Simulation Studies and Modelling Requirements for Compliance Demonstration

Version 1.0

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Version History

Version	Release Date	Comments	Document Owner
Version 1.0	23rd March, 2021	First approved release of document. Note part 4 (HVDC) is still draft.	Eirgrid Future Networks, Innovation and Planning

Governance

Any changes to this document made by Eirgrid are to be discussed at the Ireland Grid Code Review Panel prior to the new release. Similarly, proposed changes from industry should be raised through the relevant Grid Code channels. Note that changes to this document are not subject to regulatory approval.

The document includes references to the relevant EU Network Connection Codes in various sections in the form of "(Art 15-2)", to help with cross-referencing.

Contents

Introduction

With the advent of the European Network Codes, and their integration into the Ireland Grid Code, it was felt necessary to collate the requirements around simulations and modelling into one document, particularly in areas where a more detailed description than that set out in the Grid Code is warranted.

Simulation studies are an integral part of power system design, analysis and operation as they provide an easy to follow analytical process in establishing various system parameters during for example the connection of a new facility to the grid. As such, provision of up-to-date and accurate models is an imperative part of this process.

In general, simulation studies can be utilised to model and analyse power networks' dynamic behaviour in terms of voltage and frequency stability as well as other transient phenomena.

The detail and specifics of the model required is normally dictated by the type of study intended to be used. For generation facilities, this usually implies analysis of behaviour in steady-state and quasi-steady-state and as such static and RMS models to be used for various studies are required. The following table provides a summary of the different model requirements for simulation purposes.

For non-synchronous generation, more detailed modelling is required in order to capture detailed control system behaviour. This is because voltage source technologies can exhibit control instabilities due to the use of technologies that is system voltage dependent. In addition, control interaction in close proximity is a distinct possibility and the ability to model and predict these has become paramount. Electromagnetic transient time domain modelling is the industry norm for such studies and hence generator models (an in most cases the inverter/converter model) in EMT domain are required.

Generation type	**Model requirement**	**Load flow**	**Short Circuit**	**Transient Stability**	**HF Transients**	**SSCI**	**Power Quality**
Synchronous Power Generating Module	Static simulation model	✓	✓				
	RMS simulation model			✓		✓	
Power Park Module	Static simulation model	✓	✓				
	RMS simulation model			✓			
	EMT simulation model			✓	✓	✓	
	Harmonic simulation model						✓
Demand Facilities, Distribution Facilities, Closed Distribution Systems	Static simulation model	✓	✓				
	RMS simulation model			✓			
	Harmonic simulation model						✓
HVDC Systems	Static simulation model	✓	✓				
	RMS simulation model			✓			
	EMT simulation model			✓	✓	✓	
	Harmonic simulation model						✓

Compliance Process

Simulation studies and model provision is part of a larger compliance process that involves other items as per the check list[1] for the connection of a given category.

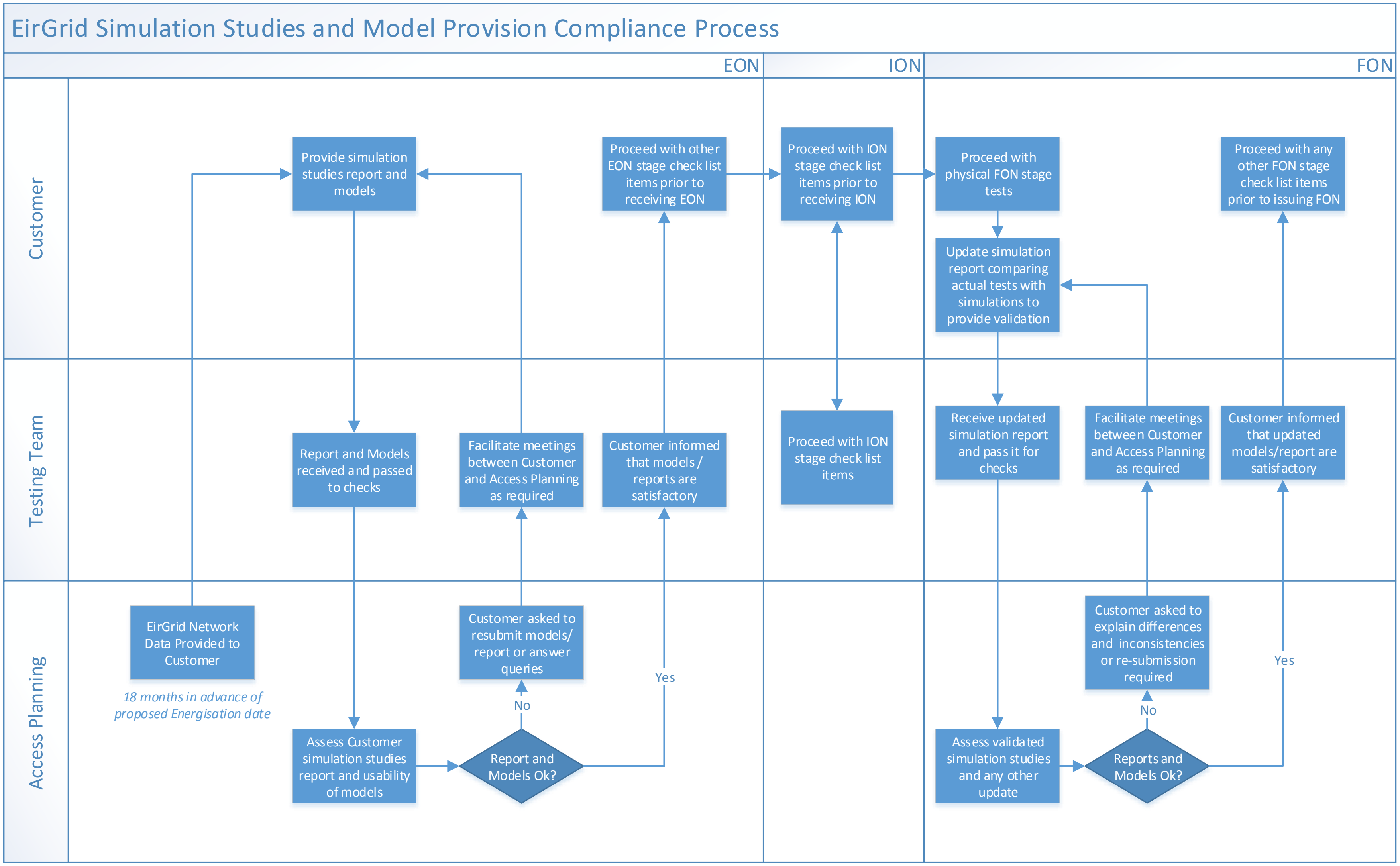
The process with regards to the provision of simulation studies and model, their check and provisional acceptance and later update and final acceptance is summarised in the next flow chart.

The process as indicated in the flow chart should be followed by all connections (or modifications) irrespective of technology.

In exceptional circumstances due to system security requirements, it may be necessary to energise a connection in the absence of a simulation study report or model with the express permission of senior level EirGrid management. In such cases, a temporary Grid Code derogation would still be required.

It is expected that there may be some adjustment of dynamic model parameters between the initial model submission, and following energisation and validation of the model, once final as-built technical parameters become known. Users are required to confirm the final model parameters when they submit model validation reports, as described in PC.A8.6.

[1] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/grid-code-compliance-test/compliance-testing/


EirGrid Simulation Studies and Model Provision Compliance Process
EON
ION
FON
Customer
Testing Team
Access Planning
Provide simulation studies report and models
Proceed with other EON stage check list items prior to receiving EON
Proceed with ION stage check list items prior to receiving ION
Proceed with physical FON stage tests
Proceed with any other FON stage check list items prior to issuing FON
Update simulation report comparing actual tests with simulations to provide validation
Report and Models received and passed to checks
Facilitate meetings between Customer and Access Planning as required
Customer informed that models / reports are satisfactory
Proceed with ION stage check list items
Receive updated simulation report and pass it for checks
Facilitate meetings between Customer and Access Planning as required
Customer informed that updated models/report are satisfactory
EirGrid Network Data Provided to Customer
18 months in advance of proposed Energisation date
Customer asked to resubmit models/ report or answer queries
No
Yes
Assess Customer simulation studies report and usability of models
Report and Models Ok?
Customer asked to explain differences and inconsistencies or re-submission required
No
Yes
Assess validated simulation studies and any other update
Reports and Models Ok?

PART 1. SYNCHRONOUS POWER GENERATING MODULES

1.1. General Provisions

Simulation studies are aimed at demonstrating the performance requirements of individual power-generating modules and the following general provisions apply: (Art 43-1)

- Generating facility shall provide technical data and documentation as part of the simulation studies compliance procedures (Art 41-3-a and b). All data requirements are detailed in the Planning Code Appendix of the Grid Code;
- Generating facility shall provide an appropriate model as part of the simulation studies compliance procedures (Art 41-3-c and d). The timeline of the model provision is covered by the phases of Operational Notification Procedure;
- EirGrid shall not accept an alternative set of simulations to those given as part of this compliance procedure (Art 43-2-a);
- EirGrid may require additional or alternative sets of simulations to those given in this procedure when deemed insufficient to demonstrate compliance (Art 43-2-b);
- Generation facility shall provide a report that includes modelling and results of all the simulation studies detailed in this procedure (Art 41-3-e & Art 43-3);
- Generation facility shall provide a validated simulation model as detailed in this procedure (Art 43-3);
- EirGrid may perform its own simulation studies based on the simulation model, simulation reports and compliance test measurements (Art 43-4);
- EirGrid shall provide the generation facility owner system data in order to carry out the simulation studies detailed in this procedure (Art 43-5); and
- EirGrid shall not accept provision of equipment certificates submitted as part of demonstrating compliance with relevant simulation study requirement (Art 52-1, 53-1, 55-1 and 56-2).

