REPORT

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Description of system needs and test cases

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0.1 – DRAFT	13.05.2016	RTE	Initial Draft
0.2 – DRAFT	26.05.2016	RTE	Comments from WP3 partners
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0.4 – DRAFT	10.06.2016	RTE	Comments from WP3 partners
1.0	11.07.2016	RTE	Comments from the Executive Board and from the Reference Group

CONTENT

1 Introduction

The share of power electronic devices in power systems is growing rapidly. Renewable generation (e.g., wind farms, PV panels, microturbines, etc.) is mainly connected through converters. At the same time, an increasing percentage of loads are themselves interfaced to the grid through power electronics. Furthermore, many onshore and offshore HVDC projects are being implemented or are planned in the near future. As a result, parts of continental Europe, such as the Iberian Peninsula or Germany, or whole synchronous areas, such as Ireland, could occasionally be operated without synchronous machines. In such conditions, power system stability will have to be ensured with the same level of reliability as today.

The matter of operating a network with 100% power electronics is quite well resolved for small islanded systems, such as microgrids [1][2][3], and grids connected to strong AC systems via HVDC, such as offshore grids.[4] The same doesn't apply for large transmission systems where grid topology and power injections are highly variable and are not known at any moment by all system components or even by a centralized entity. Distributed control schemes by independent converters are therefore the only viable alternative.

The Work Package (WP) 3 of the MIGRATE project addresses power system stability of large transmission grids without synchronous machines. Its objectives are:

(a) to develop the necessary controls and management rules ensuring system stability of transmission grids without synchronous machines
(b) to check the viability of these controls and management rules within transmission grids to which some synchronous machines are connected
(c) to infer requirement guidelines for new converter-based generating units, which will facilitate the implementation of these controls and management rules

Special attention will be given to the costs of the proposed controls and management rules. Indeed, hardware upgrades, such as additional electrical batteries or oversizing of converters, may be necessary and could be very expensive. We will try to find a "cost-effective" solution with minimal hardware upgrades. This could lead to recommending some new operational or access rules, which will be identified as part of this research work.

WP3 will at first concentrate on power systems with 100% power electronics. It means that no synchronous machine will be directly connected to the AC system, but some could be interfaced through converters. It includes both generating units, loads and transmission assets.

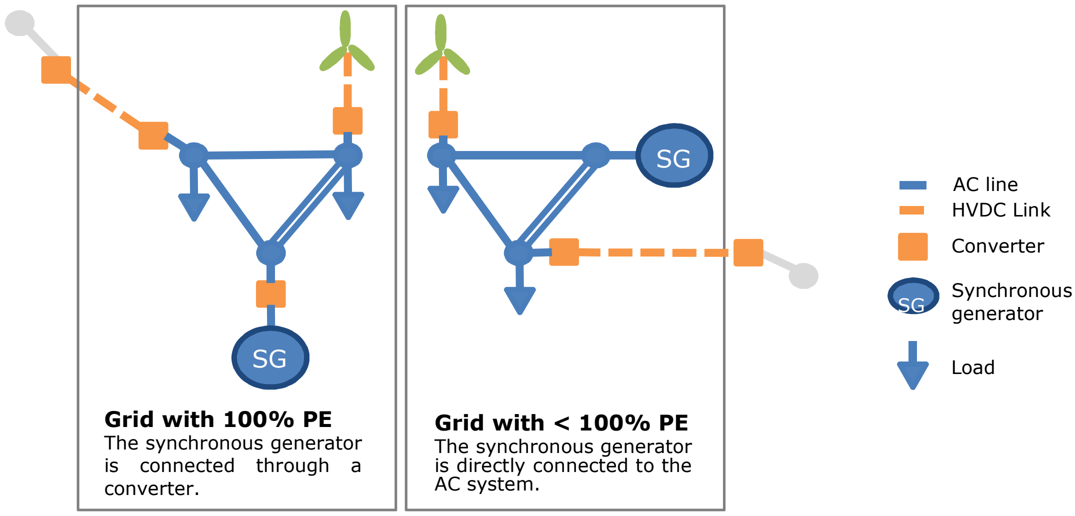

*Figure 1 – **Grids with 100% PE vs. grids with < 100% PE***

The following topics are out of the scope of WP3:

- ***Load adequacy:*** the assumption is that there is enough generation to fulfil the load at any time (no generation shortfalls).
- ***Development of new protection schemes able to clear faults on systems with 100 % power electronics:*** we will assume that such protection exists (in other words, protection strategies will adapt to the behaviour of the system and not the opposite). Protection issues are addressed in WP4.
- ***Defence plans:*** defence plans against extreme disturbances will not be developed[1].
- ***Distribution grids:*** the focus will be on large transmission systems. Distribution grids will be represented by appropriate equivalent models taking into account relevant phenomena.
- ***Power quality:*** the focus will be system stability. Power quality issues for grids with 100% power electronics should be addressed after the MIGRATE project. They are addressed in WP5 for lower penetrations of inverters.

This document sets the framework of WP3. It is divided into 5 chapters. Requirements about the global behaviour of a system with 100% power electronics (called hereinafter "system needs") are described in chapter 2. The meaning of stability for such grids is developed in chapter 3. The framework for the design of systems without synchronous machines is set in chapter 4. Chapter 5 presents the detailed description of the research work that will be performed. Test cases that will enable validation of the proposed controls and management rules are described in chapter 6.

[1] Defence plans are very similar to protection schemes and aim at diminishing the impact of large disturbances on the grid, taking into account the possibility to shed load or generation, or to isolate parts of the grid to avoid the spreading of the disturbance.

2 System needs for transmission grids with 100% converter-based devices

The behaviour of current power systems is deeply linked to the presence of synchronous machines. Developing controls and management rules that allow operation of large transmission systems without any synchronous machines implies a need to completely redesign for this behaviour. The first necessary step is to define the fundamental requirements that must be fulfilled by such a system. These requirements are called hereinafter *system needs*. They are summarized in the table below and described in details in the remainder of this chapter.

Alternating Current system .... *Transmission systems will remain composed mainly of AC devices.*	Chapter 2.1
Synchrony .... *In steady-state, voltages on all nodes must have the same frequency.*	Chapter 2.2
Balance between load and generation .... *The electrical power consumed by loads under nominal conditions and the primary power of generating units must be balanced.*	Chapter 2.3
Possibility to enforce market-driven setpoints .... *It must be possible to implement setpoints defined by markets.*	Chapter 2.4
Stability .... *Power system stability must be ensured.*	Chapter 2.5
Acceptable ranges of frequency and of voltage amplitude .... *Frequency and voltage amplitude must remain in acceptable ranges.*	Chapter 2.6
Load sharing between generating units .... *Load variations must be shared between generating units according to predefined values.*	Chapter 2.7
Robustness to system split .... *A system isolated by some disturbance must remain stable if load and generation can be balanced.*	Chapter 2.8
Black start capability .... *System restoration must be possible after a black-out.*	Chapter 2.9
Possible migration path .... *A smooth transition from current systems to systems with new controls and management rules must be possible.*	Chapter 2.10

2.1 Alternating Current system

Transmission systems will remain composed of mainly AC devices.

As inverters collect power from DC sources to convert it to AC, switching transmission systems to DC could seem to be a good idea. However, the many advantages of AC must be taken into consideration. Nowadays, power systems are operated using alternating current. Why such a choice?

- AC voltages can be readily transformed to higher or lower voltage levels, at low cost and with only copper coils (which are low tech and highly robust). In contrast, DC/DC transformers are not off-the-shelf devices and are very expensive.
- The protection of DC transmission systems would also be much more complicated. AC circuit breakers use the zero crossing of the current to open faulty elements. On a DC system, an ancillary circuit has to create a zero crossing of the current to allow circuit breakers to open. Even if the technology is available today, DC circuit-breakers are still the subject of research and they are therefore very costly products.
- Existing European transmission assets are worth billions of euros and are made for AC. Switching the whole system to DC would require replacing hundreds of thousands of devices (all AC transformers, circuit breakers, line insulation systems, etc.). All these elements are extremely costly. Moreover, certain sources of electricity, for example synchronous generators, naturally produce an alternating voltage. Replacing the AC system by a DC one would require connecting them to the power grid via AC/DC converters. The same holds true for the existing AC loads, such as motors. As there are a large number of synchronous machines and AC loads in the European network that will last for decades, a strong investment would be required.
- Besides the costly reengineering, changing lines from AC to DC would not necessarily enable transmission of more power. AC systems are today 3-phase balanced systems, which is the most interesting configuration regarding the transmitted power versus the section of cable used. As the 3 phases are balanced, there is no need for a neutral wire. Compared to 2-phase systems, adding 1 wire allows transmission of 3 times more power.

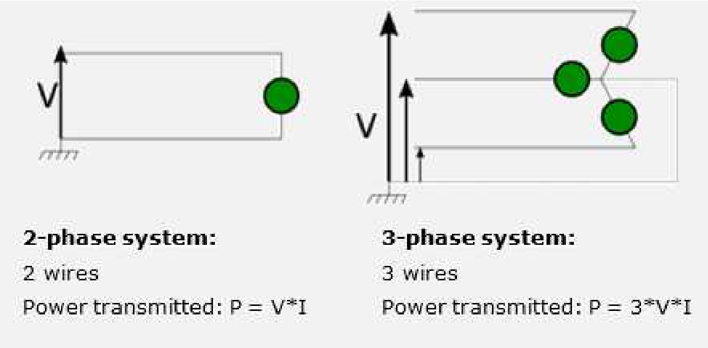

*Figure 2 – **3-phase versus 2-phase systems***

- Finally, from the perspective of controlling the power system, AC signals offer more degrees of freedom for sensing and actuation than mere DC signals, namely voltage amplitude and frequency. Whereas the former is a local measure of system stress and also present in DC system, the latter is a global signal unique to AC systems.

Keeping the AC system in the future is economically and technologically the best option[2], and it is the only one that would allow a smooth transition from the existing system to a fully power electronics power system.

The question of the frequency value could also be addressed. The power system is operated at 50 Hz in Europe. Using Power Park Modules (PPM), frequency can be easily set to other values. For example, in power system associations, connecting offshore wind farms at 16.7 Hz is one of the fashionable topics. But operating power systems at a frequency different from 50 Hz would also induce an economic issue. In fact, during the development of electric power systems, transmission assets were designed to operate in a frequency range around 50 Hz. Now, a modification would impact all existing transmission assets and therefore it would induce high costs such as AC system to DC system change.

[2] The answer could have been different in a situation where the whole power system (generation, load, and transmission assets) would have been built from scratch.

2.2 Synchronism

In steady-state, voltages on all nodes must have the same frequency.

Non-uniform frequencies in steady-state would imply variations of angle differences between the 2 ends of transmission lines or transformers and would create power swings, as illustrated in the figure below.

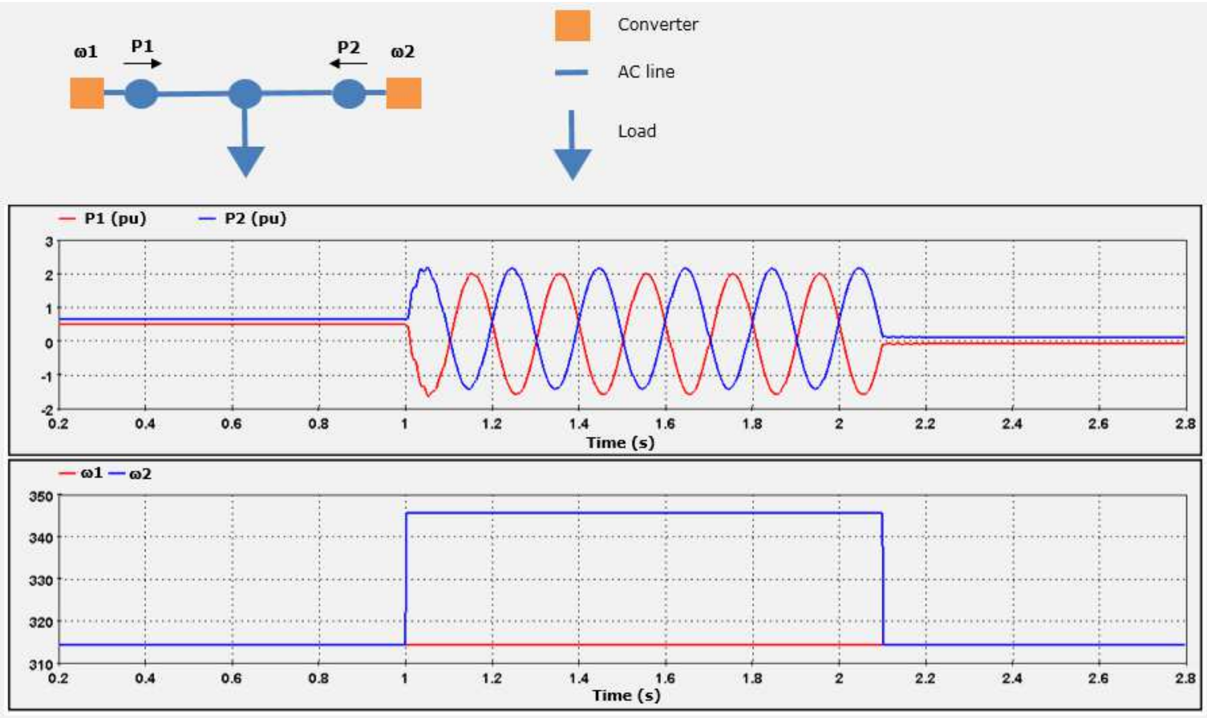

*Figure 3 – **Power swings induced by non-uniform steady-state frequencies***

For synchronous machines, frequency is connected to the rotational speed of the rotor. Synchronous machines inherently contribute to the synchronism of all of them: they all rotate at the same speed in steady state (neglecting the number of pole pairs). They, therefore, impose a uniform grid frequency. Grid-connected PE devices today measure the grid frequency and generate a current[3] at this frequency, that is, they "follow" the frequency imposed by synchronous machines. In a system with 100% power electronics, however, the inverters will have to provide waveforms at the same frequency, although there will be no synchronous machine to "follow". They will need to generate the frequency. These are also known as *grid forming* inverters. These units are controlled to provide the system with a sinusoidal voltage whose amplitude and frequency are

[3] Some generating units are inherently voltage sources, but they are controlled as current sources when they are connected to large transmission networks.

almost constant for all grid situations. It means that at least some of the inverters will be controlled as voltage sources in the future, whereas they are today all controlled as current sources.

