D2.5 Procedure for Verification of Grid Code Compliance

Olimpo Anaya-Lara, Pablo Ledesma
University of Strathclyde

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1 INTRODUCTION

The objective of this document is to provide a procedure to assess the compliance of an offshore wind energy installation with the grid codes of several transmission system operators (TSO). The procedure uses a simulation tool, and does not rely on tests on the real installation.

The software simulation tool is PSSE, as specified in the EERA-DTOC project. This tool is intended for dynamic simulation of electromechanical transients in power systems, and is valid in a range of frequencies between 0 and 10 Hz. Therefore, some topics such as flicker, harmonics, inter-harmonics and sub-synchronous resonance are out of the scope of this procedure.

Given a specific wind energy installation, the procedure has been designed to facilitate to the user the assessment of the compliance with different grid codes. Due to the expected complexity of future offshore network arrangements, it can be particularly useful in the case of the fault ride-through capability, which concerns the performance of the installation when subjected to severe faults. However, the procedure also provides guides to address other issues such as frequency and voltage control.

The procedure consists of:

- A series of steps to follow - described in Section 2. The steps are based in the simulation in PSSE of the wind energy installation subjected to disturbances as similar as possible to those described in the grid code. The output variables are then examined to assess grid code compliance.

- A set of PSSE user models specifically developed for this task - described in Section 3

The flowchart shown in Figure 1 shows the general procedure. On the left side, a base case representing the offshore network arrangement is built taking into account the layout, the static parameters and the dynamic models and parameters. On the right side, the corresponding user models are selected depending on the grid code the user wants to verify. Both entries are then used to perform several simulations in PSSE to assess the compliance with the grid code requirements.

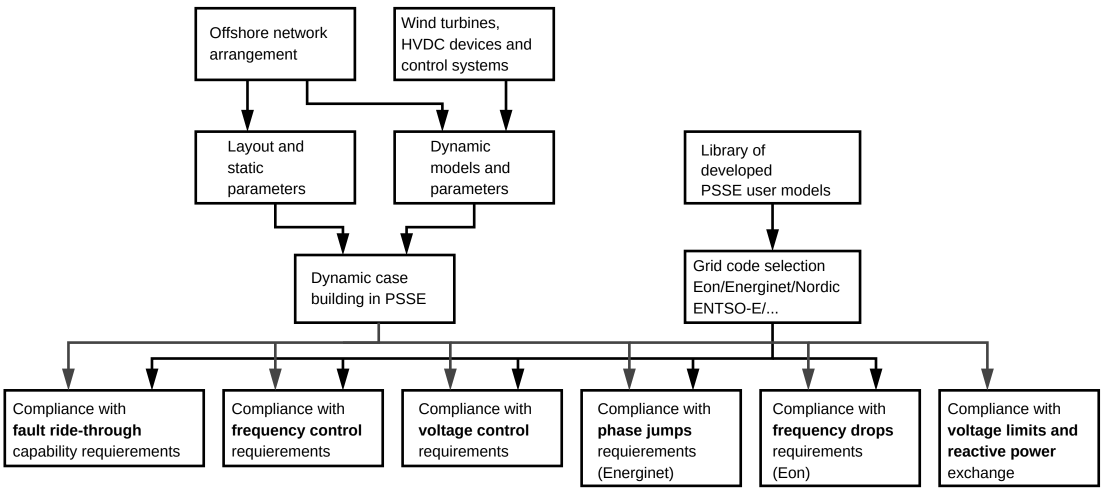

Figure 1. Overall procedure for the verification of grid code compliance

The user is supposed to know how to build a case in PSSE and to perform a dynamic simulation. Many of the steps in this procedure involve the use of a PSSE user-model, written in Fortran and provided together with this document. The use of user-models in PSSE requires their previous compilation, as explained in the PSSE documentation. The user-models have been designed to be as general as possible, in order to facilitate the adaptation of the procedure to future changes in the grid codes.

2 PROCEDURE FOR THE VERIFICATION OF GRID CODE COMPLIANCE

The following subsections are independent from one another, and the user should select one of them depending on the grid code to study.

Each of the following steps in the procedure involves a dynamic simulation. Except if there are reasonable reasons to do it otherwise, the simulations must be performed with the wind farms operating close to their maximum power.

2.1 Energinet

The grid code specifications used in this section have been obtained from [1]. No specific provisions for offshore wind farms have been found[1].

2.1.1 Deep voltage dips

The requirements for tolerance of voltage drops include a voltage dip to down to a 20% of the rated voltage and duration of 0.5 s, followed by a recovery ramp. During this voltage dip, the wind power plant must remain connected and provide voltage support.

To verify that the wind power plant complies with this requirement:

Connect user model VDENET to the point of connection and run a simulation over 4 s. Check that:

- The wind installation remains connected and continues providing power at the end of the simulation.
- The reactive current provided by the wind installation (vdenet VAR type variable number 6) is always over the minimum limit (vdenet VAR type variable number 7).

2.1.2 Other requirements

<u>Frequency limits and control</u>

The response of the wind power plant to changes in frequency can be simulated connecting user model FRQSTP to the point of connection and applying a frequency step DF, in Hz. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'FRQSTP' 1 0 0 1 0 2 DF /

where BUS is the bus number of the point of connection. The active power provided by the generating plant is stored at VAR type variable number 1.

The performance of the constraint functions can be simulated without any user model, connecting the generating plant to the PSSE standard model GENCLS. The corresponding line at the dynamic data file is:

BUS 'GENCLS' 1 0.0 0.0 /

where BUS is the bus number of the point of connection. To simulate the constraint functions, vary the control signals and observe the effect on the active power.

[1] The document “Compensation for offshore wind farms ordered to perform downward regulation”, 15.5.2009, by Elteknik, does not impose additional technical requirements.

Voltage limits and control

To verify the operation inside the voltage limits and the performance of the voltage control, connect user model VOLSTP to the point of connection and apply a voltage step to voltage V in pu. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'VOLSTP' 1 0 0 1 0 2 V /

where BUS is the bus number of the point of connection. Run a simulation over 20 s. Check the reactive power at the user model QELEC variable.

The performance of the reactive power and power factor control functions can be simulated without any user model, connecting the generating plant to the PSSE standard model GENCLS.

The corresponding line at the dynamic data file is:

BUS 'GENCLS' 1 0.0 0.0 /

where BUS is the bus number of the point of connection. To simulate the control functions, vary the control signals and observe the effect on the reactive active power and the power factor.

Phase jumps

Connect user model PHSSTP to the point of connection to apply a voltage phase step of 20 degrees. The corresponding line at the dynamic data is:

BUS 'USRMDL' 1 'PHSSTP' 1 0 0 1 0 2 20.0 /

where BUS is the bus number of the point of connection. Run a simulation over 60 s. Check that the wind power plant remains connected and providing power. The active and reactive power are stored at the user model PELQC and QELEC variables. Repeat for a voltage phase step of -20 degrees.

2.2 E.ON Netz Gmbh

The grid code specifications used in this section have been obtained from [2] and [3].

2.2.1 Faults in the grid

The fault ride through capability requirement consist of two voltage profile curves, one down to a 45% of the nominal voltage during 150 ms and other down to a zero voltage during 150 ms. Above the first voltage profile, the installation must remain connected. Above the second voltage profile, a brief disconnection is allowed by agreement with the TSO. In all the cases the generating plant must provide voltage support in the form of reactive current while it remains connected.

The extension of the simulations is 12 s because some parts of the grid code demand a power recovery with a minimum gradient of 10% of the rated power per seconds. However, the main requirements refer to the first second of the simulation.

To verify that the generating plant complies with this requirement:

1) Connect user model vdeon1 to the point of connection and run a simulation over 12 s. Check that:

- The generating plant remains connected and continues providing power at the end of the simulation.

- The reactive current provided by the wind installation (vdeon1 VAR type variable number 5) is always over the minimum limit (vdeon1 VAR type variable number 6).

- The active power provided by the generating plant (vdeon1 VAR type variable number 7) is always above the minimum limit (vdeon1 VAR type variable number 8).

2) Connect user model vdeon2 to the point of connection and run a simulation over 12 s. Check that:

    - If the generating plant remains connected, the reactive current and the active power are always above the limits as in the previous case.

    - If the generating plant is disconnected, and provided that an agreement has been reached with the TSO in this sense, the requirements of this agreement regarding reactive current, resynchronization time and active power recovery are met.

3) Connect user model vdeon3 to the point of connection and run a simulation over 12 s. Check that:

    - If the generating plant is disconnected, the resynchronization time is less than 2 s and the active power recovery is at least 10% of the rated power per second.

    - Alternatively, if an agreement has been reached with the TSO, the conditions of the agreement are met.

2.2.2 Other requirements

<u>Frequency drops</u>

Connect user model FRDEON to the point of connection. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'FRDEON' 1 0 0 0 0 2 /

where BUS is the bus number of the point of connection. Run a simulation over 70 s. Check that the active power output is not reduced.

<u>Frequency limits and stability</u>

The response of the generating plant to changes in frequency can be simulated connecting user model FRQSTP to the point of connection and applying a frequency step DF, in Hz. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'FRQSTP' 1 0 0 1 0 2 DF /

where BUS is the bus number of the point of connection. The active power provided by the generating plant is stored at VAR type variable number 1.

Voltage limits, reactive power exchange and voltage stability

The response of the generating plant when operating at different voltages can be simulated without any user model, connecting the generating plant to the PSSE standard model GENCLS. The corresponding line at the dynamic data file is:

BUS 'GENCLS' 1 0.0 0.0 /

where BUS is the bus number of the point of connection. The desired voltage and reactive power production must be specified at the power flow data.