1.2. Simulation Model Requirements

1.2.1. Static Model

The static simulation model for synchronous power generating modules should represent the steady state characteristics of the generating facility at the point of connection suitable to be used in network wide load flow and short circuit calculation studies. More specifically the static model shall be capable of:

- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu);
- representing the characteristics of the generation facility’s operating ranges for active and reactive power;

- providing calculated RMS values of all phases for all types of system faults (balanced and unbalanced); and
- providing control functionality with reference points for the following modes
  - reactive power control mode
  - voltage control mode including parameters for droop setting
  - power factor control mode

1.2.2. RMS Model

The RMS model is aimed to be used for dynamic studies and as such the simulation model shall include information or be capable of:

- representing the dynamic properties of the generation facility;
- representing the characteristics of the generation facility's operating ranges for active and reactive power;
- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu);
- handling control functionality (with input/output signals) with indication of reference point
  - power factor control,
  - reactive power control,
  - voltage control including parameters for droop setting,
  - frequency control including droop and deadband,
  - activation of protection functionality (if present);
- activating an internal protection functionality in the event of external network faults;
- utilising an internal excitation system that includes relevant voltage, frequency, stator current, over and under excitation limiters;
- providing a numerically stable simulation for a minimum of 60 seconds following any set point changes or system incidents/faults;
- be capable of running with a variable integration time step in the range of 1 to 10 ms;
- initialising in a stable operating point;
- not requiring any special settings to be implemented into a larger network model;
- simulating the dynamic behaviour of the generators (or generating facility) under system faults, voltage disturbances and frequency disturbances; and
- not containing any encrypted or compiled parts.

For newly built synchronous power generating modules and for those installed but going through a modification involving any part of the drive train, in addition to the standard RMS model, information relating to mechanical mass model for each drive train element is also required. Specific information required are:

- inertia constants;
- spring and damping constants;
- torque shear stress; and
- natural oscillation frequencies.

1.2.3. Model Submission

The provision of the simulation model shall be supported and include:

- description of each individual model components and their related parameters;
  - saturation, dead bands, non-linearity, time delays, any interpolation assumptions and any look-up tables utilised within the parameters utilised
- description of initialisation of the model for simulations
- Laplace domain transfer functions, sequence diagrams and any arithmetic or logical sequence modules within the model description
- description of input and output signals
- explanation of set-up and initialisation of the model
- limitations of the model provided
- list of protection functionality that can be triggered by external events
- diagrams of excitation system, AVR, PSS and any other equipment implemented within the excitation system in the form of standardised block diagrams
- information on excitation system constraint functions such as current limiter, over-excitation and under-excitation limiters

For a generation facility that comprises more than one generator unit, the submitted simulation model must be such that the characteristics of the generation facility is represented at the point of connection. Submitted model parameters must contain all data sets for each unit.

The RMS simulation model submitted to EirGrid must be compatible with PSSE 34 and later versions, and should be in a format that can be readily integrated into other simulation packages, such as DigSilent PowerFactory, or DSA Tools. Information relating to the mechanical mass model can be submitted in written data form rather than in a model. No special settings other than standard software settings should be required for the submitted model to be implemented.

Model validation against test measurements is a requirement and the specific simulation that needs to be validated are indicated.

The submitted simulation model and studies shall have the following accuracy requirements:

- For a linear response over a frequency range of 0.1 to 5Hz, deviations between simulated and measured waveforms of the control system must be less than 10% for amplitude and less than 5 degrees for the phase angle. Discrete waveform changes (amplitude spikes) on the simulated waveform should be less than 10% in relation to measured quantity and in the case of where this level is exceeded due to numerical integration issues, this should be documented in the report.
- For dynamic time domain simulations where non-linear response is included to replicate set point changes or response to disturbances on the wider network, the following requirements apply for deviations between simulated and measured response:

- for rapid slopes within 10% for 95% of the samples recorded within a defined event window[2], and time offset of the gradient start or end time must be less than 20 milliseconds;
- for events (e.g. switching) resulting in positive and negative spikes, the amplitude must be less than 10% from the corresponding measured value for 95% of the samples recorded;
- oscillation in active power, reactive power, voltage and frequency in the 0.1-5Hz range must have damping and the deviation in the frequency of oscillation must be less than 10% for 95% of the recorded samples;
- considering possible difference in the voltage at the point of connection, deviation in active and reactive power response must be less than 10% for 95% of the samples;
- considering possible difference in the final settled value of voltage at the point of connection, the final value of active and reactive power must settle to within 2% of the plants rated capacity.

[2] An event window is defined as the instant a reference value changes or a disturbance is initiated and lasts until the response returns to within 5% of the maximum induced or reference quantity change.

1.3. Simulation Studies

This section details simulation studies required for synchronous power generating modules (SPGM). In most of the simulation studies, a model as given in Figure 1 is sufficient for study purposes and when this is the case each simulation study directs the user to use the given model arrangement.

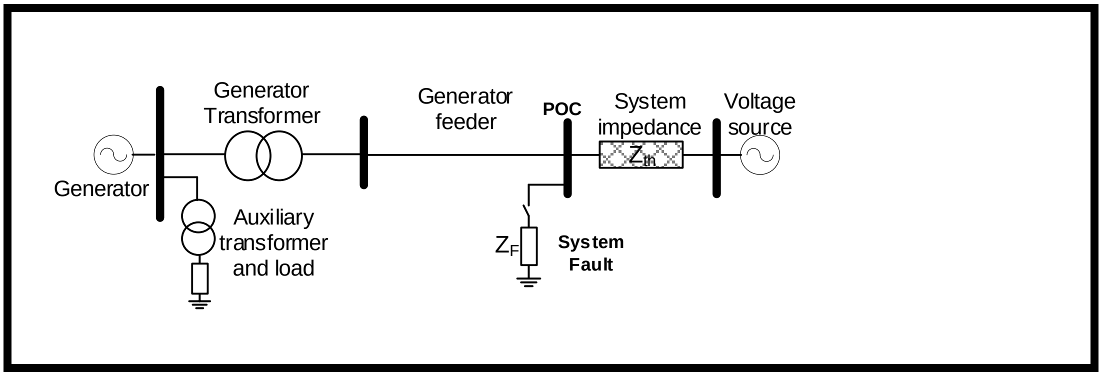


Figure 1

System impedance shown in the figure needs to be taken from Minimum System Strength Report.

A summary of the simulation studies for SPGM is given in the following table along with reference to the EU Network Code (2016/631) simulation requirement and the related EirGrid Grid Code capability requirement.

Capability Area	**EU – NC (2016/631)**	**EirGrid GC Capability**	**Validate against test**
Fault Ride Through	Art(53)3 & Art 51(4)	CC.7.3.1.1.(y)	
LFSM-O	Art51(2)	OC.4.3.4.1.8	Yes
LFSM-U	Art52(2)	OC.4.3.4.1.9	Yes
FSM	Art52(3)	OC.4.3.4.1.10	Yes
Load Rejection	Art52(4)	CC.7.3.2.1, CC.7.3.2.2 & CC.7.3.2.3	
Reactive Capability	Art52(5)	CC.7.3.6	Yes
Power System Stabiliser	Art53(2)	CC.7.3.8	

1.3.1. FRT, Active Power Recovery

Simulate fault-ride-through and active power recovery using a model as in Figure 1 with system impedance set equal to a value representing minimum short circuit level.

Set generator operation to P=Pmax, Q=Qmin (maximum leading reactive power) for the simulations.

Simulate:

Apply four different types of faults at the POC:

- phase-to-earth fault;
- phase-to-phase fault;

- phase-to-phase-to-earth fault;
- three-phase fault.

Under each of the above faults, set the faulted phases retained voltage at the POC to the values given below for the given duration. In each case clear the fault and let steady-state condition be reached before commencing the next study.

Faulted Phase Retained Voltage (p.u.)	**Fault Duration (milliseconds)**
0	150
0.5	300
0.9	1550

Check and report:

Voltage at generator terminals and POC (Point of Connection)

Active power at generator terminals

Reactive power at generator terminals

Rotor angle

Excitation Voltage

AVR and PSS output signal

Success Criteria:

Generator remains synchronised and stable while meeting the capability requirements in CC.7.3.1.1.(y)

1.3.2. LFSM-U and LFSM-O

This simulation needs to be validated against field tests.

Simulate limited frequency response using the model as in Figure 1 with system impedance set to minimum short circuit level and the generator operated at Limited Frequency Sensitive Mode with a droop setting set to 4% with active power as indicated in the table and reactive power at zero

Simulate:

Apply the following frequency step and ramps at the given loading. Each setpoint change is only initiated when steady state conditions are met.

Loading	f step or ramp
Min load	-0.5Hz (ramp of 1Hz/sec or step)
Min load	+0.5Hz (ramp of 1Hz/sec)
75%	-0.5Hz (ramp of 1Hz/sec or step)
75%	+0.5Hz (ramp of 1Hz/sec)
90%	-0.5Hz (ramp of 1Hz/sec)
92%	-0.5Hz (ramp of 1Hz/sec or step)
95%	-0.5Hz (ramp of 1Hz/sec or step)
100%	+0.5Hz (ramp of 1Hz/sec)

Check and report:

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Frequency

Success Criteria:

Generator remains stable while meeting the capability requirements in OC.4.3.4.1.8 and OC.4.3.4.1.9

1.3.3. Frequency Sensitive Mode

This simulation needs to be validated against actual compliance tests.

Simulate frequency sensitive mode using the model as in Figure 1 with system impedance set to minimum short circuit level and the generator operated in Frequency Sensitive Mode.

Generator operating at P= min load, 75%, 90%, 95%, Q=0

Generator droop settings set to 4%.

Simulate:

Apply the following frequency step and ramps.

1- Start with nominal system frequency for t<0 s

2- apply a ramped reduction of 0.5 Hz over x seconds
3- run with the reduced frequency for y seconds
4- apply a ramped increase of 0.3 Hz over z seconds
5- run with this frequency for t seconds

[x,y,z,t to be chosen as appropriate to the simulation in question].

Check and report:

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Frequency

Success Criteria:

Generator remains stable while meeting the capability requirements in OC.4.3.4.1.10

1.3.4. Islanded Operation (Load Rejection)

Simulate load rejection using the model as in Figure 1 with system impedance set to minimum short circuit level and the generator operating at P= Pmax and Q=0

Simulate:

While the generator is at maximum active power output, island the generator from the system by opening the generator breaker such that it supplies only the house load.

Check and report:

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Frequency

Success Criteria:

Generator remains connected and in operation while meeting the capability requirements in CC.7.3.1.1.w and CC.7.3.1.1.x

1.3.5. Reactive Power Capability

This simulation needs to be validated against field tests; if this is not possible then simulate as per below.

Simulate reactive power capability of the generator using the model in Figure 1 with system impedance set to minimum short circuit level. Generator operating at various points as indicated.

Simulate:

Run load flow studies with the generator at various points on the VQ/Pmax diagram.

Check and report:

Check it can supply maximum leading and lagging reactive power at Pmax at specified voltage levels in CC.7.3.6.5.

Check it can supply maximum leading and lagging reactive power at Pmin at specified voltage levels in CC.7.3.6.5.

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Success Criteria:

Simulation shows output within the boundaries of the VQ/Pmax diagrams given in CC.7.3.6.5.