This synchronism can be achieved in different ways:

- With external signals that will synchronize all converter-interfaced generating units, such as through a GPS device
- With regulators that will control (in closed loop) the frequency
- With virtual oscillator control that provides synchronization between the inverters by emulating non-linear oscillators
- ...

The chosen solution could bring new technical challenges on the network, either on the network hardware or on the telecommunication infrastructure.

2.3 Balance between load and generation

The electrical power consumed by loads under nominal conditions and the primary power of generating units must be balanced.

Controls of generating units must ensure a balance between generation and load in real time (short term). As mentioned in the introduction of this document, generation adequacy (long term) is out of scope for WP3.

Balancing load and generation at any time requires the actuation of generator controls to compensate the transient imbalances that may occur, since there are currently no massive and cheap energy storage systems capable of charging or discharging the amount of imbalanced energy with an appropriate response speed.

But what do "generation" and "load" refer to? Concerning generation, one must distinguish between:

- electrical power G_e, that is injected on power systems by generating units
- primary power G_p, that is turned into electrical power by generating units (for example mechanical power for synchronous machines)

From the load side, one must also distinguish between:

- electrical power L_e actually consumed by loads
- electrical power L_n that loads would consume under nominal conditions

With or without synchronous machines, the physical laws of power systems make electrical power injected by generating units equal to the electrical power actually consumed by loads: at any time $G_e = L_e$ (not taking losses and dissipation into account).

Loads are designed to operate for a defined range of voltage (for example, nominal voltage ± 5%). It means that $L_e = L_n$ if the voltage at their connection point is included in that range. If voltage is outside these limits, loads may not operate as expected by consumers[4].

The equality between electrical power injected by generating units G_e and primary power G_p is nowadays ensured by primary frequency control, using the link between G_e and G_p provided by the rotating mass equation. Without synchronous machines, this may be done using the link between G_e and G_p provided by the DC capacitor voltage equation.

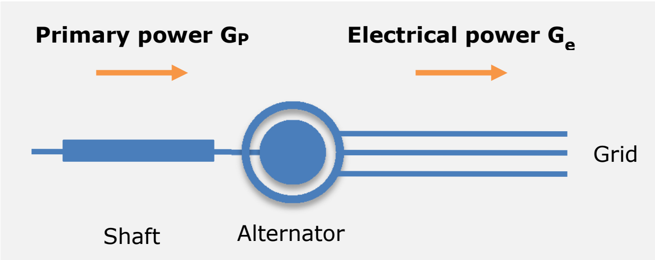

*Figure 4 – **Generation: primary and electrical power***

The system need "load and generation must be balanced at any time" can be rephrased into "$G_e = L_n$ at any time, and G_p must be controlled to follow G_e".

The load-generation imbalances can be caused by:

a) The permanent variation of instantaneous demand. Small disturbances - voltage within normal range
b) Imbalances caused by instantaneous and not scheduled trips of load or generation, due to internal problems in generation/demand assets - voltage within normal range.
c) Imbalances caused by instantaneous and not scheduled trips of load or generation, due to disconnection after fault clearance or other causes - voltage out of normal range.
d) Imbalances during voltage dips or transient overvoltages due to the different dynamic behaviour of the generation and the load in voltage disturbances - voltage out of normal range.

The different types of imbalances can appear simultaneously (can be cumulative), e.g. type c) and d) are very common after fault clearance.

In general, one can say that the effects of type d) imbalances are lower if the law of injection of active power (generator) during voltage disturbances approaches the characteristic of the power consumed as a function of the voltage (load) so the transient imbalance tends to remain zero as a function of voltage. In general, the law of load can be described approximately as follows:

$$P(V) = \sum_{r=0}^{n} P_{0r} V^r$$

[4] It is easy to illustrate for loads with a constant impedance Z, for which $L_e = \frac{U^2}{Z}$. If voltage is very low, L_e is also very low.

In a very generic and simplified way, loads whose dynamic characteristic for the power consumed as a function of voltage can be described by a square of the voltage law (r = 2) are called "constant impedance". Loads dominated by asynchronous motors can be considered as constant power (r = 0) for voltages above approximately 0.7 pu (range in which asynchronous motors can maintain constant torque).

Additionally, demand can vary if the load depends on the frequency. For example, the behaviour of asynchronous motors after a deviation of the frequency is given by:

$$\Delta P = D\Delta f$$

Δf represents frequency deviation in pu (deviation vs 50 Hz).
ΔP is the active power deviation of the power consumed by the load in pu (vs nominal load).
D is a constant of proportionality, also known as load damping coefficient.
Common values for D coefficient are from 1 (low levels of industrialization) to 2 (high level of industrialization). It is important to note that many recent asynchronous motors incorporate drivers based on PE so this characteristic may change in the future (with no sensitivity to frequency: D=0).

Generation-demand balance on power systems with synchronous machines:
In order to develop the necessary controls for a 100% PE scenario, it is useful to have in mind how currently the generation-demand balance is managed. Two phases can be distinguished:

- In an initial stage, imbalances are partially compensated through the rotational energy of the rotors (synchronous generators and the other rotating masses coupled to their axes). Regulators have not reacted yet. The acceleration or deceleration of these rotating masses modifies the frequency imposed by each generator and consequently the frequency of the system. The rotating mass equation establishes the variation of the frequency in the first seconds after an imbalance. If the load-generation imbalance is not compensated rapidly, the frequency can evolve to unacceptable values (see system need 2.6). Load-generation imbalances cause a quasi-instantaneous rotation of the angles of voltage phasors (see system need 2.6) that propagate through the network (electromagnetic phenomenon). The direction of this rotation (forward or backward) depends on the sign of imbalance (net loss of generation or demand). Such quasi-instantaneous angular rotations are shared between the synchronous generators coupled to the system so this causes a sudden change in the electric power (electric torque) at the terminals of synchronous generators balancing the load-generation initial imbalance. However, this change occurs at constant mechanical torque (constant mechanical power delivered to the shaft from the primary energy source). Disconnection/connection of grid elements (lines, transformers, etc.) also cause redistribution of power flows through the network with sudden angular jumps/differences.
- In a second stage, regulators of generating units react. To compensate generation-load imbalances each synchronous generator has a primary continuous control of the power-frequency regulation whose objective is to drive the frequency derivative to zero, but permitting a certain steady-state error. This task is done by the "governor". It can be described as a simple first-order control proportional to the error. Such control increases

the mechanical torque delivered to the generator rotor ΔP_{mec} in proportion to the speed deviation Δω (proportional to the deviation of the frequency at the generator terminals). The proportional gain K_p is the inverse of the droop R:

$$\Delta P_{mec} = K_p \Delta\omega \; = \frac{\Delta\omega}{R}$$

The primary regulation control, as all the controls that are exclusively proportional to a measured deviation signal, has a steady-state error. This, rather than a drawback is a need. The joint action of all primary controls of all generators has to be distributed to act as a large distributed control at the electrical system level. Generators should not assume autonomously the resolution of the frequency permanent error because it could introduce undesired oscillatory phenomena.

In general, it is imperative that all primary controls of all synchronous generators have the control gains proportional to their ratings, thus, the responsibility for frequency control is shared between all generators in proportion to the size of each generator.

Besides, it is positive that regulation reserves are distributed across all generators so that each one must mobilize the lowest power as possible, thus reaching the highest joint response speed.

Generation-demand balance on power systems with 100% power electronics:

Need for very short term storage to compensate load imbalances

Even if regulators of inverters can make them react faster than synchronous machines, regulators use measurements which cannot be made instantaneously. For example, for PE devices it takes 50 to 100 ms to get a reliable frequency measurement and therefore a longer time for a synthetic inertial response[5]. That is an unacceptable delay to balance load and generation in such a grid. Today, synchronous generators have an instantaneous response. On systems with 100% PE, before measurements are done and regulators start to react, a new source (or sink depending on the imbalance) of energy may be needed to compensate imbalances. This energy storage could be the energy stored on the DC bus or some additional source, which would require the installation of new specific hardware. It is also important to have in mind that immediately after a load change, when no regulator has started to react, load sharing will be done via the impedance ratio from the load to the different generators. This phenomenon will have to be taken into account for the sizing of the balancing energy source. The need for this very short term storage will be evaluated in the project.

[5] Synthetic inertial response is usually a requirement for PE device to produce more power for a short period of time when the frequency decreases.

<u>Need for a signal with information about power balance</u>

In power systems with synchronous machines, frequency and power balance are linked through the rotating mass equation. This link is missing in 100% PE grids. Inverters control the voltage frequency using, for example, a mathematical relation between the required active power and frequency, which can be chosen by design.

At first view, the missing coherence between frequency and power balance is a drawback due to the fact that the whole concept of energy balancing in conventional grids is based on this physical relationship. However, it allows the PE grids for alternative possibilities to arrange imbalances, e.g., by adjusting the generator voltage amplitudes. These additional degrees of freedom could be used as an advantage, if the operating frequency is defined as constant for all possible points of operation. Additionally, the angle could be used instead of the frequency for grid-state communication. For example, on offshore grids, communication via the angle of the grid voltage instead of the frequency could lead to a notable improvement in terms of system dynamics as it is faster than acting on the frequency which is the derivative of the angle [5].

<u>Need for controls that adapt to demand</u>

Today, inverters are controlled in a way that they feed the system with predefined active power (produced by the primary source (wind, solar) or fixed by an external set point). In the case of a system where all sources of energy are based on inverters, they need to produce what is needed by the load.

Another approach could be done using telecommunications. Loads could "send" to generation the required power level and generating units could adapt their production accordingly. However, we envision this to be merely a baseline solution for comparative studies rather than an actually implementable solution due to its robustness issues.

2.4 Possibility to implement market driven set points

It must be possible to implement setpoints defined by markets.

If the services necessary for system stability can be provided by units regardless of their geographical location, a market will probably be created to allocate these services at the lowest cost.

In addition to system stability, some criteria will have to be respected by the overall system (if not in short term, at least for the steady state system). It is very hard to describe what these criteria will be as we have no knowledge of what the controls will be. We can guess that for example cross border flows will be part of them. Today and in the future cross border capacities are allocated to actors by the market. In real time the cross border flows do not fit exactly to the forecasted values but there are mechanisms to bring it as close as possible to the target.

To illustrate it, present frequency control of Continental Europe could be used (see also chapter 2.3). The inertia and primary control are the basics of the stability of the system. They allow the system to move "slowly" and to stabilize when there is a change in load or production (see chapter 2.3). The secondary control takes the stable situation of the system after primary control has reached steady state and brings it back to a situation where 2 objectives are met:

- First, the frequency is closer to 50 Hz (it restores the frequency to its set-point value)
- Second, the flows on the cross border lines are closer to the forecasted exchange between the countries (it maintains the power flows with neighbouring countries or control areas to the scheduled value)

When these 2 objectives are fulfilled, the primary regulation is recovered to the levels previous to the disturbance and is autonomously prepared for other possible imbalances. The secondary control is driven by a signal that is sent by the national dispatch centres in all countries. Different signals are sent to units in different countries, helping the cross border flows to reach their target, and the overall signals helps the frequency to return to 50 Hz. The tertiary control is used finally to restore margins of primary and secondary controls within the scope of TSO responsibilities to ensure reliable system operations.

In the future, even if the frequency control is different, the cross border flows will have to be close to their targeted value in steady state. In that case, a national active power control will have to be established. It is possible that other market signals will also have to be designed, and therefore new regulation will have to be created.

2.5 Stability

Power system stability must be ensured.

Before defining the needs for power system stability in future systems where 100% of generation is connected via PE devices, it is important to review the meaning and impact of system stability in today's power systems where a large proportion of generation comes from synchronous machines. In its broader sense, *Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact* [6]. The concept of stability needs to be considered in the context of its extent and consequences. For example, an individual generator may lose stability (synchronism) without causing widespread instability in the main system. Similarly, individual loads or load areas may be of interest; i.e., motors may lose stability (run down and stall) without cascading instability of the main system. What is important here is that following a disturbance, the system must reach a new equilibrium state with the system integrity preserved, i.e., with practically all generators and loads still connected through a single contiguous transmission system. Some generators and loads may be disconnected by the isolation of faulted elements, but it is accepted that it would be impractical and uneconomical to design a power system to withstand every possible disturbance without the loss of any element. This stability criterion and definition can be extended to a system with 100% PE, i.e., it is reasonable to accept the loss of some power converters as long as the integrity of the bulk system is preserved.

