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# Models for Simulating Technical Scarcities on the European Power System with High Levels of Renewable Generation

D2.3



EU-SysFlex

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## ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| AC | Alternating Current |
| ADN | Active Distribution Network |
| aFRR | automatic Frequency Restoration Reserve |
| APE | Automated Plexos Extraction tool |
| AVR | Automatic Voltage Regulator |
| BESS | Battery Energy Storage System |
| CCGT | Combined Cycle Gas Turbine |
| CE | Continental Europe |
| CHP | Combined Heat and Power |
| CMOL | Common Merit Order List |
| DAST | Dynamic Automation Simulation Tool |
| DC | Direct Current |
| DG | Distributed Generation |
| DER | Distributed Energy Resources |
| DSL | DIgSILENT Simulation Language |
| DSM | Demand-Side Management |
| DSO | Distribution System Operator |
| DTS | Dispatcher Training Simulator |
| EFR | Enhanced Frequency Response |
| EHV | Extra High Voltage |
| EMS | Energy Management System |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| EPSO | Evolutionary Particle Swarm Optimization |
| EU | European Union |
| EV | Electric vehicles |
| FCR | Frequency Containment Reserve |
| FCR-D | Frequency Containment Reserve for Disturbances (in Nordic system) |
| FCR-N | Frequency Containment Reserve for Normal Operation (in Nordic system) |
| FFT | Fast Fourier Transform |
| FFR | Fast Frequency Response |
| FRR | Frequency Restoration Reserve |
| FRT | Fault Ride Through |
| HV | High Voltage |
| HVDC | High Voltage Direct Current |
| IEC | International Electrotechnical Commission |
| IEEE | Institute of Electrical and Electronics Engineers |

| | |
|---|---|
| IGCC | International Grid Control Cooperation |
| LCC | Line-Commutated Converter |
| LFG | Landfill Gas |
| LFSM-O | Limited Frequency Sensitive Mode at Over frequency |
| LFSM-U | Limited Frequency Sensitive Mode at Under frequency |
| mFRR | manual Frequency Restoration Reserve |
| MIC | Maximum Import Capacity |
| MILP | Mixed Integer Linear Programming |
| MSS | Mechanically Switched Shunts |
| MV | Medium Voltage |
| NI | Northern Ireland |
| NTC | Net Transfer Capacities |
| OCGT | Open Cycle Gas Turbine |
| OFSM | Over Frequency Sensitivity Mode |
| PCC | Point of Common Coupling |
| PCM | Preventative Control Measure |
| PDF | Probabilistic Density Function |
| PE | Power Electronics |
| PID | Proportional Integral Derivative controller |
| PLL | Phase Lock Loop |
| PSAT | Powerflow and Short-circuit Assessment Tool |
| PSS | Power System Stabilizer |
| PV | Photovoltaic |
| RES | Renewable Energy Sources |
| RES-E | Renewable Energy Sources of Electricity |
| RMS | Root Mean Square |
| ROCOF | Rate Of Change Of Frequency |
| RR | Replacement Reserve |
| SNSP | System Non-Synchronous Penetration |
| SPS | Special Protection Schemes |
| STATCOM | Static Synchronous Compensators |
| SVC | Static Var Compensators |
| TES | Tomorrow's Energy Scenarios |
| TSAT | Transient Security Assessment Tool |
| TSO | Transmission System Operator |
| TSSPS | Transmission System Security Planning Standards |
| TUV | Trip by under-voltage |
| TYNDP | Ten-Year Network Development Plan |

| | |
|---|---|
| UC | Unit Commitment |
| UCED | Unit Commitment and Economic Dispatch |
| UDM | User Defined Model |
| UFLS | Under frequency Load Shedding |
| VDIFD | Voltage Dip Induced Frequency Dip |
| VRES | Variable Renewable Energy Sources |
| VSAT | Voltage Security Assessment Tool |
| VSC | Voltage Source Converter |
| WP | Work Package |
| WTG | Wind Turbine Generator |
| WECC | Western Electricity Coordinating Council |
| WJMM | Wilmar Joint Market Model |
| WSAT | Wind Secure level Assessment Tool |

# EXECUTIVE SUMMARY

**The EU-SysFlex project aims to identify large scale deployment of flexible solutions for a European power system with a high share of Renewable Energy Sources (RES). These solutions can include technical options, system services and market designs. The project results will contribute to enhanced system flexibility, coordinating the use of both existing and new technologies. Work Package (WP) 2 is the starting point of the project, as its goal is to evaluate the scarcities arising in the future system. Task 2.3 provides dynamic models intended for simulations in Task 2.4 which will determine the technical scarcities associated with high levels of renewable generation on European system. These models will also be used in Task 2.6, which will take learnings from the demonstration projects within the EU-SysFlex project (i.e. WP6 – WP9) and integrate these, along with other solutions, to show the impacts of deploying different mitigation measures to address the various scarcities identified.**

**This report provides the outcome of the dynamic model development for the EU-SysFlex project (Task 2.3 of the project). Three European power systems are modelled: Ireland and Northern Ireland, Continental Europe and the Nordic system.**

**Task 2.3 builds on the literature review performed within Task 2.1 of the project, and uses it as a base for model categorisation and to present a high level overview of the stability issues to be investigated using the models developed by each EU-SysFlex consortium partner.**

Due to the increasing penetration of non-synchronous Variable Renewable Energy Sources (VRES), the European power system is likely to face exceptional challenges over the coming decades. These challenges, or scarcities, have been summarised in EU-SysFlex D2.1 deliverable into the five following main categories:

- **Frequency Stability** – The displacement of convention generation due to the connection of power electronics interfaced VRES to the grid is likely to result in system inertia reduction. System frequency stability is highly influenced by inertia levels and is likely to be negatively influenced.
- **Voltage Stability** – Owing to the limited fault current provision capability of power electronics interfaced VRES, a reduction of short circuit power across the transmission systems under consideration is likely, resulting in deeper voltage dips and wider fault propagation, in the event of a contingency. Additionally, it may affect the proper activation of current protection schemes.
- **Rotor Angle Stability** – The reduction of conventional generation and thereby the reduction of synchronising torque across the system is likely to impact the ability of the remaining synchronous generation to maintain synchronism following a contingency. Deterioration in the rotor angle stability margins is therefore highly likely to jeopardise the system stability. Small-signal stability should also be considered, as interactions between converter controlled generators and synchronous generators may lead to instabilities.

- **Network Congestion** – Due to the distributed nature of VRES, the number and geographical diversity of energy feed-in points is likely to increase. The magnitude and direction of power flow at the transmission and distribution levels will be affected, potentially leading to network congestion due to thermal line overloading and voltage stability issues.
- **System Restoration** – Power systems are continuously being operated closer to their limits. Partial failures, if not appropriately mitigated, can result in cascading effects potentially leading to blackouts. Large-scale synchronous generators have black start (or preparation stage) capability. The growth in VRES and consequent decommissioning of conventional plants could lead to a reduction of black start capability, and increase the complexity of supply restoration process.

Based on this broad categorisation, a classification of major stability issues was developed. It leads to a series of 14 possible system scarcities and stability issues on the European systems, listed in the Table 1.

**TABLE 1: CLASSIFICATION OF STABILITY ISSUES USED IN TASK 2.3**

| N° | System Scarcities and Stability Issues | Category |
|---|---|---|
| 1 | Rate of change of frequency | Frequency stability and control |
| 2 | Frequency containment | |
| 3 | Inertia levels | |
| 4 | Voltage dip induced frequency dip | |
| 5 | Adequate reserve provision | |
| 6 | Ramping margins and reserve sizing | |
| 7 | Short circuit levels | Voltage control |
| 8 | Fault-Ride-Through | |
| 9 | Reactive power levels | |
| 10 | Power oscillations | Rotor angle stability |
| 11 | Oscillation modes | |
| 12 | Transient stability margins | |
| 13 | Network congestion | Congestion management |
| 14 | Black-start analysis | System Restoration |

In order to further investigate the aforementioned issues, relevant models capable of addressing these issues are developed in Task 2.3. Table 2 shows the model capability compared to the stability issue to be investigated. The complementary nature of the models enables the coverage of a broad range of stability studies on the three European power systems under consideration.

TABLE 2: SCOPE OF THE MODELS DEVELOPED IN TASK 2.3

| | Developer | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | EDF | | PSE | VTT | | EirGrid & SONI | | |
| | CONTINENTAL & OPIUM | PALADYN | CE power system model | WILMAR (WJMM) | Frequency stability model | PLEXOS | WSAT | SFM |
| 1 | | X | | | X | | X | X |
| 2 | | X | | | X | | X | X |
| 3 | X | | | | X | X | | |
| 4 | | | | | | | X | |
| 5 | X | | | X | | X | | |
| 6 | X | | | | | X | | |
| 7 | | | X | | | | X | |
| 8 | | | X | | | | X | |
| 9 | | | X | | | | X | |
| 10 | | | X | | | | X | |
| 11 | | | | | | | X | |
| 12 | | | X | | | | X | |
| 13 | X | | | X | | | X | |
| 14 | | | | | | | X | |

| | |
|---|---|
| | Continental Europe power system |
| | Nordic power system |
| | Ireland and Northern Ireland power system |

For the modelling of the **Continental Europe (CE) power system**, the Unit Commitment and Economic Dispatch (UCED) model used is CONTINENTAL, associated with the model OPIUM for the assessment of reserve levels in the future system. CONTINENTAL performs a hydro and thermal dispatch optimisation to match load profiles developed for the EU-SysFlex scenarios in Task 2.2 and caters for novel technologies such as electric vehicles (EVs) and heat pumps. Generation technologies that are considered by CONTINENTAL for the dispatch are nuclear, hydro, coal, combined cycle gas turbine, open cycle gas or oil turbine, biomass, cogeneration, wind and solar.
Subsequently, PALADYN is used for frequency stability studies, as it represents the Continental Europe system in terms of a multi-zone model with individual generation technologies' corresponding inertia, frequency response, and loads.

Additionally, a separate sub-network of the CE power system model is used for dynamic voltage control and rotor angle related investigations. It comprises of a detailed model of the Poland transmission system and neighbouring countries, while the remaining counties in the CE power system are represented in a simplified manner. A distribution grid model is appended to represent the TSO-DSO interfaces in the grid.

Three stability issues are not studied for the Continental Europe power system:

- Voltage dip induced frequency dip: this topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016),
- Oscillation modes: available data and working time are insufficient to run accurate simulations on this issue,
- Black-start analysis: additional black start means are not likely to be needed on most of the Continental Europe countries, which can already rely on multiple hydro power plants. This topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016).

The **Nordic system** is studied using the UCED model WILMAR (WJMM) for dispatching and congestion assessment. The model simulates the hydro-thermal dispatch of a multi-area system for every hour of the year, given the interconnection constraints between the areas. It provides scheduled electricity production of power plants, storages, EV and other resources, scheduled heat production of heating plants and storage, and reserves allocations. The dynamic study on the Nordic system will focus on frequency stability, using a specific model. Similar to the Ireland and Northern Ireland Single Frequency Model, the frequency stability model for Nordic power system is a single bus model providing time series of system kinetic energy and frequency stability indicators.

The study on **Ireland and Northern Ireland** will be extensive; a broad variety of issues will be investigated in a sequence of models, including PLEXOS, a Unit Commitment and Economic Dispatch (UCED) model, followed by two dynamic models:

- WSAT: A suite of tools used for performing quasi steady state and time domain simulations. It is suitable for investigating classical voltage stability, frequency stability, dynamic voltage stability and rotor angle stability. The models contain a detailed representation of the Ireland and Northern Ireland transmission system, and Transmission System Operator (TSO) / Distribution System Operator (DSO) border with the implementation of the generic distribution grid model at certain locations, subject to study requirements.

- Single Frequency Model (SFM): developed in Matlab, it is a simplified version of Ireland and Northern Ireland system model assuming perfect voltage regulation and uniform system frequency. This is mainly suitable for screening type studies pertaining to active power balance in the system and hence frequency stability.

The inter-model interactions between all models are illustrated on Figure 1.

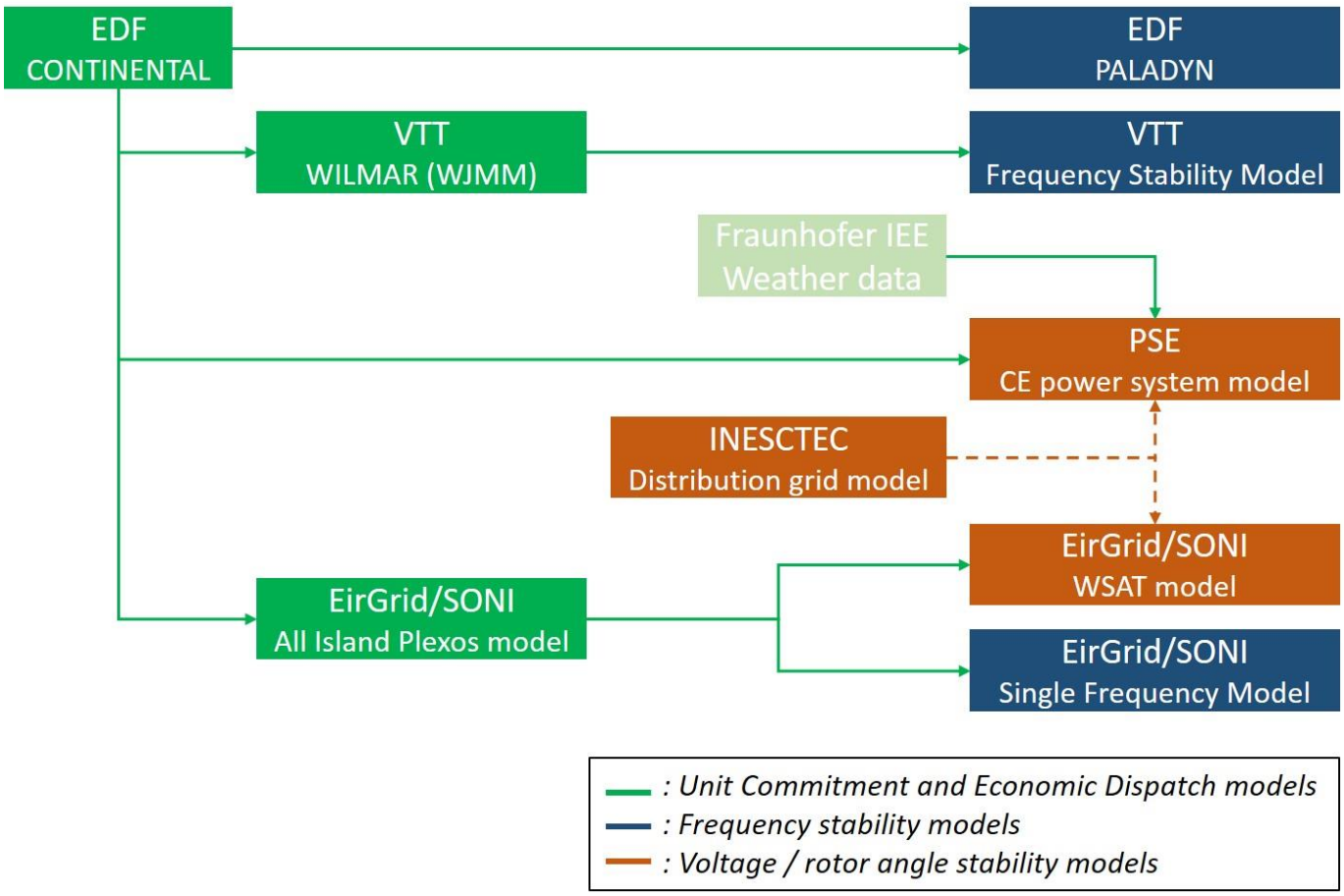



FIGURE 1: SUMMARY OF INTERACTIONS BETWEEN PARTNERS MODELS

Some details on these interactions are listed below:

- The EDF tool CONTINENTAL simulates the EU-SysFlex **Energy Transition** and **Renewable Ambition** scenarios, which have been developed in Task 2.2, and provides the following hourly data for the majority of European countries:
    - Load [MW]
    - Generation dispatch for each technology [MW]
    - Reserves (FCR, aFRR) for each technology [MW]
    - Kinetic energy [MVA.s]

  The EDF model PALADYN uses CONTINENTAL data to run frequency stability simulations on several hours of the year. VTT simulates one year with WILMAR, a more detailed Nordic model, taking into account the hourly exchanges with Continental Europe from CONTINENTAL model. EDF sends some snapshots of CONTINENTAL data to PSE for several of the worst hours in the year identified with specific stability criteria. Finally, interconnector flows are provided by CONTINENTAL to EirGrid and SONI for the study on Ireland and Northern Ireland power system UCED model with PLEXOS.