Alternatively, user model VOLSTP can be connected to the point of connection and a voltage step to a new voltage V in pu can be applied. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'VOLSTP' 1 0 0 1 0 2 V /

where BUS is the bus number of the point of connection.

2.3 Nordic Grid Code

The grid code specifications used in this section have been obtained from [4].

2.3.1 Voltage dips

The fault ride through capability requirement consist of a voltage profile curve down to 0, followed by a linear increase from 20% to 90% in 0.5 s. The installation must remain connected if the voltage do not fall under this voltage profile.

The extension of the simulations is 12 s because some parts of the grid code demand a power recovery with a minimum gradient of 10% of the rated power per seconds. However, the main requirements refer to the first second of the simulation.

To verify that the generating plant complies with this requirement, connect user model VDNORD to the point of connection and run a simulation over 5 s. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'VDNORD' 1 0 0 0 0 8 /

where BUS is the bus number of the point of connection. Check that the generating plant remains connected and continues providing power during the simulation (except when the voltage is zero). The active power is stored at the user model VAR type variable number 8.

2.3.2 Other requirements

Active power control

The response of the wind power plant to changes in frequency can be simulated connecting user model FRQSTP to the point of connection and applying a frequency step DF, in Hz. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'FRQSTP' 1 0 0 1 0 2 DF /

where BUS is the bus number of the point of connection. The active power provided by the generating plant is stored at VAR type variable number 1.

The performance of control functions regarding upper limit of the active power, ramping control and fast down regulation can be simulated without any user model, connecting the generating plant to the PSSE standard model GENCLS. The corresponding line at the dynamic data file is:

BUS 'GENCLS' 1 0.0 0.0 /

where BUS is the bus number of the point of connection. To simulate the control functions, vary the control signals and observe the effect on the active power.

Reactive power control

To verify the operation inside the voltage limits and the performance of the voltage control, connect user model VOLSTP to the point of connection and apply a voltage step to a voltage V in pu. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'VOLSTP' 1 0 0 1 0 2 V /

where BUS is the bus number of the point of connection. Run a simulation over 20 s. Check the reactive power at user model QELEC variable.

The performance of the reactive power control function can be simulated without any user model, connecting the generating plant to the PSSE standard model GENCLS. The corresponding line at the dynamic data file is:

BUS 'GENCLS' 1 0.0 0.0 /

where BUS is the bus number of the point of connection. To simulate the control functions, vary the control signals and observe the effect on the reactive active power and the power factor.

2.4 ENTSO-E

The grid code specifications used in this section have been obtained from [5]. This procedure reflects the specifications for Power Park Generation Modules of Type D[2].

2.4.1 Fault ride-through capability

The fault ride through capability requirement specifies a voltage profile defined by several voltage and time parameters, which depend on the relevant TSO.

To verify that the wind installation complies with this requirement: Connect user model VDENTS to the point of connection and select the appropriate parameters. The corresponding line at the dynamic data file, according to the parameters in Figure 3 of [5], is:

BUS 'USRMDL' 1 'VDENTS' 1 0 0 8 0 8 Uret Tclear Uclear Trec1 Urec1 Trec2 Urec2 Trec3 /

The user must define the parameters (Uret,…, Trec3) according to the specifications of the relevant TSO.

Run a simulation over 10 s. Check that the Power Park Module remains connected.

[2] Any Power Generating Module with connection point at 110 kV or above, or with a Maximum Capacity at or above 75 MW, in the case of Continental Europe, or 30 MW, in the case of Nordic and Great Britain.

2.4.2 Other requirements

Frequency stability

ENTSO-E grid code includes several provisions regarding frequency stability, with parameters to be defined by the relevant TSO. The response of the Power Park Module to variations in the frequency can be simulated connecting user model FRQSTP to the point of connection and applying a frequency step of DF Hz. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'FRQSTP' 1 0 0 1 0 2 DF /

where BUS is the bus number of the point of connection. Check the active power at user model PELEC variable.

Voltage limits and reactive power capability

ENTSO-E grid code includes several provisions the voltage range where the Power Park Module must remain connected, and the reactive power that the Power Park Module must be able to provide. The response of the Power Park Module to variations in the voltage can be simulated connecting user model VOLSTP to the point of connection and applying a voltage step to a voltage V in pu. The corresponding line at the dynamic data file is:

BUS 'USRMDL' 1 'VOLSTP' 1 0 0 1 0 2 V /

where BUS is the bus number of the point of connection. Check the reactive power at user model QELEC variable.

3 DEVELOPED USER MODELS

In order to maintain as much generality as possible, and to reduce the effort to be made during the assessment procedure, the PSSE user models described in this section have been developed. These user models have the effect of applying at the selected bus a voltage profile or a frequency with a specific profile or value.

PSSE models of conventional generators consist of a voltage source behind an impedance. The proposed models use this structure to represent a disturbance, making the impedance very small and using the voltage source to model the required voltage profile or frequency variation.

When possible, the developed models provide output variables that help to assess the compliance with the grid code; for example the reactive current and the minimum reactive current required. A complete automation of the compliance assessment is not possible, because some parameters of the grid codes are specified within a range, and some requirements are left open to the requirement of the transmission system operator.

To use the models, the user must model a plant at the point of connection when building the power flow case. A generator must be then assigned to the plant, with the identifier ‘1’. The variables RSORCE and XSORCE must be set at very small values (e.g. RSORCE=0 and XSORCE=0.001).

The voltage resulting from the solution of the power flow will be the initial value at the point of connection during the simulation.

The user must then include the model in the dynamic data file (usually with *dyr extension), according to the syntax provided in the description of the model.

3.1 Energinet

3.1.1 VDENET

This model simulates a voltage profile as specified in Figure 2. The user model stores the reactive current and active power in the VAR variables numbers 6 and 8, and the minimum reactive current in the VAR variable number 7. These variables can be examined by the user after the simulation.

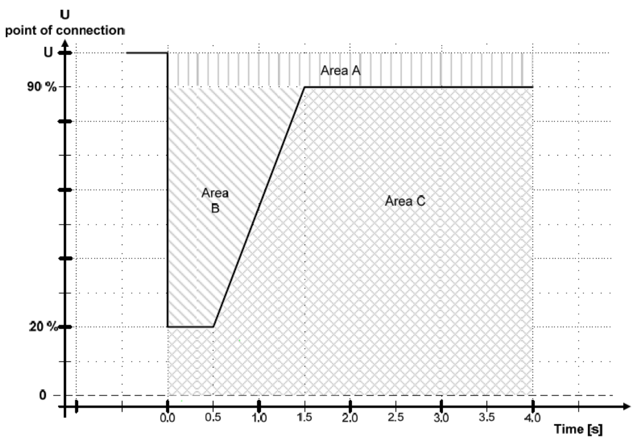

Figure 2. Voltage dip profile in the Energinet Grid Code.

The user model checks the reactive current at the connecting point, which must be in accordance with Figure 3. If it does not meet the requirements, a warning message is written in the standard output during the simulation. To help in the assessment process, the model stores the value of the minimum reactive current at PSSE VAR variable number 7.

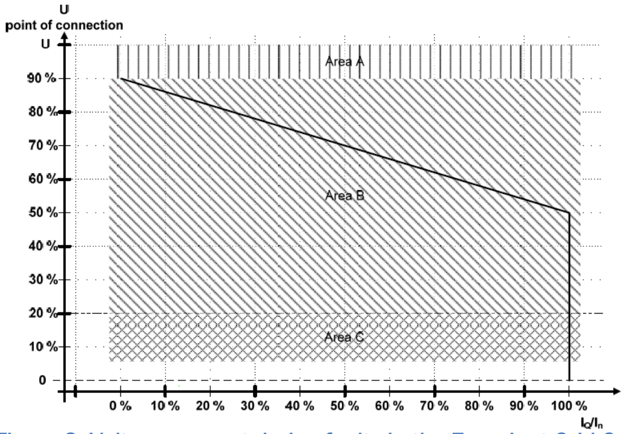

Figure 3. Voltage support during faults in the Energinet Grid Code.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDENET' 1 0 0 0 0 8 /

3.2 E.ON Netz Gmbh

3.2.1 VDEON1

This model simulates a voltage profile as specified by line 1 in Figure 4. The user model stores the reactive current and active power in the PSSE VAR variables numbers 6 and 8. These variables can be examined by the user after the simulation.

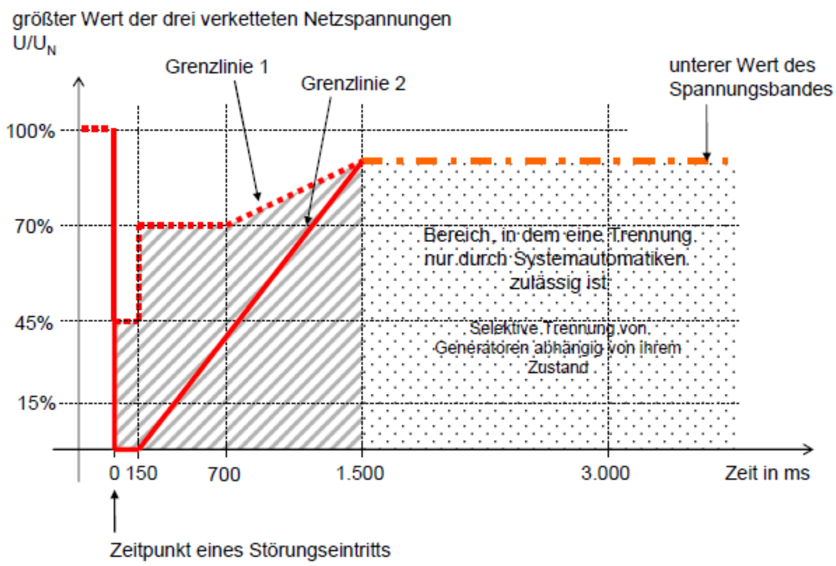

Figure 4. Voltage dip in E.ON Netz Gmbh grid code.