1.3.6. Power System Stabiliser / AVR Control

Three separate simulations cases are expected for Power System Stabiliser:

Simulation 1:

This simulation is aimed at obtaining the response time of the AVR controls and is named idle response or open circuit test.

Set generator active and reactive power to zero and apply 10% generator terminal voltage step change to check excitation system response time.

Check and report:

Generator terminal voltage

AVR output signal

Success Criteria:

Compliance with respect to rise time requirements

Simulation 2:

Voltage variation test under different disturbances

Use minimum system fault level impedance as in Figure 1 and set the generator active power to maximum and reactive power to maximum leading reactive power (i.e. Qmin).

Apply 5% step to reference voltage to check PSS response to voltage disturbances. Repeat test with PSS on and off.

Apply three-phase short-circuit at generator transformer HV side. Repeat it with PSS on and off.

Check and report:

Generator terminal voltage

Active power

Reactive power

Excitation voltage

PSS output signal

AVR output signal

Success Criteria:

Improved attenuation of system power fluctuation when PSS is on compared to when PSS is off.

Simulation 3:

This simulation is aimed at obtaining frequency response of the SPGM Excitation System in the form of Bode diagrams (both gain and phase) in order to have an insight into possible stability margins. Two separate frequency responses are expected:

Open loop frequency response

Closed loop frequency response

Check and report:

Gain and phase Bode plot for open loop frequency response with PSS on and off.

Gain Bode plot for closed loop on load frequency response with PSS on and off. Generator is operating at Pmax and unity pf.

Success Criteria:

Improved contribution with PSS operation with respect to the gain and phase margin of Excitation System during open loop frequency response.

Improved active power damping with PSS during closed loop frequency response.

PART 2. POWER PARK MODULES

2.1. General Provisions

Simulation studies are aimed at demonstrating the performance requirements of individual power-generating modules and the following general provision apply: (Art 43-1)

- Generating facility shall provide technical data and documentation as part of the simulation studies compliance procedures (Art 41-3-a and b). All data requirements are detailed in the Planning Code Appendix of the Grid Code;
- Generating facility shall provide an appropriate model as part of the simulation studies compliance procedures (Art 41-3-c and d). The timeline of the model provision is covered by the phases of Operational Notification Procedure;
- EirGrid shall not accept an alternative set of simulations to those given as part of this compliance procedure (Art 43-2-a);
- EirGrid may require additional or alternative sets of simulations to those given in this procedure when deemed insufficient to demonstrate compliance (Art 43-2-b);
- Generation facility shall provide a report that includes modelling and results of all the simulation studies detailed in this procedure (Art 41-3-e & Art 43-3);
- Generation facility shall provide a validated simulation model as detailed in this procedure (Art 43-3);
- EirGrid may perform its own simulation studies based on the simulation model, simulation reports and compliance test measurements (Art 43-4);
- EirGrid shall provide the generation facility owner system data in order to carry out the simulation studies detailed in this procedure (Art 43-5); and
- EirGrid shall not accept provision of equipment certificates submitted as part of demonstrating compliance with relevant simulation study requirement (Art 52-1, 53-1, 55-1 and 56-2).

2.2. Simulation model requirements

2.2.1. Static Model

The static simulation model for power park modules should represent the steady state characteristics of the generating facility at the point of connection suitable to be used in network-wide load flow and short-circuit calculation studies. More specifically the static model shall be capable of:

- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu),
- representing the characteristics of the generation facility’s operating ranges for active and reactive power,

- providing calculated RMS values of all phases for all types of system faults (balanced and unbalanced),
- providing control functionality with reference points
  - reactive power control mode
  - voltage control mode including parameters for droop setting
  - power factor control mode

2.2.2. RMS Model

The RMS model used for dynamic simulation studies shall include information on or be capable of:

- representing the static and dynamic properties of the generation facility
- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu)
- representing the characteristics of the generation facility's operating ranges for active and reactive power,
- handling control functionality (with input/output signals) with indication of reference point
  - power factor control,
  - reactive power control, and
  - voltage control including parameters for droop setting
  - frequency control including droop and deadband
  - activation of protection functionality
  - control signal(s) to external plants such as FACTS devices
- providing calculated RMS values for all types of system faults (balanced and unbalanced),
- activating an internal protection functionality in the event of external network faults,
- utilising an internal excitation system that includes relevant voltage, frequency, stator current, over and under excitation limiters,
- providing a numerically stable simulation for a minimum of 60 seconds following any set point changes or system incidents/faults
- running with a variable integration time step in the range of 1 to 10 ms
- initialising in a stable operating point
- not requiring any special settings to be implemented into a larger network model
- simulating the dynamic behaviour of the generators (or generating facility) under system faults, voltage disturbances and frequency disturbances

If an aggregated model instead of individual units is used, then the aggregated model must be able to represent the characteristics of the whole facility at the point of connection. Descriptive information on the aggregation approach and assumptions should be provided.

The provision of the simulation model should be supported and include:

- description of each individual model components and their related parameters,
- description of input and output signal
- explanation of set-up and initialisation of the model
- limitations of the model provided
- list of protection functionality that can be triggered by external events

The model should not contain any compiled parts in order to be embedded within a larger network model without any restrictions.

2.2.3. EMT Model Requirements

In addition to static and RMS simulation models, PPMs are required to provide an EMT model.

The EMT model should be capable of recreating all the requirements of the static and RMS models and in addition shall:

- Represent all components, control and protection systems relevant for time domain analysis
- Initialise at a fraction of the simulation time. Conditions under which the model can be assumed initialised shall be documented.
- Give the user the ability to set various activation schemes within the model (for example activation of protection functions or apparent power dispatch)
- Allow the user to set all parameters relevant to the analysis
- Be repeatable, i.e. can be used multiple times within the same model without numerical issues
- Be able to capture high frequency transients
- Be capable of representing possible signal delays between various elements (for example park controller to individual wind turbine generators)
- Include any relevant non-linearities, deadbands, saturation, limits or mathematical functions.
- Primarily be based on the use of standard components that are within the given software environment
- In the case of compiled or encrypted part, not create any complications or incompatibility with respect to its integration to a wider network model.
- Be capable of being used in later versions of the given software.

2.2.4. Harmonic Model Requirements

Harmonic model to represent the power park generating facilities harmonic emissions as well as the effect of its passive network on the transmission system harmonics is required.

The model shall be capable of or include:

- Representing integer harmonic emissions at a single unit level from 2nd to 50th harmonic.
- Being defined either as Thevenin or Norton equivalent
- Passive response of the units (lumped impedance) within 50-2500 Hz range at a resolution of 1 Hz for all sequence networks.
- Specify a summation process from multiple units either using correct phase angles for injections or utilising a summation law
- Dependency on the power park generating facilities level of generation or operating point – model valid for at least three different operating regimes (minimum, average and maximum) shall be submitted
- Details of power park generating facility infrastructure equipment such as cables, transformers, shunt compensation etc as frequency dependent components.

If the power park generating facility has more than one unit, an aggregated harmonic simulation model can be submitted instead. The aggregated model shall be such that it represents the total emissions and include the total passive harmonic impedance at the point of connection within the 5-2500 Hz frequency range may be used.

2.2.5. Model Submission

The provision of simulation model shall be supported and include:

- instruction of integrating the provided model into a wider network model so as to be used as part of wider system studies.
- guidance on the interpretation of error messages and troubleshooting.
- a comprehensive list of parameters, default and range of values applicable, block diagrams and transfer functions.
- model single line diagram showing main electrical components and connectivity to the network interface point.
- description of each individual model components and their related parameters,
- description of initialisation of the model for simulations,
- Laplace domain transfer functions, sequence diagrams and any arithmetic or logical sequence modules within the model description
- saturation, dead bands, non-linearity, time delays, any interpolation assumptions and any look-up tables utilised within the parameters utilised
- description of the electrical input and output signals, explanation on the measurement point used, signal units and base values.
- explanation on any restrictions on its use, limits applicable such as the maximum integration step size, and accuracy of the model.
- list of protection functionality that can be triggered by external events
- diagrams of control system and any other equipment implemented within the control system in the form of standardised block diagrams
- information on applicable software version, compiler version if any and simulation model unique version control.

For a power park that comprises more than one generator unit, the submitted simulation model must be such that the characteristics of the power park is represented at the point of connection. Submitted model parameters must contain all data sets for each unit.

The static and RMS simulation models submitted to EirGrid must be implemented in (or compatible with) PSSE34 and later versions. No special settings other than standard software setting should be required for the submitted model to be implemented.

The EMT model must be developed and delivered in PSCAD version 4.6.3 or later.

The harmonic simulation model shall be delivered in PowerFactory version 2020.

RMS and EMT models require verification and validation which shall be included in the submitted simulation report. The EMT model must be validated for simulations at different simulation time steps and should also include comparison of the static and RMS dynamic model response. Model validation against test measurements is a requirement and the specific simulation that needs to be validated against actual tests are indicated above.

In general accuracy requirement for PPM models and simulation follow a similar line to SPGM as in the previous section and repeated below. For EMT model and simulation accuracy, identical approach to RMS is used. However, the comparison is evaluated using RMS quantities with an appropriate filtering for power frequency component of measured and simulated parameters. The method of filtering must be agreed between EirGrid and the facility owner prior to any measurements and simulations.

The submitted simulation model and studies shall have the following accuracy requirements:

- For a linear response over a frequency range of 0.1 to 5Hz, deviations between simulated and measured waveforms of the control system must be less than 10% for amplitude and less than 5 degrees for the phase angle. Discrete waveform changes (amplitude spikes) on the simulated waveform should be less than 10% in relation to measured quantity and in the case of where this level is exceeded due to numerical integration issues, this should be documented in the report.
- For dynamic time domain simulations where non-linear response is included to replicate set point changes or response to disturbances on the wider network, the following requirements apply for deviations between simulated and measured response:
  - for rapid slopes within 10% for 95% of the samples recorded within a defined event window[3], and time offset of the gradient start or end time must be less than 20 milliseconds;
  - for events (e.g. switching) resulting in positive and negative spikes, the amplitude must be less than 10% from the corresponding measured value for 95% of the samples recorded;
  - oscillation in active power, reactive power, voltage and frequency in the 0.1-5Hz range must have damping and the deviation in the frequency of oscillation must be less than 10% for 95% of the recorded samples;
  - considering possible difference in the voltage at the point of connection, deviation in active and reactive power response must be less than 10% for 95% of the samples;
  - considering possible difference in the final settled value of voltage at the point of connection, the final value of active and reactive power must settle to within 2% of the plants rated capacity.

[3] An event window is defined as the instant a reference value changes or a disturbance is initiated and lasts until the response returns to within 5% of the maximum induced or reference quantity change.