- The VTT model WILMAR (WJMM) provides data to conduct simulations on VTT's frequency stability model for each hour of the year. WJMM outputs include:

  - scheduled electricity production (charging when applicable) of power plants, storages, EV and other resources
  - scheduled heat production (charging when applicable) of heating plants and storages
  - reserve allocation by plant and reserve type

- Fraunhofer IEE produces spatial distribution of weather data (solar radiation, wind speed and temperature), that are used by PSE to assess the repartition of wind and solar power inside the Eastern European countries.

- INESC TEC distribution grid model theory is integrated in the European sub-network and Ireland and Northern Ireland transmission network models. The aim is to assess the role of distribution flexibilities for the system stability.

- The EirGrid model PLEXOS generates unit commitment data according to the EU-SysFlex **Energy Transition** and **Renewable Ambition** scenarios, as well as the Ireland and Northern Ireland network sensitivities. This provides the following outputs:
  - Least cost dispatches for all units;
  - Total net demand;
  - Production costs;
  - VRES curtailment or dispatch down levels;
  - Indication of RES-E levels for Ireland and Northern Ireland;
  - System Non-Synchronous Penetration (SNSP) levels;
  - Inertia levels;
  - Indication of reactive power capability; and
  - Indication of system ramping capability,

  This data is used to run simulations on the Ireland and Northern Ireland system with the WSAT and Single Frequency Model.

The detailed description of the simulations conducted to investigate various non-synchronous VRES related issues will be provided in detail within Task 2.4 and Deliverable D2.4 of EU-SysFlex project. This deliverable will report on the detailed technical scarcity simulations, including model initialisation and study outcomes.

Table 3 provides an overview of the model applications, and the stability indicators which were chosen for each stability issue.

**TABLE 3: SUMMARY OF SIMULATIONS TO BE RUN IN TASK 2.4**

| Category | Power System | Scheduled simulations | Indicators |
|---|---|---|---|
| **Frequency Stability and Control** | Ireland & Northern Ireland | Loss of infeed, loss of load/export for each hour of the year | Frequency nadir/zenith, ROCOF, frequency rise/drop duration index |
| | Continental Europe | Simulation of events for each hour of the year:<br>- Interconnected incidents<br>- System splits | |
| | Nordic system | Simulation of events for each hour of the year:<br>- Interconnected incidents<br>- System splits | Frequency nadir/zenith, ROCOF |
| **Voltage Control** | Ireland & Northern Ireland | Series of faults in Ireland and Northern Ireland on each hour of the year | Short circuit levels, voltage drop/rise duration index, voltage security index, voltage stability margin, voltage stability limits |
| | Continental Europe | Series of 3-phase short-circuits for the worst hours of the year following criteria:<br>- Maximum power demand<br>- Minimum reactive power margins | Short circuit levels, FRT capability profiles, voltage security index, voltage stability margin, voltage stability limits |
| **Rotor Angle Stability** | Ireland & Northern Ireland | Series of short circuit faults in Ireland and Northern Ireland on each hour of the year | Angle margin index, critical clearing time, stability margin, decay time constants |
| | Continental Europe | Series of short circuit faults in Poland and neighbour countries, for the worst hours of the year following criteria:<br>- Minimum inertia<br>- Maximum power demand | Transient stability margin, settling time and halving time |
| **Congestion** | Ireland & Northern Ireland | Congestion assessment for base case operation and single contingency conditions | Thermal limits of equipment, compensation switching, voltage collapse margin |
| | Continental Europe | Base case operation, congestion assessment on borders | Thermal limits of equipment |
| | Nordic system | Base case operation, congestion assessment between bidding zones | Thermal limits of equipment |
| **System Restoration** | Ireland & Northern Ireland | Assessment of the 2030 system restoration plan | |

# 1. INTRODUCTION

## 1.1 TASK 2.3 WITHIN EU-SYSFLEX

The EU-SysFlex project seeks to enable the European power system to utilise efficient, coordinated flexibilities in order to integrate high levels of renewable energy sources. One of the primary goals of the project is to examine the European power system with at least 50% of electricity coming from renewable energy sources (RES-E).

In order to reach at least 50% RES-E on a European scale, it will be necessary to integrate very high levels of variable non-synchronous renewable technologies such as wind and solar. Transitioning from power systems which have traditionally been dominated by large synchronous generating units to systems with high levels of variable non-synchronous renewable technologies has been shown to result in challenges for operating power systems safely and reliably. This is due to the non-synchronous nature of these technologies as well as the variable and uncertain nature of the underlying resources. The integration of non-synchronous renewable generation results in the displacement of synchronous generators. This can consequently lead to technical scarcities in power systems due to the new technologies having to replicate traditional resilience functions of synchronous generators, and new scarcities which have been revealed due to the displacement of synchronous machines. Addressing these challenges is at the core of the EU-SysFlex project.

In this regard, Work Package (WP) 2 forms a crucial starting point for the EU-SysFlex project. Work Package 2 will perform detailed technical power system simulations in order to identify the technical scarcities of the European power system with high levels of renewable generation as well as high levels of electrification. Interactions between WP2 and the other WP in the project can be seen in Figure 2.

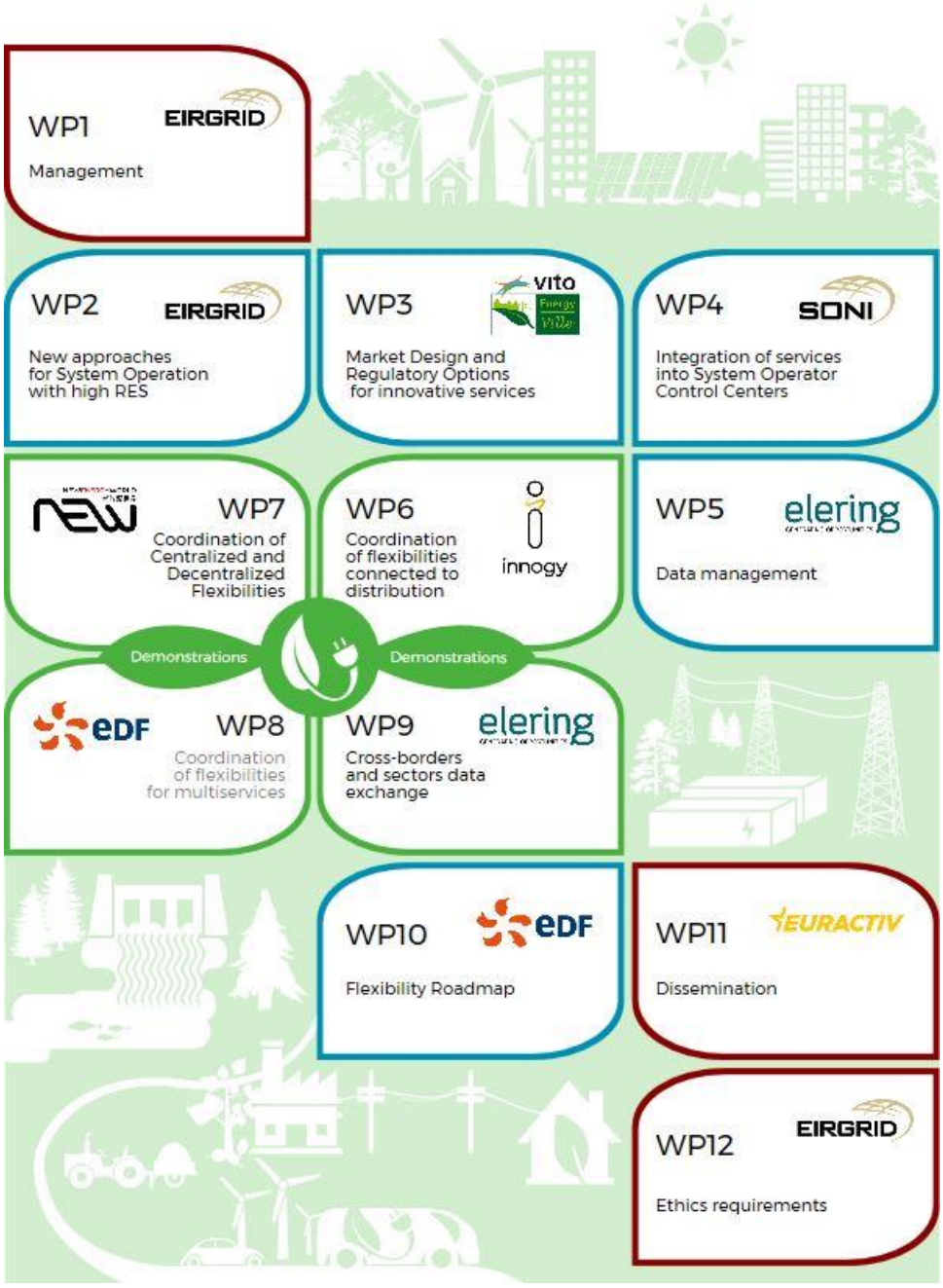



**FIGURE 2: EU-SYSFLEX WORK PLAN**

The first deliverable of WP2 was completed as part of Task 2.1 - D2.1 - State-of-the-Art Literature Review of System Scarcities at High Levels of Renewable Generation (EU-SysFlex, 2018). Task 2.2 defines a set of pragmatic and ambitious scenarios for renewable generation deployment in Europe. Task 2.3 aims at setting up detailed models to simulate technical scarcities on the European system. This task describes the Unit Commitment and Economic Dispatch (UCED) models to be used in WP2 and provides information on the dynamic modelling of a range of technologies including wind, solar, demand side, EV charging, storage, interconnection and conventional plant. In addition to accurate models of each transmission system, the increase of power generation at distribution level will be considered. An aggregated distribution model is able to adequately represent the

dynamic behaviour of DSO/TSO interfaces. Steady state, transient and small-signal simulations will be run on either all or several of the European power systems.

These models will be utilised in Task 2.4, in conjunction with the scenarios, to perform detailed studies. The studies will encompass several geographical perimeters with different characteristics. This includes a Continental European model encompassing 20 countries, which will focus primarily on frequency stability, and further subsystems which will be used for more detailed analysis. These subsystems are the Nordic power system, the Ireland and Northern Ireland power system, and a sub-network of the Continental European system focussing on Poland and the surrounding countries. The aim of these simulations is to identify a range of technical scarcities. The technical scarcities that will be identified in WP2 are central to the EU-SysFlex project as these technical scarcities will feed into WP3 which will develop innovative system services and market and regulatory options to address these scarcities.

Concurrent to the technical studies in Task 2.4, production cost modelling, based on the scenarios documented in this report, will be performed in Task 2.5 for both the Continental European power system and the Ireland and Northern Ireland power system. These modelling studies will assess potential revenues for new technologies as well as identify financial gaps in the energy market. These gaps would need to be filled by new or increased revenue streams from system services in order to create sufficient investment signals for new technologies to be realised.

The final task in WP2, Task 2.6, will seek to incorporate the findings from other WPs in the EU-SysFlex project and incorporate proposed solutions to the scarcities identified based on the learnings from the project.

## 1.2 TECHNICAL BACKGROUND

This subsection highlights the power system challenges associated with the integration of renewable energy resources and the need for developing dynamic models to evaluate the system scarcities.

Due to the increasing penetration of non-synchronous Variable RES (VRES), mostly wind and photovoltaic, the European power system is likely to face exceptional challenges over the coming decades. These challenges, or scarcities, have been summarised in EU-SysFlex D2.1 deliverable (EU-SysFlex, 2018) into the five following main categories:

- **Frequency Stability** – The displacement of convention generation due to the connection of power electronics interfaced VRES to the grid is likely to result in system inertia reduction. System frequency stability is highly influenced by inertia levels and is likely to be negatively influenced.
- **Voltage Stability** – Owing to the limited fault current provision capability of power electronics interfaced VRES, a reduction of short circuit power across the transmission systems under consideration is likely,

resulting in deeper voltage dips and wider fault propagation, in the event of a contingency. Additionally, it may affect the proper activation of current protection schemes.

- **Rotor Angle Stability** – The reduction of conventional generation and thereby the reduction of synchronising torque across the system is likely to impact the ability of the remaining synchronous generation to maintain synchronism following a contingency. Deterioration in the rotor angle stability margins is therefore highly likely to jeopardise the system stability. Small-signal stability should also be considered, as interactions between converter controlled generators and synchronous generators may lead to instabilities.
- **Network Congestion** – Due to the distributed nature of VRES, the number and geographical diversity of energy feed-in points is likely to increase. The magnitude and direction of power flow at the transmission and distribution levels will be affected, potentially leading to network congestion due to thermal line overloading and voltage stability issues.
- **System Restoration** – Power systems are continuously being operated closer to their limits. Partial failures, if not appropriately mitigated, can result in cascading effects potentially leading to blackouts. Large-scale synchronous generators have black start (or preparation stage) capability. The growth in VRES and consequent decommissioning of conventional plants could lead to a reduction of black start capability, and increase the complexity of supply restoration process.

These categories of stability issues define the scope of the EU-SysFlex studies. The simulation models need to be developed accordingly, in order to identify the technical scarcities in the future European power system.

The sixth challenge identified in EU-SysFlex D2.1 is system adequacy. With the increasing penetration of VRES, thermal plants are being decommissioned; hence capacity margins may become tighter. Uncertainty of generation capacity, the variability of VRES, and system interdependencies appear to be issues that may impact the target to achieve a capacity-adequate European power system. In the EU-SysFlex project, system adequacy is addressed by UCED models, and will be investigated as part of Task 2.5.

## 1.3 METHODOLOGY AND OBJECTIVES

The objective of the EU-SysFlex WP2 is to identify the system scarcities of the European power system with high levels of renewables. The dynamic simulations will be run in Task 2.4, using models that have been developed by several partners in Task 2.3.

This Deliverable 2.3 report provides the outcomes of Task 2.3, which are mainly the description of the detailed models for the Ireland and Northern Ireland power system, the Continental Europe system and the Nordic system. Several models are used in the task, as each partner has access to grid or assets details that cannot be shared with the other partners.

To assess the frequency stability of the system, limited grid information is required in the models. However, the behaviour of generation units, loads, storage and the dynamics of frequency control mechanisms need to be accurately modelled. This data is available for EirGrid and SONI developed Ireland and Northern Ireland system, the VTT developed Nordic system and the EDF developed Continental Europe system model.

Voltage control, rotor angle stability and system restoration simulations require a detailed specific representation of each network. As TSOs (EirGrid, SONI and PSE) have access to this data, these simulations will be performed using the Ireland and Northern Ireland system models and PSE developed Continental Europe sub-network models. The existing models were adapted to represent the 2030 network for Ireland and Northern Ireland, and Continental Europe. The 2030 networks include planned grid reinforcements and new equipment such as reactive power components (capacitors, reactors, STATCOMs), phase shifting transformers and interconnections (AC and DC).

Finally, a generic distribution grid model was developed by INESC TEC, to represent the dynamic behaviour of the TSO-DSO interface. Its parametrization uses limited distribution grids data. This model is shared among the partners of the task, and the model and theory behind the model development, will be used by EirGrid, SONI and PSE to improve their transmission grid models with a representation of the distribution system.

As several models are used for similar simulations on different grids, stability indicators are defined within this report for examining system scarcities. The stability indicators are detailed for each stability issue in the corresponding sections of this deliverable report.