The user model checks the reactive current at the connecting point, which must be in accordance with Figure 5, and the rate of recovery of the active power. If one of them does not meet the requirements, a warning message is written in the standard output during the simulation. To help in the assessment process, the model the model stores the value of the minimum reactive current at PSSE VAR variable number 7, and the value of the minimum active power at PSSE VAR variable number 9.

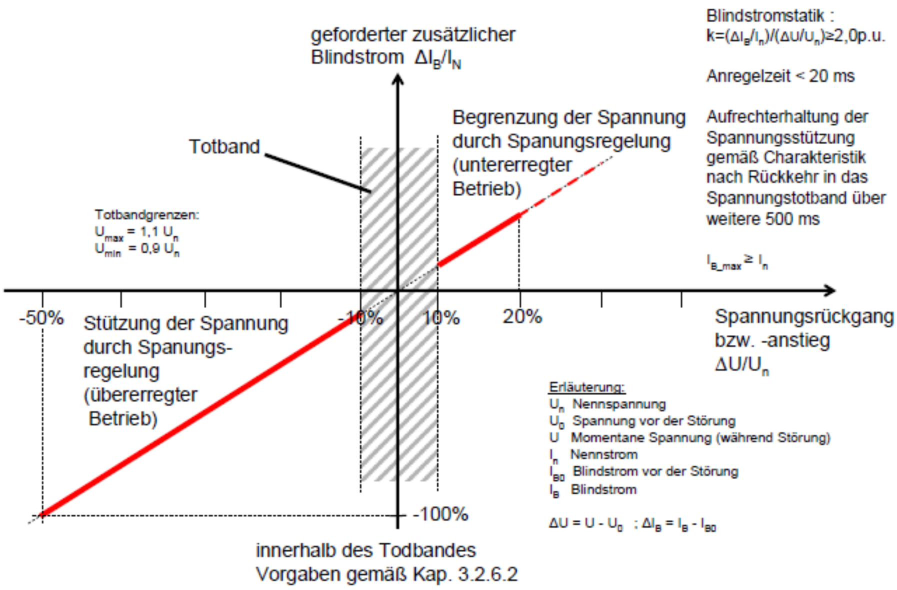

Figure 5. Voltage support according to E.ON Netz Gmbh grid code.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDEON1' 1 0 0 0 0 9 /

3.2.2 VDEON2

This model simulates a voltage profile as specified by line 2 in Figure 4. The user model stores the reactive current and active power in the PSSE VAR variables numbers 6 and 8. These variables can be examined by the user after the simulation.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDEON2' 1 0 0 0 0 9 /

3.2.3 VDEON3

This model simulates a voltage decay to zero followed by a recovery after 1.5 s, as represented in the shadowed area in Figure 4. The user model stores the reactive current and active power in the PSSE VAR variables numbers 6 and 8. These variables can be examined by the user after the simulation.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDEON3' 1 0 0 0 0 9 /

3.3 Nordic grid code

3.3.1 VDNORD

This model simulates a voltage profile as specified in Figure 6. The user model stores the active power in the type VAR variable number 8. This variable can be examined by the user after the simulation.

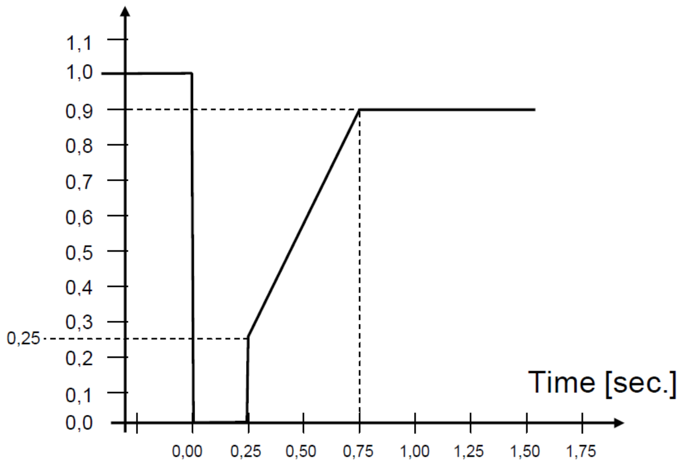

Figure 6. Voltage dip profile in the Nordic Grid Code.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDNORD' 1 0 0 0 0 8 /

3.4 ENTSO-E

3.4.1 VDENTS

This model simulates a voltage profile as specified in Figure 7. The user model stores the active power and reactive current in the PSSE VAR variables number 6 and 8. These variables can be examined by the user after the simulation.

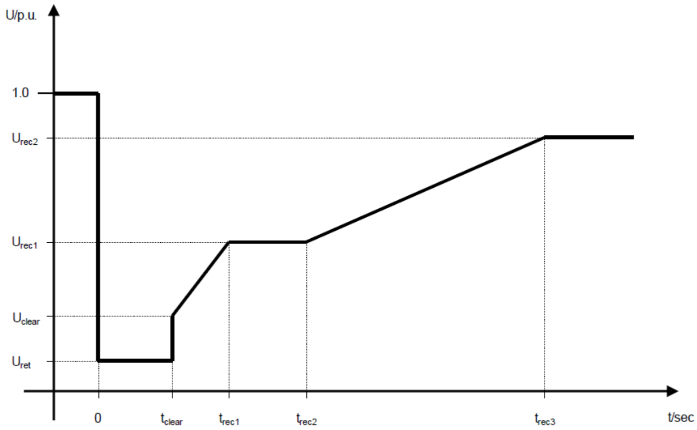

Figure 7. Voltage dip in the ENTSO-E Grid Code.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VDENTS' 1 0 0 8 0 8 Uret Tclear Uclear Trec1 Urec1 Trec2 Urec2 Trec3 /

The user must define the parameters (Uret,..., Trec3) according to the specifications of the relevant TSO.

3.5 Frequency step model FRQSTP

The frequency step model provides a step in the frequency at the connecting point of the desired value. It can be used to check the compliance of the installation with the grid codes regarding primary frequency control or disconnection by frequency protections.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'FRQSTP' 1 0 0 1 0 2 DF/

where DF is the frequency step, in Hz.

The user model stores the active and reactive power in the PSSE variables PELEC and QELEC.

3.6 Frequency drop FRDEON

The frequency transient model is designed to simulate the frequency profile represented in Figure 3 in [2].

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'FRDEON' 1 0 0 0 0 2 /

The user model stores the active and reactive power in the PSSE variables PELEC and QELEC.

3.7 Voltage module step VOLSTP

The frequency step model provides a step in the voltage module at the connecting point of the desired value. It can be used to check the compliance of the installation with the grid codes regarding reactive voltage control, power factor control, voltage control or disconnection by minimum or maximum voltage protections.

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'VOLSTP' 1 0 0 1 0 2 V /

Where V is the new value of the voltage after the voltage step, in pu.

The user model stores the active and reactive power in the PSSE variables PELEC and QELEC.

3.8 Voltage phase step PHSSTP

The voltage phase step model provides a step in the voltage phase at the connecting point of the desired value. It is designed to check the compliance of the installation with the Energinet Grid Code regarding phase jumps, as stated in section 3.3 in [1].

The format of the entry at the dynamic data file is

BUS 'USRMDL' 1 'PHSSTP' 1 0 0 1 0 2 DP /

where DP is the phase step, in degrees.

The user model stores the active and reactive power in the PSSE variables PELEC and QELEC.

3.9 Simulation of the grid without changes

Sometimes it is required to simulate the behaviour of the installation without changes in the grid, for example when simulating the response to a change in a control variable. In this case, the standard PSSE model GENCLS must be used.

The format of the entry at the dynamic data file is

BUS 'GENCLS' 1 0.0 0.0 /

The short circuit power of the grid can be specified through variables RSORCE and XSORCE at the generator entries in the power flow case.

Active and reactive powers are stored in standard PSSE variables PELEC and QELEC.

4 OFFSHORE NETWORKS WITH MORE THAN ONE POINT OF CONNECTION

Future offshore networks arrangements will probably be connected at several points of the onshore transmission grid, and even at points that belong to different power systems. However, no specific provisions have been found in the grid codes regarding this situation.

The approach adopted in this procedure can be extended to such cases by connecting several user models at more than one point. Each user model corresponds to a point of connection with a transmission grid, which in turn can correspond to the same power system or not.

In this case, the user models belonging to a same power system must be coordinated. For example, consider an offshore network arrangement with one connection point at Norway, two at Continental Europe and one at Great Britain:

- To simulate the response to a change in frequency in Norway, user model FRQSTP must be connected at the Nordic point of connection, and standard model GENCLS must be connected at the other three points.

- To simulate the response to a change in frequency in Continental Europe, two user models FRQSTP must be connected at the continental points of connection, and they must simulate the same frequency step. Standard model GENCLS must be connected at the other two points.

- To simulate a fault in the transmission level at Continental Europe, a worst case scenario can be simulated by connecting the corresponding voltage dip user model (e.g. VDEON1) at the continental points of connection. Again, standard model GENCLS must be connected at the other two points.