Power systems are subjected to a wide range of disturbances. Small disturbances in the form of load changes and variations in generation (wind, solar, etc.) occur continually and the system must be able to adjust to the changing conditions and operate satisfactorily in steady (or quasi-steady) state. It must also be able to withstand numerous disturbances of a more severe nature, such as short-circuits or loss of a large generating unit, demand centre or interconnector. Furthermore, for system integrity, the power system must be able to withstand even more severe but less probable contingencies without going into voltage collapse or uncontrolled cascading outages. Examples of High-Impact-Less-Probable (HIPL) contingencies include faults in stations resulting in the loss of numerous pieces of plant, such as busbar faults, busbar coupler faults, circuit breaker failures, protection relay mal-operation, etc. It is accepted that, for certain severe disturbances, it may be beneficial to split the system into two or more "islands" to preserve as much of the generation and load as possible. The actions of automatic controls or human operators will eventually bring the system together again into a new stable state. Failure to follow this approach could result in a run-away or run-down situation with a progressive increase in angular separation of generator rotors or a progressive decay in bus voltages, leading to cascading outages and a shutdown of the power system. Even though the risk of rotor angle instability is naturally not an issue in a system with 100% PE[6], the risk of voltage instability is still there and needs to be addressed in the design and control of the PE devices. Additionally, there are some instabilities specific to 100% PE systems.

Power system stability is essentially a single problem, however the various forms of instabilities that a power system may undergo can be better understood by using the following standard classification:

I. *Rotor Angle Stability*: refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability manifests in the form of increasing angular swings of some generators leading to their loss of synchronism with respect to other generators. Assuming that the control and stability of any synchronous generator installed behind PEs is outside the scope of this Work Package, this type of instability is not an issue in a system with 100% PE. However, it will need to be considered as part of the migration path as it is likely to impose very challenging conditions and may require special functionalities in the power converters.

II. *Voltage Stability*: refers to the ability of a power system to maintain steady state voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. The system is stable if the post-disturbance voltages return to a value close to the initial condition. Instability can manifest in the form of a progressive fall or rise of voltage at

[6] PE devices are not subject to rotor angle stability (they don't have rotor) nevertheless, angle difference in voltage can lead to high active power transient that can cause serious damage to the inverters.

some buses. In case of a progressive voltage fall system integrity is endangered as power cannot be delivered correctly to the customers. The driving force for voltage instability is usually the loads; i.e., in response to a disturbance with falling voltage, power consumed by the loads tends to be restored by the action of motor slip adjustment, distribution voltage regulators and tap-changing transformers. Restored loads increase the stress on the high voltage network by increasing the reactive power consumption and causing further voltage reductions in the transmission network. A run-down situation causing voltage instability occurs when load dynamics attempt to restore power consumption beyond the capability of the transmission network and the connected generation. In essence, low voltage stability is a problem in power systems which are heavily loaded and have a shortage of reactive power. Overvoltage instability, on the other hand, can occur in lightly loaded systems due to the capacitive behaviour of long transmission circuits and the inability of synchronous generators to absorb the excess reactive power.

Both types of voltage instability can arise in systems with 100% PE if adequate voltage regulation and dynamic reactive power capability are not provided by the power converters. An example of typical reactive power requirements for a power generating module is depicted in Figure 5. A similar conceptual curve for PE could be assumed for the purposes of this research project.

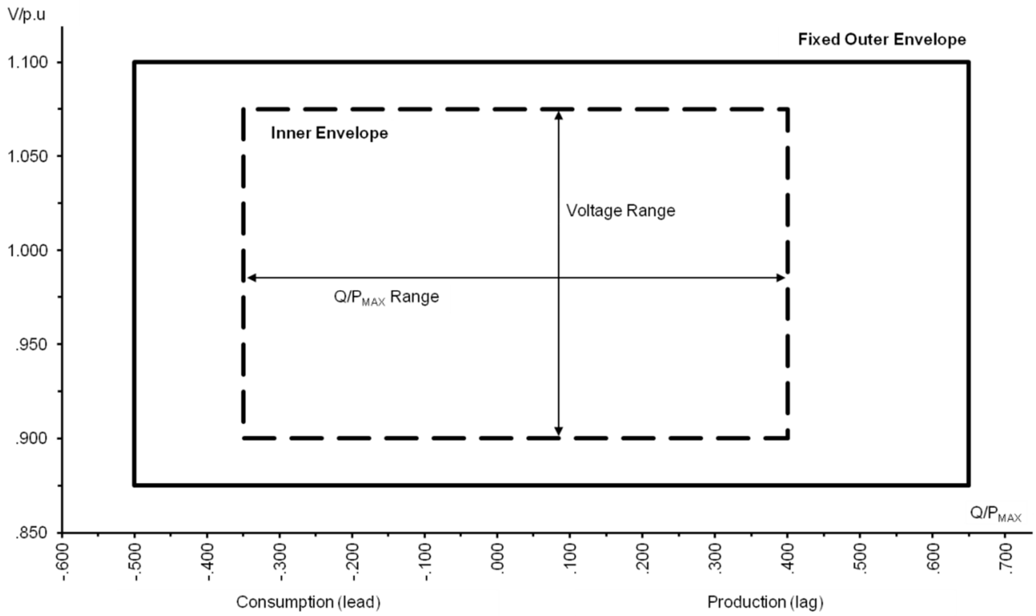

Figure 5 - ***Typical U-Q/Pmax-profile of a power generating module (ENTSO-E NC Requirements for Generators)***

An important requirement to support system stability is the capability of all generators to ride through faults, which will become critical in systems with 100% PE. This involves not only the ability to remain connected to the Transmission system during and after the voltage dip, but also the requirement to provide active and reactive power to support the system. An example of typical Fault Ride Through (FRT) requirements for a power generating module is depicted in Figure 6. A similar conceptual curve for PE could be assumed for the purposes of this research project.

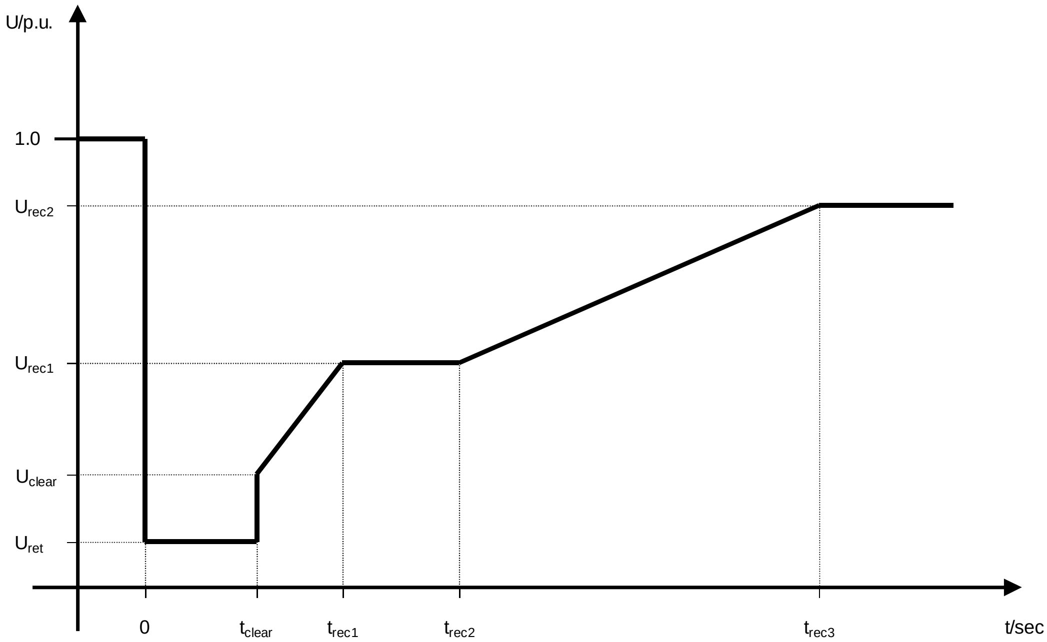

Figure 6 - ***Typical FRT profile of a power generating module (ENTSO-E NC Requirements for Generators – Article 14)***

III. *Frequency Stability:* refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load. It depends on the ability to maintain or restore equilibrium between system generation and load with minimum unintentional loss of load. Instability can manifest in the form of sustained frequency swings that can be accompanied by power swings and voltage excursions, leading to tripping of generation units and load. Generally, frequency stability problems are associated with inadequacies in equipment responses, poor coordination of control and protection equipment, insufficient generation reserve or a lack of system inertia. Given that the frequency in a system with 100% PE is not directly linked to the angular frequency of the rotating machines, the generation-demand imbalance will not automatically manifest in a frequency excursion in the transmission system voltage. This issue is covered in detail in sections 2.3 and 2.6.

It must also be noted that the standard classification of power system stability described above was developed for grids with a large amount of synchronous machines. It is possible that other stability issues occur on power systems with 100% PE. For example, one new instability mechanism which can occur in power systems with 100% PE is harmonic instability. This phenomenon was already observed in existing systems with high amount of PE (e.g. offshore and railroad grids) [4][7] and is due to an interaction among PE controllers and of PE controllers and grid resonances. Harmonic instability leads to voltage distortions caused by very high levels of harmonic voltages and can result in a cascading trip of grid elements.

2.6 Acceptable ranges of frequency and of voltage amplitude

Frequency and voltage amplitude must remain in acceptable ranges.

To ensure proper performance of all the devices that form an electrical system, avoid their damage and guarantee system stability, the new controls of a 100 % PE system should be able to maintain the variables that define the electrical state of the system – the voltage (magnitude and angle) and frequency – within acceptable ranges. All elements connected to the system (loads, elements of the distribution network, the transmission system and generators) have been designed under some physical limitations requiring voltage and frequency ranges acceptable for operation.
These ranges are more restrictive in steady state, however, wider excursions of voltage and frequency may be accepted if they are limited in time and if there are appropriate and fast enough controls to return the variables that define the electrical system within acceptable ranges (without permanent harm or damage of equipment).
For voltage and frequency, as a general reference, the limits defined in the current network codes can be considered.

Applicable ranges are:

a) Steady state ranges in voltage magnitude:
   The voltage magnitude shall remain within the corresponding admissible ranges. As absolute angles themselves have no meaning (angle *differences* determine power flow), there is no restriction on the angle value in steady state. (The nodal voltage angles of the network will be determined mainly by active power flows established by generators and loads).
   Synchronous systems are operated by adjusting the voltage magnitude of the nodes to specific values (system voltage profiles) so that, after a contingency, in the new steady state, voltage remains within acceptable ranges.
   For synchronous generators, the voltage of the network is regulated by imposing a setpoint voltage to the AVRs.
   After small perturbations, there is no need for a fast response in the controls while the voltage remains within the acceptable steady state ranges. Therefore, currently, wind farms or solar farms can perform voltage control in the absence of major disturbances with a control at park level that manages the instruction to each wind turbine or converter to maintain the voltage at the connection point to the network within acceptable steady state ranges.

b) Transient voltage magnitude (LVRT & HVRT[7])

During disturbances in the system, transient overvoltages or undervoltages (voltage dips) that exceed the acceptable ranges can appear. These disturbances must be cleared very quickly to prevent damage to equipment connected to the system and ensure its stability. In this sense, network codes usually establish technical requirements for HVRT and LVRT.

Synchronous generators use the AVRs to manage the excitation of the machines and the reactive power injected during the voltage disturbance. The fast response of such equipment enables quick voltage restoration within the steady state acceptable ranges. It also allows damping of voltage oscillations before the violation of the voltage-time profiles (both undervoltage and overvoltage) that generators and other equipment must withstand without disconnection and damage.

Possible controls for 100% PE can take as a reference the AVR and typical response speeds, however, the faster response speed the better.

Like the power-frequency primary regulators, voltage controls distributed at the different generators should not interact, causing instabilities between them when contributing to the maintenance of the local setpoint voltage at the connection node to the network.

c) Ranges of the voltage rate of change

In general, very high temporary gradients (quasi-infinite slopes) in voltage (both magnitude and angle) can appear in the system coinciding with the beginning and clearance of electrical faults or connections / disconnections of elements (loads, generators, lines, transformers, etc.).

In the case of electrical faults, quasi-instantaneous drops of voltage magnitude to 0 pu can occur (in the worst cases). In addition, sudden angular jumps occur imposed by the new impedance to the fault (mostly reactive impedance). The technical requirements for HVRT and LVRT require no disconnection during voltage dips. Consequently, they are also forcing indirectly the ability to withstand sudden angular jumps (during the appearance and clearance of the fault).

In the case of manoeuvres of connection/disconnection of generators or loads, without an electrical fault, the higher the generation-demand imbalance, the more sudden the angular differences. Sudden angular jumps also appear in lines and transformers manoeuvres. Usually, generators have the capability to cope with angular sudden differences, and TSOs take that capability into account to keep the angular jump into the admissible range within normal operation.