# 2. CLASSIFICATION OF STABILITY ISSUES AND SCOPE OF THE DETAILED MODELS

Based on the broad categorisation of system stability issues identified in EU-SysFlex D2.1, a classification of stability issues was developed (EU-SysFlex, 2018). It leads to a series of 14 possible system scarcities and stability issues on the European system, listed in Table 4.

In order to further investigate the aforementioned issues, relevant models capable of investigating these issues are developed in Task 2.3. Table 5 shows the model capability compared to the stability issue to be investigated. This table highlights the capabilities of each model and their complementarity. The complementary nature of the models enables the coverage of a broad range of stability studies on the three European power systems under consideration.

TABLE 4: CLASSIFICATION OF STABILITY ISSUES USED IN TASK 2.3

| N° | System Scarcities and Stability Issues | Category |
|---|---|---|
| 1 | Rate of Change of Frequency | Frequency stability and control |
| 2 | Frequency containment | |
| 3 | Inertia levels | |
| 4 | Voltage dip induced frequency dip | |
| 5 | Adequate reserve provision | |
| 6 | Ramping margins and reserve sizing | |
| 7 | Short Circuit levels | Voltage control |
| 8 | Fault-Ride-Through | |
| 9 | Reactive power levels | |
| 10 | Power oscillations | Rotor angle stability |
| 11 | Oscillation modes | |
| 12 | Transient stability margins | |
| 13 | Network congestion | Congestion management |
| 14 | Black-start analysis | System Restoration |

TABLE 5: SCOPE OF THE MODELS DEVELOPED IN TASK 2.3

| | Developer | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | EDF | | PSE | VTT | | EirGrid & SONI | | |
| | CONTINENTAL & OPIUM | PALADYN | CE power system model | WILMAR (WJMM) | Frequency stability model | PLEXOS | WSAT | SFM |
| 1 | | X | | | X | | X | X |
| 2 | | X | | | X | | X | X |
| 3 | X | | | | X | X | | |
| 4 | | | | | | | X | |
| 5 | X | | | X | | X | | |
| 6 | X | | | | | X | | |
| 7 | | | X | | | | X | |
| 8 | | | X | | | | X | |
| 9 | | | X | | | | X | |
| 10 | | | X | | | | X | |
| 11 | | | | | | | X | |
| 12 | | | X | | | | X | |
| 13 | X | | | X | | | X | |
| 14 | | | | | | | X | |

| | |
|---|---|
| | Continental Europe power system |
| | Nordic power system |
| | Ireland and Northern Ireland power system |

Each studied power system (Continental Europe, Nordic, and Ireland and Northern Ireland) has its specificities.

The largest system considered in EU-SysFlex is the Continental Europe system. The results from the Ireland and Northern Ireland power system will highlight future possible scarcities of the Continental Europe system. However, some issues, which are specific to large interconnected systems such as Continental Europe, will also be addressed by the models. This includes notably the specific frequency issue of grid separations, and longer distance between generators leading to weaker synchronising torques in the system. The EDF and PSE models are complementary. EDF will focus on frequency stability, while PSE will perform voltage and rotor angle stability simulations. It should be noted that three stability issues are not studied for the Continental Europe power system:

- Voltage dip induced frequency dip: this topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016),

- Oscillation modes: available data and working time are insufficient to run accurate simulations on this issue,
- Black-start analysis: additional black start means are not likely to be needed on most of the Continental Europe countries, which can already rely on multiple hydro power plants. This topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016).

The next system being analysed is the Nordic power system. The Nordic system will be tested with high levels of RES, which will come from a combination of both high installed capacities of hydro generation and significant capacities of wind generation. The reference incident, or largest contingency, on the Nordic power system is bigger than the largest reference incident in the Continental Europe power system relative to the size of the systems. This may highlight challenges relating to inertia and reserve provision. Analysis of the Nordic power system study will focus on frequency stability and network congestions.

The Ireland and Northern Ireland power system is the smallest synchronous power system area being analysed as part of EU-SysFlex. In consideration of the power systems being studied, the Ireland and Northern Ireland power system has the highest levels of non-synchronous variable renewable generation, which is predominantly wind generation. Consequently, the studies performed on the Ireland and Northern Ireland power system could reveal technical scarcities as a result of very high penetrations of variable renewable generation. These scarcities may not yet necessarily be seen from the studies on a larger system such as the Continental Europe or Nordic power system. However, these scarcities could be seen over longer time horizons on these systems. Thus, some of the results from the Ireland and Northern Ireland power system are of high interest to anticipate future needs of the Continental Europe and Nordic power systems. A considerable number of technical scarcities will be analysed on the Ireland and Northern Ireland power system, utilising EirGrid and SONI's models.

As a result of the huge variation in the power systems being studied, simulations are necessary on the three systems. The ability to perform such a variety of simulations across multiple systems and accurately compare results is one of the main advantages of the EU-SysFlex project. The EU-SysFlex **Energy Transition** and **Renewable Ambition** scenarios developed as part of Task 2.2 link the models and power systems being considered in the project, and thus ensure consistency and complementarity throughout. The results obtained from the simulations will be compared as part of Task 2.4.

# 3. DESCRIPTION OF THE DETAILED MODELS

This section presents and details the models developed for each power system being simulated in the EU-SysFlex project.

Firstly, the EDF developed unit commitment and economic dispatch (UCED) and frequency stability models for the Continental Europe (CE) system is described in section 3.4. This is followed by a description of the PSE models for voltage and transient stability of the CE power system in section 3.2. VTT's UCED and frequency stability model for the Nordic system will then be detailed in section 3.1. The UCED, steady-state, and dynamic models developed by EirGrid and SONI for the Ireland and Northern Ireland power system are outlined in section 3.3. Finally, section 3.5 is dedicated to the description of INESC TEC's generic distribution grid model.

## 3.1 CONTINENTAL EUROPE UCED AND FREQUENCY STABILITY MODELS – EDF

### 3.1.1 UNIT COMMITMENT MODEL – CONTINENTAL

#### 3.1.1.1 GENERALITIES

CONTINENTAL is an integrated electric generation and transmission market simulation model based on the fundamentals of load-generation balancing. It balances electricity supply and demand for a set of interconnected zones, minimising the overall production cost without allowing for players' strategies. It can be used for medium and long term generation expansion planning purpose.

The demand and the generating facilities are defined for each zone. Each zone represents for instance a country. The facilities comprise both various types of thermal generators (coal-fired, gas-fired, oil-fired or nuclear) and hydroelectric facilities. Hydroelectric facilities include pondage, pumping systems and seasonal reservoirs. In addition, the model represent the must-run generation, which is a zero generation cost, such as run-of-river, wind and solar power, decentralised biomass and other kind of RES technologies (tidal, geothermal, etc.). Depending on the setting, this generation can be possibly dispatched down (or curtailed) if it turns out to be cost-effective for the system.

#### 3.1.1.2 A TWO-STEP APPROACH

The model simulates the hydro-thermal dispatch of a multi-area system for every hour of the year, given the interconnection constraints between the areas.

As a first step, CONTINENTAL applies a stochastic dynamic programming method, in order to define a set of strategies of the optimal use of hydro reservoirs. The results are called the « water values » for each time step and for each hydro reservoir.

In the second step, these "water values" are then used to maximise the economic contribution of the hydro reservoirs in the context of an uncertain future.

The second step aims at generating the unit commitment (UC) and dispatch solution that minimizes thermal and hydro generation costs using mixed integer linear programming (MILP) (Langrené et al., 2011). The constraints of the MILP problem include Frequency Containment Reserve (FCR), Automatic Frequency Restoration Reserve (aFRR) procurement and generation dynamic ratings of conventional units (minimum stable generation, start-up costs, minimum up and down times). The multi area optimization includes the interconnection capacities use while respecting the Net Transfer Capacities (NTC) constraints. The problem is solved for a large number of annual scenarios of demand, wind and PV generation, water inflows, fuel costs, thermal unit availabilities and so on. Each scenario represents a full year with an hourly resolution. The model clusters similar units into groups to make the problem tractable.

It is possible to set up the variable RES generation as flexible. In this case, CONTINENTAL's algorithm can choose to de-load them and to make them participate to reserve procurement. Other innovative participants to reserve procurement, like batteries storage or demand response, can be modelled in a simple way by reducing ex-ante the amount of reserve requirement.

The outputs of CONTINENTAL include the hourly commitment status, generation output and the scheduled participation to reserves for all groups of units. Marginal prices for energy and reserves (FCR & aFRR) are also outputs for all zones.

It should be noted that CONTINENTAL is not intended to reproduce accurately the reserve markets organisation in order to output prospective refined reserve prices. The reserve modelling into CONTINENTAL aims at generating more realistic generation plans, especially during periods of high RES output which are the situations when stability issues arise. Moreover, CONTINENTAL does not manage mFRR nor RR. Based on our experience, mFRR and RR procurement have a low impact on the generation plans, contrary to FCR and aFRR.

#### 3.1.1.3 THE CONTINENTAL INVESTMENT LOOP – OUT OF THE SCOPE OF EU-SYSFLEX

The CONTINENTAL investment loop computes the thermal generation mix, using an iterative process. The objective is to obtain the thermal generation mix that ensures that for every new unit the expected market revenue equals its annualized fixed and variable costs. In the EU-SysFlex context, the investment loop was unnecessary given that all of the information pertaining to the installed generation capacity by technologies was included in the two developed scenarios, **Energy Transition** and **Renewable Ambition**, which were derived from EU Reference Scenarios. For more information, please consult the EU-SysFlex D2.2 report (EU-SysFlex, 2018-1).

The overall CONTINENTAL methodology is summed up in the Figure 3.

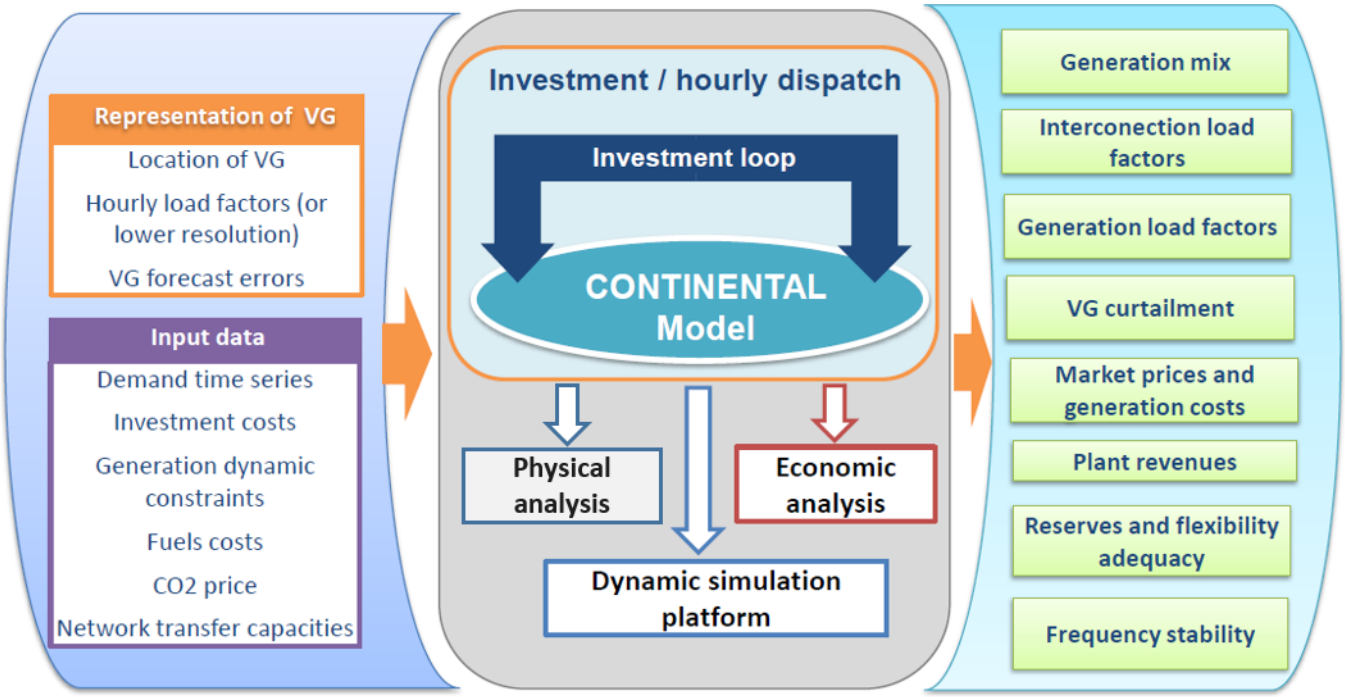



FIGURE 3: CONTINENTAL METHODOLOGY

The main outputs of CONTINENTAL that will be used for stability simulations on the European power systems are:

- Generation hourly dispatch by country and technology,
- FCR and aFRR hourly reserves procurement by country and technology,
- Hourly inertia by country,
- Hourly consumption by country,
- Power flows at the interconnections.

### 3.1.2 AFRR REQUIREMENT ASSESSMENT MODEL - OPIUM

The main objectives of the OPIUM1 tool are assessing the system uncertainty given the load and RES conditions and to calculate the level of active power margin necessary to face this uncertainty. Its approach is largely described in the literature (Hirth et al., 2015). Hereafter are reminded the main principles of OPIUM.

First, the methodology has to be applied for a certain forecast horizon. In the EU-SysFlex context, OPIUM will be applied for the 15 minutes lead-time, which is the lead-time generally chosen by the TSO to size the aFRR. Uncertainty level is therefore assessed for that time horizon. OPIUM runs in three steps:

1. Four uncertainty sources are considered separately: 1) load forecast errors, 2) wind generation forecast errors, 3) solar generation forecast errors, 4) uncertainty about the conventional unit's availability. Uncertainty is characterised based on the historical forecast errors and on the historical failure outage

[1] OPIUM : « Outil Probabiliste pour le calcul d'IncertitUdes et de Marges » or « Probabilistic Tool for Uncertainty and Margin Assessment »

rate of the conventional generation. This information enables OPIUM to generate Probabilistic Density Functions (PDF) for each uncertainty sources. Theses PDF give the probability for the system to face potential power unbalances across the 15 minutes time horizon.

2. The uncertainties are summed, applying the convolution mathematical operator to the previous PDFs. One general PDF is then obtained.

3. This general PDF can be used in order to size the proper amount of upward/downward aFRR. To achieve this, it is necessary to choose a certain risk level beyond which imbalances are still not supposed to be covered, due to a low likelihood.

Figure 4 gives an illustration of that process. In this example, the risk 0.025% is used.

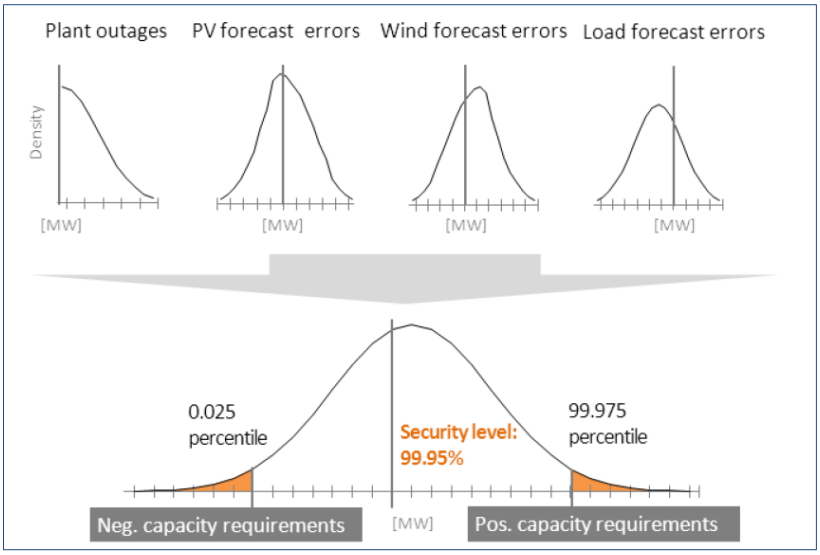



FIGURE 4: METHODOLOGY OUTLINE (HIRTH ET AL., 2015)

This assessment is dependent on the system conditions (wind, solar and consumption conditions, amount of units online) implying that it is necessary to perform it in a sufficiently diverse range of situations. In practice, this assessment is performed hourly over the entire year, using CONTINENTAL outputs and an aFRR requirement can be generated by OPIUM for each country.

