Fault Ride-Through Study Template and Assessment Guide

Version 2.1 - 12 May 2022

EIRGRID

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Revision History

Ver.	Date	Notes	Prepared by Checked by Approved by
1.1	Aug. 2017	Previous version.	Marta Val Escudero - -
2.0	14 Feb. 2022	Major update, new document structure with detailed descriptions.	Kahraman Yumak Alan Rogers Robbie Aherne
2.1	12 May 2022	Minor updates: • Section 1.2: Note added on 5 MW limit for PPMs and SPGMs. • Section 2.3.4: Background info added on prioritisation of active power. • Section 2.3.5: Figures for reactive current responses are updated. • Section 2.3.11: Section added on assessment of faults with short durations. • Sections 4.3.1, 4.3.2, 4.4.1, 4.4.2, 4.4.3: Cases with 140ms fault duration are added for PPMs. • Appendix B: Sample for the MSS data report is updated.	Kahraman Yumak Oisin Goulding Robbie Aherne

For any questions on this document, contact ped[at]eirgrid.com.

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Acronyms

BESS	Battery Energy Storage System
CP	Connection Point
CRU	Commission for Utility Regulation
DC	Distribution Code
DSO	Distribution System Operator
ESBN	Electricity Supply Board Networks
ESPS	Energy Storage Power Station
FRT	Fault Ride Through
GC	Grid Code
HV	High Voltage
HVDC	High Voltage Direct Current
LV	Low Voltage
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MSS	Minimum System Strength
MV	Medium Voltage
PPM	Power Park Module
pu	per unit
RfG	Requirements for Generators
RMS	Root Mean Square
SLD	Single-Line Diagram
SPGM	Synchronous Power Generating Module
TSO	Transmission System Operator
WEC	Wind Energy Converter

Include any additional acronyms used in the report.

Table 1 - Demarcation of Requirements

Symbol	Applicable To
○	RfG Generation Units
~~○~~	Non-RfG Generation Units

1. Introduction

Fault Ride-Through (FRT) is basically defined as the ability of a generating unit to stay synchronised to the electrical grid during and following a fault disturbance. With the increasing level of inverter-based generation, the power system dynamics are also changing due to the decreasing governor response and less synchronous inertia while creating a negative impact on frequency and voltage stability of the grid. Thus, the FRT requirements are of increasing importance - generators should remain connected during a disturbance and also provide support to the system to help maintain overall stability.

This document is intended to provide a report template and a guideline for the content and scope of the technical studies required to demonstrate compliance with the FRT requirements defined in the EirGrid Grid Code and ESB Networks Distribution Code.

This document includes references to the current version of the Grid Code at the time of writing. For connections to the distribution system, the customer is requested to replace all Grid Code references and clauses with the relevant Distribution Code version and clauses. Detailed information on the Grid Code and the Distribution Code is given in the next section. In any case of discrepancy between this document and the latest Grid Code version, the latest Grid Code version applies.

The numerical values and technical data given within this document (except explicitly stated to be used in the studies) are for illustration purposes only.

The general requirements for simulation and modelling studies are outlined in the document “Simulation Studies and Modelling Requirements for Compliance Demonstration”. The customer should be aware and comply with these requirements. Check the most up-to-date version of this document in [1]. Active version at the time of writing is accessible in [2] and the FRT related sections will be updated in reference to this template.

Note that the FRT assessment should be done based on the up-to-date controller settings of the facility. If any controller parameter is modified during the preparation of the FRT report, then the FRT assessment and the simulation models should be updated accordingly. If any controller parameter is modified after the FRT report submission, i.e. during or after the Grid Code Compliance tests, then contact EirGrid with the updated parameters and discuss if there is a material change in the settings that would significantly alter the FRT performance. Based on the impacts of the changes, the FRT study could need to be updated, but in general EirGrid does not expect more than one FRT study.

1.1. Description of the Sections

In each section, technical requirements are defined while providing a background or discussion on the specific subjects. It is suggested to follow the approach presented in this document including heading structure, table formats and plots for an effective review of the FRT study submissions.

The sections are briefly described below:

- In the first section, the timeline and the submission requirements for the FRT study are given. Also, the expected introduction section in the customer FRT report is described.
- In the second section, the relevant Grid Code and Distribution Code clauses are listed to be used as a reference during FRT studies. Also, clarifications on the Grid Code requirements are provided. For the completeness of the report, customers are requested to include all FRT-related clauses for the particular type of generation units under consideration.
- In the third section, the dynamic model of the facility is described. Customers are requested to provide all relevant information mentioned in this section.
- In the fourth section, the FRT analysis procedure and the simulation parameters are defined. The fault parameters for each type of generation units for TSO and DSO customers are presented in separate subsections. The corresponding fault parameters and case scenarios are given.
- In the fifth section, the requirements for the simulation outputs are shared. The parameters and plots needed for submission are described.
- In the conclusions section, a template summary table is given to be used in the customer reports. In case of non-compliances, potential mitigation methods and proposals should be discussed in this section.
- In the appendices, a sample Minimum System Strength (MSS) data at the connection point for the modelling of external grid is shared. Also, a checklist for the submission of the FRT study is introduced.

1.2. Overview of the FRT Requirements

All the TSO generation customers are requested to submit an FRT study to EirGrid. For the DSO generation customers, it depends on the voltage level of the Connection Point (CP) and Registered Capacity of the facility as given in the table below.

The FRT assessments must be based on the Minimum System Strength (MSS) data issued to the customers for the purpose of modelling the transmission and distribution network in the simulation studies.

Table 2 - Customers Required Submitting an FRT Study

Customer Type	Registered Capacity
TSO Generation Customers	All Customers
DSO Generation Customers	• for CP ≥ 110 kV: All Customers • for CP < 110 kV: Reg. Cap. ≥ 5 MW*

* EirGrid doesn't require an FRT study from the DSO customers < 5MW for CP < 110 kV. These customers shall contact ESB on the FRT study requirements.

The 5 MW limit:

- For PPMs : It is the total capacity at the connection point of the facility.
- For SPGMs : It is the capacity of the synchronous machine alone.

The indicative timeline for the FRT related submissions is given in the table below:

Table 3 - Indicative Timeline for FRT Study Submissions

Item	Timeline	Responsible	Submit to
MSS Data	at least 18 months before scheduled energisation of the plant*	EirGrid or ESBN	Customers
FRT Study Submission	at least 12 months before scheduled energisation of the plant	Customers	EirGrid
Review of Customer Submissions	within 2 weeks after customer submission	EirGrid	Customers
Response to EirGrid Comments	within 2 weeks after receiving comments	Customers	EirGrid

* If needed, it is possible to provide early insight on the MSS data before the given timeline. Note that it won't be the final version of the MSS data and will be updated in due course.

EirGrid makes every effort to complete the review process and provide Comment Log to customers within 2 weeks. In the same way, customers are requested to provide their responses within 2 weeks to avoid any delay in the energisation of the plants.

All the following reports/documents and data should be submitted by the customers separately to EirGrid following the timeline given above in relation to the FRT assessment studies:

Table 4 - FRT Study Submission Requirements

#	Report/Document/Data
1	Customer self-assessment FRT Report
2	Single-line diagram of the facility
3	Facility FRT dynamic modelling files
4	Validation report for the FRT dynamic model
5	Documents used as reference in the FRT study
6	Other supporting documents, if needed

More information for offshore connections will be provided in the future versions of this document. Contact EirGrid for any questions on the offshore FRT studies, if needed.

1.2.1. Customer Self-Assessment FRT Report

For an effective review process, use this template heading structure for the preparation of the customer self-assessment FRT report. Use the tables given in this template to share all required information in the corresponding sections. Refer to the provided figures for illustration needs.

1.2.2. Single-Line Diagram

Provide a legible detailed SLD in a separate file presenting at least the following information for all units, transformers and internal collector network in the facility.

- Units: Model/type, rating
- Transformers: Model/type, rating, voltage ratio, vector group
- Collector Network: Cable type, length
- Other Equipment (STATCOM, harmonic filters, capacitor banks, etc.): Rating and characteristic parameters
- Busbars: Voltage level

1.2.3. Facility FRT Dynamic Modelling Files

At the time of writing, the dynamic simulation model submitted to EirGrid needs to be compatible with PSS/E Version 34.5 format.

In principle, EirGrid has no objection to conduct FRT studies in any software which is capable of running dynamic analysis. However, in practice, EirGrid needs models that run in the platform it uses for internal studies such as modelling of the entire electricity network. Historically, in EirGrid, the transmission network has been developed in PSS/E and planning studies have been carried out using this software. Therefore, if software other than PSS/E is used for FRT analysis, then an equivalent PSS/E dynamic model (and accompanying files) of the facility is still required to be submitted. Further, a comparison report showing the equivalence between the different software and the PSS/E dynamic model is needed. This comparison report should be specific to the facility reflecting site settings including generators, controllers, internal equipment and the transmission network at the connection point. The software selection for FRT studies is left to up to the customer under these conditions.

No special settings other than standard software setting should be required for the submitted model to be implemented.

The following PSS/E modelling files developed for FRT analysis must be provided separately at the time of report submission.

- Saved case file with all facility data including sequence impedances (.sav)
- Raw and sequence files used to create the saved case (.raw, and .seq)

  Note: Raw and sequence files are requested for future studies in EirGrid in case of different software versions need to be used.

- Dynamics model data file (.dyr)
- All dynamic model library files (.dll)
- Slider file (.sld)

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. The information relating to the mechanical mass model can be submitted in written data form rather than in a model. Specific information required is:

- Inertia constants
- Spring and damping constants
- Torque shear stress
- Natural oscillation frequencies

1.2.4. Validation Report for the FRT Dynamic Model

The FRT dynamic model plays an important role in the offline analysis of the transmission network. Before the energisation of the facility, a validation report is required for the libraries used in the FRT dynamic model.

This report can consist of factory and/or type tests to validate the responses of the dynamic model components developed for the FRT analysis.

The validation should be done by comparing simulation outputs of the library models against factory FRT test measurements from a reference generation unit using a variety of different fault durations and retained voltage levels. There is no specific requirement on the selection of the disturbance parameters. The only intention of the validation study is to see the capability levels of the dynamic models on simulating the actual responses of the generation units.

1.2.5. Equipment Technical Documents

Provide manufacturer documentation on the key technical specifications of the generation units, transformers and cables. Address the documents in References [3].

1.2.6. Derogation Application

If a generation unit cannot comply with a rule or clause in the Grid Code, a derogation application might be needed.

During the FRT study review process, EirGrid will inform customers if a derogation application is required related to the FRT capability of the connecting units.

A detailed analysis on the reason of non-compliance and potential mitigation solutions to become compliant with additional cost estimations should be provided. EirGrid will review and assess the derogation application.

Following this review, EirGrid will either recommend approval or rejection of the derogation to the Commission for Utility Regulation (CUR) based on the analysis provided by the customer.

1.3. Customer Report Introduction

In the introduction section, provide the introductory information for the facility and the FRT study as shown in the following tables.

Table 5 - Facility Data

Project Number	CP/TG/DG number
Name of the Facility	Facility name
Connection Type	Wind/Solar/Battery/Conventional
Customer Type	TSO (or DSO) customer
Location	Address of the facility under study
Owner of the Facility	Company name

Table 6 - FRT Study Data

FRT Study Prepared by	Consultant company name
Grid/Distribution Code	Version number, date
Software Used	Software name and version

Provide a high-level description of the facility as presented in the table below.

Table 7 - Facility Technical Data

Connecting Station	Station name
CP Voltage	Voltage [kV]
MEC & MIC	MEC [MW] & MIC [MVA]
Generators	# of units, size [kVA], model/type
Grid Transformer	HV/MV [kV], size [MVA]
Generation Unit Transformers	MV/LV [kV], size [kVA]
Other Devices (if any)	Harmonic filters, capacitor banks, etc.

Also include a simplified single-line diagram (SLD) at least with the data given in the figure below showing the facility as represented in the dynamic model.

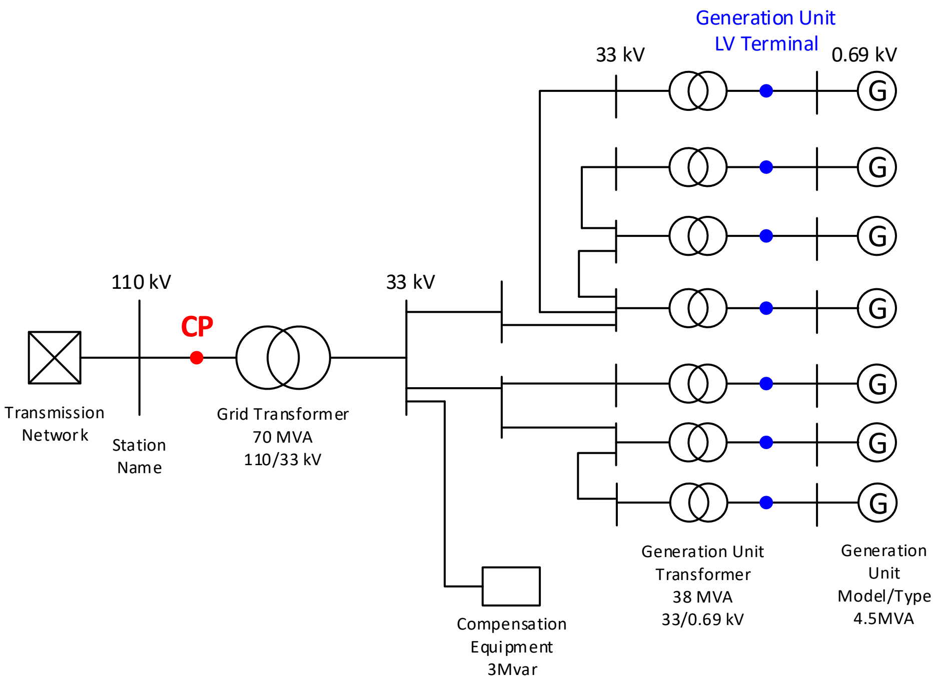


Figure 1 - Sample for the Simplified Representation of the Facility

2. Grid Code Requirements

For completeness of the study, quote all FRT-related clauses from the most up-to-date Grid Code (or Distribution Code for distribution level connections) depending on the unit type of the facility under study.

The facility could consist of Power Park Modules (PPM) or Synchronous Power Generating Modules (SPGM) or it could be an Interconnector, i.e. High Voltage Direct Current (HVDC) connection.

In the Grid Code, a PPM is defined as a generation unit or ensemble of generation units generating electricity which is connected to the network non-synchronously or through power electronics, and has a single connection point onshore to a transmission system, distribution system, or HVDC system.

Note that Battery Energy Storage Power Stations (ESPS) can also be called Battery Energy Storage Systems (BESS) and are classified as PPMs.

The relevant clauses in the current version of the codes at the time of preparation of this document are shown in the table below.