2.3. PPM Simulation Studies

This section details simulation studies required for power park modules generating modules (PPM). In most of the simulation studies, a model as given in Figure 2 is sufficient for study purposes and when this is the case each simulation study directs the user to use the given model arrangement.

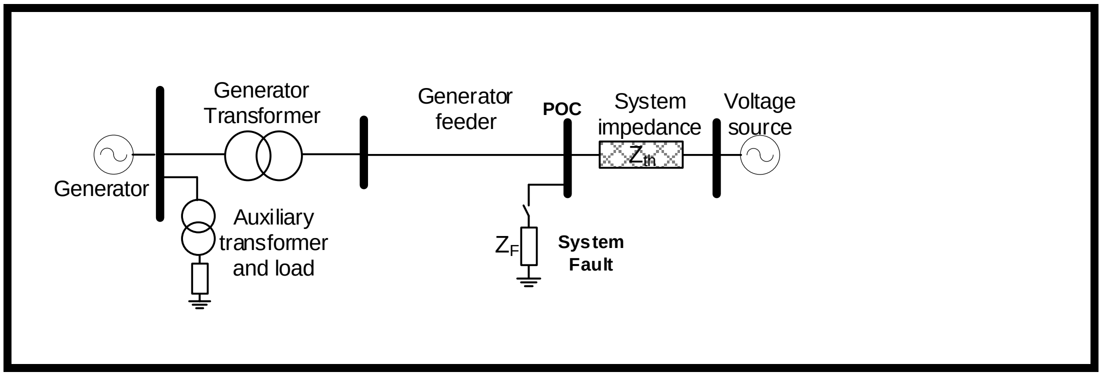


Figure 2

System impedance shown in the figure needs to be taken from Minimum System Strength Report.

A summary of the simulation studies for PPM is given in the following table along with reference to the EU Network Code (2016/631) simulation requirement and the related EirGrid Grid Code capability requirement.

Capability Area	EU – NC (2016/631)	EirGrid GC Capability	Validate against test
Fast Fault Current Active Power Recovery Fault Ride Through	Art54(3), Art54(5) & Art56(3)	GC PPM1.4.2.a, PPM1.4.2.b, PPM1.4.2.c & PPM1.4.2.f	
LFSM-O	Art54(2)	PPM1.5.3.11	Yes
LFSM-U	Art55(2)	PPM1.5.3.12	Yes
FSM	Art55(3)	PPM1.5.3.13	Yes
Load Rejection	Art55(4)	CC.7.3.2.1, CC.7.3.2.2 & CC.7.3.2.3	
Reactive Capability	Art55(6)	PPM1.6.3.1 & PPM1.6.3.4	Yes
Power Oscillation Damping	Art55(7)	N/A	

2.3.1. FRT, Active Power Recovery and Fast Fault Current

Simulate fault-ride-through and active power recovery using a model as in Figure 2 with system impedance set equal to a value representing minimum short circuit level.

Note: Please refer to the notes in Appendix A with respect to the interpretation of PPM1.4.2(c).

Set generator operation to P=Pmax, Q=0 for the simulations.

Simulation 1: Fault Ride-Through

Apply four different types of faults at the POC:

- phase-to-earth fault;
- phase-to-phase fault;
- phase-to-phase-to-earth fault;
- three-phase fault.

Under each of the above faults, set the faulted phases retained voltage at the POC to the values given below for the given duration. In each case clear the fault and let steady-state condition to be reached before commencing the next study.

Faulted Phase Retained Voltage (p.u.)	Fault Duration (milliseconds)
0	150
0.4	1250
0.85	2900

Check and report:

Voltage at generator terminals and POC

Active power and Active Current at generator terminals and POC

Reactive power and Reactive Current at generator terminals and POC

Success Criteria:

(i) Generator remains connected and stable while meeting the capability requirements in PPM1.4.2.f

(ii) Show compliance against GC PPM1.4.2.a, PPM1.4.2.b and PPM1.4.2.c **Note that Rise Time and Settling will be checked in Simulation 2 below.**

Simulation 2: Rise Time / Settling Time

Apply a three-phase fault leading to a voltage step-change to 0.5 pu retained voltage at the POC.

Check and report:

Voltage at the generator terminals and POC

Active power and active current at generator terminals and POC

Reactive power and reactive current at generator terminals and POC.

Success Criteria:

Show compliance against PPM1.4.2.c Rise Time and Settling Time criteria.

2.3.2. LFSM-U and LFSM-O

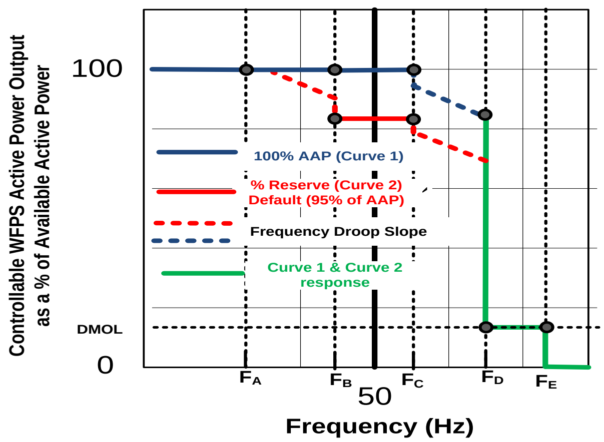
This simulation needs to be validated against actual compliance tests.

Simulate Limited Frequency Sensitive Mode response using the model in Figure 2 with system impedance set to minimum short circuit level. The generator should be operated at LFSM with an active power P as indicated in the curve shown below and reactive power set to zero.

Generator droop settings set to 4%.

Simulate:

Apply Curve 1 Resource Following Mode as shown in the next figure and table. Each setpoint change is only initiated when steady state conditions are met.



	Transmission System Frequency f (Hz)		***Required Active Power Output***
	f < 48		*100% of AAP*
F_A	*48*	***P_A***	*100% of AAP*
Under Frequency Response	*48 < f < 49.8*		*100% of AAP*
F_B	*f = 49.8*	***P_B***	*100% of AAP*
+/-0.2Hz Deadband	*49.8 < f < 50.2*		*100% of AAP*
F_C	*f = 50.2*	***P_C***	*100% of AAP*
Over Frequency Response	*50.2 < f < 51.9*		*AAP + ΔMW*[2]
F_D	*f = 51.9*	***P_D***	*Minimum of: AAP and DMOL*
F_E	*f = 52*	***P_E***	*0%*[3]
	f > 52		*0%*[3]

Check and report:

Voltage at generator terminals and POC

Active power at generator terminals and POC

Reactive power at generator terminals and POC

Frequency

Success Criteria:

Generator remains stable while meeting the capability requirements in PPM1.5.3.11 and PPM1.5.3.12

2.3.3. Frequency Sensitive Mode

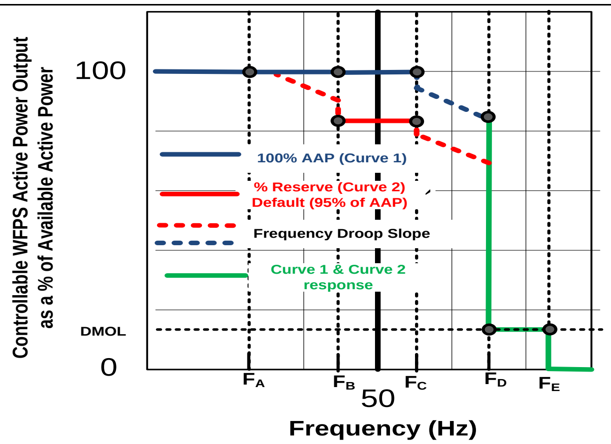
This simulation needs to be validated against actual compliance tests.

Simulate Frequency Sensitive Mode response using the model in Figure 2 with system impedance set to minimum short circuit level. The generator should be operated at FSM with an active power P as indicated in the curve shown below and reactive power set to zero

Generator droop settings set to 4%.

Simulate:

Apply the Curve 1 Active Power Control Mode as shown in the next figure and table. Each setpoint change is only initiated when steady state conditions are met.



	Transmission System Frequency *f* *(Hz)*		***Required Active Power Output***
	f < 48		*100% of AAP*
F_A	*f = 48*	***P_A***	*100% of AAP*
Under Frequency Response	*48 < f < 49.985*		*Minimum of: APC Setpoint + ΔMW and AAP*
F_B	*f = 49.985*	***P_B***	*Minimum of: APC*

			Setpoint and AAP
+/-0.015Hz Deadband	*49.985 < f < 50.015*		*Minimum of: APC Setpoint and AAP*
F_C	*f = 50.015*	***P_C***	*Minimum of: APC Setpoint and AAP*
Over Frequency Response	*50.015 < f < 51.9*		*Minimum of: APC Setpoint + ΔMW and AAP + ΔMW*[1, 2]
F_D	*f = 51.9*	***P_D***	*Minimum of: APC Setpoint and AAP and DMOL*
F_E	*f = 52*	***P_E***	*0%*[3]
	f > 52		*0%*[3]

Check and report:

Voltage at generator terminals and POC

Active power at generator terminals and POC

Reactive power at generator terminals and POC

Frequency

Success Criteria:

Generator remains stable while meeting the capability requirements in PPM1.5.3.13.

2.3.4. Reactive Power Capability

This simulation needs to be validated against actual compliance tests.

Demonstrate reactive power capability using the model in Figure 2 with system impedance set to minimum short circuit level and the generator operating at various points.

Simulate:

Run load flow studies with the generator at various points on the VQ/Pmax diagram.

Check and report:

Check it can supply maximum leading and lagging reactive power at Pmax at specified voltage levels in PPM1.6.3.4.

Check it can supply maximum leading and lagging reactive power at Pmin at specified voltage levels in PPM1.6.3.4.

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Success Criteria:

Simulation shows output within the boundaries of the VQ/Pmax diagrams given in PPM1.6.3.4.

2.3.5. Islanded Operation (Load Rejection) (Only if requested by EirGrid)

Demonstrate islanded operation capability using the model in Figure 2 with system impedance set to minimum short circuit level and the generator operating at P= Pmax and Q=0.

Simulate:

While the generator is at maximum active power output, island the generator from the system by opening the breaker connecting the power park to the system such that it supplies only the auxiliary and any local load.