It would be possible to feedback CONTINENTAL with these aFRR requirements. This option is not implemented for the first runs of CONTINENTAL, since these simulations are part of Task 2.2 and prior to the analysis of Task 2.4. However, it would be possible to input these new requirements in CONTINENTAL during Task 2.6 and assess the profitability of adding new innovative reserve suppliers, such as batteries or Demand Response.

### 3.1.3 FREQUENCY STABILITY MODEL – PALADYN

PALADYN stands for the French “PlAteforme de simuLAtion DYnamique de la fréqueNce“, which means “Dynamic simulation platform for frequency”.

The methodology provides for the evaluation of frequency behaviour with minimal input requirements. One of the main features of PALADYN is its compatibility with CONTINENTAL dispatch data.

PALADYN uses a multi-area modelling to compute the frequency of each region of the European system. Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) are represented for each area, along with the responses of each technology. aFRR responses follow a unique control signal in each zone. mFRR and RR are activated when the aFRR signal crosses an up/down defined threshold. The zones are linked through impedances derived from a detailed model.

The expected results from PALADYN are indicators of the frequency stability of each studied zone. Since the tool focuses on frequency stability, reactive power and voltage control assessments are out of the model scope.

#### 3.1.3.1 MODELLING OF ONE ZONE

##### 3.1.3.1.1 SWING EQUATION FOR A ZONE

Before detailing the multi-zone modelling, the zonal model used will be presented. Figure 5 illustrates the parameters taken into account by PALADYN in the zone modelling: total kinetic energy in the zone, dynamic response of regulating generation units following imbalances between generation and load.

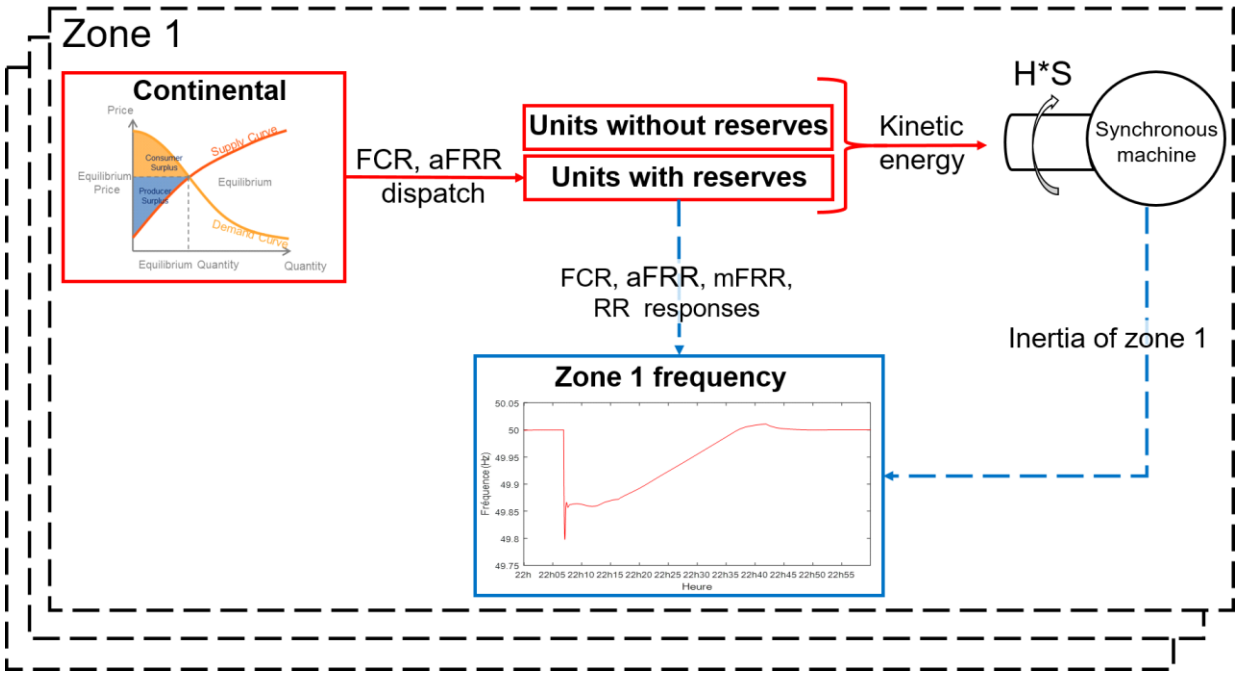



FIGURE 5: SCHEMATIC REPRESENTATION OF PALADYN ZONE MODELLING

The detailed representation of a power system containing synchronous and asynchronous generators, transmission and distribution grids, and consumers to study frequency stability would result in a model of a high order, leading to a high calculation time and high memory allocation. More importantly, it would require exhaustive input data on the grid.

An ideal solution would consist in starting from a detailed initial model, and using a reduction model strategy to reach an acceptable computation time without degrading the simulation results more than a pre-defined value. Unfortunately, such a model is not available within EDF. An alternative solution is described in (Kundur P. , 1994) for inductive grids (in which X >> R) such as European transmission grids. This method states that the system can be represented by a composite model for each zone, containing an equivalent generating unit and load.

In PALADYN, each zone is represented by an equivalent alternator, on which a mechanical torque is applied by an equivalent turbine or motor, as shown in Figure 6.

Consumption is modelled as a mechanical torque of load that is directly applied to the alternator. In real power systems, loads are consuming electrical power on several locations of the grid, which can be seen as an electromagnetic torque on the alternator. However, to avoid modelling an internal grid model for each zone, consumption is moved to the alternator shaft.

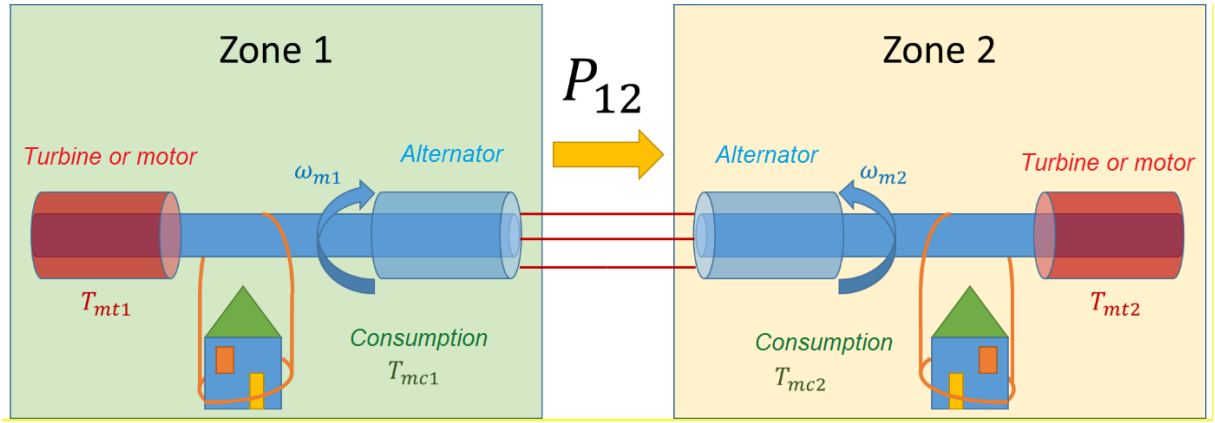



FIGURE 6: SIMPLIFIED REPRESENTATION OF A MULTI-ZONES POWER SYSTEM USED IN PALADYN

This modelling technique allows for the calculation of the power imported and exported by each zone.

The swing equation applied to a turbine and an alternator links its angular acceleration ($\dot{\omega}_m = \ddot{\theta}_m\ [rad.s^{-2}]$) to the power balance applied to its shaft.

$$J\frac{d\omega_m}{dt} + D_d\omega_m = T_m - T_{em}$$

With:

$\omega_m\ [rad.s^{-1}]$: angular speed, also called mechanical speed

$J\ [kg.m^2]$: moment of inertia of the alternator and the turbine

$T_m\ [N.m]$: sum of the mechanical torques in the turbine

$D_d\ [N.m/rad.s^{-1}]$: coefficient of mechanical losses (or damping-torque coefficient)

For power systems applications, the swing equation is often expressed in terms of the power balance instead of the torques, by assuming that $\omega_m \approx \omega_{sm}$ (synchronous speed), for a machine with one pair of poles.

$$\frac{2HS_n}{\omega_{sm}}\frac{d\omega_m}{dt} + D_m\omega_m \approx P_m - P_{em}$$

With:

$P_m\ [MW]$: mechanical power of the turbine

$P_{em}\ [MW]$: electromagnetic power of the alternator

$H\ [s]$: inertia constant of the generator

$D_m\ [MW/rad.s^{-1}]$: coefficient of mechanical losses (or damping coefficient)

$S_n\ [MVA]$: nominal apparent power of the generator

And:

$$P_m = T_m\omega_m$$
$$P_{em} = T_{em}\omega_m$$

$$H = \frac{1}{2}\frac{J\omega_{sm}^2}{S_n}$$

$$D_m = D_d\omega_{sm}$$

The frequency can then be expressed in terms of the angular speed and the number of poles of the machine, which leads to the swing equation given below.

$$\boxed{\frac{2HS_n}{f_n}\frac{df}{dt} + D\,f \approx P_m - P_{em}}$$

$$D = \frac{2\,D_m}{p}$$

With:

$f_n$ [Hz]: nominal frequency of the grid

$D$ [MW. $s^{-1}$]: damping coefficient

$p$: number of poles

In PALADYN, the D term only takes into account the self-regulation of load.

The previous equations expressed the electric frequency imposed by a generator on its stator variables (voltage, current). However, all generators located in the same zone are not modelled individually in PALADYN, but aggregated in a unique equivalent machine.

Therefore, it is necessary to define the angular speed and the frequency of this equivalent alternator. To do so, the method of the "centre of inertia" can be used (Kundur P. , 1994).

The centre of inertia of a power system, or part of it, is a fictive object that has its own frequency and voltage angle. The swing equation can be written for the centre of inertia, as the sum of the swing equations of each generator.

Theoretically, the damping power should be calculated as the sum of the damping power of each generator. As it is impossible with this method, it is calculated using only the frequency of the centre of inertia.

$$\boxed{\frac{df_{COI}}{dt} \approx \frac{f_n}{2\sum_{i=1}^{N} H_i S_{ni}}\sum_{i=1}^{N}(P_{mi} - P_{emi}) - Df_{COI}}$$

With:

$f_{COI}$ [Hz]: frequency of the centre of inertia

N: number of generators

This equation is used to calculate the frequency derivative in each zone of the PALADYN model, and subsequently its frequency. The power balance in the zone appears in the equation. First of all, the generation unit modelling

will be detailed. Then, the load calculation will be described, and a summary of the single zone model will be given.

#### 3.1.3.1.2 MODELLING OF GENERATION UNITS

In each zone, every technology is modelled. The models contain two separate blocks, corresponding to:

- The control block, that calculates the power set point for the plant.
- The dynamic response block, that receives the power set point and provides the output mechanical power of the technology.

**Control block**

The control block is composed of the hourly dispatch set point of the technology coming from CONTINENTAL, and the calculation of the frequency containment reserve (FCR) and the aFRR set points.

- Dispatch:

CONTINENTAL provides the power dispatch for each hour, each zone and each technology. This constitutes the first component of the power set point. The inertia of all energised generators is also summed, to be used in the swing equation.

- FCR:

The FCR procurement is provided by CONTINENTAL for each hour, each zone and each technology. Its activation set point is then calculated for each PALADYN simulation time step (100 ms) using the zone frequency. Each technology's droop is calculated using the following formula, to ensure a total activation of FCR reserve for a frequency excursion of 200 mHz.

$$R = \frac{\frac{\Delta f}{f_n}}{\frac{\Delta P}{P_N}} = \frac{0.2}{50} * \frac{P_N}{P_{FCR}}$$

With:

R: droop of the equivalent generation unit,
$f_n$: nominal frequency of the grid (50 Hz),
$P_N$: the nominal active power of the equivalent generation unit,
$P_{FCR}$: FCR reserve of the equivalent generation unit

This method provides an ideal droop, corresponding to an optimal activation of the FCR reserve to fulfil the TSO requirements. It is also possible in PALADYN to use operational values of droop, when such data is available. Using operational values is needed when there is a gap between them and the ideal values.

- aFRR

The aFRR power set point is calculated using the aFRR dispatch provided by CONTINENTAL for each hour, each zone and each technology. It is also necessary to calculate an activation signal for aFRR in each zone of the model. One of the advantages of using a multi-zone model is to be able to simulate the aFRR more accurately. Indeed, whereas all control areas activate FCR when the system in unbalanced, the objective of aFRR control is that only the control area affected by a power imbalance activates its aFRR as a balancing action (UCTE, 2004).

To achieve this goal, the activation signal is calculated in each zone in PALADYN using the following equation. It follows the French TSO signal calculation. This signal varies between -1 and 1, those values corresponding to a full provision of aFRR downwards or upwards.

$$N(t) = -\frac{\alpha}{P_{aFRR}} \int_0^t (\Delta F + \frac{\Delta Pi}{\lambda})\, dt$$

With:

- α [MW/round]: slope of aFRR activation
- $P_{aFRR}$ [MW]: half-band of aFRR power
- ΔF [Hz]: frequency deviation
- ΔPi [MW]: power imported/exported at the borders
- λ [MW/Hz]: power frequency characteristic of aFRR

“Normal” and “emergency” rate limitations can be applied, according to the specificities of each TSO. In France, with the normal limitation, the aFRR signal can vary from -1 to 1 in 800s, and in 133s with the emergency rate limitation.

In France, parameters α and λ are mostly known. For the other zones, those parameters are not known; therefore the Darrieus law is applied. It sizes the power frequency characteristic λ to ensure that only the zone affected by the disturbance will respond and initiate the deployment of aFRR.

$$\lambda_i = K_i = \frac{P_{ni}}{R_i\, f_n} = \frac{P_{FCR}}{\Delta f}$$

The value of α is chosen to ensure that FCR and aFRR actions are temporally dissociated.

Imbalance netting is the process agreed between several TSOs that ensures the avoidance of simultaneous activation of FRR in opposite directions by taking into account the respective frequency restoration control errors as well as the activated FRR, and by correcting the input of the involved frequency restoration processes accordingly. The International Grid Control Cooperation (IGCC) is the European Platform for the imbalance netting process of aFRR. It was launched in 2010 as a regional project and grew to cover 20 countries (23 TSOs).

In PALADYN, IGCC is not modelled, meaning that potential activations of aFRR in opposite directions could theoretically happen. However, for incident simulations such as outages or grid separations, only the aFRR activation signal of the zone affected by the disturbance will respond, following the Darrieus law given above.

Common merit order list (CMOL) in the European Union Internal Electricity Balancing Market is a list of balancing energy bids sorted in order of their bid prices, used for the activation of those bids. ENTSO-E is studying the impact of CMOL on the Continental Europe system, and a deployment is likely to happen in the following years. PALADYN does not model CMOL for the activation of aFRR. However, the impact of CMOL on incident simulations is quite limited, because the dynamics of aFRR activation is slower than FCR, and that the stability issues are likely to happen during the first seconds after incidents.

**Dynamic response**

The mechanical power applied on alternators can be generated by a steam turbine, a combustion turbine or a hydraulic turbine. This power is obtained in PALADYN by applying a process model to the power set point required for the group.

One process model exists for each conventional generation technologies:

- Hydraulic
- Nuclear
- Coal
- Open cycle gas turbine (or combustion turbine)
- Combined cycle gas turbine

The process models were built from detailed models that were validated by tests on several EDF generation units of each technology. It is assumed that the behaviour of generation units of the same technologies is similar in other European countries. A specific model was developed for lignite, which is not present in France but plays an important role in Germany and Poland.