- The EirGrid Grid Code: Version 10, 15/12/2021 [4].
- The ESB Networks Distribution Code: Version 7, 06/08/2020 [5].
- ENTSO-E Commission Regulation (EU):
  - Network Code 2016/631 - Requirements for Generators, 14/04/2016 [6].
  - Network Code 2016/1447 - HVDC Connections, 26/08/2016 [7].

Table 8 - Relevant Code Articles

Connection Type	EirGrid Grid Code	ESB Networks Distribution Code	EU Network Code
Power Park Modules (PPM)	PPM1.4	DCC11.2	2016/631 Articles: 26(2), 54(4), 55(1), 56(3)
Synchronous Power Generating Modules (SPGM)	CC.7.3.1.1(h) CC.7.3.1.1(y)	DCC12.1	2016/631 Articles: 51(3), 52(1), 53(3)
Interconnectors	CC.7.5.1.1(g)	-	2016/1447 Article: 73(3)

2.1. RfG and Non-RfG Generation Units

The clauses in the Grid Code based on the ENTSO-E notions of RfG (Requirements for Generators) or Non-RfG Generation Units should be considered for the FRT analysis. The RfG and Non-RfG Generation Units are described in the Grid Code as follows:

1. **RfG Generation Unit:**

   Indicated with the symbol of $\boxed{\bigcirc}$. A Generation Unit that is <u>not</u> a Non-RfG Generation Unit.

2. **Non-RfG Generation Unit:**

   Indicated with the symbol of $\boxed{\ominus}$. A Generation Unit with a signed Connection Agreement:

   a) Connected to the Network on or before the 30th November 2018; or

   b) Whose owner has concluded a final and binding contract for the purchase of the main Plant on or before the 30th November 2018 and provides evidence of same, as acknowledged by the TSO, on or before the 31st May 2019. Such evidence shall at least contain the contract title, its date of signature and date of entry into force, and the specifications of the main Plant to be constructed, assembled, or purchased; or

   c) Is one of the exceptions to the applicability of the RfG Generation Unit requirements and is a Generation Unit as follows:

      (i) Installed to provide back-up power and operate in parallel with the Network for less than five minutes per calendar month while the system is in normal system state; or

      (ii) No permanent Connection Point and is used by the TSO to temporarily provide power when normal system capacity is partly or completely unavailable; or

      (iii) Energy Storage Units except for Pumped Storage Plant.

   A Non-RfG Generation Unit that undergoes modernisation, refurbishment or replacement of equipment which drives a modification to its Connection Agreement, and had concluded a final and binding contract for the purchase of the Plant being modified after the 30th November 2018 will be deemed an RfG Generation Unit, unless the Plant being modified is one of the exceptions listed in c) above.

2.2. Grid Code Clauses

For the completeness of this document, the Grid Code clauses pursuant to Fault Ride-Through requirements are listed in this section. For the sake of brevity, the Distribution Code clauses are not given. Check up-to-date versions of the Grid Code and the Distribution Code before working on the FRT analysis of the facilities. Also note that the symbols with circles given with the clause numbers are for RfG and Non-RfG representations of the requirements.

2.2.1. Power Park Modules

PPM1.4.1 A **Controllable PPM** shall remain connected to the **Transmission System** for **Transmission System Voltage Dips** on any or all phases, and shall remain **Stable**, where the **Transmission System Phase Voltage** measured at the HV terminals of the **Grid Connected Transformer** remains above the heavy black line in *Figure PPM 1.1*.

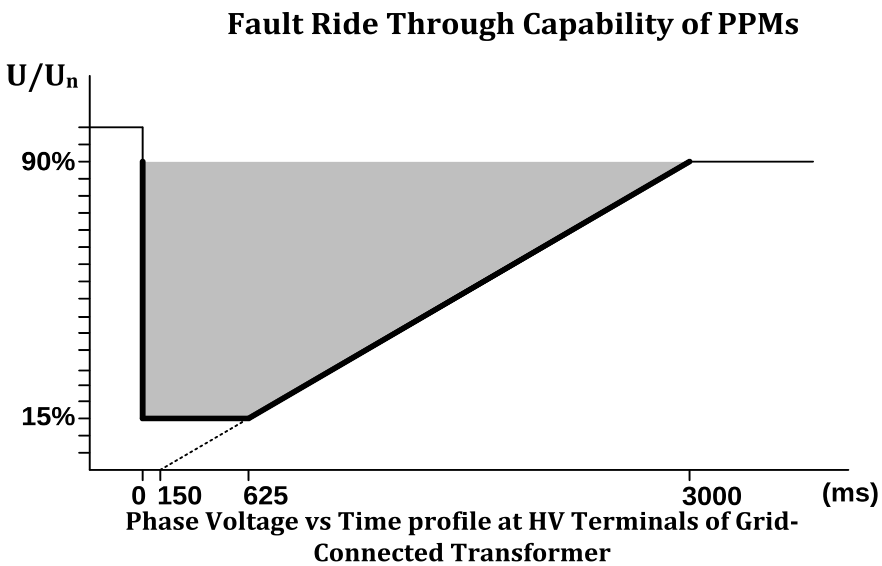


*Figure PPM 1.1 - **Fault Ride-Through** Capability of **Controllable PPMs***

PPM1.4.2 In addition to remaining connected to the **Transmission System**, the **Controllable PPM** shall have the technical capability to provide the following functions:

(a) During **Transmission System Voltage Dips,** the **Controllable PPM** shall provide **Active Power** in proportion to retained **Voltage** and provide reactive current to the **Transmission System**, as set out in PPM1.4.2(c)**.**

⊜	The provision of reactive current shall continue until the **Transmission System Voltage** recovers to within the normal operational range of the **Transmission System** as specified in CC.8.3.1, or for at least 500 ms, whichever is the sooner.

○	The provision of reactive current shall continue until the **Transmission System Voltage** recovers to within the normal operational range of the **Transmission System** as specified in CC.7.3.1.1 (x), or for at least 500 ms, whichever is the sooner.

The **Controllable PPM** may use all or any available reactive sources, including installed statcoms or SVCs, when providing reactive support during **Transmission System Fault Disturbances** which result in **Voltage Dips**.

(b) The **Controllable PPM** shall provide at least 90 % of its maximum **Available Active Power** or **Active Power Set-point**, whichever is lesser, as quickly as the technology allows and in any event within 500 ms of the **Transmission System Voltage** recovering to 90% of nominal **Voltage**, for **Fault Disturbances** cleared within 140 ms. For longer duration **Fault Disturbances**, the **Controllable PPM** shall provide at least 90% of its maximum **Available Active Power** or **Active Power Set-point**, whichever is lesser, within 1 second of the **Transmission System Voltage** recovering to 90% of the nominal **Voltage**.

(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 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**. 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. 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.

(d) The **Controllable PPM** shall be capable of providing its transient reactive response irrespective of the reactive control mode in which it was operating at the time of the **Transmission System Voltage Dip**.

~~○~~	The **Controllable PPM** shall revert to its pre-fault reactive control mode and setpoint within 500ms of the **Transmission System Voltage** recovering to its normal operating range as specified in CC.8.3.1.

○	The **Controllable PPM** shall revert to its pre-fault reactive control mode and setpoint within 500ms of the **Transmission System Voltage** recovering to its normal operating range as specified in CC.7.3.1.1 (x).

(e) The **TSO** may seek to reduce the magnitude of the dynamic reactive response of the **Controllable PPM** if it is found to cause over-voltages on the **Transmission System**. In such a case, the **TSO** will make a formal request to the **Controllable PPM**. The **Controllable PPM** and the **TSO** shall agree on the required changes, and the **Controllable PPM** shall formally confirm that any requested changes have been implemented within 120 days of received the **TSO's** formal request.

○	(f) **Controllable PPMs** connected to the **Transmission System** shall be capable of staying connected to the **Transmission System** and continuing to operate stably during **Voltage Dips**. The voltage-against-time profile specifies the required capability for the minimum voltage and **Fault Ride-Through Time** at the **Connection Point** before, during and after the **Voltage Dip**. That capability shall be in accordance with the voltage-against-time profile as specified in Figure PPM1.4.2.

○

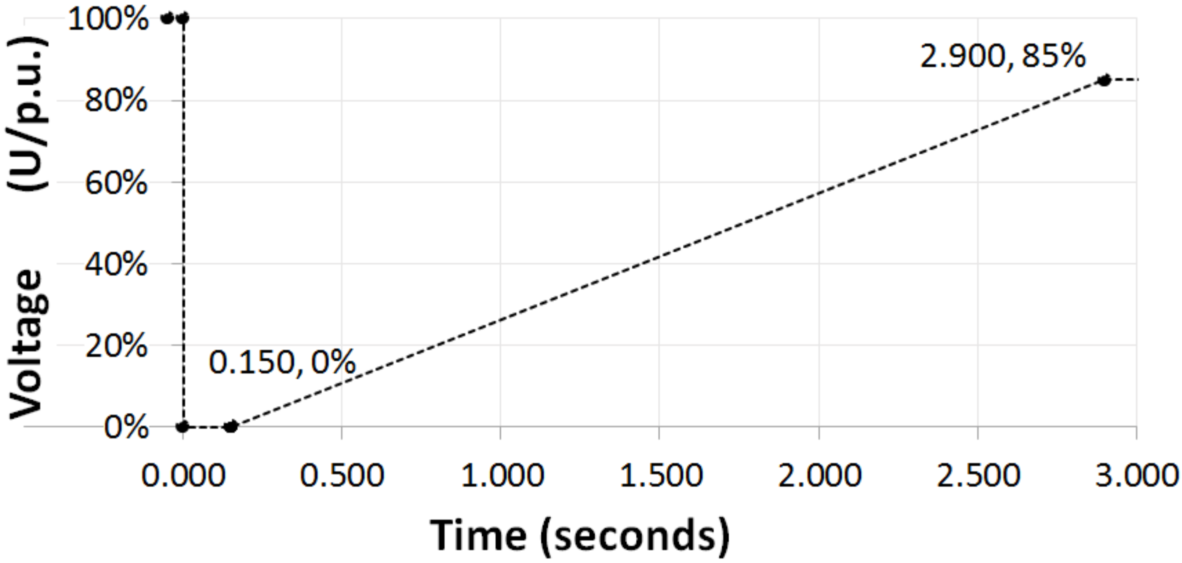


Figure PPM1.4.2: Voltage-against-time profile at the connection point for fault conditions

The **TSO** specifies the pre-fault and post-fault conditions for the fault-ride-through capability on a case-by-case base, and where requested by the **Controllable PPM**. The specified pre-fault and post-fault conditions for the fault-ride-through capability will be made publicly available. This includes;

(i) the calculation of the pre-fault minimum short circuit capacity at the **Connection Point** (MVA);

(ii) pre-fault active and reactive power operating point of the **Controllable PPM** at the **Connection Point** and voltage at the **Connection Point**; and

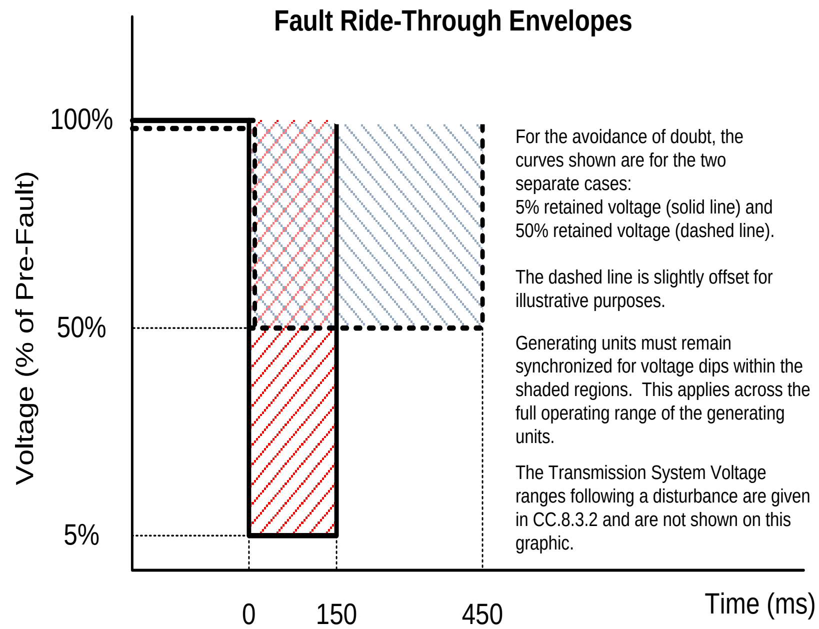
(iii) calculation of the post-fault minimum short circuit capacity at the **Connection Point** (MVA).

2.2.2. Synchronous Power Generating Modules

CC.7.3.1.1 Each **Generation Unit,** shall, as a minimum, have the following capabilities:

(h) remain synchronised during and following any **Fault Disturbance** anywhere on the **Power System** which could result **in Voltage** dips at the **HV** terminals of the **Generator Transformer** of no greater than 95% of nominal **Voltage** (5% retained) for fault durations up to and including the **Fault Ride-Through Times** as defined in the table below and **Voltage** dips of no greater than 50% of nominal **Voltage** (i.e. 50% retained) for fault durations up to and including the **Fault Ride-Through Times** as defined in the table below (see also **Fault Ride-Through** Envelopes below). Following the fault clearance the **Generation Unit** should return to prefault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response. The use of **Extraordinary Governor Response** and/or **Extraordinary AVR Response** to remain synchronised during and following a fault is prohibited unless specifically agreed with the **TSO**, such agreement not be unreasonably withheld.