Check and report:

Voltage at generator terminals

Active power at generator terminals

Reactive power at generator terminals

Frequency

Success Criteria:

Generator remains connected and in operation while meeting the capability requirements in CC.7.3.1.1.w and CC.7.3.1.1.x

2.3.6. Power System Stabiliser / AVR Control (Not Applicable Presently)

If a Power System Stabiliser is specified for voltage control or if there is one already included in the voltage control system, then a simulation demonstrating power oscillation damping capability is required. The purpose is to confirm correct operation of AVR system in kV, Q and power factor control modes, and changing between modes and to validate simulations against filed tests; if this is not possible then simulate as per below. For the AVR A step change in system voltage is created to allow analysis of the AVR rate of response. The step change is ideally created by NCC carrying out switching on the system. If this is not possible, the PPM shall carry out a manual tap change to induce a small step change in system voltage.

Simulate:

Voltage variation test under different disturbances

Use minimum system fault level impedance.

P=Pmax and Q=Qmin (maximum leading reactive power)

Apply 5% step to reference voltage to check PSS response to voltage disturbances. Repeat test with PSS on and off.

Apply an appropriate three-phase short-circuit at grid connection point, with PSS on and off, in order to show improvement with PSS on.

Check and report:

Generator terminal and POC voltage

Active power

Reactive power

Excitation voltage

PSS output signal

AVR output signal

Success Criteria:

Improved attenuation of system power fluctuation when PSS is on compared to when PSS is off.

PART 3. DEMAND FACILITIES, DISTRIBUTION FACILITIES and DISTRIBUTION SYSTEMS

3.1. General Provisions

- Simulation studies are required for new and modified (further development or modernisation of equipment) demand facilities, when the demand facility or closed distribution system is contracted to provide very fast active power control or alleged incompliance with the requirements of the Grid Code(Art 42-2)
- EirGrid shall not accept an alternative set of simulations to those given as part of this compliance procedure (Art 42-3a)
- EirGrid may require additional or alternative sets of simulations to those given in this procedure when deemed insufficient to demonstrate compliance (Art 42-3b)
- Demand facility shall provide a report that includes modelling and results of all the simulation studies detailed in this procedure (Art 42-4)
- EirGrid may perform its own simulation studies based on the simulation model, simulation reports and compliance test measurements (Art 42-5)
- EirGrid shall provide the demand facility owner system data in order to carry out the simulation studies detailed in this procedure (Art 42-6)
- Demand facility shall provide the following documents and technical data as part of the simulation studies compliance procedures (Art 35-3-a and b)
- Demand facility shall provide appropriate model as part of the simulation studies compliance procedures (Art 35-3-c and d) [timeline is covered by the phases of operational notification].

3.2. Simulation model requirements

The level of simulation model under DCC generally includes the steady-state properties of the transmission-connected demand facility or transmission-connected distribution system. Dynamic simulation models (and in some cases harmonic simulation models) are also required as part of data submission.

3.2.1. Static Model

The static simulation model for transmission connected demand facility or transmission connected distribution system should be suitable for load flow and short circuit calculation studies. More specifically the static model shall include information on:

- Total active and reactive power consumption.
- Dependency of active and reactive power on voltage and frequency (if any)

- Composition of load in terms of type (induction motor load, power electronic converter-based load etc)
- Installed embedded generation capacity
- Reactive power data both from discrete components such as shunt reactors/capacitors and also from those generated by equipment such as cables.
- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu),

3.2.2. RMS Model

The RMS model used for dynamic simulation studies shall include information or be capable of:

- representing the static and dynamic properties of the transmission-connected demand facility or transmission connected distribution system
- covering a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu)
- representing the characteristics of the demand facility's operating ranges for active and reactive power,
- providing calculated RMS values for all types of system faults (balanced and unbalanced),
- representing the voltage dependency (overvoltage and undervoltage) of the facility
- representing the frequency dependency of the facility
- activating any internal protection functionality in the event of external network faults,
- including any control functionality (such as tap changers or blocking functionality)
- utilising any internal reclosing or swapping functionality (for example local demand to UPS)
- providing a numerically stable simulation for a minimum of 60 seconds following any system incidents/faults
- initialising in a stable operating point
- running under with a variable time step in the range of 1 to 10 ms
- not requiring any special settings to be implemented into a larger network model
- simulating the dynamic behaviour of the demand facility under system faults, voltage disturbances and frequency disturbances

If an aggregated model instead of individual units is used, then the aggregated model must be able to represent the characteristics of the whole facility at the point of connection. Descriptive information on the aggregation approach and assumptions should be provided.

The provision of simulation model should be supported and include:

- description of each individual model components and their related parameters,
- description of input and output signal
- explanation of set-up and initialisation of the model
- limitations of the model provided
- list of protection functionality that can be triggered by external events

The model should not contain any compiled parts in order to be embedded within a larger network model without any restrictions. We suggest using a standard library model if possible.

3.2.3. Harmonic Model Requirements

A harmonic model is required to represent the transmission connected demand facility or transmission connected distribution system harmonic emissions as well as the passive network's effect on the transmission system harmonics.

The model shall be capable of or include:

- Representing integer harmonic emissions if any either as aggregate or at individual unit level
- Emissions being defined either as Thevenin or Norton equivalent
- Passive response of the facility (lumped impedance) within 50-2500 Hz range at a resolution of 1 Hz for all sequence networks.
- Specify a summation process from multiple units either using correct phase angles for injections or utilising a summation law

An aggregated model representative of the demand facility's total emissions, instead of multiple units can be submitted. The aggregated model must be able to represent the characteristics of the whole facility at the point of connection such that it represents the total emissions and include the total passive harmonic impedance at the point of connection within the 5-2500 Hz frequency range. Descriptive information on the aggregation approach and assumptions should be provided.

3.2.4. Model Submission

The provision of simulation model shall be supported and include:

- instruction on integrating the provided model into a wider network model so as to be used as part of wider system studies.
- guidance on the interpretation of error messages and troubleshooting.
- a comprehensive list of parameters, default and range of values applicable, block diagrams and transfer functions.
- model single line diagram showing main electrical components and connectivity to the network interface point.
- description of each individual model components and their related parameters,
- description of initialisation of the model for simulations,
- Laplace domain transfer functions, sequence diagrams and any arithmetic or logical sequence modules within the model description
- saturation, dead bands, non-linearity, time delays, any interpolation assumptions and any look-up tables utilised within the parameters utilised
- description of the electrical input and output signals, explanation on the measurement point used, signal units and base values.
- explanation on any restrictions on its use, limits applicable such as the maximum integration step size, and accuracy of the model.
- list of protection functionality that can be triggered by external events
- diagrams of control system and any other equipment implemented within the control system in the form of standardised block diagrams
- information on applicable software version and simulation model unique version control.

The static and RMS simulation models submitted to EirGrid must be implemented in or compatible with PSSE 34 and subsequent versions. No special settings other than standard software setting should be required for the submitted model to be implemented.

The harmonic simulation model shall be delivered in PowerFactory version 2020.

RMS models require verification and validation which shall be included in the submitted simulation report.

Accuracy requirement for PPM models and simulation follow a similar line to SPGM as in the previous section and repeated below.

The submitted simulation model and studies shall have the following accuracy requirements:

- For a linear response over a frequency range of 0.1 to 5Hz, deviations between simulated and measured waveforms of the control system must be less than 10% for amplitude and less than 5 degrees for the phase angle. Discrete waveform changes (amplitude spikes) on the simulated waveform should be less than 10% in relation to measured quantity and in the case of where this level is exceeded due to numerical integration issues, this should be documented in the report.
- For dynamic time domain simulations where non-linear response is included to replicate set point changes or response to disturbances on the wider network, the following requirements apply for deviations between simulated and measured response:
  - for rapid slopes within 10% for 95% of the samples recorded within a defined event window[4], and time offset of the gradient start or end time must be less than 20 milliseconds;
  - for events (e.g. switching) resulting in positive and negative spikes, the amplitude must be less than 10% from the corresponding measured value for 95% of the samples recorded;
  - oscillation in active power, reactive power, voltage and frequency in the 0.1-5Hz range must have damping and the deviation in the frequency of oscillation must be less than 10% for 95% of the recorded samples;
  - considering possible difference in the voltage at the point of connection, deviation in active and reactive power response must be less than 10% for 95% of the samples;
  - considering possible difference in the final settled value of voltage at the point of connection, the final value of active and reactive power must settle to within 2% of the plants rated capacity.

[4] An event window is defined as the instant a reference value changes or a disturbance is initiated and lasts until the response returns to within 5% of the maximum induced or reference quantity change.

3.3. DCC Simulation Studies

3.3.1. Reactive Power Capability

(Art 43 -1, 44-1)

Simulate:

Run load flow studies with the demand facility or distribution system at various load and generation conditions including minimum and maximum and simulate the lowest and highest reactive power exchange.

Run load flow study to check the level of reactive power export while the facility or distribution system is importing less than 25% of the maximum import capability.

Check and report:

Check that reactive power exchange is within the capability requirements specified in CC.7.4.2.4.

Voltage at the point of connection

Active power at the point of connection

Reactive power at the point of connection

Success Criteria:

Simulation shows output within the exchange boundaries given in CC.7.4.2.4

3.3.2. Very Fast Active Power Control

(Art 45-1)

Simulate:

In an RMS dynamic simulation to mimic a low frequency event apply a frequency step and/or ramps relative to the contractual agreement in place. There should be a contractually defined change of active power related to a measure of rate-of-change-of-frequency and a response time for the very fact active power control that should be less than 2 seconds.

Check and report:

Voltage at the point of connection

Active power at the point of connection

Reactive power at the point of connection

Frequency

Response time of control system

Success Criteria:

Facility remains within the technical capability specified in the contractual agreement.

PART 4. HVDC Converter Stations, DC Connected PPMs [Draft]

PLEASE NOTE: PART 4 IS DRAFT AND NOT YET APPROVED, BUT IS INCLUDED FOR COMPLETENESS.

