16 the results of this work has been published widely covering:

The physical cause and the tipping point for high frequency instability [10].

An initial alternative converter control strategy VSM0H to allow 100% [10]

The detrimental stability effect of true synthetic inertia [10], see also the figure below illustrating the unfortunate finding that instability (SSI) gets worse, not better with adding common synthetic inertia (if it is based on measurement, control calculation and actuation which invariably involves delays). Even if it was possible to deliver SI with only one cycle delay, analysis shows SSI is made worse.

The reference above to true inertia in [10] & [12] relates to Swing Equation Based Inertial Response (SEBIR) control, i.e. "synthetic inertia". It has been shown in this work that although SEBIR controlled synthetic inertia could help with delivering additional inertia (and hence reduce RoCoF), it is likely to destabilise the network, cause super-synchronous instability. Analysis of the impact of delays of the measurement, plus control activity and plus actuation time is shown in the figure below. It shows the impact of varied total delays. Unfortunately, even the shortest delays imaginable in this control approach of one or two cycles (20-40ms) is detrimental to super-synchronous stability.



Effects of SEBIR with various delay in the control loop (Reduced GB model in PF)

Zone 27 E\Z27E Nuclear: Frequency in Hz (With 0-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 1-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 2-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 3-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 4-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 5-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 8.5-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 10-cycle delay)
Zone 27 E\Z27E Nuclear: Frequency in Hz (With 15-cycle delay)

An alternative converter control strategy VSM to deal with both frequency & voltage stability simultaneously and a range of other challenges [12] & [13]

The alternative converter control strategy also demonstrated potential solutions for

The study (B above) and hence management / transparency challenge [12] & [13]

Delivering fault current (balanced and unbalanced) without delay (within first cycle) to secure reliable protection operation [12], [13] & [25]

Delivering sinks for harmonics (including inter-harmonics) and unbalance [12]

Broad characteristics required of possible solutions – a holistic approach

Why a holistic approach?

The TSO analysis (some of which has been shown above) indicates that challenges of fast dynamics (voltage, frequency and other stability aspects as defined) associated with low and particularly extremely low System Strength have strong inter relations.

Management of one issue is bound to affect management of several others. There are plenty of examples of this. It is therefore clear that a holistic approach is needed to prepare a path towards possible full RES penetration (even if initially limited to the first hour in a year).

It is also clear that, when average penetration is still relatively modest, the most challenging hour of the year which the System Operators need to concern themselves with sees a very much higher penetration under which the SO has to deliver the expected high level of security of supply. Typically for one country the highest hourly penetration is 4-5 times greater than the average penetration. This was demonstrated in about 2008 when Jylland (mainland Denmark, the part connected via Germany to SA CE) first reached 100% of demand covered by wind alone while the Danish average RES penetration was a more modest 20%.

In November 2016 National Grid published [4] its System Operability Framework (SOF2016) containing this holistic principle for GB in its Chapter 5 “Whole System Coordination” on pages 142 to 173.

One example of such an approach could be careful application of the VSM control strategy to an adequate proportion of the PE based sources. Analysis to date indicates that a geographical spread of the many desired technical capabilities is more resilient against the multitude of types and locations of potential problems arising. In principle most of the characteristics could be delivered by very large HVDC converters, by middle size wind generation converters or by small scale PV converters (as well as batteries).

In terms of when & how the desired capabilities are brought on stream each country need to consider below in context of the overall process diagram to be found under the heading “Collaboration”

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Appendix 5: Grid Forming performance for PEIPS in high penetration locations

Class 1 PPMs or HCSs shall be capable of supporting the operation of the ac power system (from EHV to LV) under normal, disturbed and emergency states without having to rely on services from synchronous generators.

This shall include the capabilities for stable operation for the extreme operating case of supplying the complete demand from 100% converter based power sources. The support services expected are limited by boundaries of defined capabilities (such as short term current carrying capacity and stored energy). Transient change to defensive converter control strategy is allowed (if it is not possible to defend the boundaries), but immediate return is required.