VOLTAGE DIP MAGNITUDE	Fault Ride-Through Times		
	400 kV System	**220 kV System**	**110 kV System**
95% (5% retained)	150 ms	150 ms	150 ms
50% (50% retained)	450 ms	450 ms	450 ms



○

(y) Remain synchronised to the **Transmission System** and continue to operate stably during and following any **Fault Disturbance** anywhere on the **Power System** which could result in **Voltage Dips** at the **Connection Point**. The voltage-against-time profile specifies the required capability as a function of voltage and **Fault Ride-Through Time** at the **Connection Point** before, during and after the **Fault Disturbance**. That capability shall be in accordance with the voltage-against-time profile as specified in *Figure* CC.7.3.1.1.*y.*

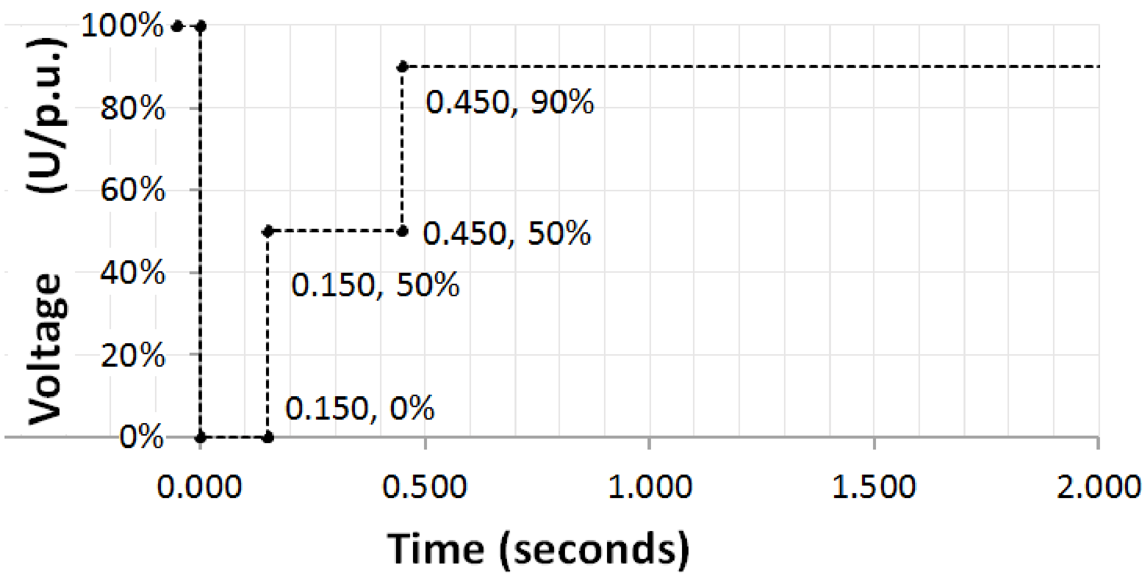


Figure CC.7.3.1.1.*y: Voltage-against-time profile at the connection point for fault conditions*

Following the fault clearance the **Generation Unit** should return to prefault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response. The use of **Extraordinary Governor Response** and/o**r Extraordinary AVR Response** to remain synchronised during and following a fault is prohibited unless specifically agreed with the **TSO**, such agreement not be unreasonably withheld.

2.2.3. Interconnectors

CC.7.5.1.1 Each Interconnector, shall have the following minimum capabilities, for the avoidance of doubt, additional performance capabilities are required from OC.4 System Services:

(g) remain connected during and following **Voltage** dips at the **HV** terminals of the **Interconnector Transformer** of 95% of nominal **Voltage** (5% retained) for duration 0.2 seconds and **Voltage** dips of 50% of nominal **Voltage** (i.e. 50% retained) for duration of 0.6 seconds. Following the fault clearance the **Interconnector** should return to prefault conditions subject to normal **Frequency Response** and **Voltage Regulation**;

2.3. Clarifications on Grid Code Requirements

This section summarizes the EirGrid position in relation to simulation and compliance of the generation units, and how certain FRT clauses within the Grid Code should be interpreted.

The FRT clauses for SPGM and HVDC connections basically set out the following requirements:

- The facility under consideration should remain synchronised (for SPGM) or connected (for HVDC) during and following voltage dips at the connection point.
- Following the fault clearance, the facility should return to its pre-fault conditions subject to;
  - For SPGM: its normal governor control system and automatic voltage regulator response.
  - For HVDC: its frequency response and voltage regulation.
- For SPGM: capable of disconnecting automatically from the transmission system to help preserve system security or to prevent damage to the generation unit.

Therefore, in this section, the grid code clauses for PPM connections are considered in detail. Also, example plots are shared to show compliant and non-compliant cases for several FRT grid code clauses. These examples are intended to help the customer in evaluating their own self-assessment report, and are for demonstration purposes only.

2.3.1. Active Power Proportionality

Grid Code PPM 1.4.2 (a): During Transmission System Voltage Dips, the Controllable PPM shall provide Active Power in proportion to retained Voltage.

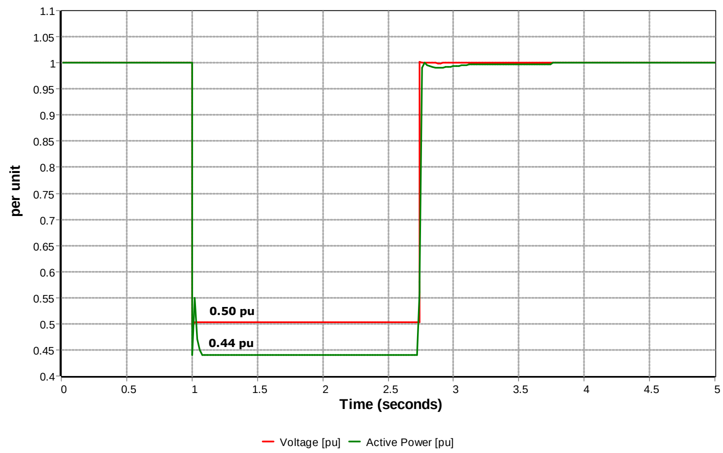
When priority during FRT event is given to active power, then PPM units are expected to provide active power output in proportion to the retained voltage at the connection point. This means that ‘the decrease in the active power’ response should not be larger than ‘the decrease in the voltage’ during disturbance duration. A tolerance value of ±5% of MEC will be allowed during assessment. For instance, if the retained voltage is 50%, then active power during FRT event should be in between 45% and 55% of pre-disturbance active power level (MEC), while supporting network during the FRT event.

See the example below for compliant and incompliant responses:

(a) Non-Compliant: Active power drop is not proportional to voltage drop (it drops more than the voltage and ±5% tolerance level).

(b) Compliant: Active power drop is proportional to voltage drop level (within ±5% tolerance)

(a)



(b)

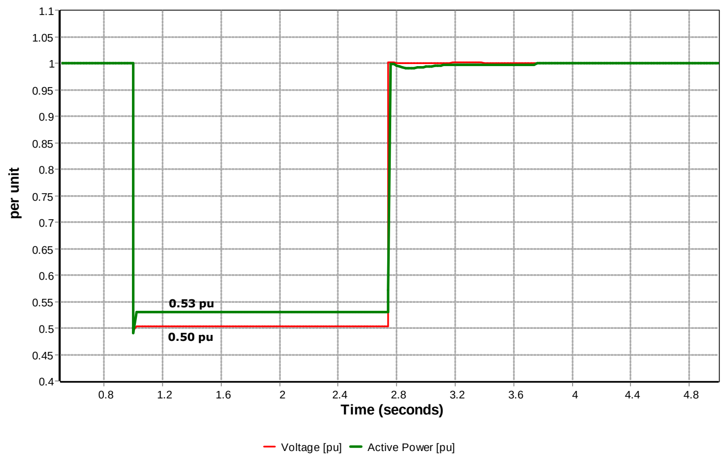


Figure 2 - Active Power Proportionality

(a) Non-Compliant (b) Compliant

2.3.2. Provision of Reactive Current

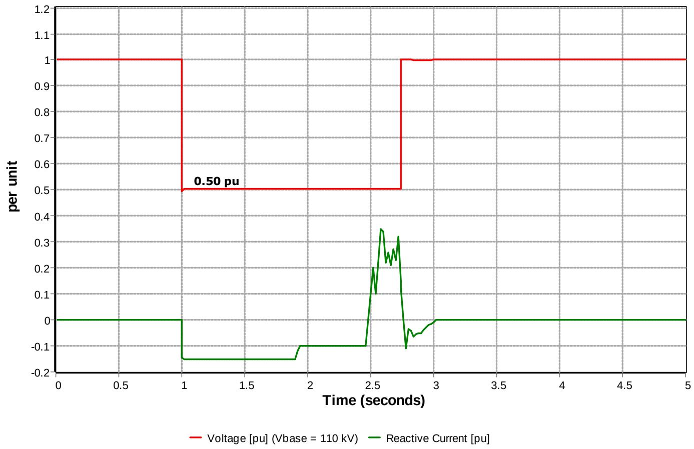
Grid Code PPM 1.4.2 (a): The provision of reactive current shall continue until the voltage recovers to nominal value or for at least 500 ms, whichever is the sooner.

See the example below for compliant and incompliant responses:

(a) Non-Compliant: Reactive current is not supporting the voltage (drops away) for the duration the fault (or for 500 ms).

(b) Compliant: Reactive current is supporting the voltage (increases and remains high) for the duration the fault.

(a)



(b)

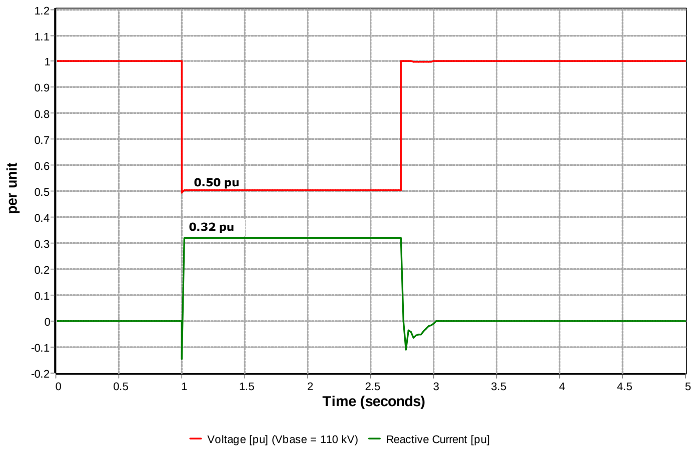


Figure 3 - Reactive Current Provision During Fault

(a) Non-Compliant (b) Compliant

2.3.3. Active Power Recovery

Grid Code PPM 1.4.2 (b): Active Power will recover to at least 90% of its maximum available power within 500 ms for fault ≤ 140 ms or within 1s for fault > 140 ms.

See the example below for a compliant response:

Compliant: Active Power recovers to its maximum available power within less than 1s for the fault > 140 ms.

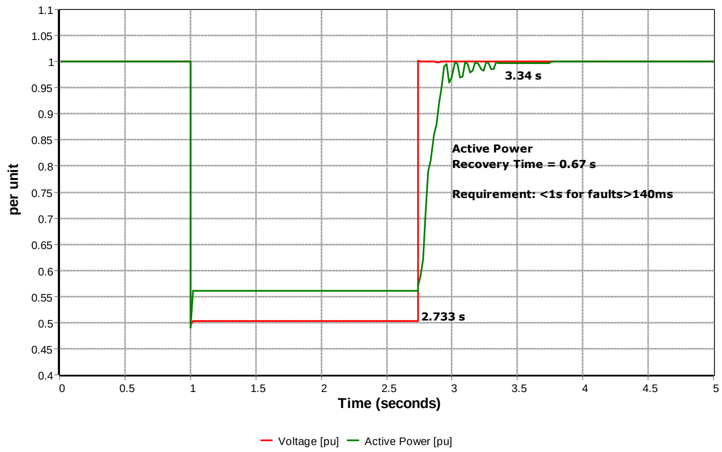


Figure 4 - Active Power Recovery After Fault Compliant Case

2.3.4. Active Power Priority

Grid Code PPM 1.4.2 (c): During and after faults, priority shall always be given to the Active Power response.

Normally, on the Irish electricity network, the priority during FRT period is required to be given to active power regardless of the pre-fault set point and control mode of the facility. Any residual capability of the PPM units is expected to be supplied as reactive current.

Prioritisation of active power is required because of the low inertia and weak interconnection of the island's network. By this way, more active power contribution is expected from the non-synchronous generators to sustain frequency stability during disturbances. On the other hand, in heavily interconnected or with high inertia networks, reactive current is usually prioritised to support voltage within the grid.

The PPM units should provide active power in proportion to retained voltage, and this is always the priority to mitigate a potential large deficit of MW that could occur if a cluster of units 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, the PPM units 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 units should be capable of handling the faults described in the Grid Code at the minimum specified system strength.

However, in some cases, prioritizing reactive current during FRT period could produce better performance in terms of active power injection and frequency/voltage regulation at the connection point of the facility.

Therefore, if such a condition occurs, provide both outputs in the report. The priority requirement during FRT period will be reviewed based on the obtained results.

2.3.5. Reactive Current Proportionality

Grid Code PPM 1.4.2 (c): Reactive Current will attempt to control the voltage back towards nominal voltage, and should be at least proportional to the Voltage Dip.

Note that this clarification is only for the reactive current proportionality requirement and should not be used for the evaluation of active power responses. For active power proportionality, refer to section 2.3.1.

This requirement means that the reactive current should be in a direction such as to tend to increase the voltage at the connection point to improve voltage stability – 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 units. 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 units. 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.

Find the indicative guideline in the figure below on how much reactive current response a unit should give, assuming I_{Qavail} is same for each fault, and assuming the fault is long enough for a steady state to be reached. These figures are just for demonstration purposes to clarify the proportionality requirement in reactive current outputs.

I_{Qavail} is the available reactive current while the active power being prioritized, with I_{max} being the total maximum current based on the rating of the unit or on the prevailing input conditions such as wind and solar at the time of the fault.

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 unit 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.

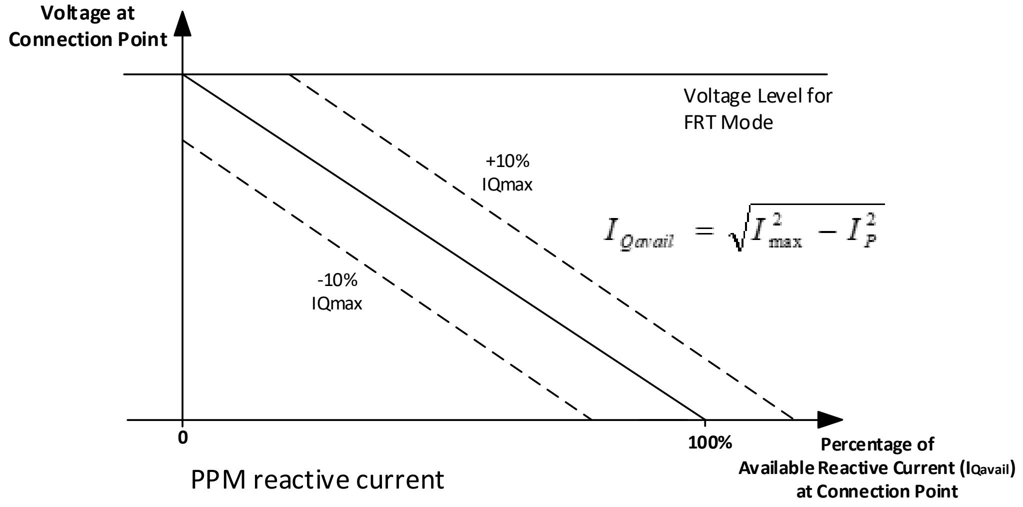


Figure 5 - Guideline for Reactive Current Response

See in the figure below presenting an 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.