Sudden angular jumps at the terminals of synchronous generators involve sudden changes of ΔP electric power (or electric torque), a current increase ΔI in the windings and torsional stress in the shaft. This phenomenon can eventually limit the life of windings and shafts due to mechanical fatigue. As a reference of admissible torsional stresses from the point of view of mechanical fatigue, the following document is available: "C37.104 IEEE Guide for Automatic Reclosing of Line Circuit Breakers for AC Distribution and Transmission Lines", specifically paragraph 6.1.1.6 "turbine-generator considerations". According to this

[7] Low Voltage Ride Trough, and High Voltage Ride Through

paragraph, the critical value for ΔP is 0.5 pu machine based. This phenomenon is of course not applicable to power systems with 100% PE, but, for grids with < 100% PE inverters, will need to participate to electric power changes to relieve constraints on synchronous machines.

d) Permanent and transient frequency ranges

   The new controls for a 100% PE system should avoid a frequency out of the acceptable permanent and transient ranges after the greatest imbalance considered (the maximum imbalance of reference for which primary and secondary regulation and corresponding reserves are sized) without load shedding by underfrequency or generation trip by overfrequency even without the physical inertia of the synchronous machines or asynchronous motors.

e) Transient ranges for the rate of change of the frequency

   Generators and new controls for 100% PE system must be able to function without disconnection or loss of control at any rate of change of frequency (both upwards and downwards). If a limitation to the rate of change of frequency is needed (to guarantee proper system operation in 100 % PE), the new controls should be able to avoid exceeding these limits if the problem is not mitigated by other means.

   In this sense, part of PE-based generators and controls of 100% PE may have the possibility to give something similar to a synthetic inertial response in order to limit the rate of change of frequency in scenarios with very few synchronous generators.

f) Ranges for short-circuit power and inertia (physical or synthetic)

   PE-based devices usually present instability in their controls of P and Q at low short-circuit power and low inertia because the voltage (in magnitude and angle) tends to vary strongly with low short-circuit power and inertia of the system. Therefore, the controls to be defined in this work package will have to be robust in any grid configuration, both high and low short circuit power and both low and high inertia.

2.7 Load sharing between generating units

Load variations must be shared between generating units according to their capabilities.

In a conventional system, effective load sharing between multiple synchronous generators is achieved by means of the droop characteristics in the speed governor and the load reference setpoint. A similar concept will need to be implemented in the power controllers in order to achieve 100% PE penetration. The dimensioning of the converters and the settings for the individual droop characteristics must be carefully considered to guarantee load sharing without exceeding their overload capabilities. These controls must be robust enough to accommodate a variable transmission system topology and impedance (see Figure 7).

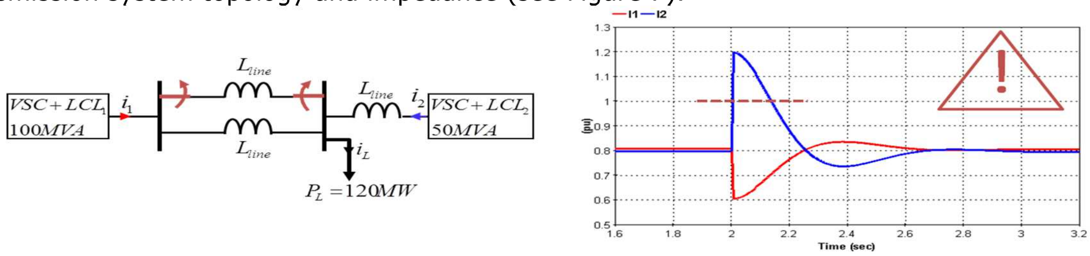

*Figure 7 – **Potential PE overload due to uneven load sharing***

2.8 Robustness to system split

A system isolated by some disturbance must remain stable if load and generation can be balanced.

To maintain today's level of reliability, robustness to system split should be ensured, provided a balance between generation and load is possible. Moreover a system split is a phenomenon that can make a fast transition between a system with few synchronous machines and a system without any of them (see figure below). The converter controls will need to be able to operate in both situations without getting any information about the presence or absence of synchronous machines. It must also be possible to synchronize again the isolated part with the main system (or isolated parts with each other) when the disturbance is over.

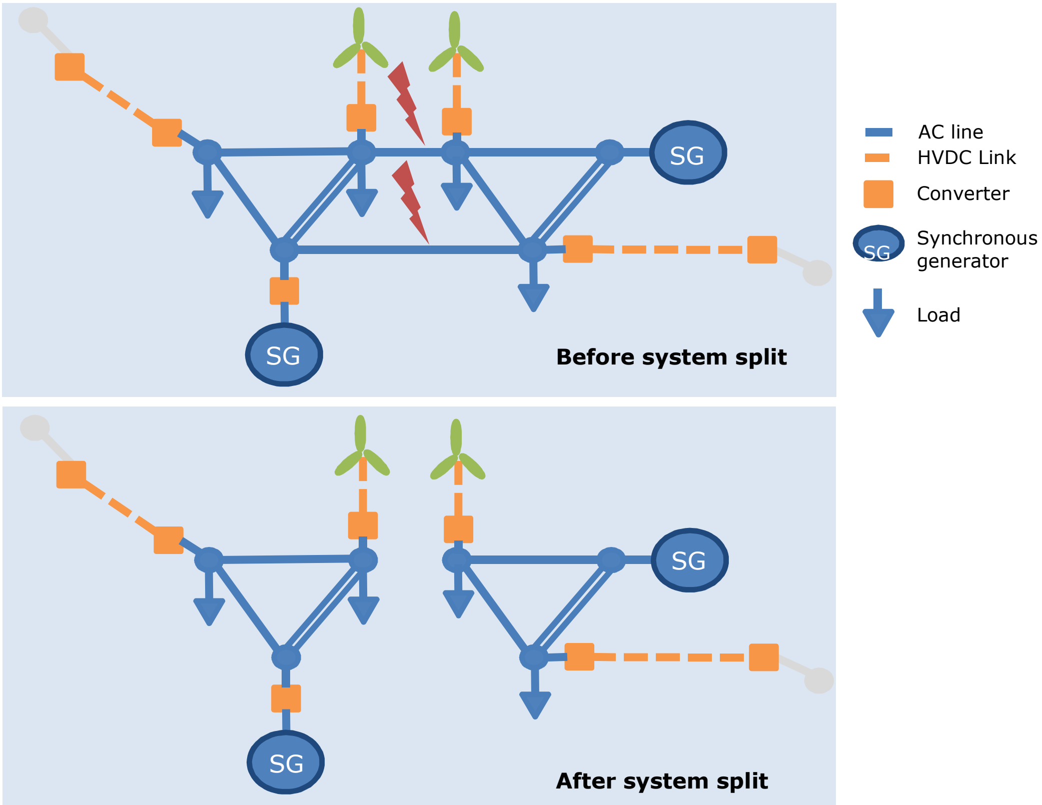

Figure 8 – **Example of system split leading to a system with 100% PE**

Load shedding might be necessary to rapidly accommodate the power imbalance. However, defence plans are out of the scope of WP3. It will therefore be assumed that the balance between generation and load can be restored by generating units in case of a system split. The stability of the isolated system will be ensured under this assumption.

2.9 Black start capability

System restoration must be possible after a black-out.

Electrical power systems require adequate technical solutions able to ensure system restoration following a black-out. A black start is the procedure to restore a power station to operation without relying on the external electric power transmission network. To provide black start capability, some power stations have small diesel generators which can be used to start the main generators.
In conventional power systems, the generators normally involved in this operation are hydroelectric and turbogas power plants, because they are characterized by a very short starting time.

The following technical capabilities are also required by the generators which provide a black start service:

- The capability to accept instantaneous loads, and to control frequency and voltage levels within acceptable limits during the block loading process.
- The reactive capability to energize the network.

In a power system with 100% PE interfaced devices, some devices will have to be able to provide the black start service. This is already a requirement for synchronous machines as well as power park modules in the network code Requirements for Generators. VSC HVDC links can also start up blacked out power systems since they can provide effective voltage and frequency stabilization during the restoring process (see for example the HVDC link between France and Spain).

2.10 Possible migration path

A smooth transition from current systems to systems with new controls and management rules must be possible.

The last system need is to ensure that a migrating from current power systems to power systems with new controls is possible. Existing requirements have to be adapted not only for 100% PE grids but also for <100% PE grids. The migration path between these stages has to be ensured. The behaviour of inverter-based connected devices fulfilling the new requirements must be compatible with:

- some inverter-based connected devices fulfilling 2016 requirements
- inverters that use different control modes (power-point tracking, droop control, oscillator-based controllers)
- some synchronous machines
- some induction motor load (which provide inertia).

The requirements must ensure that PE devices actively participate in the control of the grid e.g. voltage/frequency support or power oscillation damping taking into account all stages from medium to very high penetration of PE devices. Therefore, it is necessary to study and simulate the control interaction between PE devices as well as the interaction between PE devices and other types of devices as listed above. To validate the requirements testing methodologies need to be developed to ensure the migration path.

3 Stability of power systems without synchronous machines

Transmission system operators are responsible for power system stability. Today or tomorrow, a power system should always be operated in such a way that no probable physical disturbance could trigger cascading outages or other form of instability. Stability is clearly defined and classified for grids with synchronous machines. However, the behaviour of systems with 100% PE will be radically different and there may be kinds of instability specific to such systems. It may also happen that disturbances that are nowadays carefully studied since they can lead to stability issues for grids with synchronous machines are harmless on grids with 100% power electronics, and that harmless disturbances on power systems with synchronous machines become critical. Ensuring the stability of such grids implies checking their behaviour for all disturbances which the system must be able to withstand.

3.1 Physical disturbances on power systems

In this chapter, a list of physical disturbances that grids must withstand is elaborated.

We make the assumption that the components of power systems with 100% power electronics will be the same as on current transmission systems, with the following exceptions:

- there will be no synchronous machine directly connected to transmission systems (some could be connected through converters)
- the controls of some converters will be different
- some hardware could be added to converters

Physical disturbances that can affect grids with 100% power electronics will therefore be mainly the same as those seen on today's power systems[8]. Their characteristics, for example the duration of short-circuits, will also be assumed to be unchanged[9].

The following methodology was used to make a list of disturbances to consider for the design of grids with 100% power electronics:

- A list of disturbances likely to happen on today's power systems was made. It includes, on purpose, events with both high and low probability.
- Disturbances considered by at least one of the TSOs involved in WP3 as dimensioning (i.e. nowadays considered for system design) were selected.

[8] Depending on the results obtained in the course of WP3, it might happen that other events should be taken into account, but they cannot be defined before starting to develop the new controls. For example, if telecommunications happened to be necessary to operate systems without synchronous machines, failure of telecommunications should be added to the list of possible disturbances.

[9] WP4 of the project is devoted to protection and will confirm the hypothesis regarding fault duration.

The results are shown in the following tables. The probability of each disturbance according to the 5 TSOs involved in WP3 is also mentioned where possible (a question mark means that the 5 TSOs don't agree on the probability of the considered event).

The disturbances, among which line and generator failures are generally the most common ones, are divided into 3 categories with different consequences:

1. variations of load or generation
2. topological changes
3. short-circuits

An event from one category might eventually lead to an event of another category. For example, a fault appearing on the grid is eventually cleared by opening a line.

3.1.1 Variations of load or generation

A variation of load or of generation is the modification of the power consumed or injected by loads or generating units already connected to the grid. Such variations constantly happen on power systems. They can be predictable (modification of the active power of a thermal unit according to its schedule) or unpredictable.

Variation of load or generation is highly probable and considered as dimensioning for system design by all TSOs.

3.1.2 Topological changes

Topological changes include connection and disconnection of transmission connected loads, generation units and transmission assets. They are characterized by the closing or by the opening of one or several circuit breakers. They can be predictable or unpredictable for TSOs depending on the origin of the action. For example, circuit trips due to mal-operation of protection relays are unpredictable, but manual connections of a transmission line are predictable.

Event	Considered for system design	Probability
Disconnection of 1 generating unit	Yes	High
Disconnection of 2 generating units	Yes	?
Disconnection of n generating units (n > 2)	Yes	?
Disconnection of 1 400 kV line	Yes	High
Disconnection of 1 220 kV line	Yes	High
Disconnection of 1 v kV line (v < 220)	Yes	?
Disconnection of 1 400-220 kV transformer	Yes	High
Disconnection of 1 400-v kV transformer (v < 220)	Yes	High
Disconnection of 1 220-v kV transformer (v < 220)	Yes	High
Disconnection of loads	Yes	?
Connection of 1 generating unit	Yes	High
Connection of 1 400 kV line	Yes	High
Connection of 1 220 kV line	Yes	High
Connection of 1 v kV line (v < 220)	Yes	?
Connection of 1 400-220 kV transformer	Yes	High
Connection of 1 400-v kV transformer (v < 220)	Yes	High
Connection of 1 220-v kV transformer (v < 220)	Yes	High
Connection of 1 load	Yes	High

All connections and disconnections of 1 single load, 1 generating unit or 1 transmission grid element are considered for system design.
Disconnections of more than 1 grid element are not considered if they don't have a single common cause.

NB: Some disturbances that can affect the grid are not explicitly mentioned but are still considered. For instance, busbar coupling or decoupling is equivalent to connection or disconnection of a zero-impedance-line. The connection of shunt compensation is equivalent to the connection of a load with P = 0.

3.1.3 Short circuits

Short circuits happen unpredictably on power systems. The consecutive action of protection systems can lead to the disconnection of loads, generating units or transmission assets. In the following tables, "no resulting disconnection" means that the short circuit was not permanent, it was cleared by protection systems and then automatic reclosing of the faulty section was successful.