By comparing the dynamic mechanical power response of the technologies, for example on a power set point step, the following is observed: the nuclear response is the fastest, followed by open cycle gas turbines (OCGT), combined cycle gas turbine (CCGT) and hydraulic. The coal plants are slower, due to their process.

Wind, solar and storage responses are also modelled in PALADYN. Each of them aggregates all units of the corresponding technology, with a droop control and specific dynamics.

#### 3.1.3.1.3 MODELLING OF LOADS

In each zone, loads are aggregated as a mechanical load applied to the shaft of the equivalent alternator. Hourly consumption data is given by CONTINENTAL for each country. The dynamic behaviour of loads is a static characteristic of self-regulation, according to the frequency of their zone.

#### 3.1.3.1.4 SUMMARY ON SINGLE ZONE MODELLING

Figure 7 shows the simplified model of a single zone in PALADYN.

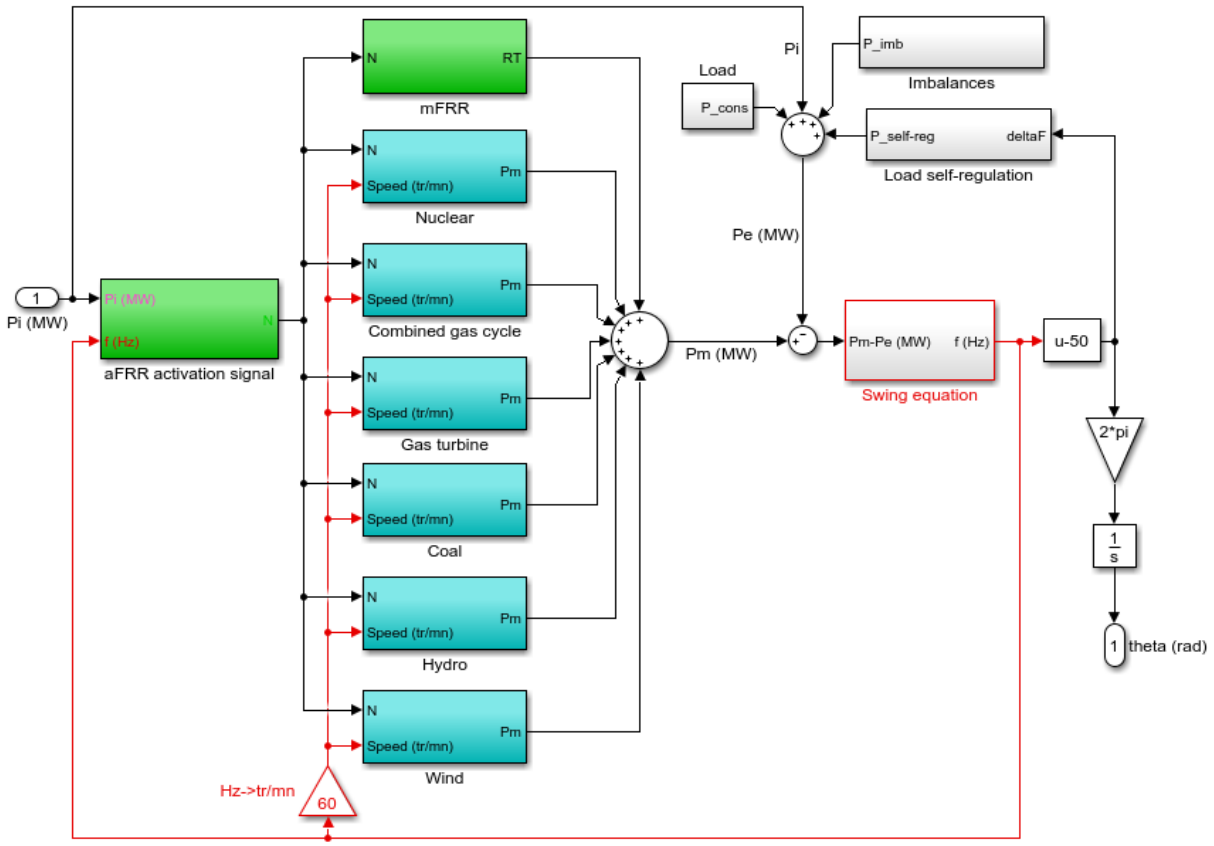



FIGURE 7: SIMPLIFIED MODEL OF A SINGLE ZONE IN PALADYN

The mechanical power Pm calculation is performed from each technology's power (in cyan), the electrical load power Pe results from the net power $Pi$ exchanged with the other zones, the imbalances between generation and load $P_imb$ and the self-regulation of load to frequency.

The first left green block computes the aFRR signal, which is common to all technologies. The second green block manages the manual frequency restoration reserve (mFRR) activation or deactivation. The mFRR and RR are activated to compensate for the residual imbalances remaining, and restore the aFRR. Their up/down activation starts when aFRR signal crosses an up/down defined threshold. After a defined latency period, its liberation starts following a specific upward/downward ramp until the aFRR signal goes back inside a proper range of values.

The gap between Pe and Pm on the shaft of the equivalent alternator is used to perform the swing equation calculation, from which the frequency and the voltage angle of the zone are obtained.

### 3.1.3.2 MULTI-ZONE MODEL

After detailing the single-zone modelling in the previous section, this subsection explains the calculation of power exchanges between zones in PALADYN.

#### 3.1.3.2.1 DC APPROXIMATION

As PALADYN does not model reactive power and voltage control, it is possible to use the DC approximation which uses the following hypotheses:

1) The serial resistances can be neglected compared to the serial reactances;
2) The difference between voltage angles of adjacent nodes is close to zero (< 20°). Therefore sin(θi- θk) ≈ θi- θk; and
3) The voltage magnitude is equal to 1 p.u. for all nodes.

Those hypotheses have two consequences: the reactive power is neglected, and the phase of one zone is close to the electromotive force angle of its equivalent alternator.

The active power flowing in a line ik between nodes i and k can be calculated with DC approximation as follows:

$$P_{ik} = \frac{V^2}{X_{ik}}(\theta i - \theta k) = V^2 . Y_{ik}(\theta i - \theta k)$$

The matrix form of this equation is given below:

$$q = V^2 Y . \theta$$

With:

q: vector of power injections
V: vector of voltage magnitudes
Y: nodal admittance matrix
Θ: vector of voltage angles

The Y matrix is constructed from the application of Kirchhoff's laws to all the nodes of the system. The nodal admittance matrix represents the admittance relationships between nodes, which then determine the voltages, currents and power flows in the system.

$V^2Y$ is the matrix of synchronizing power coefficients. With the DC approximation, V = 1 p.u. for all nodes.

In PALADYN, the vector of power injections q is calculated from the voltage angles calculated in each zone and the nodal admittance matrix of the multi-zone grid, as shown in Figure 8.

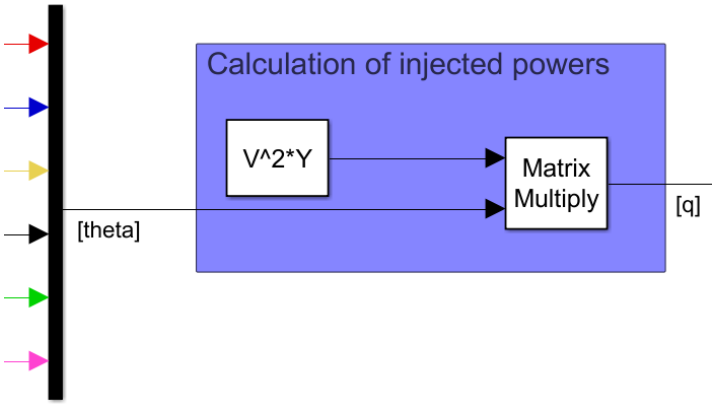



FIGURE 8: CALCULATION OF INJECTED POWERS IN PALADYN

Therefore, it is possible to calculate the injected power in each node from the voltage angles, using the DC approximation.

Starting from the Continental Europe grid, the multi-zone simulation requires the definition of the zones, and the calculation of the admittance matrix of the system.

#### 3.1.3.2.2 DEFINITION OF ZONES FOR THE CONTINENTAL EUROPE SYSTEM

The level of detail in terms of choosing the zones of the CE power system depends on the available grid data, and on the granularity of the input data.

The available grid data is a static DC model of the Western and Central Europe transmission grid, built using DIgSILENT PowerFactory (Figure 9). This is a partial model of the CE transmission system as some countries are missing such as Spain, Portugal, and Eastern Europe.

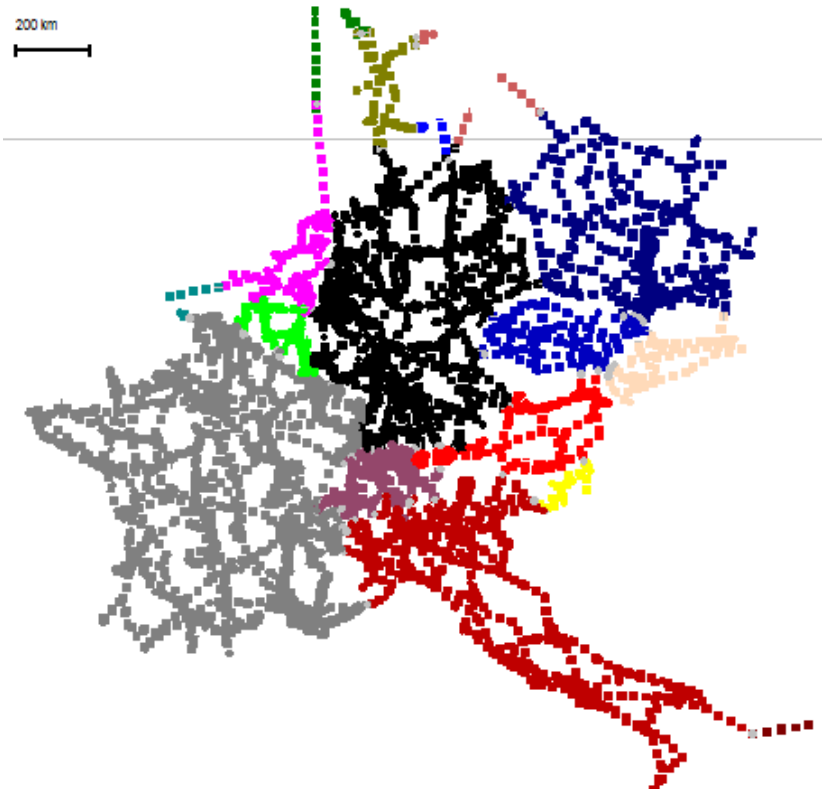



FIGURE 9: STATIC MODEL OF THE WESTERN AND CENTRAL EUROPE POWER SYSTEM

To aggregate electrical nodes into zones, the literature suggests using grid reduction techniques (Wang, 1997) (Machowski, 2008) which consist of simplifying a detailed grid, starting by identifying coherent generators, aggregating them and determining the buses that can be deleted.

The identification of coherent generators can be based on the synchronizing torques between generators, on the oscillation modes between them, or on studying their voltage angles after an incident. These methods result in generators clusters that can be different from country borders.

However, the input data provided by CONTINENTAL has a country granularity, meaning that the dispatch values (power generation and FCR & aFRR supply) are given for each country. Therefore, considering zones smaller than those specified by CONTINENTAL is not feasible for the PALADYN simulations. For this reason, network reduction techniques were not used. Instead, a multi-zone grid was proposed and its impedances were identified with the detailed grid.

On the CE power system, the zones were built as follows:

1. Spain and Portugal constitute the first zone. It has a geographical and electrical situation of peninsula, and only exchanges power flows with France. This zone roughly weighs 10 % of the total grid, in terms of historical annual consumption.

2. France is a zone, both because it plays a central role on the Western Europe grid, and because more data is available on its generation technologies within EDF. The generation modelling will be more specific in this zone. France weighs roughly 20 % of the total grid, in terms of historical annual consumption.

3. The third zone is a group of multiple Northern Europe countries: Austria, Belgium, Denmark, Germany, Luxembourg, Netherlands, and Switzerland. This large zone contains countries that are closely integrated in the power system markets and operation. It weighs roughly 30 % of the total grid, in terms of historical annual consumption.

4. Eastern Europe is a zone containing Czech Republic, Hungary, Poland, and Slovakia. For this zone, some grid and energy mix information is missing. It weighs roughly 10 % of the total grid, in terms of historical annual consumption.

5. Italy is also an electric peninsula, therefore needs to be treated in a separate zone. It weighs roughly 10 % of the total grid, in terms of historical annual consumption.

6. Finally, Turkey and Balkan countries (Albania, Bosnia, Bulgaria, Croatia, Greece, Macedonia, Montenegro, Rumania, Serbia and Slovenia) constitute the last zone of the model. Little information is available on those countries, which weigh roughly 20 % of the total grid, in terms of historical annual consumption.

The final zones used in PALADYN for the EU-SysFlex scenarios are illustrated in the Figure 10.

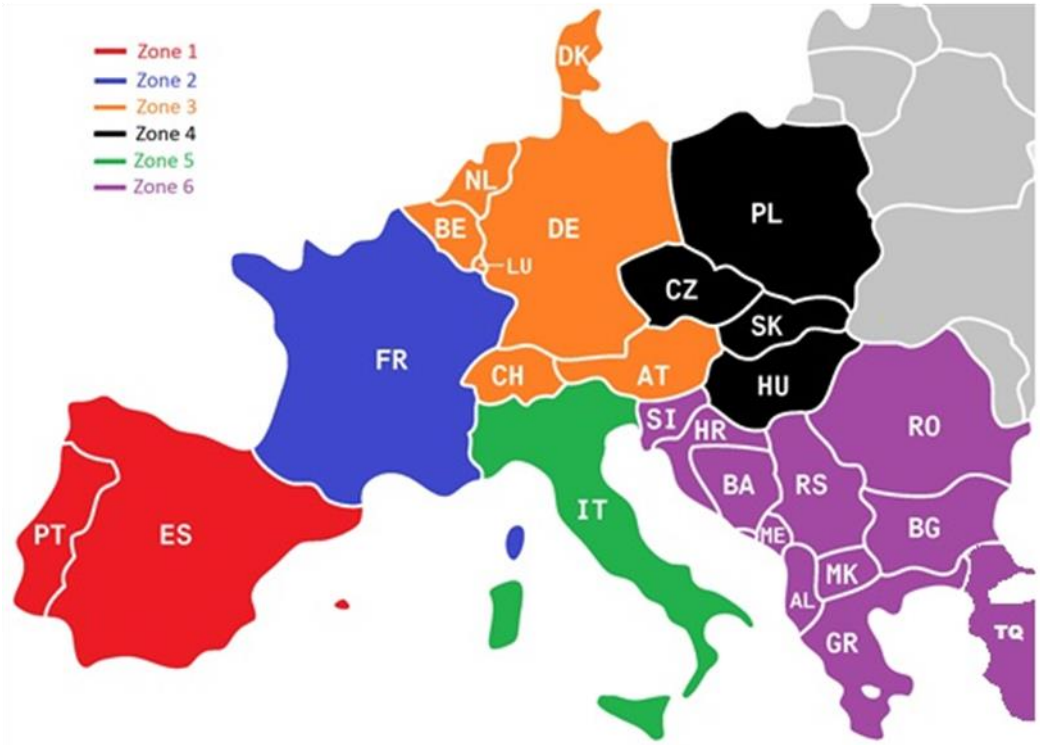



FIGURE 10: GEOGRAPHICAL ZONES USED IN PALADYN

As previously detailed, each zone is represented in PALADYN as a single electrical node. The final step for the multi-zone simulation is the calculation of the admittance matrix for this aggregated system.

#### 3.1.3.2.3 CALCULATION OF ADMITTANCES BETWEEN ZONES

The electrical model presented on Figure 11 is used in PALADYN. All admittances Yij must be calculated.