Grid Forming PPMs or HCSs

In addition to capabilities of PPMs or HCSs Classes 3 and 2, provide PPM or HCSs controls with single cycle support services allowing 100% power electronic penetration, including:

- Creates system voltage (does not rely on being provided with firm clean voltage)
  - Contributes to Fault Level (PPS & NPS within first cycle)
  - Contributes to Total System Inertia (limited by energy storage capacity)
- Supports fast dynamics (first cycle) survival for system splits and from brown & black outs
  - Giving survival time for LFDD to operate
  - Restoration including Brown & Black Start
  - Contributes to first swing stability, e.g. through dynamic breaking
- Controls act to prevent adverse control system interactions
  - Avoids contribution to super synchronous instability, e.g. through controller bandwidth limitation
  - Avoids contribution to sub synchronous resonance, e.g. through controller bandwidth limitation
  - Does not make full system dynamic studies impractical through complex non-fundamental frequency interactions
- Act as a sink to counter harmonics & inter-harmonics in system voltage
- Act as a sink to counter unbalance in system voltage

Description of one practical implementation:

Grid Forming PPMs or HCSs provide an inherent performance resulting from presenting to the system at the Connection Point a voltage behind an impedance, in effect a true voltage source.

Virtual Synchronous Machines (VSM) demonstrate stability is achievable with modest changes to PE controls

A relatively new approach for application in large scale power systems, from R&D [10], [12] & [13] following up the operability challenges identified in [7], indicates many [10] or potentially all high power electronic operability challenges can be overcome [12] &[13] by relative modest means. This suggests that building upon experience of small isolated systems (e.g. marine applications and small isolated islands with high RES) is readily doable, applying controls to power electronics which mimics the beneficial characteristics of synchronous generators, leaving out the less beneficial characteristics (e.g. tendency for oscillations) and adding some further desirable characteristics, such as dynamic breaking.

This converter control topic is broadly called Virtual Synchronous Machine (VSM). The R&D [12] & [13] has demonstrated that the selection of the exact control strategy is critical. Given a good choice of VSM characteristics [9] suggests that GB (and likely other systems) has the potential to operate stably up to 100% penetration. The effectiveness has even been demonstrated in terms of maintaining stability in a couple of extreme cases. One of these is coping with the challenge of the loss due to a nearby fault of the only large synchronous generator connected on the GB SA (example of 1600MW is studied). Even more challenging is a demonstration by study of a case of a double circuit fault followed by an England – Scotland system split (tripping of all 4 North – South circuits). This is a more severe challenge (effectively n-4) than that required by existing GB planning and operating standards.

The work demonstrates that with careful selection of converter control strategies from a system point of view, all challenges identified above can be dealt with.

Desirable characteristics of this integrated solution include:

- Contribution to inertia without tendency towards high frequency instability.
- Contribution to providing a “lead” on establishing the system voltage, rather than “follow” the provided non-firm system voltage.
- Limitation of bandwidth for the active converter controls, possibly as already applied by some TSOs to synchronous generators, i.e. less than 5 Hz to remove tendency towards high frequency (hundreds of Hz) system instability as well as sub synchronous resonance.
- Significant contribution to fault current, delivered within one cycle and including an unbalanced (NPS) contribution to improve protection detection / performance and generally enhance converter stability by raising system strength.
- Contribution to secure system voltage recovery on fault clearance, including countering impact of stalling motor drives (induction motors).
- Contribution to reduce harmonic and unbalance content of system voltage, by providing counter harmonic and unbalance current injections.
- Deliver dynamic breaking to enhance transient first swing stability and improve voltage recovery through management of angular movements during / following faults.
- Adequate models which are simple enough to allow large scale dynamic system studies reflecting the major dynamic aspects.