4.1. General Provisions

Simulation studies are aimed at demonstrating the performance requirements of HVDC systems and DC-connected power park modules. (Art 68-1)

- EirGrid shall not accept an alternative set of simulations to those given as part of this compliance procedure (Art 68-2-a)
- EirGrid may require additional or alternative sets of simulations to those given in this procedure when deemed insufficient to demonstrate compliance (Art 68-2-b)
- HVDC system owner or DC-connected power park module owner shall provide a validated simulation model as detailed in this procedure (Art 68-3)
- HVDC system owner or DC-connected power park module owner shall provide a report that includes modelling and results of all the simulation studies detailed in this procedure (Art 68-3)
- EirGrid may perform its own simulation studies based on the provided simulation models, simulation reports and compliance test measurements (Art 68-4)
- EirGrid shall provide the HVDC system owner or DC-connected power park module owner system data in order to carry out the simulation studies detailed in this procedure (Art 68-5)
- EirGrid shall not (or shall) accept provision of equipment certificates submitted as part of demonstrating compliance with relevant simulation study requirement (Art 73-1)

4.2. Simulation model requirements

4.2.1. Static Model

The static simulation model for HVDC system should represent the steady state characteristics of the converter station at the point of connection suitable to be used in network wide load flow and short circuit calculation studies. More specifically the static model shall:

- Include operational characteristics in terms of active and reactive power ranges
- Function for a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu)

- Various control functionality with reference points
    - Reactive power control mode
    - Voltage control mode including parameters for droop setting
    - Power factor control mode
- Have the capability to facilitate selection of any control mode
- Provide calculated RMS values of all phases for all types of system faults (balanced and unbalanced),

4.2.2. RMS Model

The RMS simulation model for the HVDC system is aimed to represent the dynamic behaviour of the installation at the point of connection to the wider network under all conditions that the HVDC system is designed to operate. The RMS dynamic model shall:

- Include the characteristics of the HVDC system's operating ranges for active and reactive power
- Function for a range of frequencies (47 to 52 Hz) and voltages (0 to 1.4 pu)
- Include input/output signals which include as a minimum the following:
    - Active power
    - Reactive power
    - Frequency control
    - Runback
    - Control functionality
        - active power
        - reactive power
        - power factor control
        - voltage control (with droop setting capability)
        - frequency control (with deadband)
        - protection activation
    - Emergency power control (both active and reactive)
    - Power Oscillation Damping (POD)
    - Blackstart
    - External component control (e.g. STATCOM or battery)
- Be capable of activating an internal protection functionality in the event of external network faults.
- Be capable of simulating the dynamic behaviour of the HVDC system under system faults, voltage disturbances and frequency disturbances
- Provide calculated RMS values of all phases for all types of system faults (balanced and unbalanced).
- Be able to represent the HVDC plant's FRT characteristics.
- Be able to operate with a variable time step for numerical integration running in the range of 1 to 10ms.
- Initialise to a stable operating point and be numerically stable at instantaneous phase angle jumps of up to 20 degrees.

- Be able to run in a stable manner for up to 100 seconds following any setpoint changes or events on the system
- Not require any special settings to be implemented into a larger network model
- Not contain any encrypted or compiled parts
- Include any special functionality provided by the actual HVDC system, such as control scheme for weak grids.

4.2.3. EMT Model

The static and RMS simulation models are aimed to represent the steady-state and dynamic properties of the HVDC system at the network connection point. Therefore, the need is to have simulation models that correspond sufficiently accurately to the steady-state response of the actual facility for a valid steady-state operational point, and for the dynamic response associated with a setpoint change or an external event in the wider power supply network.

In addition to the static and RMS model, an EMT model for the HVDC system shall be submitted to EirGrid to be used in electromagnetic time domain studies.

The EMT model should be capable of recreating all the requirements of the static and RMS models and in addition shall:

- Include implementation of network components and other assets including control systems and protective devices that are part of the infrastructure to a level of detail valid for the EMT-studies.
- Include component models especially with respect to power electronics at individual switching device level.
- Include user adjustable simulation time for activation of protection functions
- Include user adjustable simulation time for apparent power dispatch
- Primarily be based on the use of standard components that are within the given software environment
- In the case of compiled or encrypted part, not create any complications or incompatibility with respect to its integration to a wider network model.
- Be capable of using it in later versions of the given software.
- Be suitable for use under black start and islanded operation
- Initialise at a fraction of the simulation time. Conditions under which the model can be assumed initialised shall be documented.

4.2.4. Harmonic Simulation Model

Harmonic model to represent the HVDC system harmonic emissions as well as the effect of its passive network on the transmission system harmonics is required.

The model shall be capable of or include:

- Representing integer harmonic emissions
- Being defined either as Thevenin or Norton equivalent
- Passive response of the units (lumped impedance) within 50-2500 Hz range at a resolution of 1 Hz for all sequence networks.
- Dependency on the HVDC system operating point – model valid for at least three different operating regimes (minimum, average and maximum power transfer) shall be submitted
- Details of the HVDC system infrastructure equipment such as cables, transformers, shunt compensation etc as frequency dependent components.

4.2.5. Model Submission

The models provided must be accompanied with a user guide that should include descriptions of the implemented automatic control, protection and regulation functions and enough information to allow EirGrid to implement the model in other platforms as required. More specifically the model guide document submission must include:

- Description of the setup and initialization process for the model
- Instruction of integrating the provided model into a wider network model so as to be used as part of wider system studies.
- Guidance on the interpretation of error messages and troubleshooting.
- Model single line diagram showing main electrical components and connectivity to the network interface point.
- Description of the electrical input and output signals, explanation on the measurement point used, signal units and base values.
- A comprehensive list of parameters, default and range of values applicable, block diagrams and transfer functions.
- Explanation on any restrictions on its use, limits applicable such as the maximum integration step size, and accuracy of the model.
- Description of HVDC system functions not included in the model and the effect this will have on the relevant model use (for example in the case if EMT model on transient studies).
- Information on applicable software version, compiler version if any and simulation model unique version control.

The static and RMS simulation models submitted to EirGrid must be implemented in or compatible with PSSE 34. No special settings other than standard software setting should be required for the submitted model to be implemented.

The EMT model must be developed and delivered in PSCAD version 4.6.3.

The harmonic simulation model shall be delivered in PowerFactory version 2020.

RMS and EMT models require verification and validation which shall be included in the submitted simulation report. The EMT model must be validated for simulations at different simulation time steps and should also include comparison of the static and RMS dynamic model response. Model validation against test measurements is a requirement and the specific simulation that needs to be validated against actual tests are indicated.

Accuracy requirement for HVDC models and simulation follow a similar line to other technologies as in the previous sections and repeated below. For EMT model and simulation accuracy, identical approach to RMS is used. However, the comparison is evaluated using RMS quantities with an appropriate filtering for power frequency component of measured and simulated parameters. The method of filtering must be agreed between EirGrid and the facility owner prior to any measurements and simulations.

The submitted simulation model and studies shall have the following accuracy requirements:

- For a linear response over a frequency range of 0.1 to 5Hz, deviations between simulated and measured waveforms of the control system must be less than 10% for amplitude and less than 5 degrees for the phase angle. Discrete waveform changes (amplitude spikes) on the simulated waveform should be less than 10% in relation to measured quantity and in the case of where this level is exceeded due to numerical integration issues, this should be documented in the report.
- For dynamic time domain simulations where non-linear response is included to replicate set point changes or response to disturbances on the wider network, the following requirements apply for deviations between simulated and measured response:
  - for rapid slopes within 10% for 95% of the samples recorded within a defined event window[5], and time offset of the gradient start or end time must be less than 20 milliseconds;
  - for events (e.g. switching) resulting in positive and negative spikes, the amplitude must be less than 10% from the corresponding measured value for 95% of the samples recorded;
  - oscillation in active power, reactive power, voltage and frequency in the 0.1-5Hz range must have damping and the deviation in the frequency of oscillation must be less than 10% for 95% of the recorded samples;
  - considering possible difference in the voltage at the point of connection, deviation in active and reactive power response must be less than 10% for 95% of the samples;
  - considering possible difference in the final settled value of voltage at the point of connection, the final value of active and reactive power must settle to within 2% of the plants rated capacity.

[5] An event window is defined as the instant a reference value changes or a disturbance is initiated and lasts until the response returns to within 5% of the maximum induced or reference quantity change.

4.3. Simulation Studies

A summary of the simulation studies for HVDC converter station is given in the following table along with reference to the EU Network Code (2016/1447) simulation requirement and the related EirGrid Grid Code capability requirement.

Capability Area	EU – NC (2016/1447)	EirGrid GC Capability	Validate against test
Fault Ride Through	Art 73(3)	CC.7.5.12.1	
Fast Fault Current	Art 73(2)	CC.7.5.12.4	
Active Power Recovery	Art 73(4)	CC.7.5.12.6	
Reactive Capability	Art 73(5)	CC.7.5.10.(d)	Yes
Power Oscillation Damping	Art 73(6)	CC.7.5.4.(k)	
Active Power Modification	Art 73(7)	CC.7.5.8.5	
Active Power Reversal	Art 73(8)	CC.7.5.1.1.(k)	

DC connected Power Park Modules and remote-end HVDC converter stations are also subject to simulation studies and these are given in the following table. Studies associated with DC connected PPMs should in principle follow a similar line to any other controllable PPM and the remote-end HVDC converter station simulation study should follow the study line for HVDC converter station.

Capability Area	EU – NC (2016/1447)	EirGrid GC Capability	Validate against test
Fast Fault Current (DC PPM)	Art 74(2)	PPM1.4.2.c	
Active Power Recovery (DC PPM)	Art 74(3)	PPM1.4.2.b	
Reactive Capability (DC PPM)	Art 74(4)	PPM1.6.3.5	Yes
Reactive Capability (remote end HVDC)	Art 74(5)	CC.7.5.10.(f)	Yes
Power Oscillation Damping (DC PPM)	Art 74(6)	N/A	
Fault Ride Through (DC PPM)	Art 74(7)	PPM1.4.2.f	

4.3.1. Fault Ride Through

Simulate Fault Ride Through capability of the HVDC installation using the model in Figure 1 with system impedance set to minimum short circuit level. HVDC system operating at both import and export configuration with P=Pmax.

Simulate:

Apply four different types of faults at the POC:

- phase-to-earth fault;
- phase-to-phase fault;
- phase-to-phase-to-earth fault;
- three-phase fault.

Under each of the above faults, set the faulted phases retained voltage at the POC to the values given below for the given duration. In each case clear the fault and let steady-state condition to be reached before commencing the next study.

Faulted Phase Voltage (p.u.)	Fault Duration (milliseconds)
$U_{ret} = 0$	150 ($t_{clear} = 150$)
$U_{rec1} = 0.85$	2350 ($t_{rec1} = 2500$)
$U_{rec2} = 0.90$	7500 ($t_{rec2} = 10000$)

Check and report:

Voltage at HVDC station terminals

Active power at HVDC station terminals

Reactive power at HVDC station terminals

Real and reactive currents at the HVDC terminals.

Provide same plots for the remote end converter station.

Success Criteria:

HVDC system remains connected and stable while meeting the capability requirements in xyz [GC clause that specifies the voltage against time profile – CC.7.5.12.1 but may change!]

4.3.1. Fast fault current injection

In order to demonstrate fast fault current injection, use simulation results from the Fault Ride Through.