3ph short circuit with…	Considered for system design	Probability
… no resulting disconnection	Yes	?
… disconnection of 1 generating unit	Yes	?
… disconnection of 2 generating units	Yes	?
… disconnection of n generating units (n > 2)	Yes	?
… disconnection of 1 400 kV line	Yes	?
… disconnection of n 400 kV lines (n > 1)	Yes	?
… disconnection of 1 220 kV line	Yes	?
… disconnection of n 220 kV lines (n > 1)	Yes	?
… disconnection of 1 v kV line (v < 220)	Yes	?
… disconnection of n v kV lines (n > 1, v < 220)	No	-
… disconnection of 1 400-220 kV transformer	Yes	?
… disconnection of n 400-220 kV transformers (n > 1)	No	-
… disconnection of 1 400-v kV transformer (v < 220)	Yes	?
… disconnection of n 400-v kV transformers (n > 1, v < 220)	No	-
… disconnection of 1 220-v kV transformer (v < 220)	Yes	?
… disconnection of n 220-v kV transformers (n > 1, v < 220)	No	-
… disconnection of 1 400 kV busbar	Yes	Low
… disconnection of n 400 kV busbars (n > 1)	No	-
… disconnection of 1 220 kV busbar	Yes	Low
… disconnection of n 220 kV busbars (n > 1)	No	-
… disconnection of 1 v kV busbar (v < 220)	Yes	Low
… disconnection of n v kV busbars (n > 1, v < 220)	No	-

Two classes of short circuits can occur on transmission lines: balanced faults which involve all three phases and unbalanced faults which involve only one or two phases and potentially the ground. The most common type of short-circuit is single line-to-ground faults, followed by line-to-line faults, double line-to-ground faults, and balanced three-phase faults [8].

Balanced solid three-phase faults are always studied, since they are considered to be the worst case. They are also easier to analyze. Indeed, unbalanced faults depend on network configuration, especially on grounding connections. Grounding connections are not the same in the different European countries and all configurations cannot be considered in WP3. Only three-phase faults will therefore be considered to design the new controls of converters. Fault clearing time will be assumed to be shorter or equal to 250 ms.

3.2 Criteria to assess system stability

Any likely disturbance should lead to an acceptable transient and an acceptable steady-state.

A steady-state is acceptable if at least the frequency and voltage amplitudes are within an acceptable steady-state range (see chapter 2.6).

A transient is acceptable if:

- frequency and voltage amplitudes remain within acceptable profiles (see chapter 2.6)
- oscillations of electrical values are well damped (minimum damping factor of approximately 10%)
- a limited amount of generating units or load are tripped (besides the ones isolated by the disturbance or by protections actions): this amount depends on the risk assessment policy of each TSO. No generation or load should be tripped for highly probable contingencies (other than those isolated by the disturbance or by the action of protections) but it could be acceptable for rarer disturbances.

Although this is not a strict requirement, a transient should also impact as few grid users as possible. For example, in case of a short circuit, the geographical spread of the induced voltage dip should be as small as possible.

3.3 Suitability of existing models and tools

Most existing simulating tools used for large systems were developed for systems comprising a large number of synchronous machines. Doing so, assumptions were made regarding waveforms and system behaviour that ease the simulation process. For example, some models require generating units to be represented as current sources whereas, in 100% PE grids, at least some inverters will have to behave as voltage sources. Phasor models also make assumptions about system frequency since they calculate the amplitude of waveforms. But the meaning of frequency will be radically different for 100% PE systems (see chapter 2.2). The validity of these assumptions will have to be reviewed for grids with PE only and tools may need to be adapted.

Moreover to facilitate the work of TSOs most of these tools offer toolboxes to evaluate stability of system using the present criteria that are also based on the behaviour of synchronous machines. In the future, it is possible that new phenomena that are not critical today have to be dealt with carefully (and vice versa, some phenomena presently critical may not be in the future). This may also imply adapting tools.

The aim of WP3 is not to adapt or develop new tools suitable for power systems with 100% PE. Controls of converters and management rules will be developed based on EMT simulations. Whenever possible, “built-in” models of power system components will not be used to free as much as possible from tools’ assumptions. In particular, equations describing the behaviour of converters will be written. The possibility to simplify EMT models to assess the behaviour of large systems with reasonable computation time (and possibly using categories of tools different from EMT) will be assessed during the project. Recommendations for adapted simulation tools could be an outcome of WP3.

4 System design

WP3 aims at designing a “grid-forming” control strategy for inverters, together with the associated system management rules. This chapter sets the framework for the design of such systems.

4.1 Hierarchical and distributed controls

Nowadays, the operation of power systems is based on the principle of hierarchical controls decoupled in time and space:

- Primary controls react in some seconds and are based on local measurements. They ensure system stability.
- Secondary controls react in some minutes and use non-local measurements. Their aim is to optimize the state of transmission grids.
- Tertiary controls are manual. Operators restore reserves of secondary controls in some tens of minutes.

We want to apply the same principle to grids with 100% PE. Three levels of controls were arbitrarily defined based on existing schemes and will be referred to in the remainder of this document:

- *Local control* refers to a combination of the inner control of converters and of other controls like FRT or synchronizing control. On today’s grid, local control is the equivalent of the internal process of synchronous machines. The main difference is that the internal process of synchronous machines is based on physics, whereas the behaviour of converters is imposed by control. Local control will be based on local measurements[10] and will act in tens of milliseconds.
- *System services* includes:
    - *a decentralized layer* aiming at stabilizing the grid similar as primary frequency and voltage controls do nowadays
    - *ancillary services mechanisms* acting at a slower time scale and having the goal of optimizing the system according to some economic aspects
- *System operation* includes management rules necessary to prepare operation of the previous layers of controls.

This breakdown is based on the current breakdown of controls. It is difficult to say whether it is fully relevant for 100% PE grids before defining controls and management rules. It may therefore have to be adapted in the course of the project.

[10] Provided that not relying on telecommunications is possible

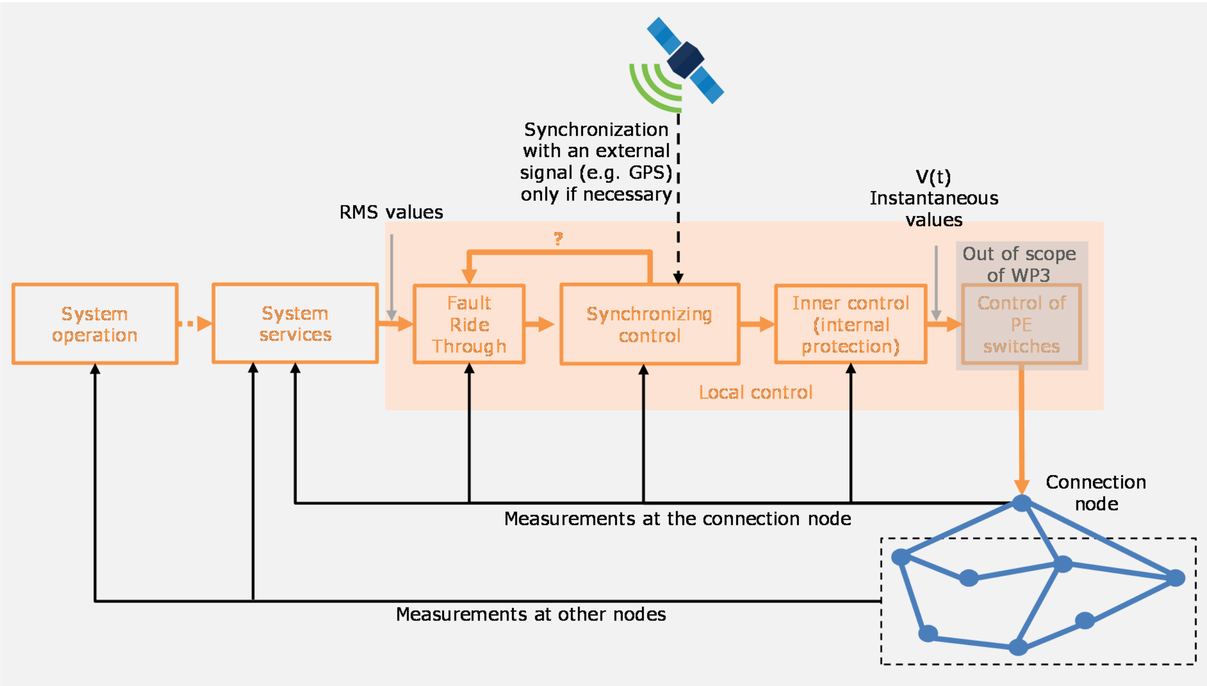

Figure 9: Considered breakdown of controls

4.2 Minimal addition of hardware

While keeping reliability at high standards, we want to find a way to operate 100% PE grids which brings the most social welfare, which means highest benefits for the lowest overall cost. Generally it means a minimal addition of hardware compared to current inverters. Such addition of hardware may be necessary since controls are based on measurements which incur some delay. Nowadays, before primary controls start acting, the development of a disturbance is "slowed down" by synchronous machines that immediately react according to their physical laws. Without synchronous machines, the behaviour of the system will be driven by controls only. Although controls of converters can be far quicker than those of synchronous machines, measurements will not be made instantaneously, and some kind of storage, acting as an energy "buffer" as synchronous generators now do, will be needed to give time to react to controls of converters. The amount of energy stored in the DC bus of converters may not be sufficient and additional storage capacity (synchronous condensers, electrical batteries, oversizing of converters…) may be necessary.

Generally the lowest overall cost means the minimal addition of hardware. This may be achieved:

- By imposing some rules, such as:
  - a limitation on the load that can be connected nearby an inverter, using for example a ratio between load and the power of individual converters. This rule would be similar to ones imposing the voltage level of connection as a function of the load power and could help to limit the current provided by inverters immediately after a modification of topology or after a short circuit.
  - a limitation of the admissible angle difference between the 2 ends of a line or a transformer before attempting to close it. This rule is already applied nowadays to limit torsional stress on synchronous machines. It could stay valid for other purposes with 100% PE.
- By taking advantage of the cooperation between converters rather than imposing a uniform behaviour to all of them. If the developed grid-forming control strategies require too expensive hardware or oversizing of converters, we could consider using a reduced number of grid-forming converters, while the others would be grid-feeding[11] or grid-supporting[12]. A large portion of inverters will be used to inject wind and solar energy into the grid. Due to the variability of these energy sources, some inverters will have remaining capacity to offer grid-forming capability. This raises the question of the minimum number of grid-forming converters and of the minimum electrical distance between them that would be required to operate such a system.

The implementation of such solutions or others will be considered in WP3.

4.3 Additional criteria to evaluate the performance of inverters during transients

Today, synchronous machines react instantaneously to grid disturbances, but the response of their controls is relatively slow, they are not able to respond to setpoint changes very rapidly. They are also not very sensitive to short term disturbances. Therefore there are very few requirements in the first milliseconds after the appearance of a disturbance, for example regarding the voltage waveform. The evolution of voltage in the first tens of milliseconds after a disturbance is driven by physical laws and cannot be changed by regulators of synchronous machines. Inverters are sensitive to instantaneous values of both voltage and current. It will be necessary to have specific requirements for their behaviour during and after transients together with criteria/methods to quantify it. Today such quantitative criteria are used for power quality (for example to measure flicker) and could maybe be used to derive criteria to evaluate inverter performance during transients.

[11] *Grid-feeding* inverters inject power on the grid without providing any service to the grid. They are controlled as current sources.

[12] *Grid-supporting* inverters are controlled as current sources but provide some services to the grid. For example their active power injection can be increased if frequency decreases, or they can perform voltage control.

5 Detailed description of tasks

This chapter presents the detailed description of the research work that will be performed in WP3. It is divided in 5 tasks:

- Modelling aspects are of great importance, both for the development of test cases and to be able to represent the behaviour of converters accurately enough and with a reasonable computation time. One task is therefore dedicated to this topic *(task 1 in the remainder of this document, non-described as such in the project's Description of Work)*.
- 3 tasks aim at developing the controls and management rules that will enable operation of transmission grids without synchronous machines. Based on the hierarchical structure of controls described in chapter 4.1, one of them is dedicated to local control *(task 2 in the remainder of this document, 3.2 in the project's Description of Work)*, another one to system services *(task 3 in the remainder of this document, 3.3 in the project's DoW)* and the third one to system operation *(task 4 in the remainder of this document, 3.4 in the project's DoW)*.
- 1 final task will allow to perform system integration tests gathering the results of the 3 previous tasks *(task 5 in the remainder of this document, 3.5 in the project's DoW)*. Tests will be performed on a reduced-size real system to prove the effectiveness of the developed solution. Requirement guidelines for converter-interfaced generating units will be inferred.