5 SPECIFICATION OF THE SHORT CIRCUIT AT FAULT RIDE-THROUGH CAPABILITY REQUIREMENTS

The ENTSO-E Grid Code makes reference to the provision by TSOs of post-fault minimum short circuit power at the Connection Point. This is certainly a point that affects the dynamic performance of the installation after a severe fault and should be taken into account, although many grid codes do not mention it.

It is not possible to change the short circuit power in PSSE during a simulation by means of the user model variables RSORCE and XSORCE. Instead, any change must be applied outside the model, by means of the following procedure:

1) Connect the selected user model to the connection point through a line. This implies the addition of a new bus.

2) Set the impedance of the line to a very small value (e.g. 0.0001 pu).

3) Run the simulation to the point where the fault is cleared (i.e. Tclear in the case of the ENTSO-E Grid Code).

4) Change line impedance to the value representing the post-fault short circuit power. This is done by the PSSE activity ALTR.

5) Run the rest of the simulation.

6 RECOMMENDATIONS FOR FUTURE GRID CODE DEVELOPMENTS

The following recommendations are suggested to be taken into account in any future Grid Code development.

- At a specific level include, in the fault ride-through capability requirements, provisions for the conditions to perform the tests regarding:
  - The pre-fault active and reactive power production.
  - The short circuit power of the post-fault grid.

  The ENTSO-E Grid Code includes already provisions in this sense.

- At a more generic level, define specific requirements for the case of offshore network arrangements with more than one connecting point. This can be an opportunity to improve the operation and control of transmission grids, as the presence of several connection points increases the possibilities of control of the active power fluxes.

7 EXAMPLE: VERIFICATION OF THE COMPLIANCE WITH E.ON NETZ GMBH FAULT RIDE-THROUGH REQUIREMENT

The wind farm shown in Figure 8 is used as an example to verify the compliance with the fault ride-through capability requirements in the E.ON Netz Gmbh grid code. The wind farm consists of variable speed windmills with synchronous generators connected to the grid through full-size converters. The raw data file and the dynamic data file of the case, in PSSE format, are shown in appendix II and III. The parameters of the case have been obtained from [6].

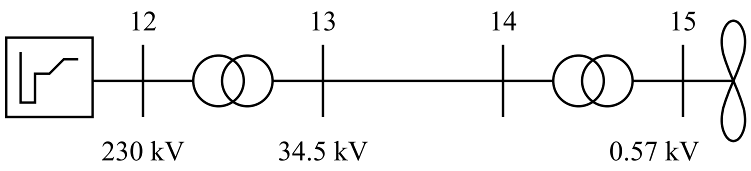

Figure 8. Example test system.

User model VDEON1 is connected to the connecting bus 12, and a simulation is run. Figure 9 shows the voltage profile at buses 12 and 15. It can be seen that the voltage profile at bus 12 follows the shape provided by line 1 in Figure 4.

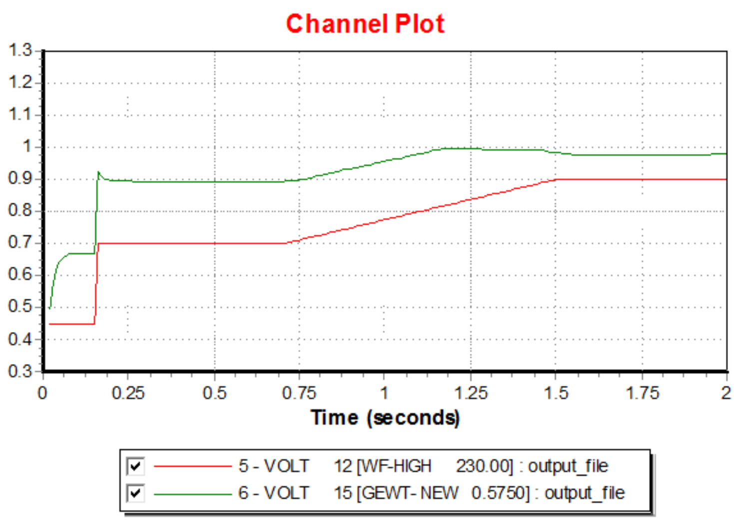

Figure 9. Voltage profile at the connecting bus (red) and the wind farm (green).

The green line in Figure 10 represents the reactive current required to comply with the voltage support, as stated by Figure 5. The red line shows the reactive current provided at the connecting point. It can be seen that the wind farm provides enough voltage support.

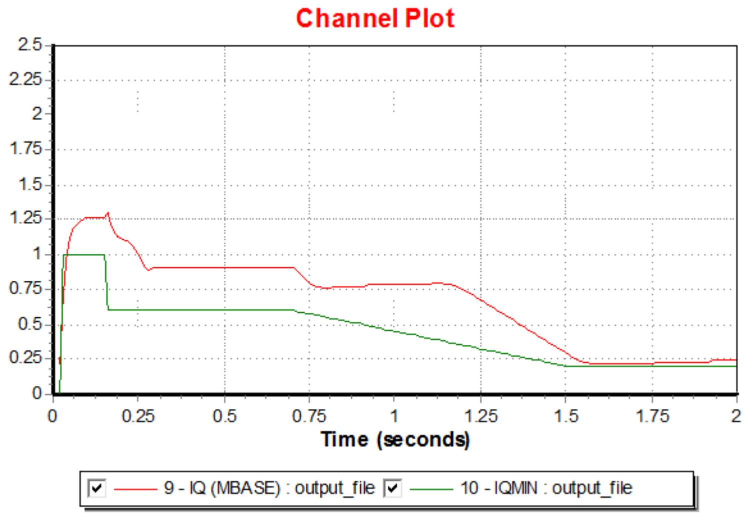

Figure 10. Reactive current (red) and minimum required (green).

The green line in Figure 11 represents the minimum active power required to comply with a rate of recovery of 20% of the nominal power by second after the fault clearance, as specified by E.ON Netz Gmbh grid code. The red line represents the active power output to the grid. It can be seen that the active power recovery rate is much faster than the minimum required.

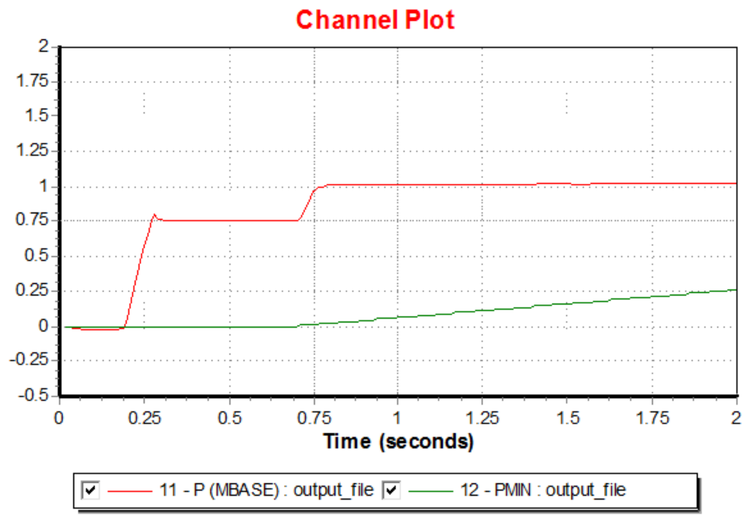

Figure 11. Active power (red) and minimum required (green).

8 REVIEW OF GRID CODE REQUIREMENTS FOR CONNECTION OF LARGE WIND POWER PLANTS (WPP)

8.1 Introduction

The seamless integration of additional wind generation capacity into existing grids and the growing needs for ancillary services in distribution and transmission systems are requiring further more advanced functional capabilities from wind power plants (WPPs). Present demands from System Operators (i.e. TSOs or DNOs) generally include reactive power capability and controllability for grid voltage control; ride-through capabilities against common contingencies; and active power control to support grid frequency deviations.

These interconnection standards vary from country to country depending on local grid characteristics and utility-specific requirements – involving bespoken solutions and enhanced control techniques. Some of the strictest regulations are found in the UK, Ireland, and some provinces in Canada such as Ontario's Independent Electricity Service Operator (IESO) system [7].

The large-scale deployment of offshore wind turbines in the North Sea will potentially involve various wind turbine providers, introducing different turbine designs, with varying specifications and performance characteristics. It is envisaged that control requirements and dynamic performance of these future offshore wind power systems, with such a variety of technology and complex network arrangements, may be significantly different from conventional and comparatively simpler existing power networks. Consequently, the establishment of suitable Grid Codes satisfying so many variables is a difficult challenge to be addressed.

In this context, this review aims to provide, in addition to a general overview of grid codes worldwide, some insight into how future offshore grid codes may look like, and what would be some potential solutions, from the manufacturer, developer and operator perspective.

The review focuses on the technical regulations imposed on large wind farms connected to the high-voltage transmission system, regarding their voltage and frequency operating limits, fault ride-through capability and provision of inertial response. This review is based on ENTSO-E, GERMANY and GB grid code regulations.

Several solutions have been proposed and implemented by wind turbine manufacturers, in order to achieve grid code compliance. Hence, a brief introduction is provided on available technologies of modern, commercially available wind turbines, in terms of their electrical system configuration, as far as their response to grid disturbances and compliance to grid code requirements is concerned [8].

8.2 Power system dynamics and stability with wind power

Squirrel-cage induction generators used in fixed-speed turbines can cause local voltage collapse after rotor speed runaway. During a fault (and consequent network voltage depression), they accelerate due to the unbalance between the mechanical power from the wind and the electrical power that can be supplied to the grid. When the fault is cleared, they absorb reactive power depressing the network voltage. If the voltage does not recover quickly enough, the wind turbines continue to accelerate and to consume large amounts of reactive power. This eventually leads to voltage and rotor speed instability. In contrast to synchronous generators, whose exciters increase reactive power output during low network voltages and thus support voltage recovery after a fault, squirrel-cage induction generators tend to impede voltage recovery.