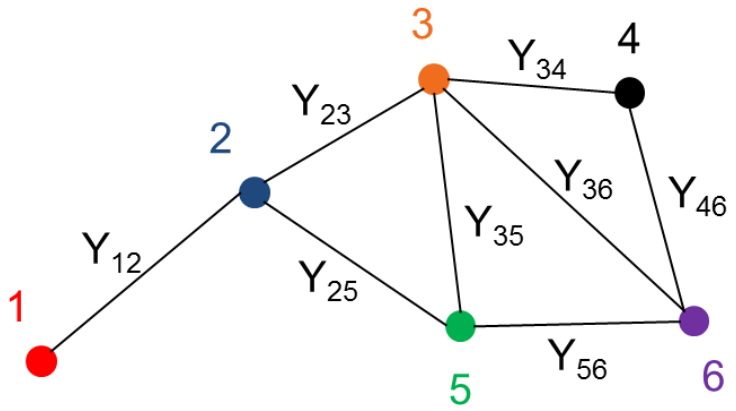



FIGURE 11: MULTI-ZONE ELECTRICAL MODEL USED IN PALADYN

The static model available in PowerFactory is used to determine the admittances between zones 2, 3, 4 and 5. Several DC load-flows are calculated on this grid. The vector of power injections of each zone can be calculated from the load-flow results, as well as the vector of voltage angles θ.

The vector of voltage angles is calculated from the angles of each node, following the method developed in (Machowski, 2008). The voltage angle of each zone equals the weighted average of the voltage angles of its nodes. The weight can be relative to the power injected in each node (for static stability studies), or the inertia of each node (for transient stability studies).

$$\theta_a = \frac{\sum_k S_k \theta_k}{\sum_k S_k} \text{ or } \theta_a = \frac{\sum_k M_k \theta_k}{\sum_k M_k}$$

Then, the following system can be used to calculate the admittance matrix Y.

$$q = V^2 Y.\theta$$

Finally, the admittances of each fictional line connecting zones are calculated, and the DC calculation of power injected by each zone is performed.

The remaining admittances ($Y_{12}$, $Y_{36}$, $Y_{46}$, $Y_{56}$) were extrapolated from available data. For example, to calculate the admittance between zones 1 and 2, zone 2 is known (France) as well as the interconnections between France and Spain. The missing data is the grid within zone 1 (Spain and Portugal). An assessment was made to derive the

admittance $Y_{12}$ from known data. A similar approach was used to calculate admittances $Y_{36}$, $Y_{46}$ and $Y_{56}$, because only a partial model of zone 6 was available.

## 3.2 CONTINENTAL EUROPE VOLTAGE AND TRANSIENT STABILITY MODEL – PSE

### 3.2.1 SCOPE OF INTEREST OF CONTINENTAL EUROPE POWER SYSTEM'S MODEL

In order to identify future technical scarcities of the Continental Europe power system (for the determined EU-SysFlex scenarios), the following types of power system studies will be performed:

- Long-term small and large-disturbance voltage stability, because of decreased reactive power capability available in conventional synchronous generation (all the possible relationship between P, Q and V, protection relays, tap changers, Var-control, excitation limiters will be represented),
- Short-term transient (rotor angle) stability, because of decreased system inertia and synchronising torque (electromechanical transients modelling generators, AVR, PSS, turbines and governors, protection relays, etc.).

For the purpose of performing the aforementioned stability studies, a power system model for CE has been prepared. The CE power system model represents several generation capacity scenarios in 2030 and distinguishes different areas covered by three levels of modelling complexity:

- A detailed representation of the transmission 400 kV and 220 kV (EHV) and sub-transmission 110 kV (HV) power grid in Poland;
- A simplified representation of the neighbouring countries (aggregation of lines in parallel, busbars, power plants); and
- Equivalent models for Western and Southern Europe countries which are part of CE power system.

The purpose of the presented model is to predict and analyse stability problems related to high share of renewable energy sources in CE power system. The scope of interest for the power system model has been presented in Figure 12. Simplified modelling scheme for individual countries has been presented in Figure 13.




FIGURE 12: SCOPE OF INTEREST FOR CONTINENTAL EUROPEAN POWER SYSTEM VOLTAGE AND TRANSIENT STABILITY MODEL

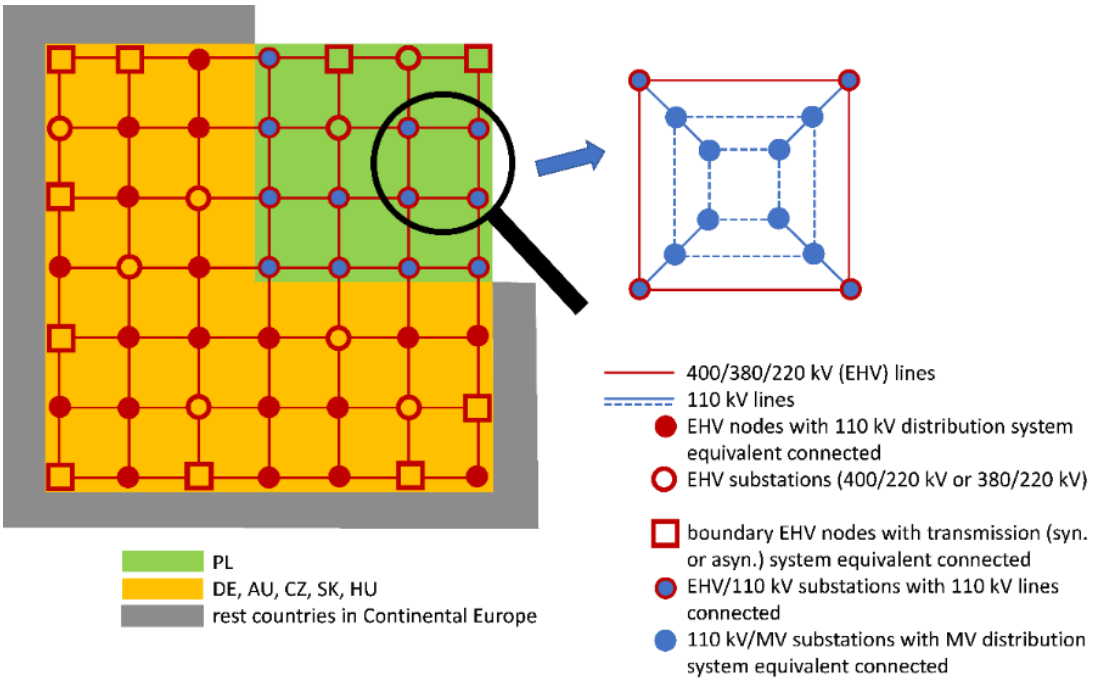



FIGURE 13: SIMPLIFIED MODELLING SCHEME FOR SPECIFIC AREAS IN THE SCOPE OF POWER SYSTEM IN CONTINENTAL EUROPE

The Poland's neighbouring area includes Germany, Austria, Czech Republic, Slovakia and Hungary. Particular power systems are internally connected in the synchronous mode. Only the EHV power network is represented as a nodal-branch model. Substation busbar systems and sections are aggregated to one terminal. Generation units in a power plant are also aggregated to one equivalent model and connected to single EHV terminal. Nonetheless, different types of generation are modelled separately, e.g. coal, hydro, wind, etc. The level of modelling of the neighbouring countries has been presented in Figure 14 which is an example of Germany.




FIGURE 14: LEVEL OF MODELLING POLAND'S NEIGBOURING COUNTRIES ON AN EXAMPLE OF GERMANY (ENTSO-E, 2018)

Figure 15 presents a geographical map of the planned development of transmission system grid in Poland for 2021. The Polish transmission system is synchronously interconnected with Germany, Czech Republic, Slovakia, and Ukraine (individual generators synchronized with Polish grid) and is HVDC interconnected with Lithuania and Sweden. The transmission system in Poland operates at 400 kV, 220 kV and partially at 110 kV as a sub-transmission grid. There is also one 750 kV line, which is a part of non-working interconnection with Ukraine. Most of transmission lines are single and double-circuit overhead lines, but there are exceptions to this, such as underground HVDC cable interconnecting Polish and Swedish systems. As presented in Figure 15 by 2021 there

are planned two installations of phase shifters installed in Poland-German interconnections to mitigate circular power flows through Central European countries.

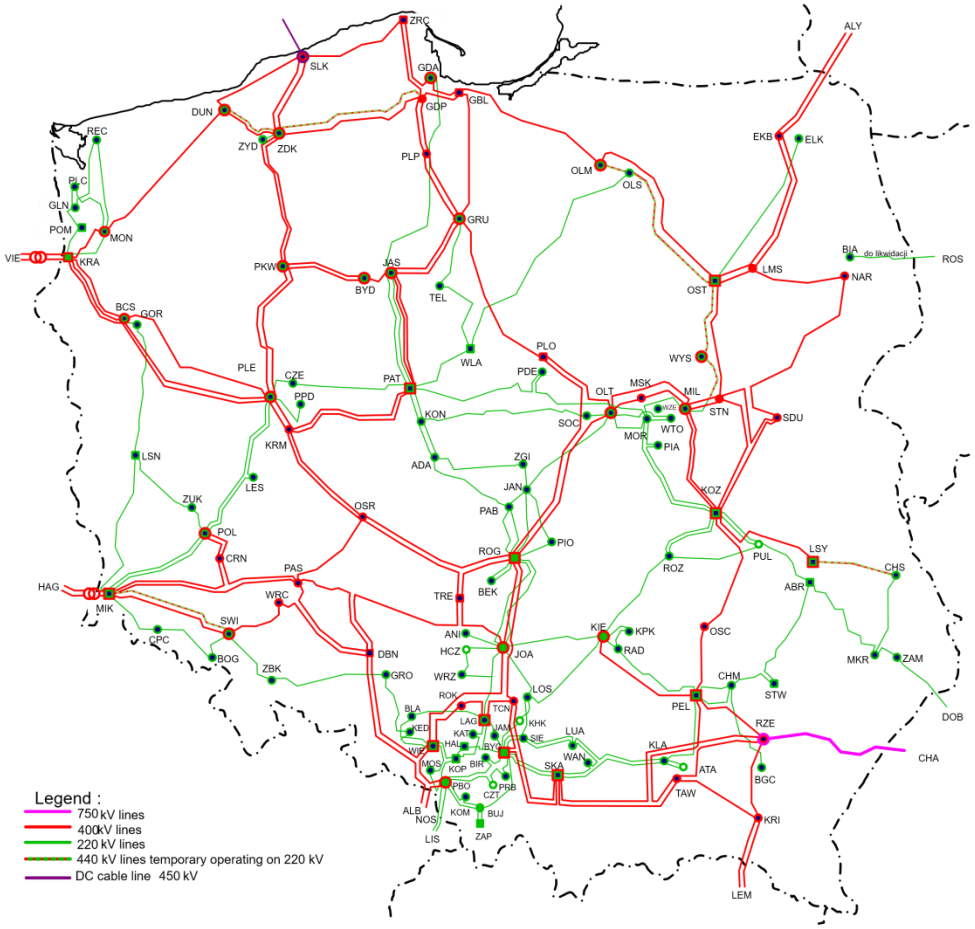



**FIGURE 15: MAP OF POLISH TRANSMISSION SYSTEM IN 2021**

PSE is the National TSO which operates the Polish transmission grid including:

- 258 transmission lines – 14,195 km length including:
  - 1 non-operating 750 kV line – 114 km length;
  - 93 transmission 400 kV lines – summary length 6,326 km; and
  - 164 transmission 220 kV lines – summary length 7,755 km.
- 106 EHV substations
- Undersea HVDC 450 kV cable interconnection – summary length 254 km.

The presented CE power system model corresponds to the state of Polish transmission grid development which will be achieved by 2021, when significant transmission grid development works are planned to be finalised. Some conventional generation units located in the southern Poland are planned to be shut-down and most of wind generation will be located in the North of Poland. It was crucial to strengthen the transmission grid in that part of Poland. Further development of Polish transmission network between 2021 and 2030 will be minor in

relation to the development to 2021. Therefore, the 2021 state of model development has been proposed to be the basis for the network being studied for EU-SysFlex. The second important reason for the using the 2021 grid structure in stability studies is to keep the consistency of two power system models between:

- CE model being developed for the stability analysis in WP2; and
- CE model being developed in Dispatcher Training Simulator (DTS) for the demonstration of new system services in WP4 – Task 4.2.

Based on the assumptions related to Polish transmission system, the same approach has been applied for neighbouring countries in the CE sub-network model. Nonetheless, the installed generation capacity scenarios as a result of EU-SysFlex D2.2 are considered.

The installed capacity per production type for CE's countries in the **Energy Transition** scenario is presented in Table 6. Details about the scenario can be found in the EU-SysFlex D2.2 report (EU-SysFlex, 2018-1). Presented dataset provides a benchmark against which reliable increase renewable sources generation in presented model of CE power system can be assumed.

**TABLE 6: INSTALLED NET CAPACITY PER PRODUCTION TYPE IN THE EU-SYSFLEX ENERGY TRANSITION SCENARIO FOR THE POLISH AND SURROUNDING COUNTRIES SUBNETWORK**

| | Energy Transition | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Country | Nuclear energy (MW) | Renewable energy (MW) | Hydro (pumping excluded) (MW) | Wind (MW) | Solar (MW) | Solids fired (MW) | Gas fired (MW) | Oil fired (MW) | Biomass-waste fired ) (MW) | Hydrogen plants (MW) | Geothermal heat (MW) |
| AT | 0 | 21,121 | 13,756 | 4,545 | 2,821 | 778 | 2,902 | 423 | 813 | 0 | 2 |
| CZ | 4,006 | 3,987 | 1,109 | 488 | 2,391 | 8,797 | 1,783 | 64 | 274 | 0 | 0 |
| DE | 0 | 137,031 | 5,857 | 67,214 | 63,959 | 36,775 | 26,978 | 1,248 | 6,894 | 1 | 170 |
| EE | 0 | 454 | 8 | 445 | 1 | 1,408 | 272 | 0 | 154 | 0 | 0 |
| HU | 4,482 | 640 | 57 | 477 | 106 | 396 | 2,531 | 5 | 357 | 0 | 52 |
| PL | 0 | 11,478 | 1,039 | 10,339 | 99 | 20,704 | 5,403 | 155 | 2,105 | 0 | 0 |
| SK | 4,020 | 2,424 | 1,725 | 19 | 680 | 483 | 1,097 | 84 | 332 | 0 | 0 |
| **Total** | 12,508 | 177,135 | 23,551 | 83,527 | 70,057 | 69,341 | 40,966 | 1,979 | 10,929 | 1 | 224 |

The increasing amount of renewable generation in Europe, and subsequent decommissioning of fossil-fuelled conventional synchronous power units, can lead to the occurrence of new scarcities in power systems. Decreasing synchronous inertia and synchronizing torque as well as decreasing reactive power capability available in conventional synchronous generation, mean a greater importance is placed on analysing voltage and transient stability issues. Therefore, the CE power system model has been prepared to be suitable both for voltage and transient stability analysis.

The CE power system model assumes the following generation capacity scenarios:

1. The EU-SysFlex **Energy Transition** Scenario Installed Capacities (as presented in Table 6)
2. Network Sensitivity scenarios to the main **Energy Transition** Scenario:
    a. Continental Europe Network Sensitivity 1 – **Going Green**
    b. Continental Europe Network Sensitivity 2 – **Distributed Renewables**

The scenario **Going Green** assumes more installed capacity wind and PV generation in Poland, i.e.:

- Wind generation capacity: 19,860 MW (in this 3,500 MW is offshore)
- PV generation capacity: 3,260 MW

The percent of installed renewable generation capacity connected to the EHV and 110 kV network (D type) is 83%. In turn, the percent of installed renewable generation capacity connected to the MV and LV networks is 17%.

The **Distributed Renewables** scenario assumes the same values of installed capacity as in **Going Green** scenario. The difference between them is that the ratio of renewable generation installed in EHV and 110 kV network to the generation installed in MV and LV networks is reduced. The percent of installed renewable generation capacity connected to the EHV and 110 kV network (D type) is 40%. In turn, the percent of installed renewable generation capacity connected to the MV and LV networks is 60%. More details about the aforementioned scenarios can be found in the EU-SysFlex D2.2 report (EU-SysFlex, 2018-1).