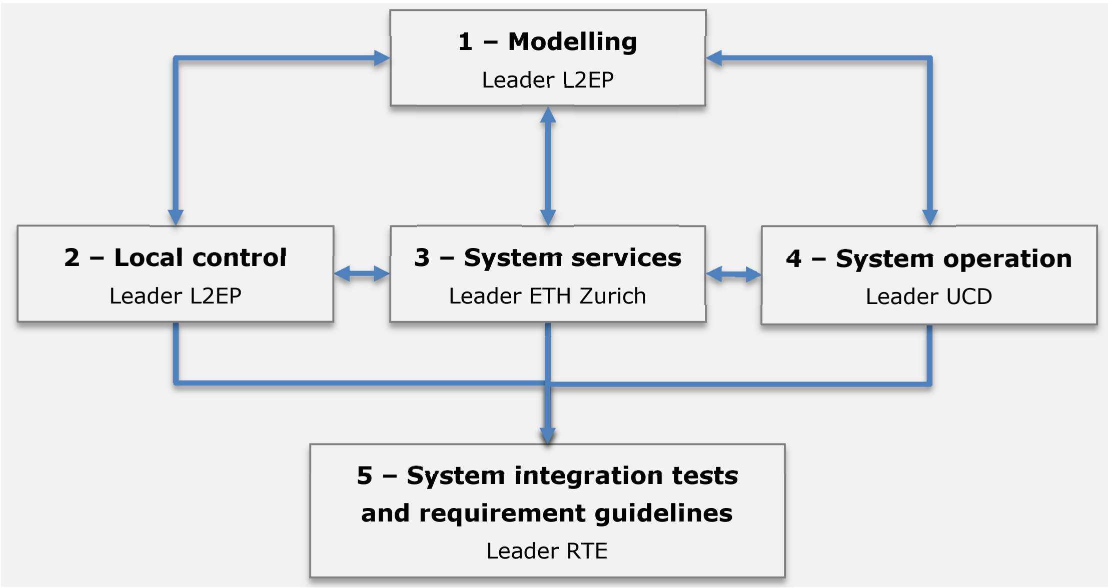

Figure 10 – ***Research and validation tasks of WP3 and related links***

5.1 Task 1: Modelling

5.1.1 Motivation

Modelling of power systems with 100% PE is of great importance to be able to effectively test the solutions developed in WP3. As explained in chapter 3.3, the suitability of existing tools to simulate the behaviour of such grids may be questionable. Therefore, whenever possible, the use of “built-in” models of system components will be avoided to free as much as possible from tools’ assumptions about the presence of synchronous machines. Considering the emphasis put on converters in the project, the work will be split into 2 subtasks:

- one will be dedicated to modelling of converters
- test cases will be developed in the second one

These 2 subtasks are described below.

5.1.2 Subtasks

Subtask 1.1: Converter models (L2EP)

2 topics will be addressed in this subtask.

Subtask 1.1.1: Standard control of power electronic switches for the development of local control (L2EP)

Modelling part or totality of converters is necessary to be able to develop new controls and management rules. In particular, when developing local control, the control of power electronic switches must be modelled to be able to perform simulations, even though the work of WP3 is not about this part of the control system of converters (see chapter 4.1). In this subtask, standard control of power electronic switches suitable to develop local control will be identified and implemented in the software chosen to perform simulations.

System services and management rules will be developed assuming that converters behave as ideal voltage sources.

Subtask 1.1.2: Reduced models of local control and system services (L2EP)

Converter controls that are able to provide services to 100% PE grids along with being able to protect themselves against the specific events that can appear in large transmission systems will be developed in tasks 2 and 3 based on EMT simulations. Their validation on a transmission grid composed of a large number of interconnected converters is necessary and raises the question of the necessary degree of accuracy of the models, to be able to simulate a very large system in a “reasonable” computation time[13].

[13] The largest test system that will be used in WP3 is a simplified model of the Irish grid (see chapter 6). It is small enough to allow for detailed EMT simulations with a reasonable computation time. The same doesn’t apply for larger synchronous areas, such as the European continental synchronous zone.

In this subtask, based on the controls developed in tasks 2 and 3, different levels of model complexities and their inherent limitations will be studied, from detailed EMT converter models to "simpler" models (maybe similar to nowadays phasor converter models[14]) to simulate such a complex and novel grid. Comparison between EMT and other simulations will be done in order to offer criteria in the choice of solutions for the simulation of the developed controls.

Subtask 1.2: Development of test cases (L2EP, ETHZ, UCD)

Subtask 1.2.1: Models of non-power electronics based devices for dynamic simulations (ETHZ, L2EP)

For the design and the testing of the developed local control, grid-forming, short term balancing mechanisms and energy management rules, the modelling of the system and the components in the system is mandatory. Consequently, this subtask consists of identifying and if needed deriving suitable mathematical models for non-power electronics based devices and their interactions through the network. We aim to strike a balance between high fidelity of the models and their analytic and computational tractability for latter device-level control design and overall system analysis and simulations. Test cases for tasks 2 and 3 will be developed using these models and the converter models provided by subtask 1.1.1.

Subtask 1.2.2: Test systems and critical scenarios for unit commitment (UCD, L2EP)

The work completed within task 4 will be based around the analysis of 2 test systems: a 3-bus test system and a simplified representation of the Irish transmission system. The adopted resolution of the network models and the complexity of the converter control models will be sufficient, for example, to investigate controller interactions between devices and the proximity to nearby loads. The simulation tools will be configured to represent a range of (24 hour) days at a sub-hourly resolution, representing summer/winter and weekday/weekend variations. The generation mix for the test systems will in turn be based upon wind-dominated, PV-dominated, and a mix of wind and PV generation technologies, with both 100% and <100% converter-based scenarios being represented.

5.1.3 Links with other tasks

Subtasks 1.1.1, 1.2.1 and 1.2.1 will allow developing models and test cases that will be used to validate the proposed local control (in task 2), system services (task 3) and operational rules (task 4).

The outputs for task 1.1.2 could also be used for the validation of system services or of operational rules.

[14] The relevance of phasor models to simulate 100% PE grids is questionable (see chapter 3.3).

5.2 Task 2: Local control

5.2.1 Motivation

Today, grid connected inverters use the voltage signals measured at their grid connection points to control their active and reactive power, thus exhibiting a *grid-following* behaviour. A Phase Locked Loop (PLL) device is generally used to extract the time-varying frequency and angle of the grid voltage, while the amplitude is also measured. This reference is imposed by the system powered and controlled by large rotating synchronous generators which maintain the voltage amplitude and frequency as steady as possible while the angle fluctuates due to the active power flows.
In a 100% PE fed network, the frequency will no longer be imposed by synchronous machines; thus, the voltage waveform has to be created and controlled by the inverters: a *grid-forming* behaviour is required. As inverters have no physical inertia (as known today with synchronous machines), the frequency and angle of the voltage may change very rapidly (or even in discrete steps) leading to a faster transient behaviour. Such control approaches need further investigations because they are very different from the state-of-the-art control approaches. While some experiments have been done on microgrids, they have to be largely adapted for transmission systems and their validity has to be revisited since:

- The network topology is not radial and is time-varying, that is, it can change during the day;
- System reliability (ex: N-1) at transmission level requires a dispersed control responsibility amongst units (without centralized decision makers or a master-slave architecture);
- Highly variable generation and consumption localizations combined with random topological configurations can lead to unpredictable large transients applied at the output of limited capacity inverters;
- The ratio between inductance and resistance are different (distribution networks are mainly resistive whereas transmission networks are mainly inductive);
- The mere size of large interconnected transmission systems considered in this project imposes new challenges both in the dynamics observed but also in the coordination of the inverters.

5.2.2 Research questions

Based on the experience gained through previous works performed in collaboration by RTE and L2EP, several fundamental questions have emerged:

- What are the best choices for the technology and the optimal sizing of the converter, according to the level of power to be exchanged with the grid?

- How to organize and design the control structure of the converters in order to provide the right services to the grid along with being able to protect them against grid events at an affordable investment cost?
- Are the control tunings chosen for some interconnected converters still valid when several converters are interconnected? What could be the best tunings and the optimal strategies for such a situation?

5.2.3 Subtasks

The foreseen structure of local control is reminded on the figure below.

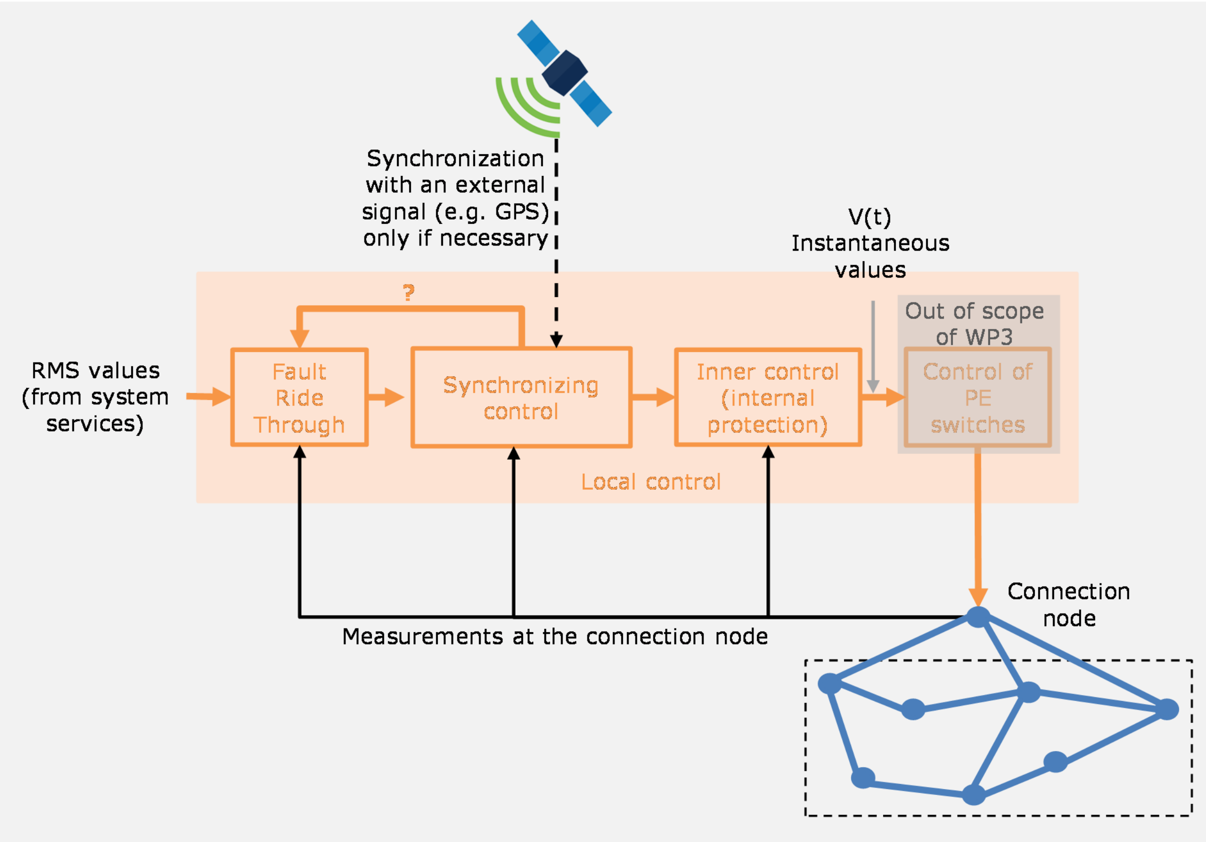

Figure 11: Structure of local control

Subtask 2.1: Sizing and inner control for a grid-forming inverter (L2EP)
The topic addressed in this task is highly technology dependent. Indeed, the sizing of the components (filter components for example) and the necessary inner control are not the same for one technology to another one. According to previous works, the choice of a generic converter topology could be restrictive and not able to reflect all the possible constraints that have to be

taken into account. Since there are two main types of converter-based generating units present in a 100% PE grid, which are small scale inverters (wind turbines / PV) and large scale ones (HVDC links that connects offshore generation), it is decided to investigate two converter technologies: classical Pulse Width Modulation (PWM) topologies and Modular Multilevel Converter (MMC) VSCs.
Specific methodologies for the sizing of the converter, for the choice of the control structure and for the sizing of its parameters will be developed. Proposed solutions will be validated by EMT simulations.
The proposed controls will be developed taking into account that the inverter will have grid-forming capabilities.

Subtask 2.2: Synchronising control and Fault Ride Through capability (L2EP, ETHZ)
This subtask aims at defining the synchronising control and the control that provide Fault Ride Through (FRT) capability. These controls will also have to take into account the protection of the inverter against grid transients (load changes, topological changes, symmetrical and asymmetrical faults). Both topics (synchronization and fault ride through capability) will be dealt with in the 2 following subtasks, which differ from each other by the considered synchronization strategies.

Subtask 2.2.1: Power droop synchronization strategy (L2EP)
As a converter must have grid-forming capabilities, therefore classical PLL is not relevant. A droop controller, will be added to the inner control proposed in subtask 2.1. Some design rules based on the inverter behaviour in case of faults or network reconfiguration will be given.
The topology of the used test cases will be limited to some interconnected inverters (less than 10) of different technologies to validate the interoperability of the proposed solutions.

Subtask 2.2.2: Other synchronizing strategies (ETHZ)
Controls based on virtual oscillators or other synchronizing strategies will be investigated in subtask 2.2.2.

5.2.4 Links with other tasks

In both subtasks, special attention will be given to the interface with system services (see the description of task 3 in chapter 5.3). The outputs of the controls defined for system services will be the inputs of local control. Depending on the design choices, the boundary between system services and local control might also be different than the one presently considered (see Figure 11). In particular, droop control could be used both for synchronization purposes and to automatically balance load and generation as present primary frequency control does.

All developed controls in task 2 will be designed in order to be easily implemented on the experimental test bench developed in task 5.

5.3 Task 3: System services

5.3.1 Motivation

One of the most challenging tasks in the operation of electric power systems is guaranteeing its stability. This refers to the ability of the system to bring itself back to a state of operating equilibrium after being subjected to a disturbance. Currently, this requirement is fulfilled by the physical properties of synchronous generators as well as multiple control layers acting through them, with the purpose of maintaining the system *frequency* and *voltage* within some predefined acceptable bounds; both in the short-term period after a disturbance as well as in the long-term.