With variable-speed wind turbines, the sensitivity of the power electronics to over-currents caused by the network voltage depressions can have serious consequences for the stability of the power system. If the penetration level of variable-speed wind turbines in the system is high and they disconnect at relatively small voltage reduction, a voltage drop over a wide geographic area can lead to a large generation deficit. Such a voltage drop could, for instance, be caused by a fault in the transmission grid. To prevent this, Grid Companies and Transmission System Operators require that wind turbines have a Fault Ride-Through capability and withstand voltage drops of certain magnitudes and durations without tripping. This prevents the disconnection of a large amount of wind power in the event of a remote network fault.

8.3 Reactive power and voltage support

The voltage on a transmission network is determined mainly by the interaction of reactive power flows with the reactive inductance of the network.

Fixed-speed induction generators absorb reactive power to maintain their magnetic field and have no direct control over their reactive power flow. Therefore, in the case of fixed-speed induction generators the only way to support the voltage of the network is to reduce the reactive power drawn from the network by the use of shunt compensators.

Variable-speed wind turbines have the capability of reactive power control and may be able to support the voltage of the network to which they are connected. However, individual control of wind turbines may not be able to control the voltage at the point of connection, especially due to the fact that the wind farm network is predominantly capacitive (a cable network).

In many occasions the reactive power and voltage control at the point of connection of the wind farm is achieved by using reactive power compensation equipment such as static var compensators (SVCs) or static synchronous compensators (STATCOMs).

8.4 Contribution of wind generation systems to frequency regulation

With the projected increase in wind generation, a potential concern for transmission system operators is the capability of wind farms to provide dynamic frequency support in the event of sudden changes in power network frequency.

8.4.1 Frequency support

In any electrical power system, the active power generated and consumed has to be balanced in real time (on a second-by-second basis). Any disturbance to this balance causes a deviation of the system frequency (see Figure 12). In the event of a sudden failure in generation or connection of a large load, the system frequency starts dropping (region OX in Figure 12) at a rate mainly determined by the total angular momentum of the system (addition of the angular momentum of all generators and spinning loads connected to the system). Primary response is provided by an automatic droop control loop and generators increase their output depending on the dead band of their governor and time lag of their prime mover (e.g. that of the boiler drum in steam units). Secondary response is the restoration of the frequency back to its nominal value using a supplementary control loop.

To provide frequency support from a generation unit, the generator power must increase or decrease as the system frequency changes. Thus, in order to respond to low network frequency, it is necessary to de-load the wind turbine leaving a margin for power increase. A fixed-speed wind turbine can be de-loaded if the pitch angle is controlled such that a fraction of the power that could be extracted from wind will be “spilled”. A variable-speed wind turbine can be de-loaded by operating it away from the maximum power extraction curve, thus leaving a margin for frequency control.

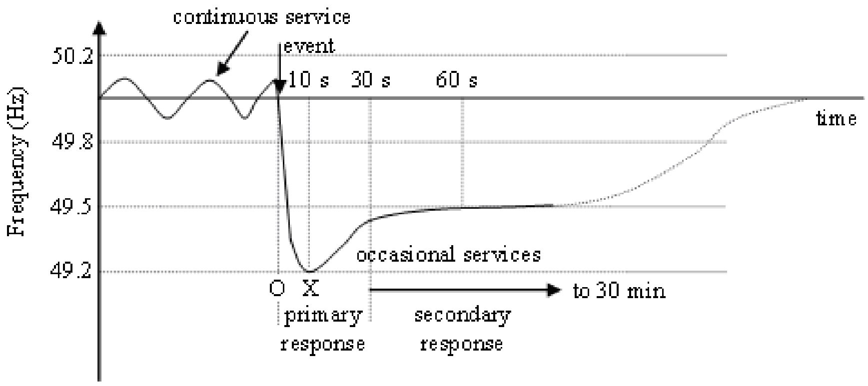

Figure 12. Frequency control in England and Wales.

8.4.2 Wind turbine inertial response

An FSIG wind turbine acts in a similar manner to a synchronous machine when a sudden change in frequency occurs. For a drop in frequency the machine starts decelerating. This results in the conversion of kinetic energy of the machine to electrical energy thus giving a power surge. The inverse is true for an increase in system frequency.

In the case of a DFIG wind turbine, equipped with conventional controls, the control system operates to apply a restraining torque to the rotor according to a pre-determined curve against rotor speed. This is decoupled from the power system frequency so there is no contribution to the system inertia.

With a large number of DFIG and/or FCWT wind turbines connected to the network, where the angular momentum of the system will be reduced (see Figure 13), the frequency may drop very rapidly during the phase OX in Figure 12. Therefore it is important to reinstate the effect of the machine inertia within these wind turbines. It is possible to emulate the inertia response by manipulating their control actions. The emulated inertia response provided by these generators is referred to as fast primary response (also called ‘virtual’ or ‘synthetic’ inertia).

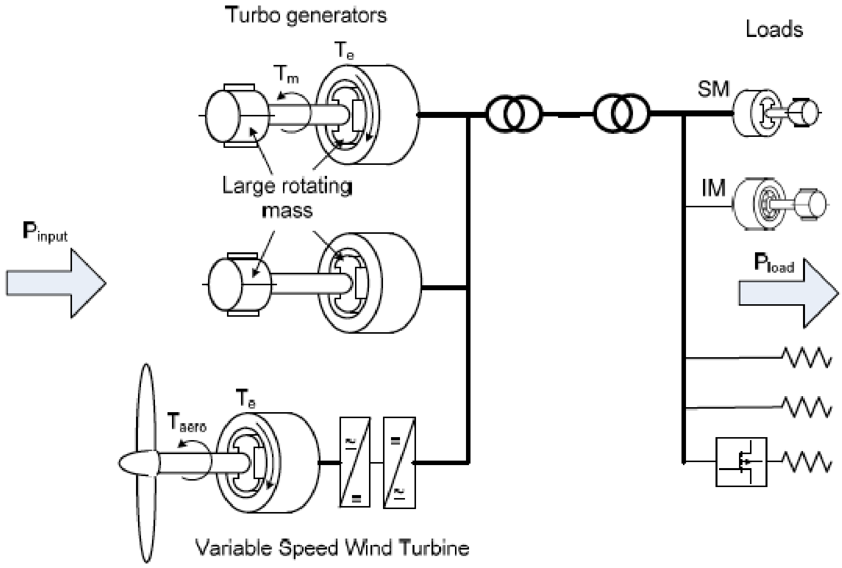

Figure 13. Illustration of electrical machine topology, torque and power imbalance in relation to system inertia [10].

8.5 Grid Code regulations for the integration of wind generation

Grid connection codes define the requirements for the connection of generation and loads to an electrical network, which ensure efficient, safe and economic operation of the transmission and/or distribution systems [9]. Grid Codes specify the mandatory minimum technical requirements, that a power plant should fulfil and additional support that may be called on to maintain the second-by-second power balance and maintain the required level of quality and security of the system. The additional services that a power plant should provide are normally agreed between the transmission system operator and the power plant operator through market mechanisms.

The connection codes normally focus on the point of connection between the Public Electricity System and the new generation. This is very important for wind farm connections, as the Grid Codes demand requirements at the point of connection of the wind farm not at the individual wind turbine generator terminals. The grid connection requirements differ from country to country and may differ from region to region. They have many common features but some of the requirements are subtly different, reflecting the characteristics of the individual grids.

As a mandatory requirement the levels and time period of the output power of a generating plant that should be maintained within the specified values of grid frequency and grid voltages is specified in Grid Codes. Typically this requirement is defined as shown in Figure 6 where the values of voltage, V_1 to V_4, and frequency, f_1 to f_4, differ from country to country.

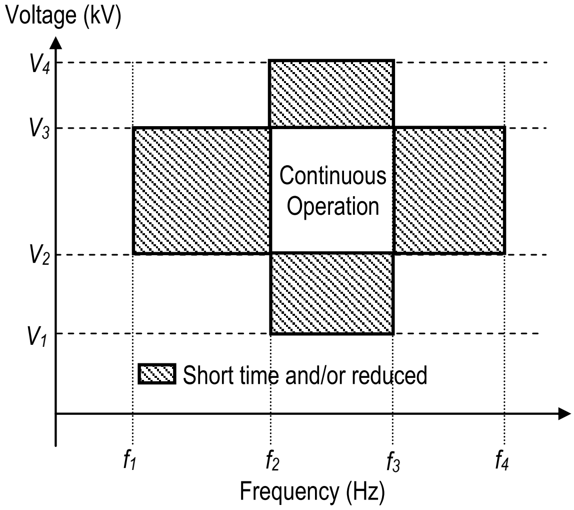

Figure 14. Typical shape of continuous and reduced output regions (after GB and Irish Grid Codes).

Grid Codes also specify the steady-state operational region of a power plant in terms of active and reactive power requirements. The definition of the operational region differs from country to country. For example Figure 15 shows the operational regions as specified in the Great Britain and Ireland Grid Codes.

Almost all Grid Codes now impose the requirement that wind farms should be able to provide primary frequency response. The capability profile typically specifies the minimum required level of response, the frequency deviation at which it should be activated and time to respond.