For the studies of the Continental Europe sub-network, further sensitivity analysis will be carried out in the following way:

- **Going Green** – Sensitivity analysis will be carried out on the inertia constants outside Polish power system. This sensitivity analysis will simulate further increases in non-synchronous generation in all CE countries beyond Poland.
- **Distributed Renewables** – Sensitivity analysis will be carried out on equivalent impedances connecting the Continental Europe sub-network to other countries, as well as the EHV to distribution system equivalent impedances located in Germany, Austria, Czech Republic, Slovakia and Hungary. This sensitivity analysis will simulate further increases in non-synchronous generation within these countries, as well as simulating where these generators are connected in Germany, Austria, Czech Republic, Slovakia and Hungary, i.e. the transmission system or the distribution system.

When carrying out studies related to voltage and transient stability, the next step is a definition of operation snapshots reflecting stability problems. With regard to the definition of operation snapshots, a worst-case approach will be applied. Studies based on worst-case operation snapshots try to assess the system's performance for credible worst case operating conditions.

Operational snapshots will be determined, for particular generation outputs, based on data provided from EDF's Unit Commitment Model – CONTINENTAL, such as: generation for each technology, inertia, load and power

reserves. All of these parameters will be provided at a national level for the following countries: Germany, Austria, Denmark (continental part), Switzerland, Belgium, Spain, Portugal, France, Hungary, Italy, Netherlands, Poland, Czech Republic and Slovakia. Additionally, aggregated values will be provided, based on public data for the countries such as: Romania, Serbia, Bosnia, Croatia, Bulgaria, Macedonia, Albania, Greece and Turkey, in order to estimate operational scenarios for the rest of CE power system model. The provided data on a national level will be allocated to particular power network elements in the CE power system model and adapted to obtain realistic load flow cases.

The operational snapshots on national level will be found with the use of EDF CONTINENTAL model and consider the following three criteria:

1. Minimum inertia in the power system
2. Maximum power demand
3. Minimum power reactive margins for the synchronous generation.

The following sets (perimeters) of countries will be considered in order to find particular operation snapshots:

- All countries in CE (only for criteria 1 and 2)
- Poland, Germany, Austria, Czech Republic, Slovakia and Hungary
- Poland and Germany
- Poland

Often voltage instability and transient instability occur together and one may lead to the other. In this way the aforementioned criteria will be considered as “worst case” operation snapshots for the purpose of both voltage and transient stability studies. An assignment of particular criteria to relevant stability studies is presented in Sections 5.3.1 and 6.3.1.

### 3.2.2 IMPLEMENTATION OF MODEL IN DIGSILENT POWER FACTORY

The proposed CE power system model for the purposes of voltage and transient stability analysis has been implemented in DIgSILENT PowerFactory power system analysis package. The presented modelling approach refers to the representation of the analysed transmission system, including considered devices and their controllers, which will be in the scope of stability analysis. The following sections describe the assumed approach to modelling the analysed power system’s devices in PowerFactory, where the particular attention is paid to the modelling of synchronous generators, wind turbines and PV systems.

TABLE 7: PROPOSED STATIC AND DYNAMIC MODELS OF SYSTEM ELEMENTS IN POWERFACTORY

| Element | Details |
|---|---|
| Synchronous generator | *ElmSym / TypSym* |
| Automatic Voltage Regulator (AVR) | *ESAC8b, ESST1a, ESST4B, EXAC1A, EXAC4, REXSYS* |
| Turbine governor (GOV) | *GAST, GGOV1, IEEEG1, TGOV1* |
| Power System Stabilizer (PSS) | *IEEEST, PSS2a, PSS2b* |
| Two winding-transformer | *ElmTr2* |
| Load | *ElmLod / TypLod* |
| Transmission line | *ElmLne / TypLne* |
| Busbars | *ElmTerm* |
| Static generators | *ElmGenstat* |

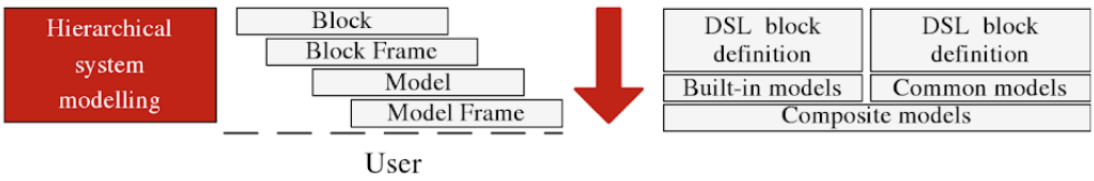



FIGURE 16: SCHEMATIC REPRESENTATION OF THE TRANSIENT HIERARCHICAL SYSTEM MODELLING APPROACH (DIGSILENT, 2016)

The transient stability modelling philosophy assumed in DIgSILENT PowerFactory package is targeted towards a hierarchical system modelling approach, which combines both graphical and script-based modelling methods. The assumed dynamic modelling approach is formed by the basic hierarchical levels of time-domain modelling presented in Figure 16.

A detailed description of PowerFactory dynamic modelling approach can be found in reference (DIgSILENT, 2016).

#### 3.2.2.1 SYNCHRONOUS GENERATORS MODELS

There are two types of transient stability analysis models of synchronous generators included in presented CE power system: detailed standard model used for most synchronous generators included in model and simplified classical model for generators which parameters for detailed model could not be obtained.

According to standard synchronous generator dynamic model presented in detailed technical reference (DIgSILENT, 2016), rotor d-axis is always modelled by two rotor loops representing the excitation (field) winding and the 1d-damper winding. For the q-axis, PowerFactory supports two models, a salient-pole rotor machine model having only the 1q-damper winding and a round-rotor machine model with the 1q- and 2q-damper windings. These two models can also be referred to as Model 2.1 and Model 2.2, respectively.

Classical synchronous generator model is a simplified model represented by a voltage behind an impedance. The classical synchronous machine model is used for representing equivalents of CE countries that are not in a scope of analysis and synchronous machines that are not represented in detail.

The assumed synchronous generator dynamic model structure in PowerFactory defining the connections between the inputs and outputs of the various controller models has been presented in Figure 17. For detailed transient stability model of Polish transmission power system, controller models and parameters for each synchronous generator have been selected according to state of the art in power system transients modelling presented in previous transient stability analyses conducted by PSE. The proposed generator and controller models are included in Figure 17.

For the power system models of neighbouring countries included in CE model, the following approach of modelling is assumed:

- Synchronous generator is represented by detailed Model 2.2 or simplified classical model, if detailed dynamic model parameters are unavailable,
- Automatic Voltage Regulator (AVR) is represented by standard IEEE EXAC4 model, including default model parameter's values,
- Turbine governor (GOV) is represented by standard IEEE TGOV1 model, including default model parameter's values,
- Power System Stabilizer (PSS) is represented by standard IEEE PSS2a model, including default model parameter's values,

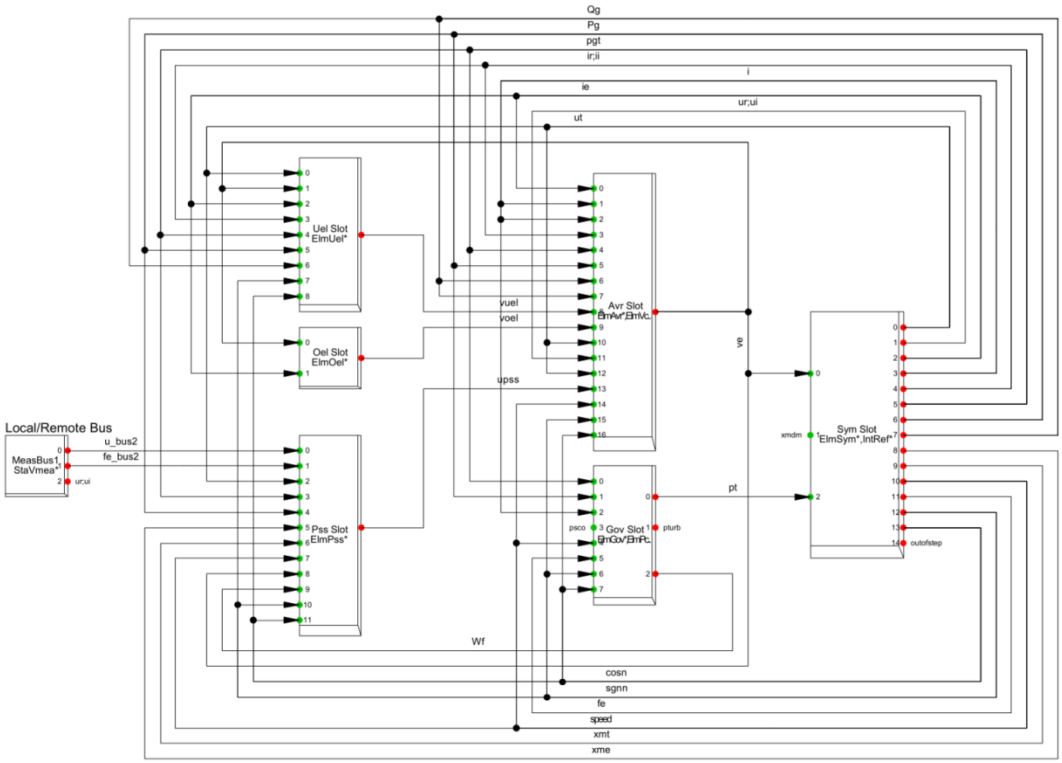



FIGURE 17: SYNCHRONOUS GENERATOR DYNAMIC MODEL STRUCTURE IN POWERFACTORY

### 3.2.2.2 WIND TURBINES MODELS

Wind turbine models which are used in CE power system model for stability analysis are based on DIgSILENT PowerFactory standard IEC 61400-27-1 models presented in (DIgSILENT, 2016). The IEC 61400-27 provides an international standard series for dynamic wind turbines and power plant models used in power system stability analysis. This standard specifies generic models for different types of wind turbines which are commonly installed in power systems. The proposed model of wind turbine included in CE power system model refers to Type 3 turbine model, representing doubly fed asynchronous generator with converter included in rotor circuit, as presented in Figure 18.

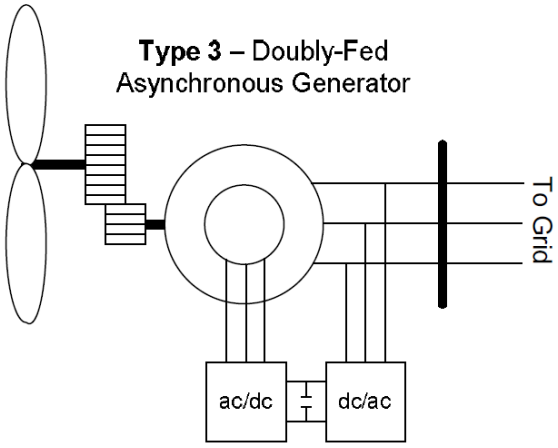



FIGURE 18: WIND TURBINE TYPE 3 STRUCTURE.

The structure of proposed transient stability analysis wind turbine model has been presented in Figure 19 below. This wind turbine model consists of 4 elementary models which are described below:

- Mechanical model which is represented by Mechanical DSL block modelling two mass oscillator and an aerodynamic two dimensional model responsible for the calculation of wind turbine mechanical power output;
- Measurement models, responsible for measurements of power, voltage and frequency directly at the terminals of wind turbine;
- Generator part, including Generator slot for *ElmGenStat* standard PowerFactory model for generators which are generally connected to the grid through a static converter, and Generator System DSL block; and
- Control part of the model including both active and reactive power controller models with limitation, pitch angle controller, phase locked loop (PLL) block and grid protection model including over and under frequency and voltage protection according to grid codes requirements.

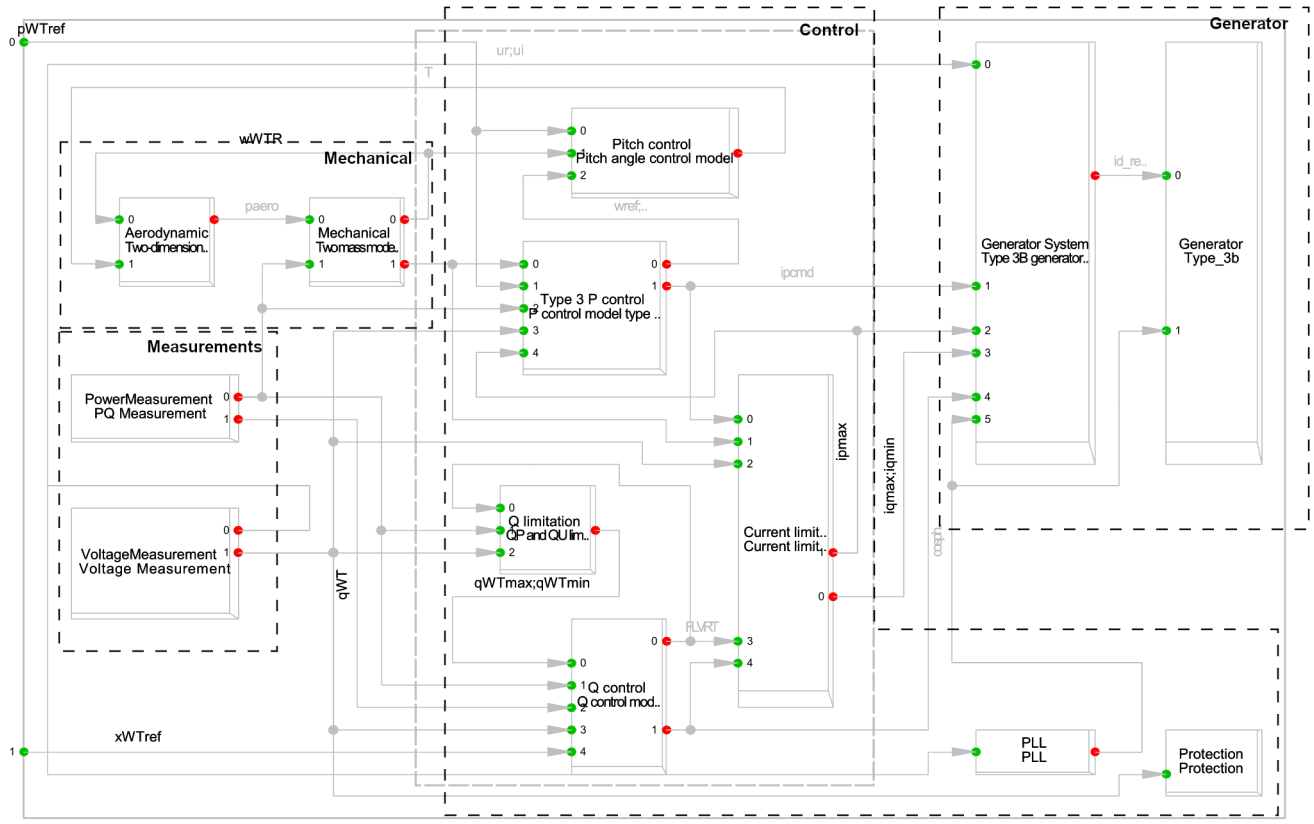



FIGURE 19: STRUCTURE OF WIND TURBINE TYPE 3 MODEL IN POWERFACTORY

The Type 3 wind turbine's grid connection interface proposed for the CE power system model has been presented in Figure 20. The wind turbine generator is represented by *ElmGenstat* generic PowerFactory model, two winding transformer is modelled with *ElmTr2* default model.