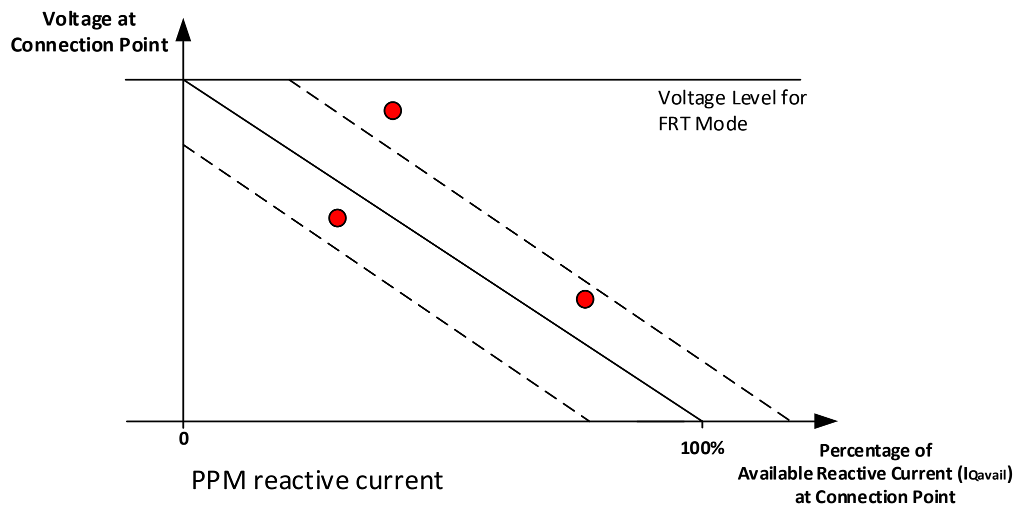


Figure 6 - Incompliant Reactive Current Response

See in the figure below for a compliant response example - reactive current increases as voltage dip worsens. A higher voltage dip elicits more reactive response, and allowance is given for over and under provision. The TSO expects that the control systems of the unit 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 units on how they actually implement this.

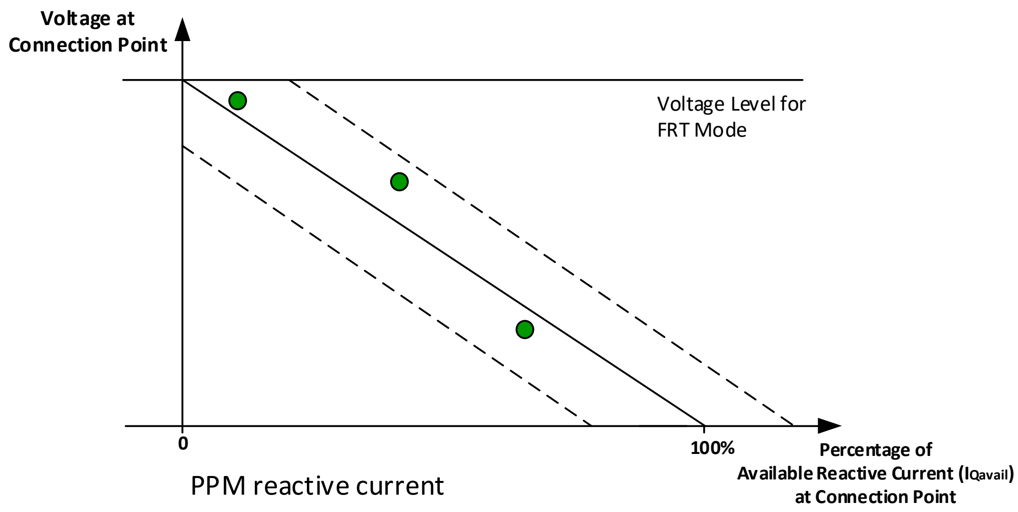


Figure 7 - Compliant Reactive Current Response

2.3.6. Reactive Current Supply

Grid Code PPM 1.4.2 (c): The reactive current response shall be supplied within the rating of the Controllable PPM.

PPM units are required to inject reactive current subject to their capacity while giving priority to active power contribution. The reactive current injection should not be less than its pre-fault level and should present an increase to its maximum capability in line with the fall in the voltage while ensuring the transient and steady state rating of the PPM units is not exceeded.

Depending on the internal design and installed equipment, a positive reactive power support at the connection point might not be provided by the facility. If such a situation occurs, indicate the reason and provide a discussion if an improved response is possible.

The locus given in the figure below representing the total current of 1.0pu is assumed on the MVA base of the PPM units. The output of the units is not required to exceed the rating under any normal or abnormal conditions.

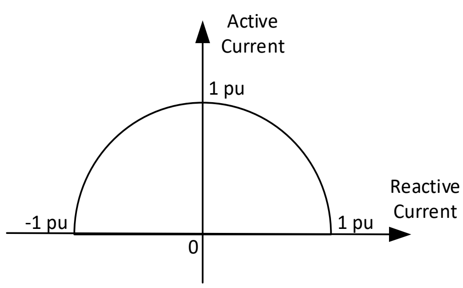


Figure 8 - Locus of Active and Reactive Current

For the studies when priority is given to reactive current, similar to the approach provided above, remaining capacity of the PPM units should be used for active power support during FRT events.

2.3.7. Reactive Current Rise and Settling Times

Grid Code PPM 1.4.2 (c): Reactive Current rise time will be no greater than 100 ms and settling time no greater than 300 ms.

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 generator controller. Therefore, they are not going to be assessed for short duration faults (i.e. faults whose duration is less than the settling time of 300 ms) as the facility response may not have reached a steady state prior to fault clearance.

The term of N/A (Not Applicable) can be used in the results for these parameters.

See the example below for a compliant response.

> Compliant: Reactive current rise time, following start of fault, within 100 ms and settling time, during fault, within 300 ms.

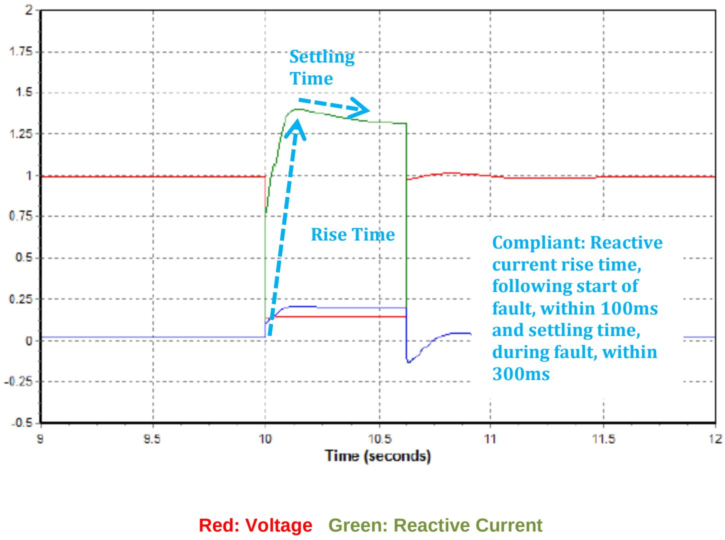


Figure 9 - Reactive Current Rise and Settling Time Compliant Case

2.3.8. Other Reactive Devices

Grid Code PPM 1.4.2 (c): 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.).

If static reactive support devices (capacitor banks or harmonic filters) are to be installed in the facility, two additional scenarios must be assessed with all reactive devices switched in and all reactive devices switched out. All the disturbances that apply to the facility under study must be tested for each scenario.

The scenarios that are unrealistic and creating unstable operation of the facility could be excluded in the simulations by providing clarification on the conditions of the specific cases. These conditions should be discussed with EirGrid before the FRT report submission.

2.3.9. Returning to Pre-Fault Control Mode

Grid Code PPM 1.4.2 (d): Revert to pre-fault reactive control mode and setpoint and control mode within 500 ms of fault clearance.

Once the voltage has recovered above 0.9 pu, the PPM has 500 ms to switch back into normal operation (pre-fault control mode, and pre-fault reactive set-point). It then has a further 1 second (in total 1.5 second) to achieve those values based on Grid Code PPM1.6.2.4 clause.

Grid Code PPM1.6.2.4: The speed of response of the Voltage Regulation System shall be such that, following a step change in Voltage at the Connection Point the Controllable PPM shall achieve 90 % of its steady-state Reactive Power response within 1 second. The response may require a transition from maximum Mvar production to maximum Mvar absorption or vice-versa.

The voltage droop should take into account the fact that the transmission voltage may be different to what it was before the fault. It is not necessarily expected the PPM to go back to the pre-fault Mvar value if system conditions have changed.

2.3.10. Dynamic Reactive Response

Grid Code PPM 1.4.2 (e): The TSO may seek to reduce the magnitude of the dynamic reactive response of the Controllable PPM if it is found to cause over-voltages on the Transmission System.

The TSO can seek to change the slope of the line in the Figure 5 to elicit a smaller reactive response if it is found that the reactive response is too great.

The reactive current during a fault should be greater than zero as measured at the generation unit LV terminals irrespective of pre-fault reactive current value. 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.

2.3.11. Assessment of Faults with Short Durations

Note that while facilities are expected to ride through a variety of different fault types and durations, very short faults (less than or equal to 150 ms) 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. Network Dynamic Modelling

For the dynamic simulations, an RMS model of the facility is needed. This RMS dynamic model must be prepared using vendor specific library files.

It should contain an accurate representation of all generation units, generation unit transformers, internal MV collector network, grid connected transformer and any associated controls and other equipment to be installed in the facility. Relevant documentation for the equipment must be provided during the report submission [8].

The submitted simulation model must be such that the characteristics of the facility are represented at the Connection Point. Submitted models must contain all data sets for each unit.

For computational reasons, an aggregate model capturing the combined response of all components (such as individual wind turbines) is strongly preferred.

The provision of the simulation model should include:

- Explanation of set-up and initialisation of the model,
- Simulated full or aggregated model of the facility,
- Description of each individual model components and their related parameters,
- Active power output set value,
- Control mode under normal operating conditions and during FRT disturbances (priority setting, i.e. priority given to active power or reactive current),
- Assumed transformers tap positions,
- Assumptions for other devices such as STATCOM, harmonic filter(s), capacitor banks, etc.,
- Any limitations of the model provided.
- List of protection functionality that can be triggered by external events.
- Include any special functionality provided by the facility, if any.

3.1. Dynamic Model Capabilities

The dynamic model of the facility shall 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 dead band,
    - 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,
- Able to run with a time step in the range 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,
- The model should not contain any compiled parts in order to be embedded within a larger network model without any restrictions.

3.2. Modelling of External Grid

The external power system must be represented as an infinite bus behind the Equivalent Thevenin Impedances (i.e. Minimum System Strength data) provided by EirGrid or ESB Networks. An example report is shown in Appendix B: Sample MSS Data Report.

The model must include two external grids with a changeover between the pre-disturbance and post-disturbance characteristics. The switchover scheme is presented in the following figure.

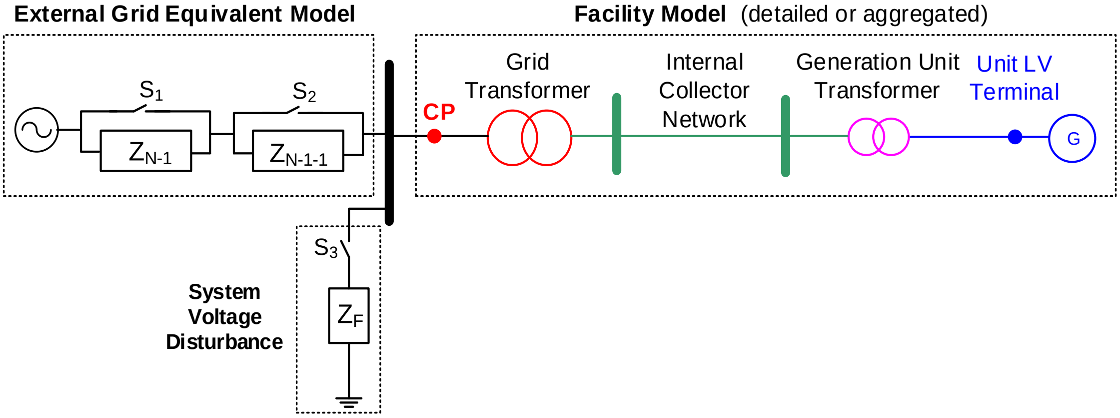


Figure 10 - Representation of External Grid

The switching scheme is described in the table below.

Table 9 - Switching Scheme of External Grid Equivalents

Period	S_1	S_2	S_3	Comment
Pre-disturbance **T < T1**	Open	Closed	Open	Steady state under Z_{N-1}.
Disturbance **T1 ≤ T < T2**	Open	Closed	Closed	Apply voltage disturbance under Z_{N-1}.
Post-disturbance **T2 ≤ T**	Closed	Open	Open	Remove disturbance, Change external grid impedance to Z_{N-1-1}.

As shown in the following table, indicate the external grid impedance values assumed in the study as provided by EirGrid (or ESB Networks for distribution level connections) with the Minimum System Strength (MSS) data applicable at the Connection Point [9]. Indicate the base impedance value used for external grid per unit calculations as Z_{base1} parameter.

As the positive and zero sequence impedances are sufficient to model branches in PSS/E, negative sequence components could be skipped in the table.

Table 10 - External Grid Impedance Values Assumed at CP*

	N-1 Condition (Z_{N-1}) [pu]	N-1-1 Condition (Z_{N-1-1}) [pu]
R_{pos}	0.0XY	0.0XY
X_{pos}	0.0XY	0.0XY
R_{zero}	0.0XY	0.0XY
X_{zero}	0.0XY	0.0XY
Z_{base1}	XY [Ohm]	For S = 100 [MVA] V = CP Voltage$_{LL}$ [kV] $Z_{base} = V^2/S$

* As given in the MSS data issued by EirGrid or ESB Networks.

3.3. Modelling of Generation Facility

In this section, indicate the components of the generation facility and provide relevant information. 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 connection point. Descriptive information on the aggregation approach and assumptions should be provided.

The values of the electrical parameters used in the aggregated model (e.g. generation units transformers, internal collector network, etc.) should also be provided in the customer report as described in the following subsections.

3.3.1. Generation Units

Describe the configuration of the generation units and how they are represented for the purpose of FRT studies (i.e. detailed representation, aggregation, etc.).

The reactive power capability of the entire facility at the connection point must be presented for all relevant voltage magnitudes and power factors. A sample plot is given below for illustration purposes only.

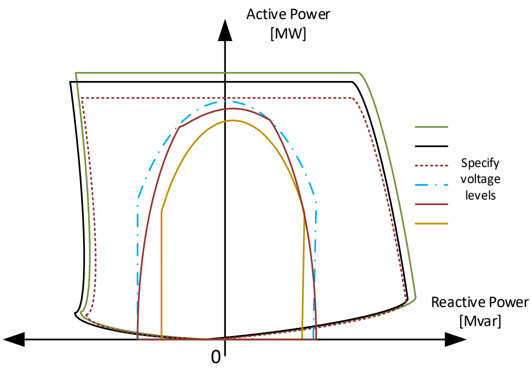


Figure 11 - Reactive Power Capability of the Facility

3.3.2. Library Models

Indicate the library models (name and version) used to represent the generation and controller units in the table below. Indicate any assumption or known limitation of those models (if applicable).