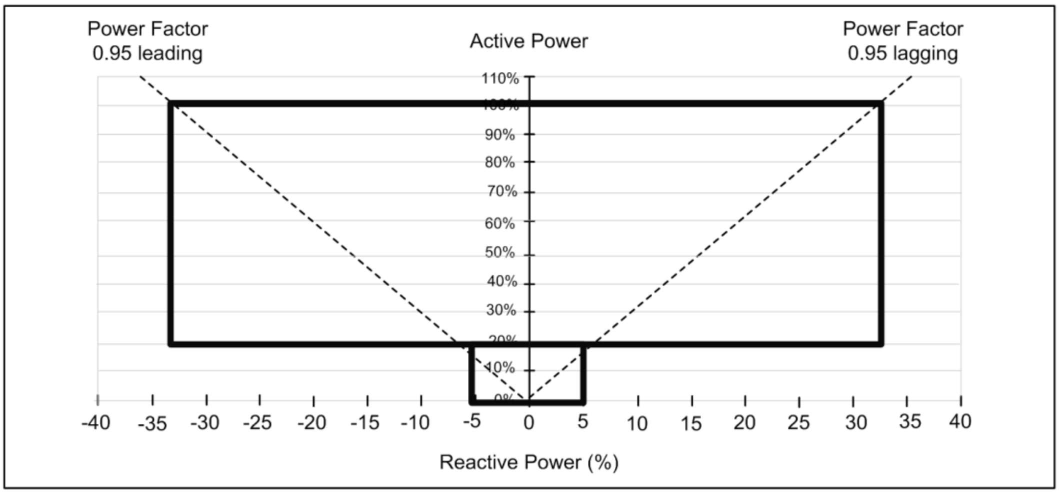

Figure 15. Typical steady-state operating region (after GB & Irish Grid Codes).

Traditionally wind turbine generators were tripped off once the voltage at their terminals reduced to less than 20% retained voltage. However, with the penetration of wind generation increasing, Grid Codes now generally demand Fault Ride-Through (FRT) – or Low-Voltage Ride-Through (LVRT) – capability for wind turbines connected to transmission networks. Figure 16 shows a plot illustrating the general shape of voltage tolerance that most grid operators demand. When reduced system voltage occurs following a network fault, generator tripping is only permitted when the voltage is sufficiently low and for a time that puts it in the shaded area indicated in Figure 16.

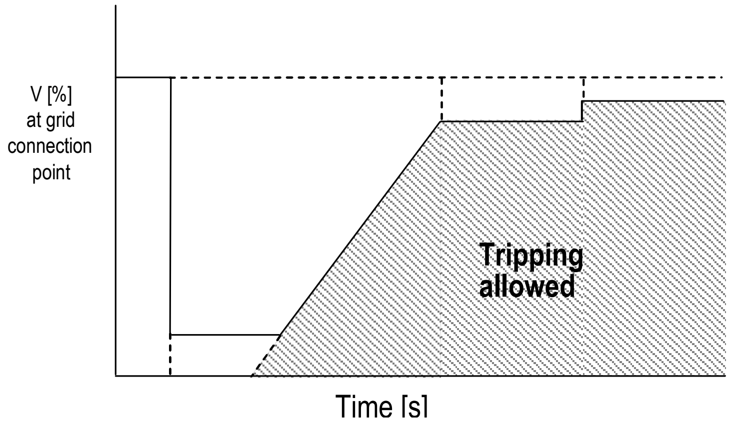

Figure 16. Typical shape of Fault Ride-Through capability plot (after GB and Irish Grid Codes).

8.6 Requirements for Offshore Grid Connections

The following requirements pertain to the grid connections of offshore wind parks in seas, which are referred to here as offshore grid connections.

8.6.1 Frequency characteristics and support

NATIONAL GRID

The frequency of the National Electricity Transmission System shall be nominally 50Hz and shall be controlled within the limits of 49.5 – 50.5Hz unless exceptional circumstances prevail.

The system frequency could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of User's Plant and Apparatus and OTSDUW Plant and Apparatus must enable operation of that Plant and Apparatus within that range in accordance to the following:

Frequency Range	Requirement
51.5Hz – 52Hz	Operation for a period of at least 15 minutes is required each time the frequency is above 51.5Hz
51Hz – 51.5Hz	Operation for a period of at least 90 minutes is required each time the frequency is above 51Hz
49.0Hz – 51 Hz	Continuous operation is required
47.5Hz – 49.0Hz	Operation for a period of at least 90 minutes is required each time the frequency is below 49.0Hz
47Hz – 47.5Hz	Operation for a period of at least 20 seconds is required each time the frequency is below 47.5Hz

For the UK grid, generating plant above 50MW in size including dc converter and Power Park Modules[3] "must be fitted with a fast acting proportional frequency control device (or turbine speed governor) and unit load controller or equivalent control device to provide frequency response". The frequency control device (or speed governor) is required to be operated and designed to a European specification or commonly used European standard and have a droop of

[3] A Power Park Module is a collection of generators, powered by a variable source, which utilize a common connection

between 3 and 5% and dead band of ±15mHz. Control of frequency via this plant is achieved by instruction to operate in either one of two modes:

Frequency Sensitive Mode (FSM). This mode provides the primary and secondary response for negative frequency excursions as illustrated in Figure 12. Generators in this mode must also have capability to provide 'high frequency' response. The minimum required responses for FSM are shown in Figure 17. The rate of change of output is set by an ancillary service agreement with National Grid.

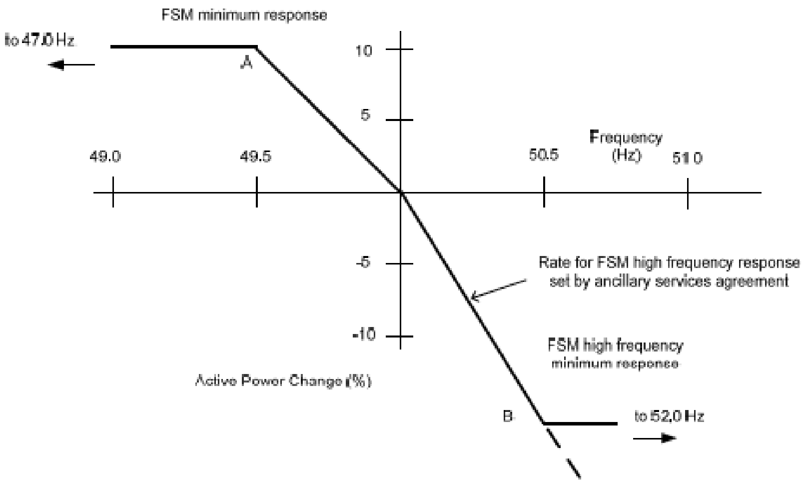

Figure 17. National Grid primary/secondary and high frequency response active power versus frequency requirements for plant operating in Frequency Sensitive Mode (FSM).

For the low frequency response the effective 'droop' in the proportional band between point A and 50 Hz:

Droop (%) = 100% x (pu change in frequency)/(pu change in power)
= 100% x (0.5/50)/(0.1) = 10%

Limited Frequency Sensitive Mode (LFSM). This mode has high frequency response capability only, the minimum required response and the required maintenance of active power during low frequency within this mode is shown in Figure 18. Generator should maintain normal active power between 49.5 and 50.4 Hz. Above this proportional high frequency response of 2% change in output per 0.1 Hz deviation above 50.4 Hz is required (equivalent to 10% droop). Below 49.5 Hz proportional reduction of active power output is allowed up to a maximum of 5% at 47.0 Hz (equivalent droop of -100%)

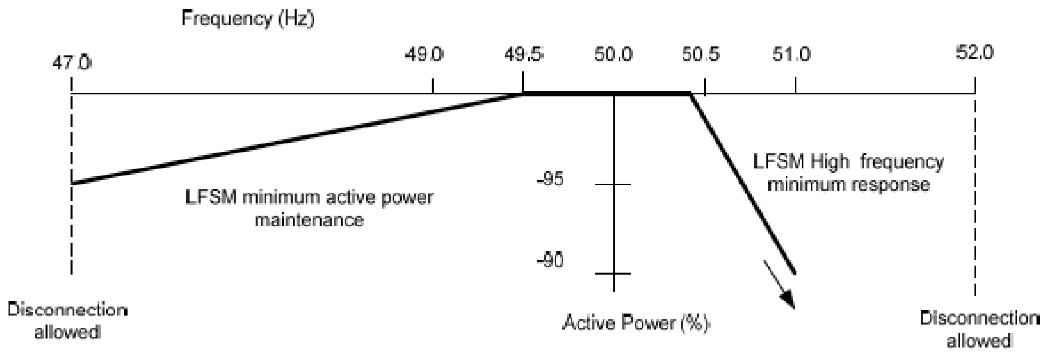

Figure 18. National Grid requirements for high frequency response and maintenance of active power during low frequency for plant operating in LFSM.

For Combined-Cycle Gas Turbines (CCGTs) disconnection is allowed if frequency remains below 48.8 for more than 5 minutes. Some type of plant such as 'existing gas cooled reactor plant' are exempt from FSM capability and operate only in LFSM.

Reduction of required response capability due to plant loading for primary/secondary and high frequency response is shown in Figure 19. The figure corresponds to operation at point A or B on Figure 17. For low frequency (i.e. primary/secondary) response the full minimum increase in output (10% of registered capacity) is required between 55 and 80% loading with a proportional reduction allowed until loading reaches 100%. For high-frequency response the full reduction in response (set in ancillary service agreement) is required at loadings between 70 and 95%. Generators must have a high-frequency response capability when operating at the minimum generation level (65%), this capability being indicated by a requirement to operate down to the Designed Minimum Operating Limit (DMOL) at 55% (or if feasible below).