Check and report:

Voltage at HVDC station terminals

Active and Reactive Current at HVDC station terminals

Active power at HVDC station terminals grid side of the converter station transformer and POC

Reactive power at HVDC station terminals grid side of the converter station transformer POC

Success Criteria:

HVDC system provides fault current within the rating of the interconnector converter station with a rise time and settling times as specified in GC CC.7.5.12.4.

4.3.2. Active power recovery

Simulate post fault active power recovery capability of the HVDC installation using the model in Figure 1 with system impedance set to minimum short circuit level. HVDC system operating at both import and export configuration with P=Pmax.

Simulate:

Apply a fault and clear within 500 ms (all four fault types).

Apply a fault and clear at a time longer than 500 ms (all fault types).

Check and report:

Voltage at the HVDC station terminals

Active power from the HVDC station

Reactive power from the HVDC station

Reactive current from the HVDC station

Success Criteria:

Show compliance against GC active power recovery requirements in xyz [current proposals indicate CC.7.5.12.6 but may change!]

4.3.3. Reactive power capability

This simulation needs to be validated against actual compliance tests.

Simulate reactive power capability of the HVDC installation using the model in Figure 1 with system impedance set to minimum short circuit level. HVDC converter station operating at various points as indicated.

HVDC system operating at both import and export configuration.

Simulate:

Run load flow studies with the HVDC system at various points on the VQ/Pmax diagram given in Grid Code CC.7.5.10.(d).

Check and report:

Check that the HVDC system can supply maximum leading and lagging reactive power at Pmax at specified voltage levels in CC.7.5.1.1.(v) [voltage levels will be those that come due to the requirements of Art 18 from the EU code – they are given in Annex III].

Check that the HVDC system can supply maximum leading and lagging reactive power at Pmin at specified voltage levels in CC.7.5.1.1.(v) [voltage levels will be those that come due to the requirements of Art 18 from the EU code – they are given in Annex III].

Check that the HVDC system operating point can move and operate anywhere within the VQ/Pmax diagram when operating at P<Pmax.

Voltage at HVDC converter station and point of connection.

Active power at HVDC converter station and point of connection.

Reactive power at HVDC converter station and point of connection.

Success Criteria:

Simulation shows output within the boundaries of the VQ/Pmax diagrams given in GC CC.7.5.10.(d).

4.3.4. Power oscillations damping control

Power Oscillation Damping (POD) study is conducted to demonstrate performance of the damping control of the HVDC system. POD is normally tuned to specific frequency range of oscillations and the network conditions that lead to these oscillations. It is therefore imperative that the developer initiates an early technical communication channel with EirGrid so that network conditions identified by EirGrid from a dynamic stability assessment that indicate stability limits and potential stability problems can be obtained as the starting point. Although not recommended, an alternative approach would be to perform a survey to identify oscillation conditions on the wider system where the performance of POD control functionality can be demonstrated.

Simulate:

Apply system fault leading to oscillations of electromechanical nature. The time domain simulations should be of sufficient duration in order to identify stabilization (this is particularly the case for oscillations involving frequency variations) – around 60 to 100 seconds.

Time domain studies shall be supported with additional eigenvalue studies in order to demonstrate the oscillation modes and damping performance with and without the POD controller in operation.

An additional time domain simulation is to introduce a change of active power transfer of the HVDC system (level is project specific and should be agreed with EirGrid).

Check and report:

Voltage, frequency, speed, active power flow as applicable at the point (busbar, generator terminals etc) required to demonstrate oscillation mode (local, inter-area etc) and the poorly damped oscillation itself.

Voltage, active and reactive power of HVDC station as appropriate.

Eigenvalues, eigenvectors and the frequency of oscillation with damping values and a classification on whether these are well damped, damped, poorly damped or unstable (especially with regards to POD being in operation or not). Unstable oscillation with the POD in operation will require appropriate tuning of the control system and this shall be agreed between EirGrid and the HVDC system owner.

Check active and reactive power and terminal voltage of the HVDC system during the change of active power simulation.

Success Criteria:

POD function of the HVDC system damps oscillations of the HVDC system (local mode) and/or damps or does not make worse identified network oscillations (inter-area or global).

Change of active power transfer does not lead to undamped oscillations in active or reactive power of the HVDC system.

4.3.5. Active power modification

Simulate active power modification capability of the HVDC installation using the model in Figure 1 with system impedance set to minimum short circuit level. HVDC converter station operating at various points as indicated.

Simulate:

Introduce 10% step change in active power during steady state operation for the following cases:

P=Pmax exporting with export station (connected to EirGrid system if it is providing a connection to a different system) providing DC and AC voltage control and the remote end providing active and reactive power control

P=Pmax importing with import station (connected to EirGrid system if it is providing a connection to a different system) providing active power and AC voltage control and the remote end providing DC voltage control and reactive power control

Repeat the same simulations under different pulse width modulation if that is within the HVDC system functionality.

Check and report:

Voltage at HVDC converter station

Current at HVDC converter station

Active power at HVDC converter station

Reactive power at HVDC converter station

Control signals relating to control settings of the station.

Success Criteria:

Change in active power within given timeframe as defined by EirGrid on site-specific basis as per Gc CC.7.5.8.5.

4.3.6. Fast active power reversal

This study should be based on the conditions leading to the specification of fast active power reversal, for example due to transient stability.

Use a model to represent the system such that it covers the topology leading to the conditions necessitating the provision of fast active power reversal.

HVDC system operating at appropriate import or export configuration leading to the requirement of fast active power reversal.

Simulate:

Apply system fault leading to transient instability (for example this could be a critical fault clearance time issue) with appropriate signals to the HVDC system.

Check and report:

Voltage at HVDC station terminals

Active power at HVDC station terminals

Active power associated with the condition leading to transient stability.

Other signals as appropriate (for example if it is associated with the critical clearance time of a generator, rotor angle plot of the generator can be presented).

Success Criteria:

HVDC system remains connected and stable while meeting the capability requirements in CC.7.5.1.1.(k). [GC clause that specifies the fast active power reversal Art 13-1-c within the specified time limit]

4.3.7. Interaction studies (Art 29 not within simulation study part)

When several HVDC converter stations or other plants and equipment are within close electrical proximity, adverse control interactions may occur. EirGrid may request that a study is performed to demonstrate that no adverse interaction will occur. If adverse interactions are identified, the studies shall identify possible mitigating actions to be implemented to ensure compliance with the requirements of the Grid Code.

The responsibility of these studies rests with the connecting HVDC system owner. All parties relevant to the connection point as identified by EirGrid shall provide relevant data and models as reasonably required to meet the scope of the studies.

The result of the studies shall be assessed by EirGrid and if deemed necessary, additional studies in line with the scope may be requested.

All relevant data and models as part of the interaction study shall be provided to EirGrid such that the studies can be replicated if required.

Any mitigation actions identified by the studies shall be carried out by the HVDC system owner as part of the connection compliance process.

4.3.8. Sub-synchronous torsional interaction studies (Art 31 not within simulation study part)

It is required that HVDC system shall not cause subsynchronous torsional interaction and that shall be capable of contributing to electrical damping of torsional frequencies.

Simulation studies confirming the damping characteristics of the HVDC system with regards to SSTI shall be submitted by the HVDC system owner. All parties relevant to the connection point as identified by EirGrid shall provide relevant data and models as reasonably required to meet the scope of the studies.

The result of the studies shall be assessed by EirGrid and if deemed necessary, additional studies in line with the scope may be requested.

All relevant data and models as part of the interaction study shall be provided to EirGrid such that the studies can be replicated if required.

Any mitigation actions identified by the studies shall be carried out by the HVDC system owner as part of the connection compliance process.

APPENDIX A: PRINCIPLES FOR SIMULATION COMPLIANCE EVALUATION AND INTERPRETATION OF GRID CODE FAULT RIDE THROUGH CLAUSES

Background:

This note summarizes the Eirgrid position in relation to simulation and compliance of Power Park Modules (PPMs), and how certain clauses within the Grid Code should be interpreted. This note is the result of several years of discussions between Eirgrid and the Irish wind industry, trying to resolve some ambiguities encountered in the simulation and testing of the performance of windfarms, that grew out of changes made to the Grid Code by the DS3 project. There are two parts to the note: the first part sets out some guiding principles Eirgrid will use in assessing Fault Ride-Through reports submitted by users; and the second part attempts to clarify the intention and meaning of PPM1.4.2 (c) in the Ireland Grid Code.

High-Level Principles:

1. PPMs such as windfarms and solar farms generally operate in two distinct modes – normal operation, and fault-ride through mode. In normal operation, the TSO is chiefly concerned with the PPMs behaviour and characteristics at the HV connection point, such as P-Q capability, voltage control modes, ramping behaviour, and frequency response. During faults, the behaviour of the PPM is typically delegated to the individual PPM units, such as individual wind turbines or solar modules. However the TSO does not have visibility down to the individual module level at present, and so performance monitoring of PPMs is done at the connection point. From a simulation and model compliance viewpoint, performance assessment should take into account behaviour at this lower voltage level as well as at the connection point in order to capture the effects of depressed voltages on cables and transformers and obtain a more holistic view of the PPM FRT response.
2. While PPMs are expected to ride through a variety of different fault types and durations, very short faults (less than or equal to 150ms) can be difficult to assess, as a steady-state may not be reached within such a short time frame. Accordingly, very short faults will be assessed to confirm overall stability and direction of response, but not in a strictly quantitative way.
3. The Grid Code PPM1.4.2(c) states that the reactive current shall be supplied within the rating of the PPM. By extension, this means that the maximum expected current at the connection point should not exceed the current at full power output and 0.95 power factor. Similarly, at the PPM module level, the current from an individual module is not expected to exceed the value when operating at maximum power output and 0.95 power factor at the connection point. We note that the DS3 System Service products incentivise performance in excess of the Grid Code requirements to help achieve high levels of non-synchronous generation, and so depending on the DS3 product

definitions, reactive currents in excess of the Grid Code requirement could be warranted for those services, but that assessment is separate from the normal Grid Code assessment.