Table 11 - Library Files Used in Dynamic Model

Model	Library File	Remarks (if any)
Generator/Converter	Library Full Name	…
Electrical Control	…	…
Plant Controller	…	…
…	…	…

As shown in the table below, include site specific parameter settings highlighting any parameters that have been changed from the generic default settings and reasons why. The full parameterisation tables of the libraries can be shared in the Appendices.

Table 12 - Updated Variables in the Generation Unit Library File

Variables (CON/ICON)	Value	Description	Comment
J+1	X.X	The description of the variable	Any clarification, if needed.
…	**…**	**…**	**…**

3.3.3. Transformers

Describe the representation of the grid and generation unit transformers at least with the following parameters given in the tables below. Note that the values given below are for demonstration purposes only.

Table 13 - Representation of Generation Units Transformers

Parameter	Value
Total Number	7
Rating [MVA]	38
Voltage Ratio	33 / 0.69
Vector Group	Dyn11
Short Circuit Impedance [%]*	8

Parameter		Value
Resistance [%]*	positive	0.1234
	zero	0.1234
Reactance [%]*	positive	12.123
	zero	12.123
Load-Losses [kW]		12.34
No-Load Losses [kW]		1.23
Exciting I [pu]		0.001
Tapping type		Off-Load
Tap changer winding		HV
Tap changer resolution		±2x2.5%

* based on transformer MVA

Table 14 - Representation of Grid Transformer

Parameter		Value
Total Number		1
Rating [MVA]		70
Voltage Ratio		110 / 33
Vector Group		YNyn0
Short Circuit Impedance [%]*		12
Resistance [%]*	positive	0.1234
	zero	0.1234
Reactance [%]*	positive	12.123
	zero	12.123
Load-Losses [kW]		12.234
No-Load Losses [kW]		1.23
Exciting I [pu]		0.001
Tapping type		On-Load
Tap changer winding		HV
Tap changer resolution		±8x1.25%

* based on transformer MVA

3.3.4. Internal Collector Network

Describe the internal collector network and how the individual generation units are interconnected. Provide section lengths and values of resistance (R), reactance (X) and susceptance (B) for each internal circuit in the facility. Also, indicate each base impedance value used for per unit calculations of internal circuit.

Table 15 - Internal Circuit Electrical Parameters at XY kV Level

Circuit	From - To	Type	Length [m]	R & R_{zero} [pu]	X & X_{zero} [pu]	B & B_{zero} [pu]
C1	Bus1-Bus2	Cable Type	12	0.001234 & 0.0056789	0.012345 & 0.056789	1.234567 & 2.345678
C2	Bus2-Bus3	…	…	…	…	…
…	…	…	…	…	…	…
Z_{base2}	X.YZ [Ohm]		For S = 100 [MVA], V_{LL} = Voltage [kV] $Z_{base} = V^2/S$			

3.3.5. Other Equipment

Describe the representation and site-specific parameter settings of any other devices such as STATCOM, harmonic filter(s), capacitor banks, etc. (when applicable).

4. Study Methodology

Dynamic simulation studies must be carried out to demonstrate that the facility is designed to comply with the FRT requirements defined in the most up-to-date Grid Code (or Distribution Code for distribution level connections) version.

Indicate the time steps specified in the simulation studies as given in the table below:

Table 16 - Dynamic Simulation Settings

Simulation and Output Time Step Settings in PSS/E	
Time Step (DELT)	0.01sec
Write every	1 (time steps)

4.1. Simulation Procedure

The simulation procedure consists of three main intervals: Pre-disturbance, Disturbance and Post-disturbance periods.

- **The pre-disturbance period:**
  - The pre-disturbance voltage magnitude at the Connection Point (CP) must be set to 1 pu.
  - Output of the facilities at the CP shall be equal to the values given below:

Table 17 - Outputs at CP in the Pre-Disturbance Period

Facility Type	Outputs
PPM	$P = MEC \ \& \ Q = 0$
PPM - Battery ESPS	$P = MEC \ \& \ Q = 0$ $P = MIC \ \& \ Q = 0$ for both export and import configuration
Synchronous Generator	$P = MEC \ \& \ Q = \ Q_{min}$ maximum leading reactive power
HVDC	$P = MEC \ \& \ Q = 0$ $P = MIC \ \& \ Q = 0$ for both export and import configuration

  - If facility has more than one operating mode, then it must be tested for all modes in terms of FRT performance. For example, Battery ESPS and HVDC connections must be tested for both operating modes at import and export configuration with P=Pmax.

- The external grid must be modelled using the impedance under N-1 condition (Z_{N-1}) issued by EirGrid (or ESB Networks for distribution level connections) in the Minimum System Strength (MSS) data report.
- Set the control mode of the facility under normal operating conditions.

- **The disturbance period:**
  - Apply fault at the CP with suitable fault impedance (Z_F) as long as the defined duration to depress the voltage at the CP to the retained voltage level.
  - Make sure the control mode during disturbance period is changed to FRT mode prioritizing active power (or reactive current, if needed to check facility performance).
- **The post-disturbance period:**
  - Remove voltage disturbance at the CP.
  - Change external grid model with the impedance under N-1-1 condition (Z_{N-1-1}) issued by EirGrid (or ESB Networks for distribution level connections) in the Minimum System Strength (MSS) data report.
  - Revert to pre-fault reactive control mode and setpoint.
  - The simulations must be run until a new steady state is reached at the CP in terms of system voltage, active power and reactive power output from the facility before commencing the next study.
  - Save obtained results and plots.

4.2. Faults to Apply

The studies must simulate faults at the CP with suitable fault impedance (Z_F) to depress the voltage at the CP to the levels described in the relevant tables below. For the FRT assessment of generation units, the following fault types will be simulated at the CP:

Table 18 - Faults to Apply at CP

#	Fault Type	Z_{Fault}
1	3 Phase	Z_F
2	2 Phase to Earth	Z_F (line to line) Z_F (line to ground)
3	1 Phase to Earth	Z_F (line to ground)
4	Phase to Phase	Z_F (line to line)

The fault resistance and reactance values (R_F and X_F) must be calculated for each simulation case to achieve retained voltages specified at the CP. The retained voltage levels at the connection point and fault parameters for each facility type are given in the following sections. Indicate fault impedances applied for each case study as shown in the following table.

Table 19 - Fault Impedances Applied at CP

	Fault Type	R_F [Ohm]	X_F [Ohm]	X/R*
Case 1	3 Phase	X.YZ	X.YZ	X
Case 2	3 Phase	X.YZ	X.YZ	X
…		…	…	…
Case N	Line to line	X.YZ	X.YZ	X
	Line to ground	X.YZ	X.YZ	X

* The fault X/R ratio should be in between 3 and 20. N/A for bolted faults.

In unbalanced fault cases, the fault impedance should be adjusted considering the target retained voltage level of the faulted phase.

A bolted fault (i.e. fault with zero impedance) needs to be applied at the connection point for the following unbalanced cases:

- 2 Phase to Earth fault with 0% retained voltage
- 1 Phase to Earth fault with 0% retained voltage
- Phase to Phase fault with 50% retained voltage

For the other unbalanced faults with 5% and 15% retained voltage target levels, the fault impedance should be adjusted considering the phase voltage at the connection point.

As PSS/E is a positive sequence simulation software, only positive sequence results at the connection point and the generation unit LV terminal are expected to be reported.

If the inverters don't enter FRT mode during any targeted retained voltage level, then simulate a more onerous fault at the CP to be able to obtain FRT response of the generation facility.

4.3. Fault Parameters for TSO Customers

In this section, the fault parameters for TSO customers are presented. The voltage levels and disturbance durations for each simulation case in FRT analysis for different type of generation units are given. Refer to the corresponding subsection based on the type of the facility under study. Note that the voltage disturbances are described in terms of retained voltage at the Connection Point (i.e. the HV bushings of the grid transformer).

4.3.1. PPM RfG Units

The FRT capability curve for PPM RfG units as given in Grid Code PPM1.4.2(f) can be seen in the figure below. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

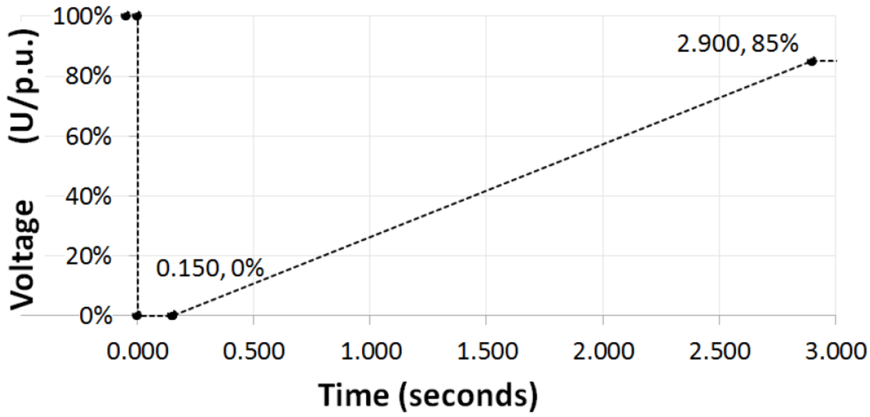


Figure 12 - FRT Capability Curve for PPM RfG Units (TSO Customer)

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 20 - FRT Testing for PPM RfG Units (TSO Customer)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
0%	140 ms	X	X	X
0%	150 ms	150 ms	150 ms	X
50%	1767 ms	X	X	1767 ms
85%	2900 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the TSO customer PPM RfG units.

Table 21 - Case Scenarios for PPM RfG Units (TSO Customer)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	0%	3 Phase	140 ms
Case 2	0%	3 Phase	150 ms
Case 3	50%	3 Phase	1767 ms
Case 4	85%	3 Phase	2900 ms
Case 5	0%	2 Phase to Earth	150 ms
Case 6	0%	1 Phase to Earth	150 ms
Case 7	50%	Phase to Phase	1767 ms

4.3.2. PPM Non-RfG Units

The FRT capability curve for PPM Non-RfG units as given in Grid Code PPM1.4.1 can be seen in the figure below. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

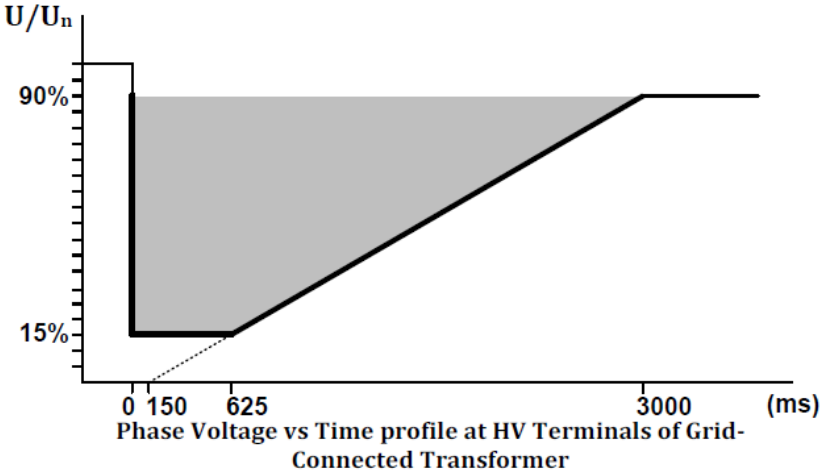


Figure 13 - FRT Capability Curve for PPM Non-RfG Units (TSO Customer)

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 22 - FRT Testing for PPM Non-RfG Units (TSO Customer)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
15%	140 ms	X	X	X
15%	625 ms	625 ms	625 ms	X
50%	1733 ms	X	X	1733 ms
85%	2842 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the TSO customer PPM Non-RfG units.

Table 23 - Case Scenarios for PPM Non-RfG Units (TSO Customer)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	15%	3 Phase	140 ms
Case 2	15%	3 Phase	625 ms
Case 3	50%	3 Phase	1733 ms
Case 4	85%	3 Phase	2842 ms
Case 5	15%	2 Phase to Earth	625 ms
Case 6	15%	1 Phase to Earth	625 ms
Case 7	50%	Phase to Phase	1733 ms

4.3.3. SPGM RfG Units

The FRT capability curve for SPGM (Synchronous Power Generating Modules) RfG units as given in Grid Code CC.7.3.1.1(y) can be seen in the figure below. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

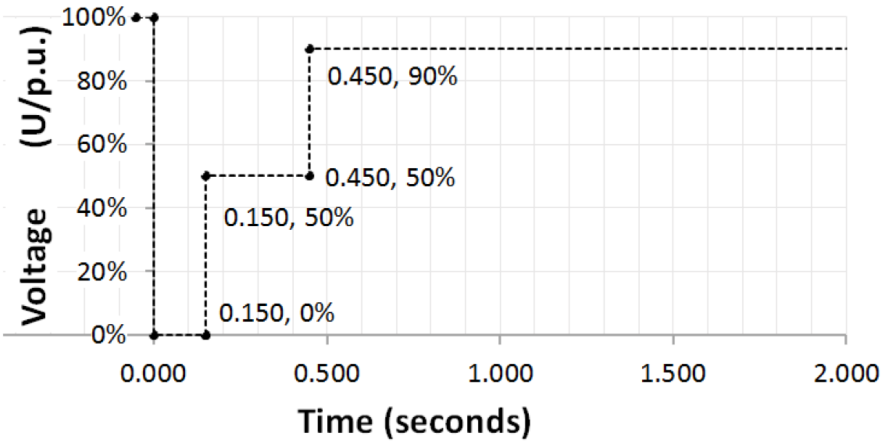


Figure 14 - FRT Capability Curve for SPGM RfG Units (TSO Customer)

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 24 - FRT Testing for SPGM RfG Units (TSO Customer)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
0%	150 ms	150 ms	150 ms	X
50%	450 ms	X	X	450 ms
90%	3000 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the TSO customer SPGM RfG units.