The traditional way to balance generation and load in the short term is the deployment of primary and secondary frequency controls. Primary frequency control is based on speed droop control, i.e., it is a fully decentralized control concept which uses the local frequency as input, and its purpose is to stabilize the frequency within a range of seconds. Secondary frequency control on the other hand is a centralized concept which uses frequency and tie line flows as inputs to determine the power adjustment signals that should be sent to generators with the objective to bring the frequency and the tie line flows to their respective nominal values. The time frame is within seconds to minutes. Hence, primary frequency control corresponds to a local proportional controller whereas secondary frequency control corresponds to a centralized PI controller.

The workings of these concepts heavily depend on the availability of frequency as a global signal and the existence of rotational inertia. The first is the feedback signal for both primary and secondary frequency control and the latter is the reason why only comparably slow changes in frequency occur, therefore providing sufficient time to react to imbalances in the system.

Contrary to frequency problems, which are driven by generation-load imbalances, voltage problems are due to the electrical distance between the generation and loads and refer to the ability of the system to maintain/restore equilibrium between load demand and load supply. This requirement becomes more challenging with fast restoring loads, such as motors or inverter-interfaced loads. In the short term, the voltage profile is traditionally maintained by fast acting devices such as Automatic Voltage Regulator (AVR) equipped synchronous generators or Static Var Compensators (SVCs). In the long-term, slower acting devices, such as Load Tap Changing transformers or capacitor banks are used to restore a feasible equilibrium.

5.3.2 Research questions

Task 3 is concerned with the design and testing of stabilizing and balancing mechanisms in a system with *no* or *only few synchronous machines*. In such systems, frequency does not reflect anymore the global power balance equilibrium and the operator cannot rely on the presence of physical inertia as a power buffer. In addition, many of the traditional control mechanisms currently implemented by synchronous generators, for both frequency and voltage stability, will not be available anymore; thus, a new control structure has to be devised to guarantee the power system stability.

In particular, the following two research directions will be pursued, both focusing on systems driven by power electronics:

- Derivation and design of a decentralized converter control approach
- Derivation and design of ancillary service mechanisms

While most likely new delineations/classifications of short-term balancing mechanisms will emerge from this work, the first is comparable to the role currently fulfilled by primary frequency control and the latter comparable to the role of secondary frequency control. However, we do not envision that our contributions are merely restricted to frequency stability and control, but we also target other power system stability tasks and control mechanisms relevant in low-inertia power systems. Finally, we aim to design these control strategies in a modular framework such that they are compatible with the local control strategies in Task 2.

5.3.3 Subtasks

In order to find answers to the above mentioned research questions, the following tasks will be carried out.

Subtask 3.1: Identification of Objectives and Constraints (ETHZ)
As previously mentioned, in a system with few or no synchronous machines frequency might become an artificial artefact. While the main objective in system operation will still be to ensure the balance between demand and supply, what constitutes an optimal way to achieve this may however change. Additionally, concepts such as angle or frequency stability may become obsolete and new definitions or new types of stability need to be derived. Hence, the overall goal of this task is to identify the objectives and constraints for each of the above mentioned levels of control based on which the controllers should be designed in the next task.

Subtask 3.2: Structure of Controls (ETHZ)
Possible control structures not only differ by internal design of the controllers but also by the inputs they take; particularly where the respective information is coming from (for example, DC and/or AC side of the converter), and how much they interact with other controllers/entities in the grid through communication of critical control variables and measurements. The chosen approach may be different depending on the time scales the controllers operate.

Subtask 3.2.1: Decentralized Converter Control (ETHZ)
A completely decentralized layer of control will be designed and serves to stabilize the grid in a similar way as primary frequency control do nowadays. Hence, it needs to be identified which physically measurable signal can serve a similar purpose like the frequency in the traditional system and how the controller needs to be designed to fulfil the objectives and constraints defined in the previous task for the first stage frequency containment and grid stabilization. It will be particularly interesting to answer this question with respect to the newly defined stability definitions. In this subtask, such decentralized control strategies will be designed in a modular fashion so that they are compatible with local device-level controllers developed in task 2 and the higher-level ancillary service control layers discussed in the following subtask.

Subtask 3.2.2: Ancillary Service Mechanism (ETHZ)

It is expected that similar to traditional controls, there will be a short term balancing mechanism which will operate at a slower time scale than the decentralized primary control which will be implemented as an ancillary service, i.e., there are economic aspects that need to be considered when the control is designed. Additionally, given the time scale as well as the fact that this level of control might be less critical, it could potentially be implemented as a distributed approach in which communication may play a role. Hence, in this second subtask, the control level previously fulfilled by secondary frequency or voltage control will be studied and appropriate strategies will be derived. In the scope of this subtask, we will also explore distributed control strategies leveraging communication between the units and pursue questions of the form how much performance or robustness can be gained by leveraging non-local information?

Subtask 3.3: Case Studies (ETHZ)

The provided test systems will be used to study the performance of the control design derived in task 3.2 with respect to optimality, robustness and stability. The small system will be used to carry out in-depth studies on the effects of the proposed designs with a high time resolution whereas the larger system will be used with simplified models and lower time resolution to study longer time horizons. This also needs to include a comparison with other types of possible control designs.

5.3.4 Links with other tasks

Throughout task 3, there will be close collaboration with task 2 to make sure that the developed system services are compatible with the local controls developed in that task. The requirements and constraints of the developed system services will also be provided to task 4 for the proper design of the system operation methods.

5.4 Task 4: System operation

5.4.1 Motivation

High level management has the aim of ensuring that the power system is robust against a range of critical scenarios, e.g. network faults, generator failures, system splitting, which may occur in the near-term operational future, using predominantly on-line resources, supported in the slightly longer term by fast-starting offline resources. In doing so, the power system should be operated in an economical and efficient manner, and the capital & operational costs imposed on generators and other resources should be minimised. Where possible, the outcome of any critical (or dimensioning) event should not result in the disconnection of loads, excepting where the nature of the event itself makes this unavoidable. For non-dimensioning events the probability of occurrence, and the capital and operational cost of corrective actions may influence the degree of survivability of such events, and the level of load shedding, or other measures, considered appropriate. However, again, the power system should be operated in an economical and efficient manner in light of such events, and the costs imposed on generators, and other resources, should be minimised. Of course, for a 100% converter-based scenario, it is not entirely clear what the dimensioning events for such a system would be, beyond those normally considered as part of power system planning and daily operations, and it is also not clear what measures would need to be enacted to mitigate against such scenarios.

The management process essentially enforces the requirements arising from grid codes, e.g. frequency control capability, low/high voltage fault ride-through capability, and coordinates the supply of ancillary services, while also ensuring that all necessary reserves are available on-line to robustly operate the system. Traditionally, such ancillary services have included operational reserve capability (contingencies and short-term regulation), reactive power and voltage control and blackstart capability, amongst others. More recently, given the growth of variable renewables, such as wind and solar, ancillary services are being proposed, or are already in place, in various systems to incentivise ramping capability to combat forecast uncertainties, fast frequency response (or emulated inertia) to enhance the system response (from non-synchronous sources) in the initial seconds of a frequency transient, sometimes coupled with a synchronous inertial response to reduce the minimum stable generation of large conventional units (and hence enhance the system-wide online synchronous inertia), and also enhanced dynamic active and reactive power capability during faults, going beyond the capability specified in existing grid codes.

It is further expected that a grid with 100% converter-based devices will require additional and/or substitute ancillary services or modified grid code requirements, e.g. grid forming capability, which implies that traditional high level management processes will also need to be adjusted. Such new services, and even traditional services, may include a regional or locational requirement, recognising the fact that while the pre-disturbance system state may incorporate a number of synchronous-based generators, the post-disturbance state, particularly if system splitting occurs, may result in sub-regions which consist entirely of non-synchronous generation sources and loads. Each sub-region, where possible, should be dynamically stable and viable until the large system can be re-integrated. Alternatively, the transition between a 100% converter-based state may occur more smoothly, following the decommissioning of the last few synchronous-based generators. It follows, therefore, that an individual converter-based generating unit may not know if there are none, or just a few, synchronous-based generators on-line, and hence all control mechanisms, e.g. demand-generation balancing, and ancillary service arrangements (system-wide and regional) should be insensitive to the actual system state.

5.4.2 Research questions

- What management rules and operational procedures relating to active power balancing / voltage control are required to ensure the secure and reliable operation of 100% converter-based power systems, subject to a range of power imbalance dimensioning events?
- Is there a need for a regional requirement for grid-forming capability?
- If the (minimum set of) management rules and operational procedures differ between the 100% and <100% converter-based generation states, what additional operational procedures are required to ensure a transition (in either direction) between both system states?
- What are the additional constraints if the system stability relies on a (complex) communication infrastructure, with the associated propagation delays, the potential presence of unreliable information and the possible outages of telecommunications?

5.4.3 Subtasks

Subtasks 4.1, 4.2 and 4.3 described below aim at developing high level management rules to allow operation of a grid with 100% PE devices. Their operational cost effectiveness and the associated operational risk will be evaluated, initially based upon the schedules defined in subtask 1.3, and subsequently by snapshot stability analysis of individual events (as indicated in the dimensioning events list) on the 3-bus system and the Irish transmission system. The analysis will be completed for the test days and plant portfolios introduced in subtask 1.3. Successful implementation of the management rules should result in all dimensioning events being survivable, and without load shedding or similar measures, and with reserves restored to a predefined level, tie lines flows restored to pre-event levels, an acceptable voltage profile across the network, an adequate stability margin against potential events, etc. to ensure that new contingencies can be faced.

Subtask 4.1: Operational rules for active power balancing and voltage control (UCD)

A 100% power electronics scenario implies that a locally measurable signal (system frequency or generator speed) may not be available to ensure system balancing of demand against generation. However, Task 3.3 (System Services) will propose a decentralised converter control structure which can ensure that real-time system balancing can be achieved. Although perhaps co-ordinated in a different way to today, some reserves will be required. Maybe new types of reserve will need to be defined. If so, a methodology to calculate the necessary volumes of reserve will be defined, based at least on demand forecasts and renewable generation output forecasts. The benefits of regional allocation of reserves will be assessed to protect against system splitting, ensure robustness against all other dimensioning events (see chapter 3), and robust operational rules will be proposed. It will be checked if the implementation of such rules within a Reliability Constrained Unit Commitment (RCUC) tool will reduce the volume of detailed analysis required in assessing the stability of a given system state in advance of real-time.

It will be investigated if the interactions between 'active power balancing' rules and 'reactive power / voltage network' rules necessitate modified objective functions, reserve targets, etc. for identified system conditions.
If needed, the technical specification for new ancillary services will also be considered.

Subtask 4.2: Assessment of the need for regional requirements for grid forming capability (UCD)

The need for regional requirements for grid forming capability will be assessed (ratio of grid-forming vs grid-feeding inverters, maximum electrical distance between electrical devices…) similar to the work completed in WP1 concerning synchronous machines. As explained before, such requirements could provide more robustness to system splitting. But they may also be needed to ensure system stability. As explained in chapter 4.2, some kind of storage, acting as an energy "buffer" as synchronous generators now do, will be needed to give time to react to converter controls. The concentration of grid-forming inverters and consequently of energy "buffers" in one part of a system could lead to instabilities.

Subtask 4.3: Interactions between generating units (UCD)

Interactions between local controllers in grid-forming modes (subtask 2.1 and 2.2), or between inverters and synchronous machines, may imply the need for more sophisticated control designs, and/or the incorporation of tertiary supervisory controls and additional operational rules based on, for example, the electrical distance between devices. The need for such tertiary controls or operational rules will be assessed in this subtask.

Subtask 4.4: Communications and IT Infrastructure (UCD)

Power system balancing has relied on a local measure of the system frequency, effectively enabling instantaneous communication of the power system 'health' status across the power system. On slightly longer timeframes, dispatch signals are sent to individual units and commitment / decommitment instructions can also be issued on longer timescales. Similarly, in relation to voltage control, local control actions are supported by updating of equipment control setpoints in light of variations in system demand, geographical location of dispatched generators, etc. However, while two-way communication systems can enable the real-time control of distributed loads and generators, it is highly desirable that a complex communications infrastructure is avoided - the communications infrastructure may become the 'weak link' rather than the 100% converter-based system in determining the reliability of the overall system. Adopting a time series approach for the test days, the communication requirements (frequency of updates and nature of information communicated) between the control systems of individual, distributed plant equipment and the co-ordinating control platform will be investigated. The ability for equipment controllers to operate autonomously for short-term periods, and to infer the system state from local information will be investigated - system redispatch, involving the communication of updated controller setpoints or switching of plant modes, should be used to ensure system optimality, e.g. minimising operational cost, rather than being required for system stability. Similarly, the effect of propagation delays and unreliable information on the robustness of the active power and reactive power management policies will be assessed.

5.4.4 Links with other tasks

Special attention will be given to the interface between system services (see the description of task 3 in chapter 5.3). High level management rules will be needed to define the inputs of the controls defined for system services.

For the specific case of the test facility in the L2EP laboratory, a set of operational rules, generator operating modes and dispatch quantities will be specified for examination across a number of scenarios including fault conditions, switching in/out lines, and variations in local load.

5.5 Task 5: System integration and requirement guidelines

5.5.1 Motivation

The objective of this task is twofold:

- Laboratory tests will validate the controls and rules developed in WP3. It will be checked that they enable the operation of a grid with few or no synchronous machine and fulfil the system needs defined in chapter 2. The physical limitations of inverters are not always precisely defined in digital simulations; the use of a reduced size real system will guarantee that converters controlled as defined in previous tasks are operated below their physical capacities.
- A set of requirement guidelines for converter-based generating units will be defined. They will be as far as possible set at the connection point, disregarding the technology and not defining any hardware specification.