The VSM example converter controller in [12] & [13] delivers all these benefits. The performance aspects rather than the exact implementation define the system needs. Countries, particularly as identified with penetration levels and duration of low inertia above the indicative thresholds in the process diagram in the section “Collaboration” may consider carefully the possibility of introducing these characteristics.

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The amount of each characteristic needed will vary between synchronous areas and even between countries. Obtaining enough capabilities will depend upon when the capabilities start to be delivered in volume and the amount of RES already in place at that time.

The longer the start of implementation is delayed, the more is required from the subsequently connected RES, assuming retrospective action is to be avoided without limiting further development of RES. Adequate time should however be provided for manufacturers of converters to be ready to deliver the required characteristics. If it is confirmed that the desired characteristics can be delivered by converters at a modest cost compared to the cost of alternative actions (see section 3), then options for early implementation should be examined.

These characteristics can be introduced for converters in HVDC, wind generation and solar PV. A geographical spread is required in order to be most effective. However, introduction for the smallest units (RfG Type A and also in part Type B) may not be facilitated by the existing version of the NC RfG.

Where the need is strongest, consideration is needed regarding either delaying progress for small units until an issue 2 of the relevant NCs, which may be developed to facilitate this or to seek use of the national freedom to introduce new requirements which are not explicitly covered at a European level, taking care to avoid contradicting the NCs.

Expert Group Fast Fault Current Injection (EG FFCI) proposed Classification of Converters or PPMs (Power Park Modules)

In order to simplify the description of converter capabilities, the following list of Classes can be used to describe the functional performance of a converter. Predominantly, the functional performance is defined by the control software, although there are power, current, dV/dt, energy and other hardware considerations within a converter.

Class 1 PPM

Class 1 PPMs (or "Grid Forming" PPMs) shall be capable of sharing in the management of the operation of the AC power system (from EHV to LV) under normal, disturbed and emergency states including extremes of 100% converter based power sources, without having to rely on services from synchronous generators.

In addition to capabilities of PPM Classes 3 and 2, a Class 1 PMM provides controls with single cycle support services allowing 100% power electronic penetration, including:

- Creates system voltage (does not rely on being provided with firm clean voltage)
- Contributes to Fault Level (PPS & NPS)
- Act as a sink to counter harmonics & inter-harmonics in system voltage
- Act as a sink to counter unbalance in system voltage
- Contributes to Total System Inertia or provides Fast Frequency Response
- Supports fast dynamics (first cycle) survival for system splits and from brown & black outs
  - Giving survival time for LFDD to operate
  - Restoration including Brown & Black Start
  - Contributes to first swing stability, e.g. through dynamic breaking
- Controls act to prevent adverse control system interactions
  - Avoids contribution to super synchronous frequency instability, e.g. through controller bandwidth limitation
  - Avoids contribution to sub synchronous resonance, e.g. through controller bandwidth limitation
  - Does not make full system dynamic studies impractical through complex non-fundamental frequency interactions

Class 2 PPM, divided into Class 2A, 2B and 2C

A Class 2 PPM has “Advanced Control” and additional capabilities over and above a Class 3 PPM.

For Class 2A, all the Class 3 and Class 2B, 2C requirements, plus:

- Voltage control through reactive power when P=0
- Provides damping
- Fast Fault Current Injection FFCI
  - FFCI – Period B and C for PPS
  - FFCI – Periods B + C for NPS
  - FFCI – Periods B + C provide bias choice between reactive & real current

For Class 2B, all the Class 3 and Class 2C requirements, plus:

- Voltage control – dynamics
- FSM
- LFSM-U

For Class 2C, all the Class 3 requirements, plus:

- Basic FRT (Fault Ride Through)
- Voltage control – steady state with $P \neq 0$

Class 3 PPM

A Class 3 PPM represents the basic level of grid-connected converter functionality, with a main focus on basic converter survivability.

- Capable of exporting or importing a specified quantity of real and/or reactive power when connected to a stable pre-existing AC grid, relying on the influence of synchronous generators or Class 1 PPMs to keep the voltages and power quality within acceptable bounds.