Table 25 - Case Scenarios for SPGM RfG Units (TSO Customer)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	0%	3 Phase	150 ms
Case 2	50%	3 Phase	450 ms
Case 3	90%	3 Phase	3000 ms
Case 4	0%	2 Phase to Earth	150 ms
Case 5	0%	1 Phase to Earth	150 ms
Case 6	50%	Phase to Phase	450 ms

4.3.4. SPGM Non-RfG Units

The FRT capability curve for SPGM Non-RfG units as given in Grid Code CC.7.3.1.1(h) can be seen in the figure below. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

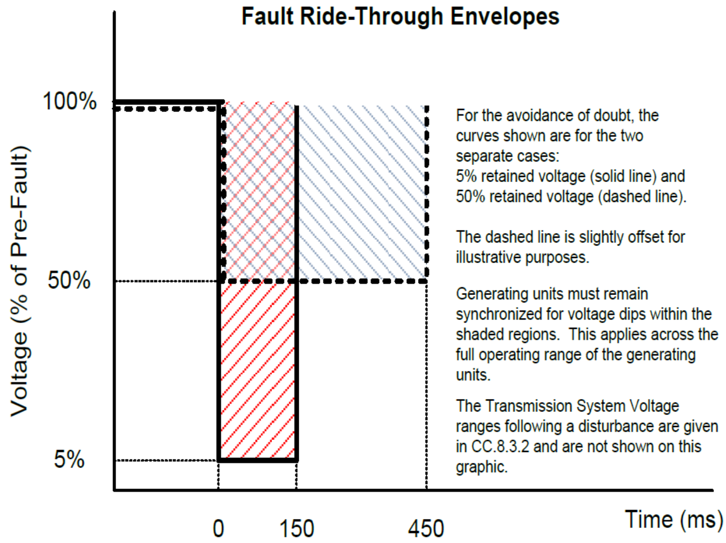


Figure 15 - FRT Capability Curve for SPGM Non-RfG Units (TSO Customer)

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

**Table 26 - FRT Testing for
SPGM Non-RfG Units (TSO Customer)**

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
5%	150 ms	150 ms	150 ms	X
50%	450 ms	X	X	450 ms

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the TSO customer SPGM Non-RfG units.

**Table 27 - Case Scenarios for
SPGM Non-RfG Units (TSO Customer)**

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	5%	3 Phase	150 ms
Case 2	50%	3 Phase	450 ms
Case 3	5%	2 Phase to Earth	150 ms
Case 4	5%	1 Phase to Earth	150 ms
Case 5	50%	Phase to Phase	450 ms

4.3.5. HVDC Connections

The FRT capability for HVDC (High Voltage Direct Current) connections is defined in Grid Code CC.7.5.1.1(g). The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the table below.

**Table 28 - FRT Testing for
HVDC Connections (TSO Customer)**

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
5%	200 ms	200 ms	200 ms	X
50%	600 ms	X	X	600ms

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the TSO customer HVDC connections.

Table 29 - Case Scenarios for HVDC Connections (TSO Customer)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	5%	3 Phase	200 ms
Case 2	50%	3 Phase	600 ms
Case 3	5%	2 Phase to Earth	200 ms
Case 4	5%	1 Phase to Earth	200 ms
Case 5	50%	Phase to Phase	600 ms

4.4. Fault Parameters for DSO Customers

In this section, the fault parameters for DSO customers are presented. The voltage levels and disturbance durations for each simulation case in FRT analysis for different type of generation units are given. Refer to the corresponding subsection based on the type of the facility under study. Note that the voltage disturbances are described in terms of retained voltage at the Connection Point (i.e. the HV bushings of the grid transformer).

Each instant of the FRT capability curve is given in Distribution Code DCC11.2.1.1 as presented in the figure below.

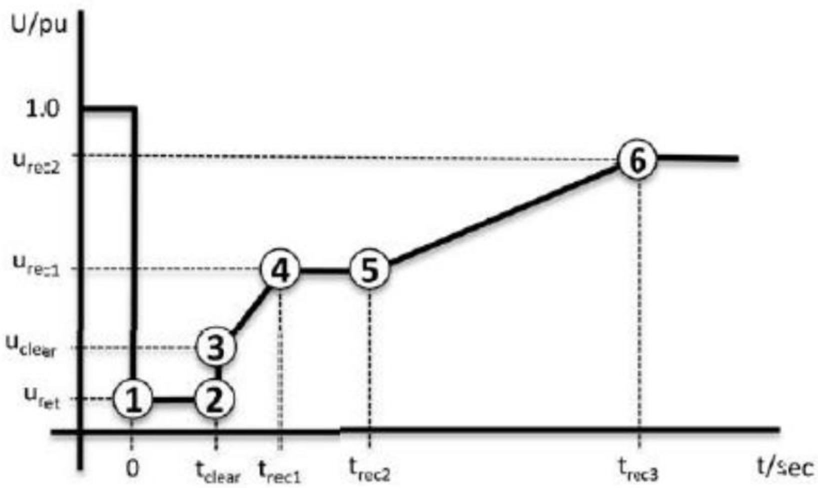


Figure 16 - FRT Capability Curve Instants for DSO Customers

The RfG generation unit types for DSO customers are defined in Distribution Code DCC10.1.6 as presented in the following table.

Table 30 - RfG Generation Unit Types

Type	Registered Capacity
A	800W up to 0.09MW
B	0.1MW up to 4.9MW
C	5MW up to 10MW
D	Greater than 10MW
All generation units at ≥ 110 kV are Type D.	

4.4.1. PPM RfG Units at ≥ 110 kV

The FRT capability curve for DSO customer PPM RfG units connecting to distribution network at ≥ 110 kV (Type D PPMs) as given in Distribution Code DCC11.2.2.3 can be seen in the figure below. Corresponding parameters of the curve are given in the following table. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

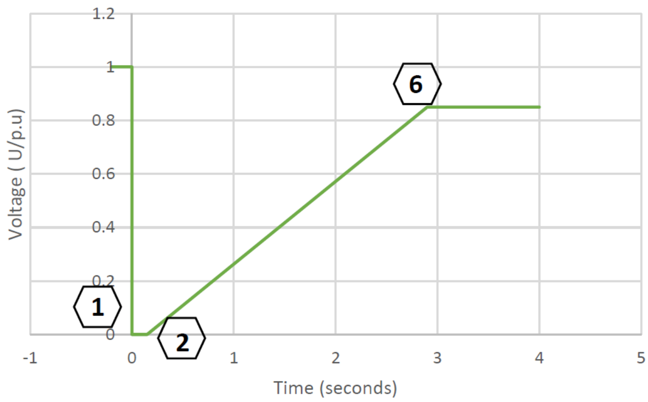


Figure 17 - FRT Capability Curve for PPM RfG Units (DSO Customer ≥ 110 kV)

The time and retained voltage parameters on the FRT capability curve are given in the table below.

Table 31 - Parameters on the Curve for PPM RfG Units (DSO Customer ≥ 110 kV)

No. on Graph	Parameter	Value
1	U_{ret}	0 pu
2	U_{ret}	0 pu
	t_{clear}	150 ms
6	U_{rec2}	0.85 pu
	t_{rec3}	2.9 s

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 32 - FRT Testing for PPM RfG Units (DSO Customer ≥ 110 kV)

Retained Voltage	Fault Type			
	3 Phase	**2 Phase to Earth**	**1 Phase to Earth**	**Phase to Phase**
0%	140 ms	X	X	X
0%	150 ms	150 ms	150 ms	X
50%	1767 ms	X	X	1767 ms
85%	2900 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the DSO customer PPM RfG units connecting at ≥110 kV.

Table 33 - Case Scenarios for PPM RfG Units (DSO Customer ≥ 110 kV)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	0%	3 Phase	140 ms
Case 2	0%	3 Phase	150 ms
Case 3	50%	3 Phase	1767 ms
Case 4	85%	3 Phase	2900 ms
Case 5	0%	2 Phase to Earth	150 ms
Case 6	0%	1 Phase to Earth	150 ms
Case 7	50%	Phase to Phase	1767 ms

4.4.2. PPM RfG Units at < 110 kV

The FRT capability curve for DSO customer PPM RfG units connecting to distribution network at < 110 kV (Type B, C & D PPMs) as given in Distribution Code DCC11.2.2.4 can be seen in the figure below. Corresponding parameters of the curve are given in the following table. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

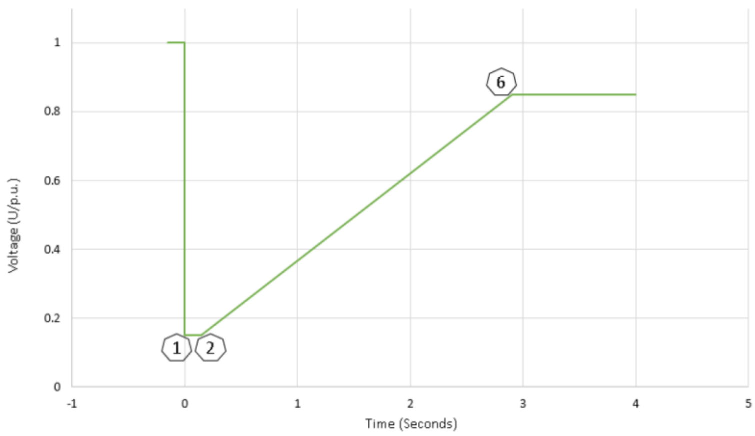


Figure 18 - FRT Capability Curve for PPM RfG Units (DSO Customer < 110 kV)

The time and retained voltage parameters on the FRT capability curve are given in the table below.

Table 34 - Parameters on the Curve for PPM RfG Units (DSO Customer < 110 kV)

No. on Graph	Parameter	Value
1	U_{ret}	0.15 pu
2	U_{ret}	0.15 pu
	t_{clear}	250 ms
6	U_{rec2}	0.85 pu
	t_{rec3}	2.9 s

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 35 - FRT Testing for PPM RfG Units (DSO Customer < 110 kV)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
15%	140 ms	X	X	X
15%	250 ms	250 ms	250 ms	X
50%	1575 ms	X	X	1575 ms
85%	2900 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the DSO customer PPM RfG units connecting at <110 kV.

Table 36 - Case Scenarios for PPM RfG Units (DSO Customer < 110 kV)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	15%	3 Phase	140 ms
Case 2	15%	3 Phase	250 ms
Case 3	50%	3 Phase	1575 ms
Case 4	85%	3 Phase	2900 ms
Case 5	15%	2 Phase to Earth	250 ms
Case 6	15%	1 Phase to Earth	250 ms
Case 7	50%	Phase to Phase	1575 ms

4.4.3. PPM Non-RfG Units

The FRT capability curve for DSO customer PPM Non-RfG units as given in Distribution Code DCC11.2.1.2 can be seen in the figure below. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

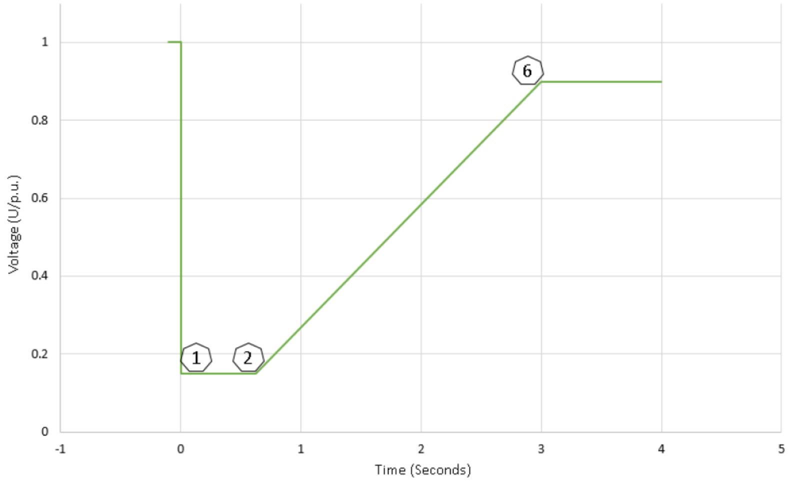


Figure 19 - FRT Capability Curve for PPM Non-RfG Units (DSO Customer)

The time and retained voltage parameters on the FRT capability curve are given in the table below.

Table 37 - Parameters on the Curve for PPM Non-RfG Units (DSO Customer)

No. on Graph	Parameter	Value
1	U_{ret}	0.15 pu
2	U_{ret}	0.15 pu
	t_{clear}	650 ms
6	U_{rec2}	0.9 pu
	t_{rec3}	3.0 s

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 38 - FRT Testing for PPM Non-RfG Units (DSO Customer)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
15%	140 ms	X	X	X
15%	650 ms	650 ms	650 ms	X
50%	1746 ms	X	X	1746 ms
85%	2843 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the DSO customer PPM Non-RfG units.

Table 39 - Case Scenarios for PPM Non-RfG Units (DSO Customer)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	15%	3 Phase	140 ms
Case 2	15%	3 Phase	650 ms
Case 3	50%	3 Phase	1746 ms
Case 4	85%	3 Phase	2843 ms
Case 5	15%	2 Phase to Earth	650 ms
Case 6	15%	1 Phase to Earth	650 ms
Case 7	50%	Phase to Phase	1746 ms

4.4.4. SPGM RfG Units at ≥ 110 kV

The FRT capability curve for DSO customer SPGM (Synchronous Power Generating Modules) RfG units connecting to distribution network at ≥ 110 kV (Type D SPGMs) as given in Distribution Code DCC12.1.3 can be seen in the figure below. Corresponding parameters of the curve are given in the following table. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

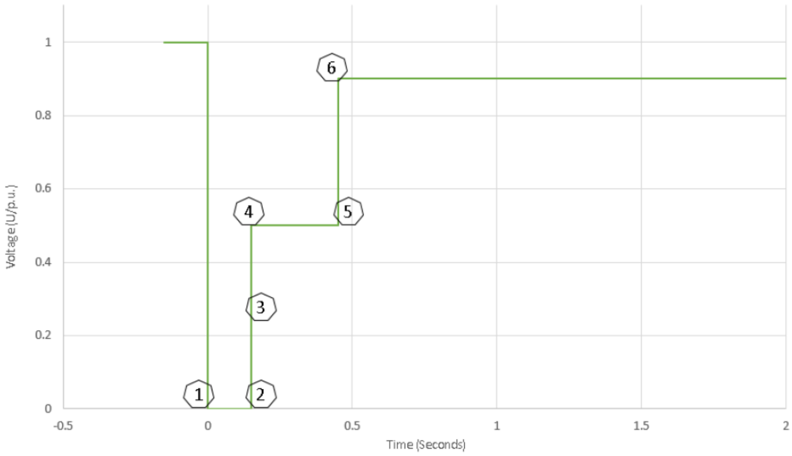


Figure 20 - FRT Capability Curve for SPGM RfG Units (DSO Customer ≥ 110 kV)

The time and retained voltage parameters on the FRT capability curve are given in the table below.

Table 40 - Parameters on the Curve for SPGM RfG Units (DSO Customer ≥ 110 kV)

No. on Graph	Parameter	Value
1	U_{ret}	0 pu
2	U_{ret}	0 pu
	t_{clear}	150 ms
3	U_{clear}	0.25 pu
	t_{clear}	150 ms
4	U_{rec1}	0.5 pu
	t_{rec1}	150 ms*
5	U_{rec1}	0.5 pu
	t_{rec2}	450 ms
6	U_{rec2}	0.9 pu
	t_{rec3}	450 ms

* Given 450 ms in the Distribution Code. Taken 150 ms based on the curve.

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 41 - FRT Testing for SPGM RfG Units (DSO Customer ≥ 110 kV)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
0%	150 ms	150 ms	150 ms	X
25%	150ms	X	X	X
50%	450 ms	X	X	450 ms
90%	3000 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the DSO customer SPGM RfG units connecting at ≥110 kV.