Delivery of the active power increase for low response is shown in Figure 20. It is required that "output should be released increasingly with time over the period of 0 to 10 seconds from the time of the start of the frequency fall". Capability for reactivation of the response is required within 20 minutes. Figure 20 also shows the method of testing of frequency response by injection of a test frequency (upper plot), and the measurement of response delivered. For primary response this is the minimum sustained increase in output over the 10 to 30 seconds time period (in this case point P) and for secondary response the minimum sustained increase in output over the 30 seconds to 30 minutes time period (point S).

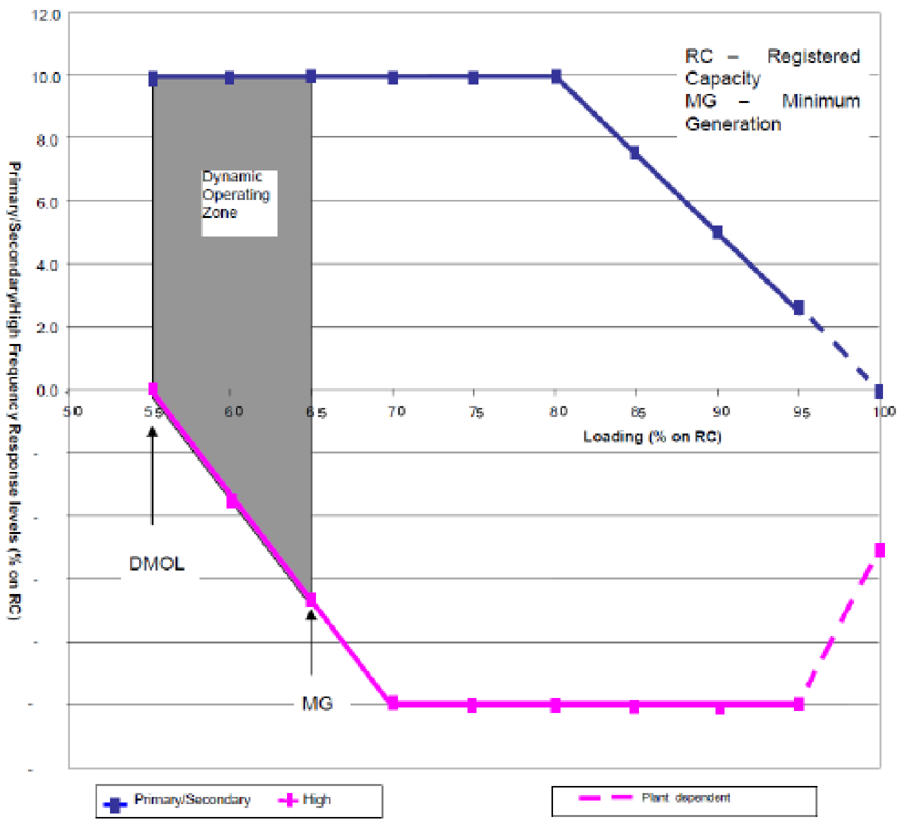

Figure 19. National Grid generator frequency response versus loading for 0.5 Hz deviation (National Grid 2010b).

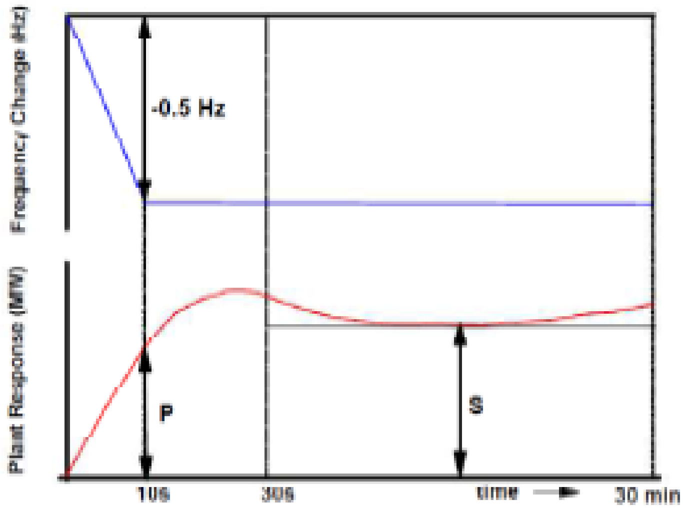

Figure 20. National Grid primary/secondary response. Measurement (lower) and frequency injection test stimulus (upper) (National Grid 2010b).

<u>E.ON Netz Gmbh</u>

➢Grid Voltage Variations

- Nominal voltage specified for the grid connection point[4]: 155 kV – continuous operating voltage of 140-170kV.

➢Grid Frequency Variations

- The nominal frequency for the offshore grid connection is 50Hz. An extended range is applicable offshore:
    - o Within an uninterrupted continuous operation and within a limited operation of 10 minutes: 47.5 - 51.5 Hz.
    - o Limited to up to 10 seconds: 46.5 and 53.5 Hz.

➢ Frequency Response (EON-Netz)

Frequency response capability is required from all generators above 100 MW, this response capability being termed ‘primary control’. Continuous operation of generating plant is required

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[4] Grid connection system: the term grid connection system denotes all connections between the grid coupling point and the connectee. Depending on the connection design, the grid connection system can consist of partial DC transmission (HVDC, or a direct AC connection.
Grid connection point: The grid connection point is the point at which the connectee’s station is connected to the grid connection system. For the offshore wind parks this is the offshore cable sealing end of the grid connection system. Concurrently, it represents the ownership boundary between the connectee’s facility and that of the TSO.

between 49.0 and 50.0 Hz. Operation outside these limits, down to 47.5 and up to 51.5 Hz, is required but only for between 30 and 10 minutes where after they may disconnect. Offshore wind generators have an extended short term operating region for 10 seconds duration between 46.5 and 47.5 and between 51.5 and 53.5 Hz.

Governor droop is specified as adjustable with a dead-band of less than ±10mHz. The active power range capability must be a minimum of ±2% of rated power and the response delivered must be activated within 30 seconds and supplied for a minimum of 15 minutes. Reactivation capability is required within 15 minutes of return to nominal frequency.

Minimum requirements for ‘over-frequency’ are a reduction in active power at rate of 5% droop beginning at 50 Hz. For onshore generators, which are subsidized via the German ‘Renewable Energy Act’, the reduction in frequency begins at 50.2 Hz. For offshore wind generators the droop is 2% and the threshold frequency 50.1 Hz.

For ‘under-frequency’ minimum requirements are that active power must remain constant down to 49.5 Hz and below this not drop below an equivalent droop of 10%. The E.ON Netz grid code in addition to including a diagram similar to Figure 18 includes specification for maintenance of active power during a short-term frequency event. This is reproduced in Figure 21 and specifies that no change in active power is allowed above the thick red line shown.

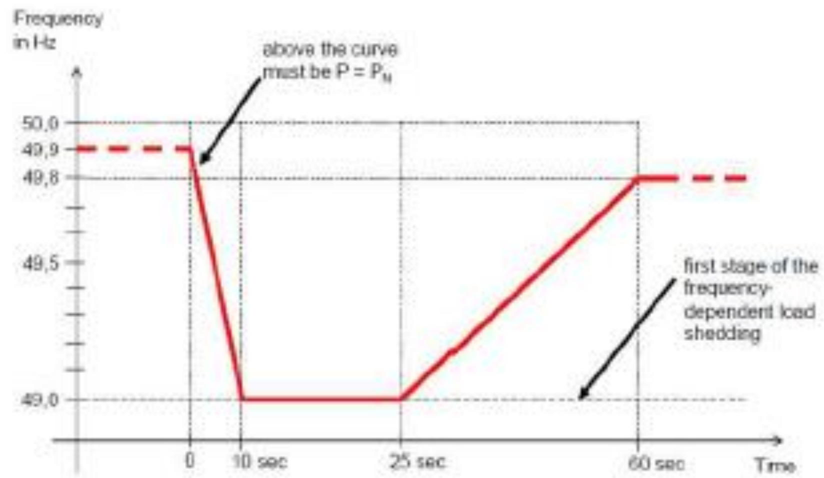

Figure 21. E.ON Netz active power maintenance requirement for short-term frequency deviation (EON-Netz 2006).

ENTSO-E

The European draft code requires ‘active power frequency response’ capability from all generators (synchronous and non-synchronous) according to Figure 22, where power is indicated on the y-axis and frequency on the x-axis. Generators operating in ‘frequency sensitive mode’ are required to operate according to droop characteristics 1 and 2 (thick red line).

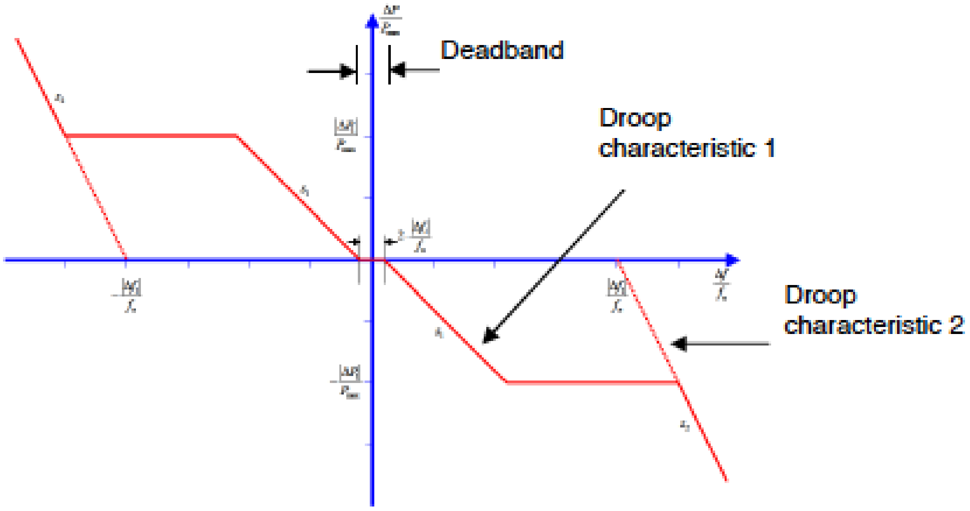

Figure 22. ENTSO-E ‘frequency sensitive mode’ and ‘limited frequency sensitive mode’ active powr versus frequency requirements (ENTSO-E 2010).