4. The reactive current during a fault should be greater than zero as measured at the PPM element terminals irrespective of pre-fault reactive current value. We understand that other jurisdictions have different requirements but we have not seen stability issues in Ireland related to this requirement. If stability issues are experienced in reality, the Grid Code empowers the TSO to reduce the magnitude of the response from the PPM, in discussions with the PPM owner.
5. The Rise Time and Settling Time requirements are to be assessed by applying a step-change to 50% retained voltage at the PPM connection point in the simulation, and plotting the reactive current, reactive power, and voltage at the PPM element terminals, and also the reactive current, reactive power, and voltage at the connection point. It is assumed by the TSO that the gains and time constants in the PPM control systems do not change depending on the fault. If this is not the case, the OEM or PPM must inform the TSO so that a wider suite of simulations are carried out.
6. In assessing the simulated reactive current response, a tolerance of +/-10% of the maximum reactive current as measured at the connection point, will be allowed. Thus if the maximum current for a PPM is 1kA (reactive), the tolerance will be +/-100A. If 500A was the expected response, a value between 400-600A will be deemed acceptable. Ultimately, the response of the model should accurately represent the behaviour of the physical unit under fault conditions. Deviations outside the tolerance band will need to be explained and discussed with the TSO.
7. Once the voltage has recovered above 0.9pu, the PPM has 500ms to switch back into normal operation (pre-fault control mode, and pre-fault reactive setpoint). It then has a further 1 second to achieve those values based on PPM 1.6.2.4. The voltage droop should take into account the fact that the transmission voltage may be different to what it was before the fault. We do not necessarily expect the PPM to go back to the pre-fault MVAr value if system conditions have changed.
8. Accurate dynamic models are of utmost importance to the TSO for both system operations and planning. Every device or PPM that connects to the grid should have an appropriate dynamic model. As TSO we expect (and require through the Grid Code) that developers will supply us with models that are good enough for carrying out transient simulations, and these should be in the form of standard PSSE/WECC 2nd Generation models and DigSilent PowerFactory models, or customised models with supporting documentation and Laplace diagrams. In summary, if the developer is able to produce simulations to allow us to assess compliance, then they should also be in a position to provide the TSO with the models used to carry out those simulations, so that the TSO can carry out its own functions. We also now seek EMT models for PPMs to help us manage the power system as the proportion of power electronic converter based devices increases significantly. These may be supplied as “Black Box” models within PSCAD.

Clarification and Interpretation of Grid Code FRT Requirement PPM1.4.2(c):

"During and after faults, priority shall always be given to the **Active Power** response as defined in PPM1.4.2(a) and PPM1.4.2(b)."

The PPM should give active power in proportion to retained voltage, and this is always the priority to mitigate against a potential large deficit of MW that could occur if a cluster of PPMs were all affected by the same transmission fault and were prioritising reactive power. From the power relationship, P = V x I , it is understood that active current should remain constant during the fault. If angular instability is detected in reality due to weak network conditions, the PPM should do what it can to remain connected, including reducing active power. This should not occur in the FRT simulation as a rule, as the expected minimum strength will have been provided by the TSO, and the PPM should be capable of handling the faults described in the Grid Code at the minimum specified system strength.

"The reactive current response of the **Controllable PPM** shall attempt to control the **Voltage** back towards the nominal **Voltage**, and should be at least proportional to the **Voltage Dip**."

This means that the reactive current should be in a direction such as to tend to increase the voltage – the PPM should not be absorbing reactive power during a fault as a rule, although there may be particular cases where the reactive power at the connection point is effectively zero despite the best efforts of the individual PPM modules.

All other things being equal, a voltage dip by 0.5pu should elicit a reactive current response approximately twice that of a dip of 0.25pu. In other words, the reactive current response should be proportionate – it should depend on the severity of the fault. However, the available reactive current will also depend on the pre-fault MW output of the PPM. The following diagram illustrates the general principle, where the reactive current should ideally be on or close to the diagonal line, with more severe faults eliciting larger reactive responses from the PPM. Some examples are given of compliant and incompliant responses. Note the diagrams are assuming that the available reactive current is constant across the different voltage dips – this may not necessarily be true in reality.

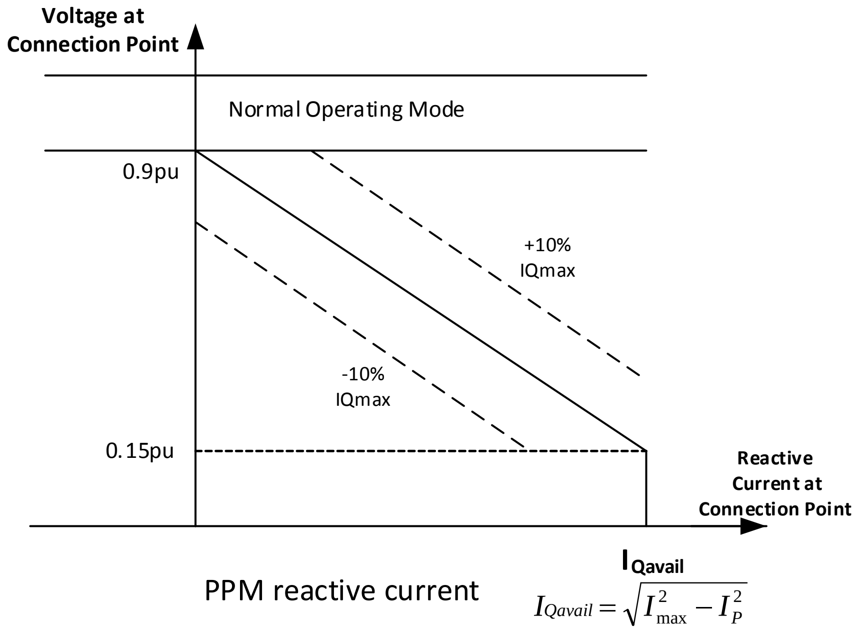


Figure A.1: Guideline on how much reactive current response a PPM should give, assuming I_{Qavail} is the same for each fault, and assuming the fault is long enough for a steady-state to be reached

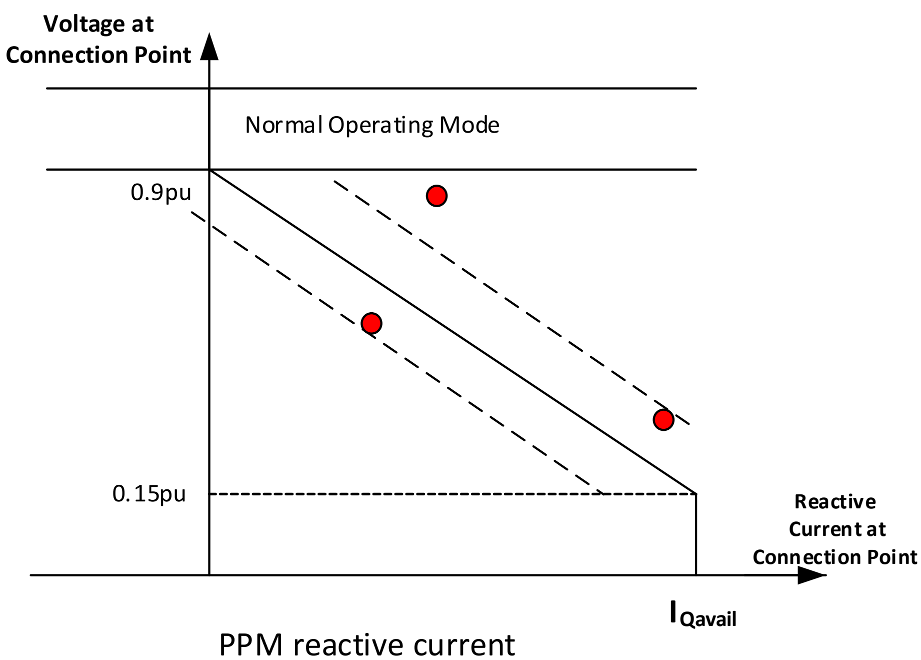
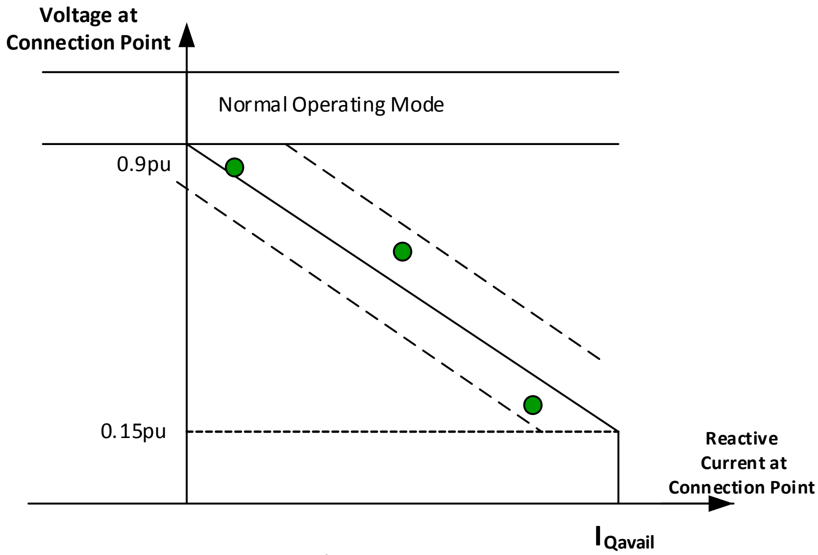


Figure A.2: Incompliant response example – reactive current is not proportional to voltage dip; Upper point shows too large a response for a slight voltage dip, and the middle voltage dip point has less of a reactive response than the upper point.



PPM reactive current

Figure A.3: Compliant response example - reactive current increases as voltage dip worsens

I_{Qavail} is the available reactive current (the active current being prioritized), with I_{max} being the total maximum current based on the rating of the PPM or on the prevailing wind/solar conditions at the time of the fault. A voltage dip to 0.15pu elicits the maximum reactive response, and allowance is given for over and under provision (see principles above). The TSO expects that the control systems of the PPM would consider the difference between the nominal voltage and the fault voltage and provide a type of fast-acting proportional response, although it is up to the PPM on how they actually implement this. Under PPM1.4.2(e), the TSO can seek to change the slope of the line to elicit a smaller reactive response if it is found that the reactive response is too great.
Note that for unbalanced faults, the response should be determined with respect to the positive sequence voltage, but within the technical limits of the plant.

"The reactive current response shall be supplied within the rating of the **Controllable PPM**, with a **Rise Time** no greater than 100ms and a **Settling Time** no greater than 300ms."
As stated above, the normal maximum current within the rating of the PPM is the current at the connection point when the PPM is operating at maximum MW output and 0.95 power factor, and this current will consist of a real and a reactive component. The magnitude of the reactive component will depend on the severity of the fault and the available reactive current. The rise time and settling time are defined terms, but these can only be accurately assessed for long duration faults or application of a step-change to the PPM controller.

"For the avoidance of doubt, the **Controllable PPM** may provide this reactive response directly from individual **Generation Units**, or other additional dynamic reactive devices on the site, or a combination of both."
Some PPMs have installed statcoms, and these may be used to provide some of the necessary reactive current during a fault in addition to the reactive current from the individual generation units (Wind Turbines / Solar Modules etc.)