Table 42 - Case Scenarios for SPGM RfG Units (DSO Customer ≥ 110 kV)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	0%	3 Phase	150 ms
Case 2	25%	3 Phase	150 ms
Case 3	50%	3 Phase	450 ms
Case 4	90%	3 Phase	3000 ms
Case 5	0%	2 Phase to Earth	150 ms
Case 6	0%	1 Phase to Earth	150 ms
Case 7	50%	Phase to Phase	450 ms

4.4.5. SPGM RfG Units at < 110 kV

The FRT capability curve for DSO customer SPGM RfG units connecting to distribution network at < 110 kV (Type B, C & D SPGMs) as given in Distribution Code DCC12.1.2 can be seen in the figure below. Corresponding parameters of the curve are given in the following table. The facility shall be capable of staying connected to the transmission system and continuing to operate stably during voltage dips as specified in the voltage-against-time profile below.

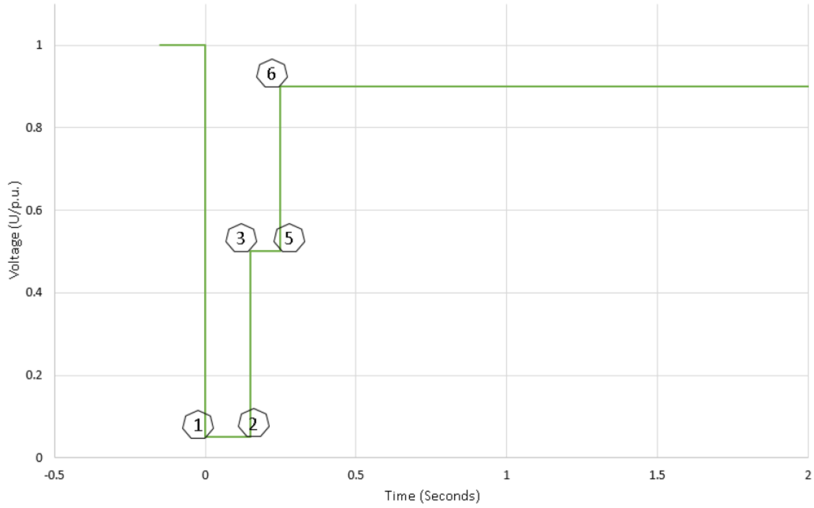


Figure 21 - FRT Capability Curve for SPGM RfG Units (DSO Customer < 110 kV)

The time and retained voltage parameters on the FRT capability curve are given in the table below.

Table 43 - Parameters on the Curve for SPGM RfG Units (DSO Customer < 110 kV)

No. on Graph	Parameter	Value
1	U_{ret}	0.05 pu
2	U_{ret}	0.05 pu
	t_{clear}	150 ms
3	U_{clear}	0.5 pu*
	t_{clear}	150 ms
4	U_{rec1}	U_{clear}
	t_{rec1}	t_{clear}
5	U_{rec1}	U_{clear}
	t_{rec2}	450 ms
6	U_{rec2}	0.9 pu
	t_{rec3}	t_{rec2}

* Given 0.7 pu in the Distribution Code. Taken 0.5 pu based on the curve.

For each fault type, the retained voltage and duration limits based on the FRT capability curve are given in the table below.

Table 44 - FRT Testing for SPGM RfG Units (DSO Customer < 110 kV)

Retained Voltage	Fault Type			
	3 Phase	2 Phase to Earth	1 Phase to Earth	Phase to Phase
5%	150 ms	150 ms	150 ms	X
50%	450ms	X	X	450 ms
90%	3000 ms	X	X	X

X: Simulation is not required.

The following faults are required to simulate at the CP for FRT assessment of the DSO customer SPGM RfG units connecting at <110 kV.

Table 45 - Case Scenarios for SPGM RfG Units (DSO Customer < 110 kV)

Cases	Retained Voltage	Fault Type	Fault Duration
Case 1	5%	3 Phase	150 ms
Case 2	50%	3 Phase	450 ms
Case 3	90%	3 Phase	3000 ms
Case 4	5%	2 Phase to Earth	150 ms
Case 5	5%	1 Phase to Earth	150 ms
Case 6	50%	Phase to Phase	450 ms

5. Simulation Results

Provide numerical results of active power and reactive current responses at the Connection Point for each simulated case scenario as shown in the following tables. Indicate non-compliances in red colour. Note that if a positive sequence simulation package is used (such as PSS/E), then just provide the positive sequence results.

The numerical values and non-compliances in red shown in the tables below are for demonstration purposes only without referral to any particular simulation case.

The corresponding Grid Code clauses for PPMs are given in the tables. The parameters reflect FRT requirements for PPM connections. The parameters can be updated depending on the facility type under study.

Table 46 - Active Power Results at CP

Case #	Active Power Results			
	Priority given to Active Power (Yes/No)	Active Power During Pre-disturbance / Disturbance Periods		Recovery Time (to 90%) [ms]
		[MW]	Ratio (%)*	
	PPM1.4.2(c)	PPM1.4.2(a)		PPM1.4.2(b)
C1	Yes	100 / 30	30%	340
C2	Yes	100 / 45	45%	1200
…	…	… / …		…
Cn	…	… / …		…

* Ratio (%) = Active Power at Disturbance Period / Pre-disturbance Period

Table 47 - Reactive Current Results at CP

Case #	Reactive Current Results				
	Provision Time [ms]	Pre-disturbance / Disturbance Periods [kA]	Revert Time [ms]	Rise Time [ms]	Settling Time [ms]
	PPM1.4.2(a)	PPM1.4.2(c)	PPM1.4.2(d)	PPM1.4.2(c)	PPM1.4.2(c)
C1	600	0.0 / 1.7	1540	N/A	N/A
C2	750	0.0 / 1.65	2625	70	130
…	…	… / …	…	…	…
Cn	…	… / …	…	…	…

TSO does not have visibility down to the individual module level at present and so performance monitoring of generation units is done at the connection point. From a simulation and model compliance viewpoint, performance assessment should take into account behaviour at the 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 FRT response.

For this purpose, simulation results at a selected generation unit LV terminal are required. The same table format used for Connection Point can be used to present results at generation unit LV terminal as shown below.

The FRT responses of the generation facilities will only be assessed at the Connection Point and the Grid Code requirements don't apply at the generation unit LV terminals. Therefore, the Grid Code clauses are removed in the tables below. Note that the numerical values are for demonstration purposes only without referral to any particular simulation case.

Table 48 - Active Power Results at Generation Unit LV Terminal

Case #	Active Power Results			
	Priority given to Active Power (Yes/No)	Active Power During Pre-disturbance / Disturbance Periods		Recovery Time (to 90%) [ms]
		[MW]	Ratio (%)*	
C1	Yes	110 / 35	31.8%	340
C2	Yes	110 / 50	45.5%	1200
…	…	… / …		…
Cn	…	… / …		…

* Ratio (%) = Active Power at Disturbance Period / Pre-disturbance Period

Table 49 - Reactive Current Results at Generation Unit LV Terminal

Case #	Reactive Current Results				
	Provision Time [ms]	Pre-disturbance / Disturbance Periods [kA]	Revert Time [ms]	Rise Time [ms]	Settling Time [ms]
C1	600	0.2 / 1.3	1540	120	380
C2	750	0.4 / 1.4	2625	70	130
…	…	… / …	…	…	…
Cn	…	… / …	…	…	…

Note that the pre-disturbance and disturbance period results for active powers and reactive currents are requested to evaluate the changes in the facility responses before and during FRT events.

In case of giving priority to reactive current (instead of active power) produces better outputs in terms of active power injection and frequency/voltage regulation at the Connection Point, provide both simulation results for review.

5.1. Plotting Requirements

Provide plots of the RMS response of the facility, as seen at the Connection Point and at the Generation Unit LV Terminal, for each of the case scenarios defined for the particular type of units.

For each scenario, clear plots showing the following parameters must be provided as a minimum. Additional plots can be included to illustrate specific behaviour of individual generation units, if necessary (for example, to illustrate the trip of a group of units and the retained voltage at their terminals).

Table 50 - Required Plots

Plot #	Parameters	Node	Unit
Plot 1	Voltage, Active Power & Reactive Current	CP	Per Unit
Plot 2	Apparent, Active & Reactive Powers	CP	Actual Values
Plot 3	Voltages	CP & Generation Unit LV Terminal	Per Unit
Plot 4	Apparent, Active & Reactive Powers	Generation Unit LV Terminal	Actual Values

Important notes for the plots:

- Use the image file formats of ".emf (enhanced metafile)" or ".wmf (windows metafile)" providing vector graphics of the plots with a good resolution and small file size in kilobyte. Avoid using raster graphics file formats such as ".jpeg", ".png" or ".gif".
- All outputs should be plotted in the requested units aligned in the same horizontal axis (i.e. same intervals with same scales). This feature is important for an effective review of the proportionality requirement in the outputs.
- Cursors in the plots showing results at relevant times would be appreciated.
- Ensure all information (time marks, obtained outputs) in the plots corresponds to summary results table.

- The scale and resolution of the plots must be sufficient to clearly identify the FRT-response during and after the voltage disturbance and to allow easy comparison against the responses specified in the Grid Code, which must be captured in the graphs as well.
- The scale may need to be readjusted for the different disturbances to clearly show compliance with the required timescales. In some cases, it may be necessary to provide a second plot with a zoomed-in area. The relevant outputs and response times must be clearly highlighted in the plots.

5.2. Case Study 1

Include plotted results and commentary. Sample plots are provided below showing the level of detail and clarity required in the simulation results. The plots and the numerical results are for demonstration purposes only.

The following plots are obtained from a hypothetical TSO level connection of a PPM Non-RfG facility with 22 generation units, reaching a total of MEC = 50 MW at the connection point. The 50% retained voltage case with event duration of 1.733s is assumed.