5.5.2 Subtasks

Subtask 5.1: Specification of the system integration tests (RTE)

In the different stages of development for technological applications, a reduced scale demonstrator (with part of the equipment being simulated while others are reduced scale hardware) is often an important validation phase after simulation analysis and prior to first real size prototypes or industrial installations. Digital simulations produce significant results but some phenomena are not observable in this way. For example, the physical limitations of inverters are not always precisely defined in digital simulations; the usage of physical mock-ups obviously guarantees that these devices are operated below their physical capacities.

For this reason, system integration tests of the controls and rules developed in tasks 2, 3 and 4 will be done using a reduced size real system implemented on the hardware facilities available in L2EP.

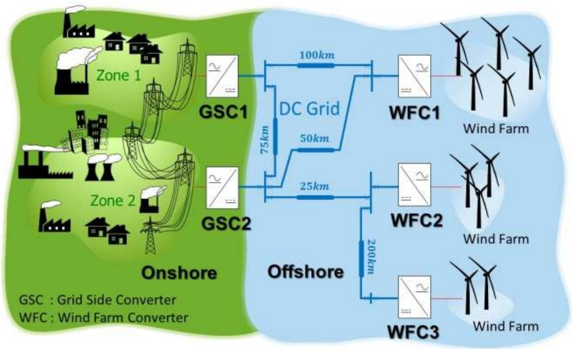

*Figure 12 – **Twenties mock up***

Description of the hardware facilities available in L2EP

The L2EP's facilities combine real electrical power components such as cables and converters, communication and control equipment with real-time simulation tools. They provide an interesting intermediate and flexible step between simulations and on site demonstrator. They were developed in the framework of the FP7 TWENTIES demo project to implement a low power and low voltage (250 V) mock-up of a MTDC grid, with a homothetic design chosen to represent at best a high voltage network. This DC grid was successfully connected to a virtual AC power system. Each component – including physical cables and real converters – was integrated in a power system configuration and evaluated under different operation scenarios with various conditions (see Twenties deliverables 11.1 to 11.3, http://www.twenties-project.eu/node/18).

For several ongoing projects, new real electrical components (inverters with MMC and other technologies) will be installed on the platform. These elements can be used to validate the operation of a 100%PE grid.

Subtask 5.1.1: Hardware specification for the system integration tests (RTE, L2EP)

Based on the test cases defined in chapter 6, the reduced size real systems to be implemented on the L2EP's hardware facilities to validate the developed controls and rules will be chosen. The specifications of new hardware to be purchased for the future tests will be drawn up.

The tests performed in WP3 will require to purchase new specific hardware: a high performance linear amplifier 3x20kVA which is a key point to interconnect real-time simulations to real devices. This concept is known as Power Hardware In the Loop (PHIL) simulation. In addition to the increase of the bandwidth and a better power quality which come from the classical technological improvement, this new generation of hardware which is more powerful than those already available on the platform will make possible to greatly improve the performance of PHIL simulation. Thanks to this amplifier, it will be possible to emulate different power electronic topologies connected to a power system with a better accuracy.

Subcontractor

Puissance+ who is a specialist on design and production of power electronics equipment will provide the hardware. It has developed a complete range of 4 quadrant linear current and voltage amplifiers which allow real-time PowerHIL simulation for conventional power grid but also SMART GRID, and other complex applications like More Electric Aircrafts development. Puissance+ constantly upgrades their products and will be able to run real time models directly on the control board embedded in their products (due to high performance FPGA embedded devices).
Puissance+ supplied the products used by the L2EP lab.

Subtask 5.1.2: Detailed specifications of the system integration tests (RTE, all partners)

Based on the results of tasks 2, 3 and 4, detailed specifications of the system integration tests will be drawn up. They will include:

- the topology of the test cases
- the characteristics of the different components (type of converters, type of loads, characteristics of lines…)
- the considered operating points (for example setpoints of converters, value of loads…)
- the scope of the tests that will be implemented on hardware facilities
- the transients expected to occur on a transmission grid to be simulated

These specifications will be based on the test cases defined in chapter 6, which will be refined using the findings of tasks 2, 3 and 4. Both topology and event list will evolve during the project as new constraints/events are identified.
The topology of the studied grid will be limited to some interconnected inverters (less than 10 in simulation and less than 4 real converters connected to a real-time simulated grid (Hardware-in-the-loop), but could be of different technologies to check interoperability.

Subtask 5.2: Implementation of the test cases (L2EP)

Using the detailed specifications, the test cases will be implemented on the hardware facilities and on the real-time simulator.

Subtask 5.3: System integration tests and validation of the developed controls and rules (RTE, all partners)

The transients that are expected to occur on a transmission grid will be simulated. The VSC controls (control of power, control of voltage) and hardware will be tested. The tests will have to ensure the system stability as defined in the WP. It will also be checked if the system needs defined in chapter 2 are fulfilled or if there is a need for adaptation. Ancillary services and high level management developed in tasks 3 and 4 will also be tested. The results of simulations and of laboratory tests will be compared.

Subtask 5.4: Guidelines for new requirements (RTE, all partners)

The output of the simulations and laboratory tests performed in WP3 will be summarized into requirements for new inverters. It will allow to validate if requirements at the connection point are sufficient to ensure system stability or if it is necessary to go for hardware requirements. The level of details for the requirements will be one of the outputs of this task and an input for WP6 about future guidelines for grid codes.

General guidelines will also be proposed for operational rules which may be applied to a range of power systems with 100% converter-based generation. A balance will be sought between robust and cost-effective solutions, and guidance will be given on necessary features of future (technology agnostic) grid codes and the technical design of ancillary services, ensuring acceptable operation with existing equipment while providing requirement guidelines for future devices. Operational procedures for the transition (in both directions) between 100% and <100% converter-based generation will also be proposed, as a result of a post-disturbance state or as a planned transition.

6 Description of test cases

WP3 is a very forward-looking Work Package: it will look into a future that is very different from the current operation of transmission systems. Some of the issues that can be raised on grids with 100% PE may not have been encountered yet and must be studied carefully. This is why a wide range of test cases will be used, from very simple grids to an existing transmission system.

6.1 Test case 1: 2-node system

The first test case is a 2-node system, with an inverter directly connected to a node with either an infinite bus or a load. This represents the two extreme cases for transmission grids:

- one where the inverter is connected to an infinite bus, which means a very strong grid (test case 1a)
- one where the inverter only fed a load, which is similar to a very weak grid (test case 1b).

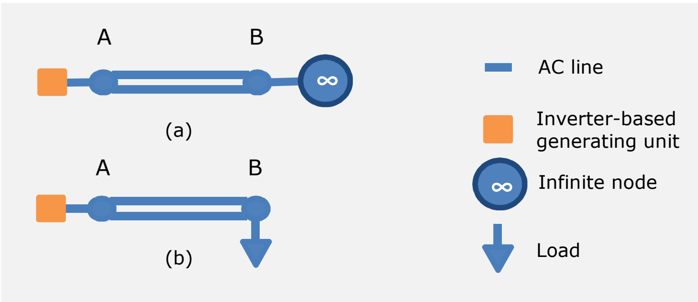

*Figure 13 – **Test case 1***

On the first system, the impact of the inverter on the grid will be low and the inverter will have to follow what the electric system imposes. Therefore, its controls will have to smoothly react to avoid transients "against" the grid.
On the second system, there will be nothing to "follow". The impact of changes on the inverter will be directly transmitted to the grid as there will be no other active component on the grid.
In reality, the situation of an inverter connected on the grid will be anywhere between these two situations, and the controls that exist today work exclusively for the first one. Finding control laws that work for both of these situations is already a challenge.
The simplicity of this 2-node system will allow to carry out "theoretical"/"ideal" tuning and to test it. It will then be tested on more complex configurations.

6.2 Test case 2: 3-node system

The second test case is a triangle shape network with one double line, 3 inverter-based generating units and 2 loads[15] connected to it. The size of the inverters will be different. The proposed topology offers a loop that is a distinctive feature of transmission systems and has not been studied on microgrids for example.

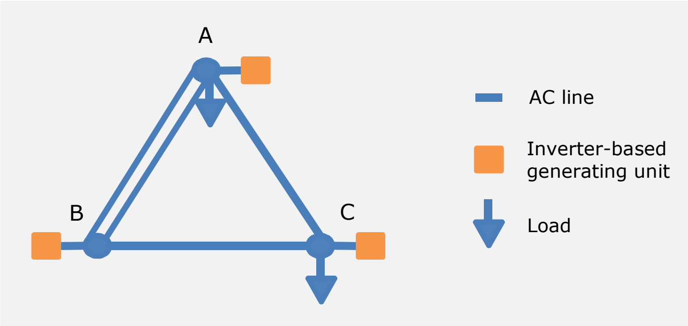

*Figure 14 – **Test case 2***

This system is still simple but will allow different events that are very interesting for transmission system operators:

- change the load at node B,
- trip one of the lines between nodes A and B,
- start from a situation where one of the A-B lines is open and close it,
- switch out the line between nodes B and C,
- start from a situation where the B-C line is open and close it.
- trip one of the inverters
- short-circuit
- …

The developed control rules will have to make the system robust at least against the events mentioned above. The inverters will be assumed to have enough primary energy to fulfill the loads at any time: the goal of WP3 is to find a way to transmit this energy to the grid, without telecommunication signals (if possible) and without exceeding the physical limitations of each inverter.

The first event (load change) is the most typical disturbance that happens on transmission grids. Load is never constant, therefore for such a system it is very important to validate that the inverter controls can adapt to the load and provide it with the needed energy. In addition, the controls must be able to choose how the load is shared between the different inverters.

[15] Loads could be impedances, inverters…

Line switching (on or off) is another interesting event because it usually leads to significant transients. Let's take the example of the second event above (tripping of one of the lines between A and B). The power that flows between A and B is, with some approximation, as follows:

$$P_{A\rightarrow B} = V_A V_B * \frac{\sin(\theta_A - \theta_B)}{X_{A-B}}$$

It is assumed that the angles θ cannot change immediately as they are controlled by the inverters. When one of the 2 lines is switched off, the impedance between the 2 nodes rapidly changes and the power flow between the 2 ends of the remaining line is suddenly modified. Therefore, it can lead to a power flow higher than the maximum capacity of the inverters. This 3-node test system will therefore allow testing of limitation strategies that will be implemented in the controls of the inverters.

The different events will stress the system at different levels. For example it can be expected that opening or closing one line of a double circuit will be less constraining that opening or closing a single circuit (which will open or create a loop in the system).

6.3 Test case 3: Irish system

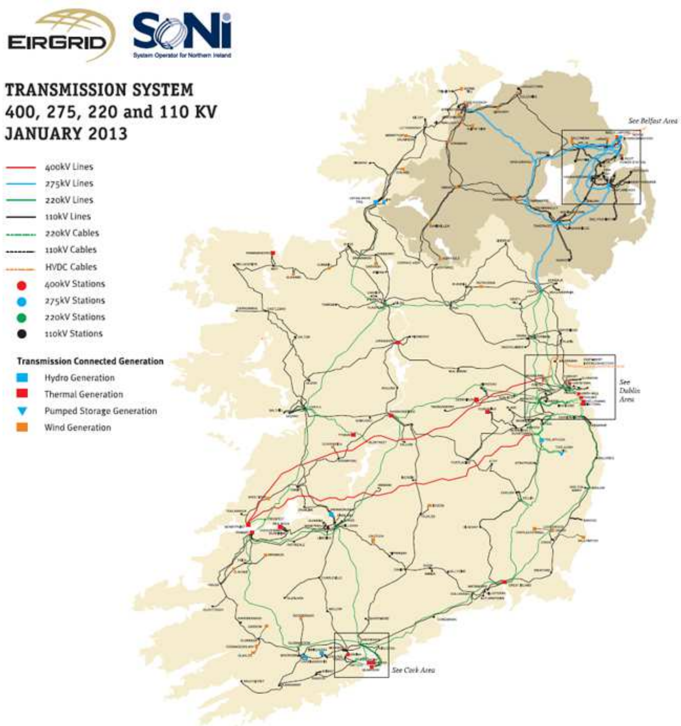

*Figure 15 – **Test case 3***

The Irish test case will probably be the most complex network that will be studied in WP3. The system is big enough to accurately represent transmission issues (for example the network is meshed and includes transformers at several voltage levels), but is also small enough to be represented in high detail in simulation software and to allow the simulation to run in a reasonable time. Moreover the "reduced" size of the system will allow a deeper analysis than what would have been done on a bigger system, such as continental Europe. It will be possible to model the 400, 275 and 220 kV networks in EMT type models, and the 110 kV level will be attempted to be included to obtain the most representative network.

The inverters will be modeled with as much detail as technically possible - they are the key components of WP3. The main issue addressed here is how to transfer to the grid the power that is needed without damaging the inverters and keeping the power quality as good as it is today.

Modelling of the DC source in such a new context would be challenging, it is therefore assumed that the DC source is a perfect constant voltage source, this is not completely unrealistic as it could represent a large battery. Some refinements might be introduced during the project on the DC source (add some time lag, or some internal impedance…), but this is not the core problem that has to be solved. Nevertheless, the impact of changing the DC source will be evaluated to check if a more complex model of the DC source leads to more or less constraining situations.

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