When not operating in this mode, generators should operate in ‘limited frequency sensitive mode’ where they are only required to change active power according to droop characteristic 2 (thick and dotted thin part of red line). Ranges of active power, dead-band, and minimum response times are also specified.

ELTRA (ENERGINET.DK)

Continuous operation of wind turbines is required between 49.5 and 50.5 Hz. Outside these limits, reductions in power are possible, disconnection is allowed at 47.5 and 53.0 Hz.

All wind turbines are required to have ‘automatic frequency regulation’ capability and similar to the ENTSO-E grid code, a frequency versus active power diagram is included (see Figure 22). Droop and dead-band are specified as adjustable and active power rang is required to be variable between 20 and 100%. Delivery of response must be adjustable between 1 and 10% of rated power per second.

EIR

Frequency range requirements dictate that wind farms must operate at normal output between 49.5 and 50.5 Hz. Either side of this central band they must remain connected for 60 minutes or for 20 seconds if between 47.0 and 47.5 Hz.

A ‘frequency response system’ is specified for wind farms above 5 MW and 10 MW in size. Similar to the ENTSO-E grid code a frequency versus active power diagram is included to illustrate the requirements. For wind farms between 5 and 10 MW, high-frequency response capability is required and for low frequency, active power is required to be maintained at 100% of that available. For wind farms greater that 10 MW low- and high-frequency response is required. Values for droop and dead-band where applicable are specified in agreement with EIR. The response rate of each turbine is required to be a minimum of 1 % of rated capacity per second.

8.6.2 *Synthetic Inertia Requirements*

Specification of inertial response from non-synchronous generators appears in the Canadian grid code and the draft generator requirements published for consultation by ENTSO-E.

<u>HYDRO-QUEBEC</u>

An 'inertial response' from wind turbines is required to act during 'major frequency deviations' in order to help restore system frequency:

"To achieve this, the (frequency control) system must reduce large, short-duration frequency deviations at least as does inertial response of a conventional synchronous generator whose inertia (H) equals 3.5. s. This target performance is met, for instance, when the system varies the real power dynamically and rapidly by at least 5 % for about 10 s when a large, short-duration frequency deviation occurs on the power system."

<u>ENTSO-E</u>

An active power response, from Power Park Modules (PPM), above an agreed size, is required of the form shown in Figure 23 "in order to limit the rate of change of frequency following a sudden generation loss". Full delivery must occur within 200ms and "the initial injected active power supplied to the network shall be in proportion to the rate of change of network frequency". The transmission system operator is required to define the support duration period where the response (now exponentially declining), must remain of a positive magnitude and similarly define a suitable recovery period.

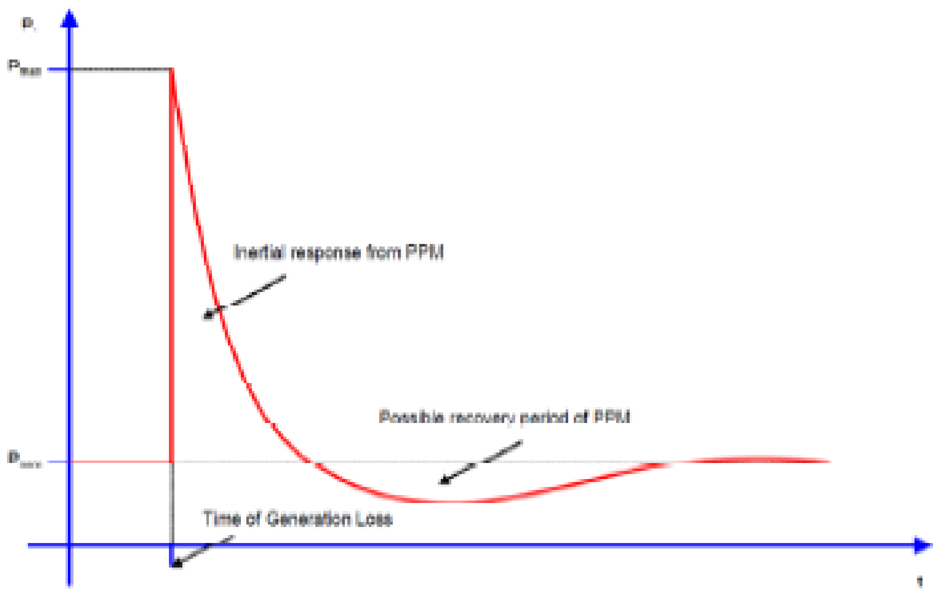

Figure 23. ENTSO-E non-synchronous inertial response (ENTSO-E 2010).

This synthetic inertial capability must operate when the plant is in Limited Frequency Sensitivity mode. Operation in combination with active power response during frequency sensitive mode is desirable but not compulsory. The control system, which provides the synthetic inertia must have an adjustable rate of change frequency dead-band and a method to “limit the bandwidth of the output” to remove the possibility of exciting torsional oscillations in other generating plant.

9 AKNOWLEDGMENTS

Pablo Ledesma would like to thank Universidad Carlos III de Madrid for allowing him to stay as an academic visitor at University of Strathclyde.

10 REFERENCES

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[10] I. Moore, “Inertia Response from wind turbines,” PhD Thesis, Cardiff University, 2012.
[11] E.On Netz, Requirements for offshore grid connections in the E.On Netz Network, 1 April 2008.

11 APPENDIX I: DATA FILES USED IN THE EXAMPLE

11.1 Power flow data (*raw file)

```
0,   100.00, 33, 0, 1, 50.00     / PSS(R)E-33.1    FRI, NOV 23 2012  22:00
  AGGREGATED WIND FARM

    12,'WF-HIGH     ', 230.0000,3,   1,   1,   1,1.00000,
4.9149,1.10000,0.90000,1.10000,0.90000
    13,'WF-LOW      ',  34.5000,1,   1,   1,   1,0.98934,
10.6744,1.10000,0.90000,1.10000,0.90000
    14,'WF-LOW2     ',  34.5000,1,   1,   1,   1,1.00320,
12.1598,1.10000,0.90000,1.10000,0.90000
    15,'GEWT- NEW   ',   0.5750,2,   1,   1,   1,1.00246,
15.0324,1.10000,0.90000,1.10000,0.90000
0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGIN FIXED SHUNT DATA
    15,'1 ',1,     0.000,    48.400
0 / END OF FIXED SHUNT DATA, BEGIN GENERATOR DATA
    12,'1 ',   -99.284,    15.654,  9999.900, -9999.900,1.00000,     0,
100.000, 0.00000E+0, 1.00000E-4, 0.00000E+0, 0.00000E+0,1.00000,1,  100.0,
9999.900, -9999.900,   1,1.0000
    15,'1 ',   100.800,   -47.600,   -47.600,   -47.600,1.02500,     0,
112.000, 0.00000E+0, 3.02200E-1, 0.00000E+0, 0.00000E+0,1.00000,1,  100.0,
105.000,     0.000,   1,1.0000,    ,      ,    ,      ,    ,      ,1, 1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
    13,    14,'1 ', 1.50000E-2, 2.50000E-2,   0.01000,  120.00,  120.00,
0.00,  0.00000,  0.00000,  0.00000,  0.00000,1,1,   0.00,   1,1.0000
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
    12,    13,     0,'1 ',1,1,1, 0.00000E+0, 0.00000E+0,2,'            ',1,
1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000,'            '
 0.00000E+0, 1.00000E-1,   100.00
1.00000,   0.000,   0.000,   120.00,   120.00,     0.00, 0,      0, 1.10000,
0.90000, 1.10000, 0.90000,  33, 0, 0.00000, 0.00000,  0.000
1.00000,   0.000
    15,    14,     0,'1 ',1,1,1, 0.00000E+0, 0.00000E+0,1,'            ',1,
1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000,'            '
 0.00000E+0, 5.00000E-2,   100.00
1.00000,   0.000,   0.000,     0.00,     0.00,     0.00, 0,      0, 1.10000,
0.90000, 1.10000, 0.90000,  33, 0, 0.00000, 0.00000,  0.000
1.00000,   0.000
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
   1,     0,     0.000,    10.000,'TEST        '
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
   1,'TEST        '
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
   1,'TEST        '
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN GNE DATA
0 / END OF GNE DATA, BEGIN INDUCTION MACHINE DATA
0 / END OF INDUCTION MACHINE DATA
Q
```

11.2 Dynamic data (*dyr file)

```
12 'USRMDL' 1 'VDEON1' 1 0 0 0 0 9 /
15 'WT4G1' 1 0.02 0.02 0.87537 0.898853 1.111951 1.12 2.0 10.0 0.02 /
15 'WT4E1' 1 5 0 1 0 0.15 18.0 5.0 0.5E-01 0.1 0.0 0.8E-01 0.47 -0.47 1.1
0.0 0.5 -0.5 0.5E-01 0.1 0.9 1.1 120.0 0.5E-01 0.5E-01 1.7 1.11 1.11 /
```