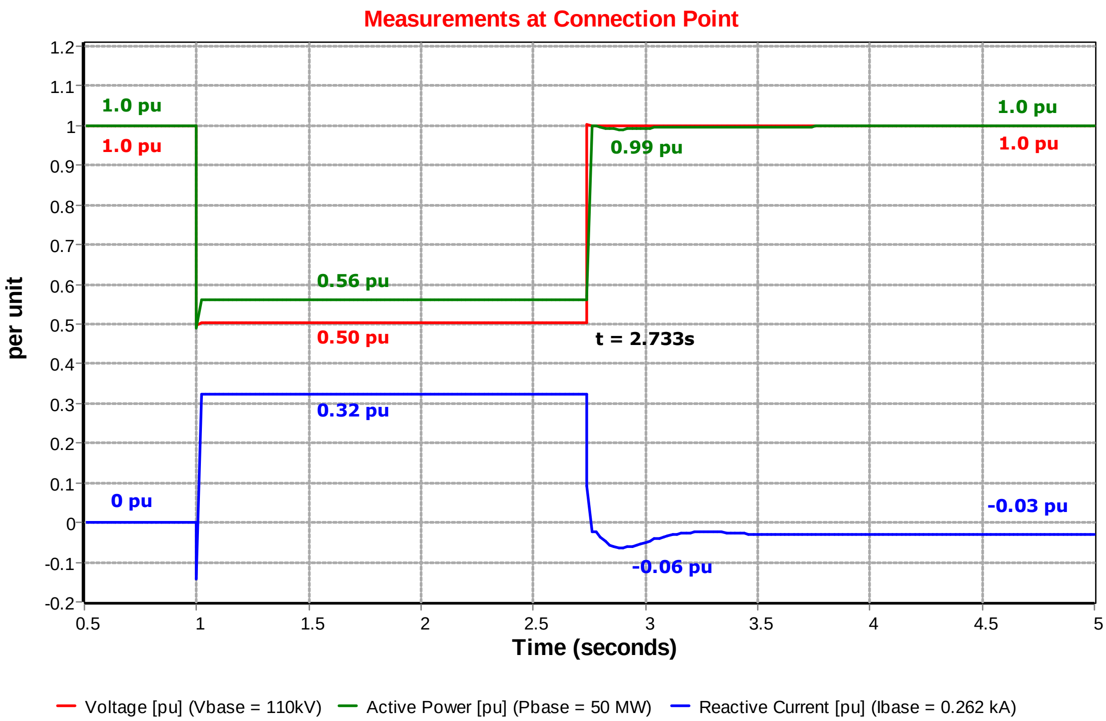


Figure 22 - Voltage, Active Power & Reactive Current at CP

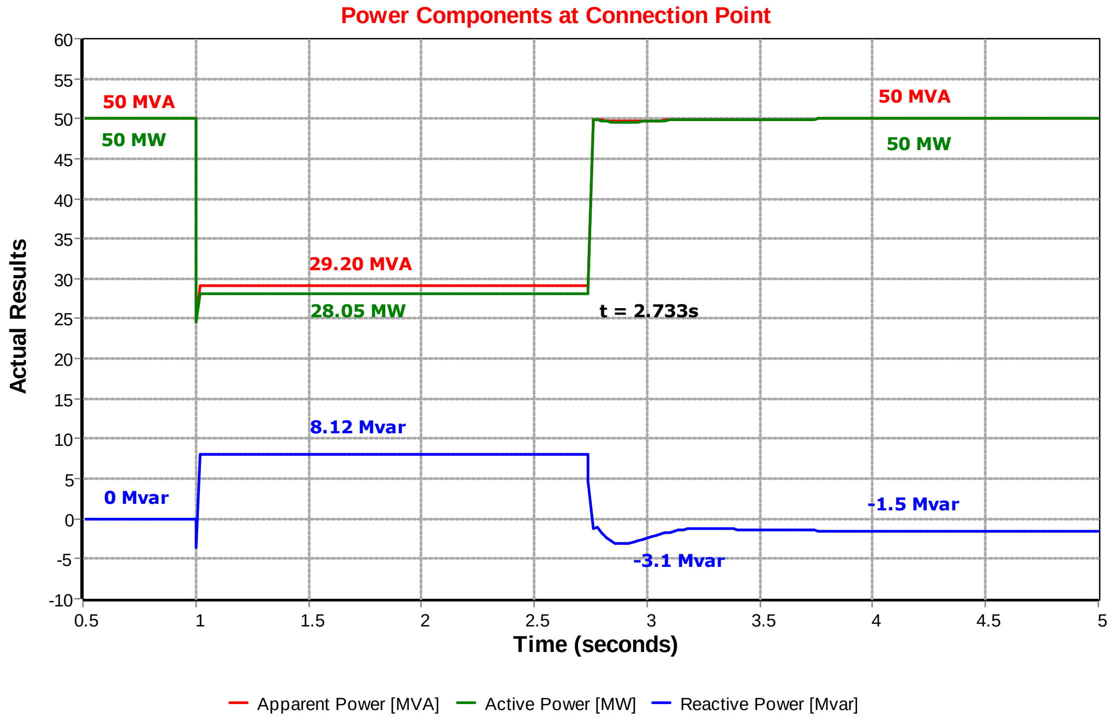


Figure 23 - Apparent, Active & Reactive Powers at CP

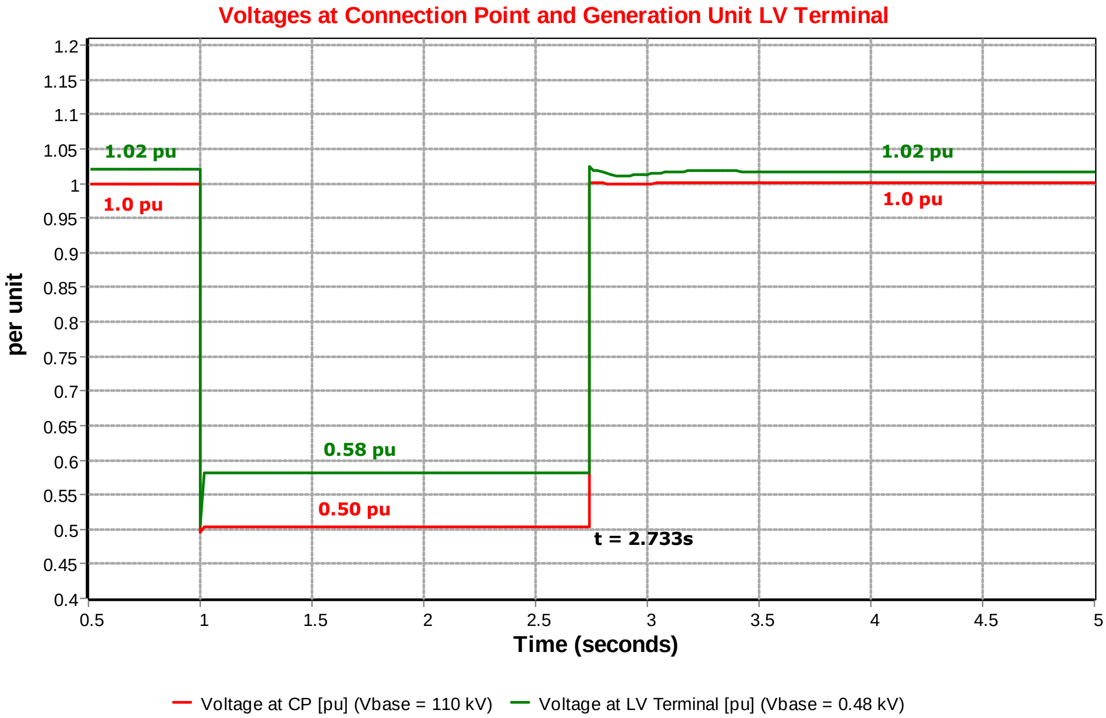


Figure 24 - Voltages at CP and Generation Unit LV Terminal

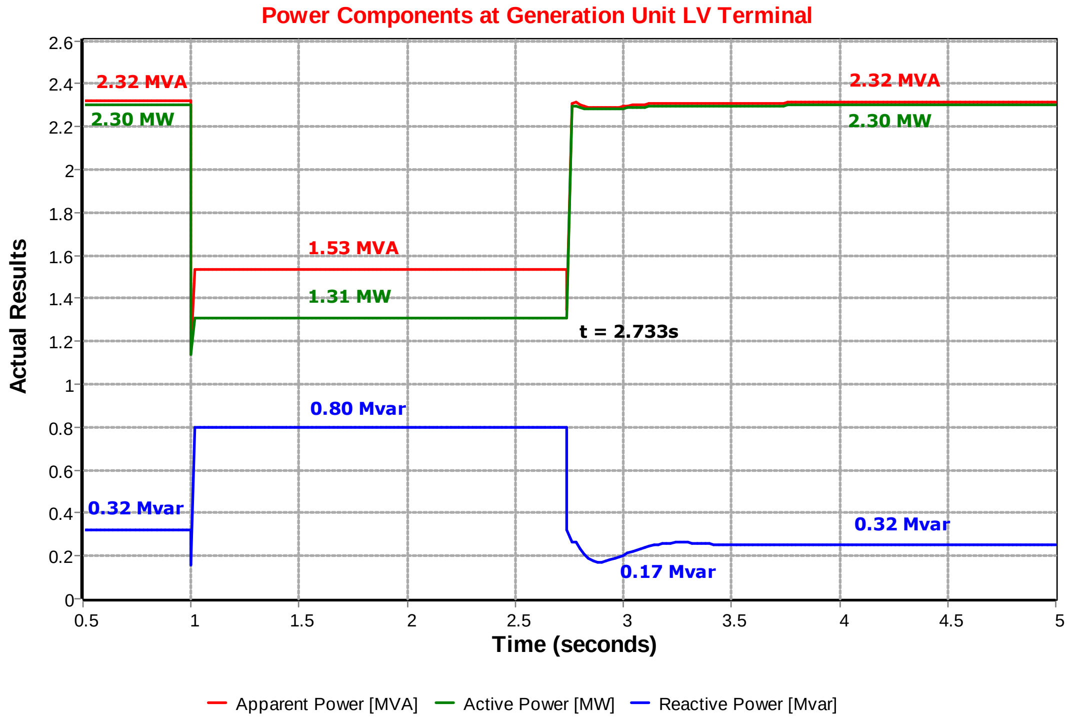


Figure 25 - Apparent, Active & Reactive Powers at Generation Unit LV Terminal

5.3. Case Study N

Include plotted results and commentary for all the case studies.

6. Conclusions

Include a high-level description of the scope and findings of the FRT study. Include a summary table as given below for PPM connections flagging all non-compliances. A similar table could be developed for other types of connections.

Fill in the table stating compliance and non-compliance with the relevant clause for each case study. Indicate the numerical values describing the maximum performance that achieved during simulation studies (i.e. the ratio of active power supplied during FRT event to pre-disturbance level, active power recovery time, pre-disturbance and disturbance periods reactive current injection levels, rise time of reactive current response, etc.). The clauses below apply to the Grid Code only. For connections to the distribution system, change references to the relevant Distribution Code clauses. Following the table, for the non-compliances, address potential mitigation methods and proposals, and discuss the responses at the generation unit LV terminals.

Note that the numerical values given in the table below are for demonstration purposes only without referral to any particular simulation case for PPM connections.

Table 51 - Summary of FRT Compliance Assessment at CP

Clause	Requirement	Obtained Results	Notes
PPM 1.4.2(a)	Active power proportionality: Pre-disturbance/Disturbance Ratio (%)	Case 1: 30% Case 4: 57% Other cases compliant.	Reached unit maximum capacity. Non-compliance is due to XY condition.
	Reactive current provision time:	All cases compliant.	-
PPM 1.4.2(b)	Active power recovery time to 90% of its maximum:	Case 2: 1200 ms. Case 4: 1110 ms. Case 5: 1148 ms Other cases compliant.	High oscillations in post-disturbance due to XY limitation in the inverters.
PPM 1.4.2(c)	Priority given to Active Power during FRT:	All cases compliant.	-
	Reactive current proportionality: Pre-disturbance/Disturbance [kA]	Case 1: 0.0/1.7 kA Case 6: 0.3/2.5 kA Other cases compliant.	Internal XY equipment absorbs more reactive power due to XY settings during FRT event.
	Reactive current rise time within 100 ms:	All cases compliant.	-
	Reactive current settling time within 300 ms:	Case 3: 340 ms Case 4: 424 ms Other cases compliant.	Non-compliance is due to XY condition. Discussion provided in section XY.
PPM 1.4.2(d)	Revert to pre-fault reactive control mode and setpoint within max. 1.5s*:	Case 1: 1.54 s Case 2: 2.625 s Other cases compliant.	Non-compliances are due to XY parameters and XY conditions. Improvement suggestions are shared in section XY.

* Check section 2.3.9 for clarification on this requirement.

References

Provide source documents used as reference throughout the study.

[1] https://www.eirgridgroup.com/library

[2] "Simulation Studies and Modelling Requirements for Compliance Demonstration", EirGrid, Version 1.0, 23 March 2021. Available on:

http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Simulation-Requirements.pdf

[3] Datasheets/technical specifications or reports for equipment.

[4] EirGrid's Grid Code

https://www.eirgridgroup.com/customer-and-industry/general-customer-information/grid-code-info/

[5] ESB Networks' Distribution Code

https://www.esbnetworks.ie/who-we-are/distribution-code

[6] ENTSO-E Network Code 2016/631 - Requirements for Generators

https://www.entsoe.eu/network_codes/rfg/

[7] ENTSO-E Network Code 2016/1447 - High Voltage Direct Current Connections

https://www.entsoe.eu/network_codes/hvdc/

[8] Guidelines/user manuals or technical reports for dynamic modelling.

[9] Information on the MSS data provided by EirGrid or ESB Networks (MSS data report title with issue date/email with date and sender information).

[10] Other used documents.

Appendix A: Supporting Information

If needed, include any additional supporting information, such as:

- The parameterisation tables of the generation and controller unit libraries.
- Further explanation, discussion or information not addressed in the report chapters.

Appendix B: Sample MSS Data Report

Minimum System Strength (MSS) Data

EIRGRID — **Future Networks Innovation & Planning**

Facility Name	Facility Name	**TSO / DSO Code**	CPXYZ
Connection Type	Connection Type	**Node**	Station Name XYZ kV
Customer Type	Customer Type	**MEC & MIC**	XY MW & XY MVA
Energisation Date	dd/mm/yyyy	**Gate**	Gate Info
Connection Method	Brief description of connection method		

Equivalent Thevenin System Impedance [pu]
at Station Name XYZ kV Busbar

Customer's facility is not included. $S_{base} = 100\ MVA,\ V_{base} = Busbar\ Voltage\ \ kV\ ,\ Z_{base} = V^2/S$

	R_{pos} [pu]	X_{pos} [pu]	$(X/R)_{pos}$	R_{neg} [pu]	X_{neg} [pu]	$(X/R)_{neg}$	R_{zero} [pu]	X_{zero} [pu]	$(X/R)_{zero}$	3Ph Skss [MVA]
N	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	XYZ.X
N-1	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	XYZ.X
N-1-1	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	0.0XY	0.0XY	X.YZ	XYZ.X

Notes:

1. The technical parameters provided in this document relate to the Minimum System Strength (MSS) conditions that can be reasonably expected at the specified busbar under a range of operating conditions.
2. The Equivalent Thevenin System Impedance is provided to facilitate the design of the facility in accordance with the Grid Code (or Distribution Code for DSO customers) clauses related to Power Quality (PQ) and Fault Ride Through (FRT). This technical information should not be used for any other purposes without consultation with EirGrid.
3. The MSS data provided only relates to the transmission network. For DSO customers, it is the responsibility of the DSO to amend it accordingly for its customers in order to capture the distribution network between the transmission grid busbar and each customer connection point. The DSO is responsible for ensuring compliance with the relevant Power Quality and Voltage Fluctuation standards and limits for the connection of the DSO customers.
4. Based on the customer types, the following technical studies are required to be submitted to EirGrid at least twelve (12) months before the scheduled energisation of the facility:
   - All TSO Generation Customers : Both PQ and FRT studies
   - All TSO Demand Customers : Only PQ study
   - DSO Generation Customers : Only FRT study (ESB Networks will issue MSS data to DSO customers)

     For Connection Point ≥ 110 kV - All DSO Generation Customers.

     For Connection Point < 110 kV - DSO Generation Customers ≥ 5 MW.

     EirGrid doesn't require an FRT study from the DSO Generation Customers < 5MW with Connection Point < 110 kV.
5. Power Quality study should demonstrate that the facility is designed to comply with the allocated limits issued by EirGrid to each customer in the PQ Requirements report.
6. FRT study should demonstrate with dynamic simulations that the facility is designed to comply with the most up-to-date version of the Grid Code (or Distribution Code for DSO customers).
7. Check the guidance documents provided on EirGrid's webpage for Simulation Studies and Modelling Requirements: https://www.eirgridgroup.com/customer-and-industry/general-customer-information/simulation-studies/
8. The MSS data must be used at the connection point to model external power system as follows:
   - PQ Voltage Fluctuation Assessment : (N-1) impedances to be assumed as steady-state condition.
   - FRT Assessment : (N-1) impedances to be assumed prior and during the voltage disturbance. (N-1-1) impedances to be assumed during voltage recovery.

Revision:	1.0	**Date Issued:**	dd/mm/yyyy
Prepared by:	Name Surname	**Date:**	dd/mm/yyyy
Checked by:	Name Surname	**Date:**	dd/mm/yyyy
Signed off by:	Name Surname	**Date:**	dd/mm/yyyy

Appendix C: Checklist

An indicative timeline for the FRT study submissions is given in the following figure.

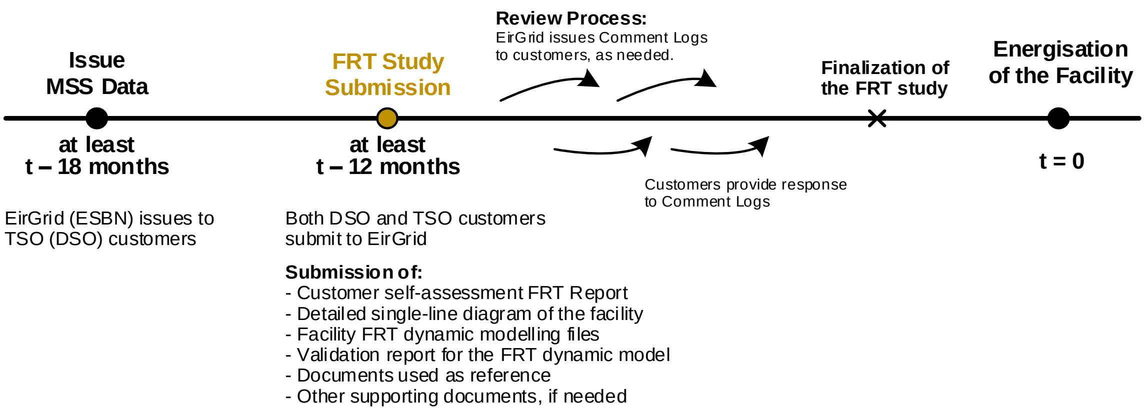


Figure 26 - Indicative Timeline for FRT Study Submission

For an effective review process, items (2-6) below are requested to be submitted as separate files/documents, i.e. not in the FRT self-assessment report appendices.

Table 52 - Checklist for FRT Study Submission

#	Item	Note
1	Customer Self-Assessment FRT Report	Use this template heading structure for an effective review. In MS Word, save as in pdf format with “Create bookmarks using: Headings” option selected.
2	Detailed SLD of the Facility	Must be legible.
3	Facility FRT Dynamic Modelling Files	Provide all modelling files together including libraries during the FRT report submission. (.raw, .seq, .sav, .dyr, .dll and .sld)
4	Validation Report for the FRT Dynamic Model	Factory and/or type tests to validate the responses of the dynamic model developed for the FRT analysis.
5	Documents Used as Reference	For EirGrid’s records.
6	Other Supporting Documents	If needed.