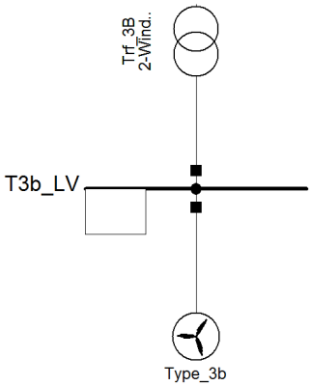



FIGURE 20: TYPE 3 WIND TURBINE'S GRID CONNECTION INTERFACE

### 3.2.2.3 OTHER DISTRIBUTED GENERATION AND STORAGE MODELS

The CE power system voltage and transient stability model, proposed by PSE, also includes simplified dynamic model of other power facilities connected to the grid with electronics converter, such as: PV generation, small wind generation, batteries, and gas micro-turbines. A dynamic model of DER generation or storage is based on

distribution grid dynamic equivalent model proposed by INESC TEC model, which refers to distributed generation model for stability analysis. The proposed model implements demand grid codes requirements for generation connected to the grid, including Fault Ride Through (FRT) reactive power injection capability and Over Frequency Sensitive Mode (OFSM) active power control, according to the approach proposed by INESC TEC.

The structure of proposed transient stability analysis RES model has been presented in Figure 21 below. This RES model consists of 3 elementary components which are described below:

- Measurement models, responsible for measurements of power, voltage and frequency directly at the terminals of generation model;
- Converter Controller model including both active and reactive current controllers models with limitation and both FRT and OFSM functions according to grid codes requirements; and
- Generator part, including Generator slot for *ElmGenStat* standard PowerFactory model for generators which are generally connected to the grid through a static converter.

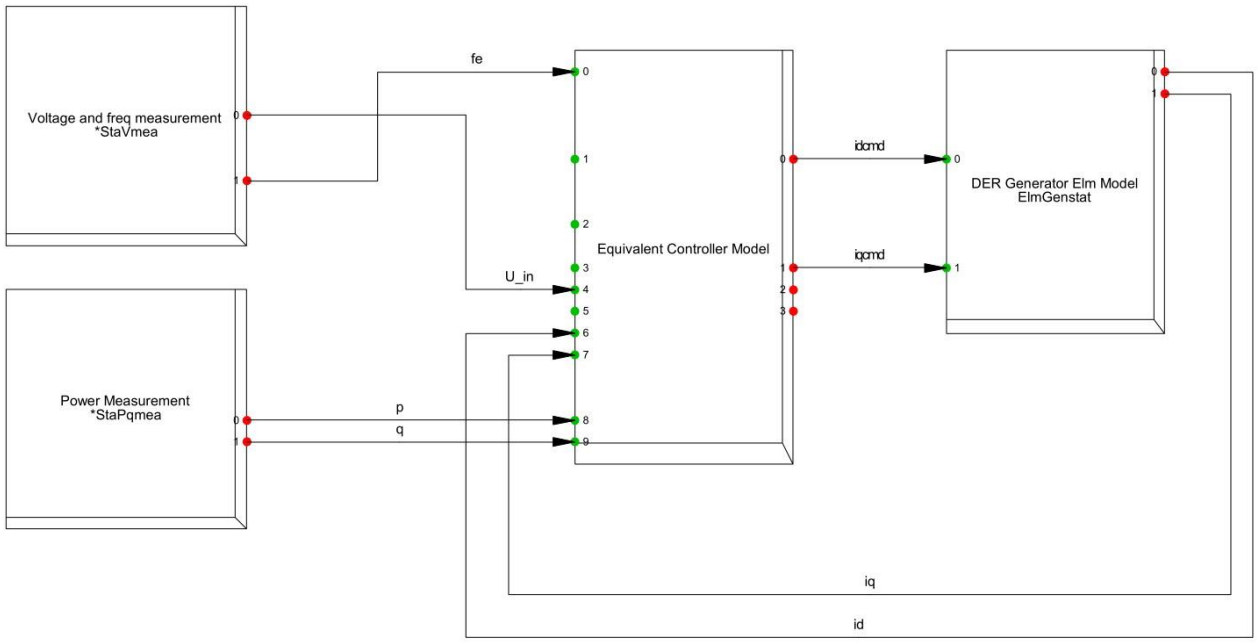



FIGURE 21: STRUCTURE OF THE PROPOSED RENEWABLE ENERGY SOURCE MODEL IN POWERFACTORY

The detailed structure of the proposed power electronics converter controller model for RES connected to the grid has been presented in Figure 22 below. The model is based on a state-of-the-art representation, according to controller models proposed by INESC TEC and WECC, implemented in the d-q reference frame, including control capability over the active and reactive components of the current. The controller model consists of 3 main control paths which are described below:

- $i_d$ control referring to the active current component control path equivalent to active power control, including OFSM function, which is being activated when frequency deviation exceeds specified deadband. During the normal operation state, OFSM control path is deactivated and reactive power component is

calculated according to the reference $P_{init}$ active power value which is defined as a result of the initial load flow and also actual voltage at the terminal of the generator.

- $i_q$ control loop referring to the reactive current component control path equivalent to reactive power control, including FRT current injection capability, which is being activated when voltage deviation exceeds specified dead band. During the normal operation state, FRT control path is deactivated and reactive power component is calculated according to the reference $i_q$ value which is defined as a result of the initial load flow.
- Current limits block, implementing proposed by INESC TEC control logic, assuming priority to the reactive current injection increase, by decreasing the active component in the case of sudden voltage dips.

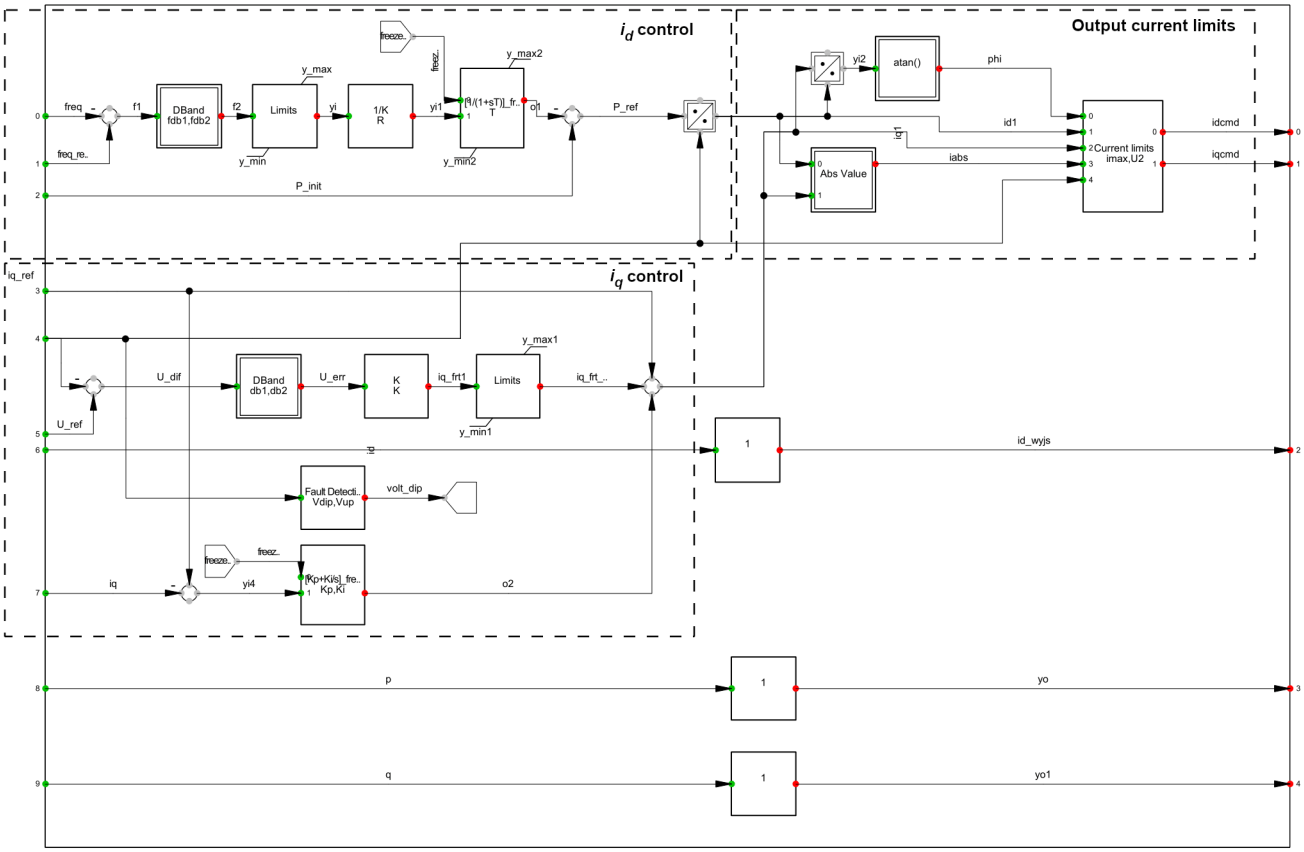



FIGURE 22: DETAILED STRUCTURE OF THE PROPOSED CONVERTER CONTROLLER MODEL IN POWERFACTORY

### 3.2.2.4 LOAD MODELS

General load installed in the CE power system model have been represented with generic PowerFactory *ElmLod* element and *TypLod* type model component defining load type in detail. Complex load models with high penetration of electrical engines have been also implemented using default *TypLodind* dynamic analysis type model component. Implemented complex load models include both typical industrial load and power station's internal load models, distinguished by dynamic to static load percentage ratio values.

The load values in the proposed CE power system model are originally defined for maximum winter peak of power demand in the Polish transmission system. Operation snapshots data will be adapted using load scaling factors.

A static load flow model proposed for voltage stability analysis implements load's voltage dependency based on polynomial load model, commonly referred to as a $ZIP$ model, consisting of the sum of the constant impedance ($Z$), constant current ($I$) and constant power ($P$) terms:

$$P = P_0\left[a_1\left(\frac{V}{V_0}\right)^2 + a_2\left(\frac{V}{V_0}\right) + a_3\right] \quad (3.1)$$

$$Q = Q_0\left[a_4\left(\frac{V}{V_0}\right)^2 + a_5\left(\frac{V}{V_0}\right) + a_6\right] \quad (3.2)$$

where $V_0$, $P_0$ and $Q_0$ are normally taken as the values at the initial operating conditions. The parameters of presented polynomial model are the coefficients from $a_1$ to $a_6$ and the power factor of the load. A constant power model, often used in load flow calculations, is voltage invariant and allows loads with a stiff voltage characteristics to be represented. The constant current model gives a load demand that changes linearly with voltage and is a reasonable representation of the real power demand of a mix of resistive and motor devices. When modelling the load by a constant impedance the load power changes proportionally to the voltage squared and represents some lighting loads well but does not model stiff loads at all well. The proposed load modelling ZIP characteristics coefficients for load modelling, both for static and dynamic analyses, have been presented in Table 8 below. For the purpose of static calculations, both real and reactive power are represented by the constant power model. In the case of dynamic simulation, dynamic simulations are run using mixed model, assuming 50% of constant current and 50% of constant impedance load for real power and constant impedance load representation for reactive power.

**TABLE 8: PROPOSED LOAD MODELLING ZIP CHARACTERISTICS**

| Type of analysis | ZIP model coefficients | Type of $P(V)$, $Q(V)$ characteristics |
|---|---|---|
| Static | $a_1 = a_2 = 0; a_3 = 1;\ a_4 = a_5 = 0; a_6 = 1$ | $P = P_0 = \text{const.};\ \text{Q} = \text{Q}_0 = \text{const.}$ |
| Dynamic | $a_1 = a_2 = 0{,}5\ ;\ a_3 = 0;\ a_4 = 0{,}5; a_5 = a_6 = 0$ | $P = P_0\left[0{,}5\left(\frac{V}{V_0}\right)^2 + 0{,}5\left(\frac{V}{V_0}\right)\right];$ $\text{Q} = Q_0\left(\frac{V}{V_0}\right)^2$ |

For the purposes of dynamic stability analyses, load models in Poland representing high penetration of electrical motors have been modelled assuming the mixed proportion of 30% motor load to 70% static load for typical industrial load. The internal load models of power stations have been implemented assuming 99% motor load penetration.

#### 3.2.2.5 TRANSMISSION SYSTEMS REPRESENTED FOR POLAND'S NON-NEIGHBOURING COUNTRIES

Transmission systems of Poland's non-neighbouring countries are represented with a simplified equivalent model, that contains a classical transient stability model of synchronous generation and load model as presented in Figure 23. Transmission system equivalents are connected to the boundary EHV terminals located in the "yellow" zone (see Figure 12). Both a synchronous machine and load enable to simulate a cross-border power transfer representing simultaneously an assumed inertia (energy stored in rotating masses).

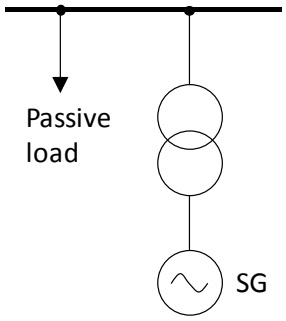



FIGURE 23: PROPOSED METHOD OF MODELLING A TRANSMISSION SYSTEM EQUIVALENT (SG – SYNCHRONOUS GENERATION)

#### 3.2.2.6 OTHER POWER SYSTEM COMPONENTS MODELS

Other transmission system elements, including lines, transformers, shunts, HVDC interconnectors, station controllers etc. have been modelled using standard DIgSILENT PowerFactory models, adapted to the CE model parameters obtained from previous transient stability analyses conducted by PSE. FACTS are not used in Polish power system. There is no FACTS representation in other countries due to the assumed simplification.

## 3.3 NORDIC SYSTEM MODELS – VTT

### 3.3.1 UNIT COMMITMENT MODEL - WILMAR

Wilmar Joint Market Model (WJMM) will be used as the UCED model for Nordic system studies. Similarly to the CONTINENTAL model, the model simulates the hydro-thermal dispatch of a multi-area system for every hour of the year, given the interconnection constraints between the areas. The model can perform system-wide optimization for the scheduling of power plants, storages and demand response. WJMM is a stochastic optimization model. Indeed, in order to analyse the market impacts of wind and solar power adequately, it is essential to explicitly model the stochastic behaviour of wind and solar generation and to take the forecast errors into account. In an ideal, efficient market setting, all power plant operators will take the prediction uncertainty into account when deciding on the unit commitment and dispatch. This will lead to changes in the power plant operation compared to an operation scheduling based on deterministic expectations. WJMM is able to consume an ensemble of forecasts for wind and solar power generation and electricity demand.

WJMM geographically resolves the model area in several nodes which have been selected in the Nordic model as bidding zones or group of bidding zones as shown in Figure 24.

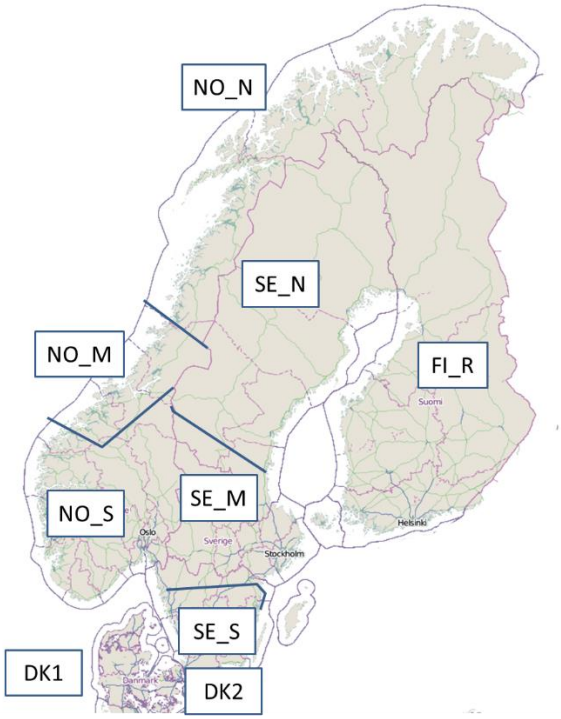



FIGURE 24: WILMAR JMM ELECTRICAL NODES

The model uses rolling horizon as shown in Figure 25. The model is iteratively solved several times for any given time period, simulating the improvement in demand and generation forecasts closer to the operating period (Meibom, 2006). The model may be configured so that larger adjustments are done according to the current day-ahead market time schedule and smaller adjustments are performed continuously.

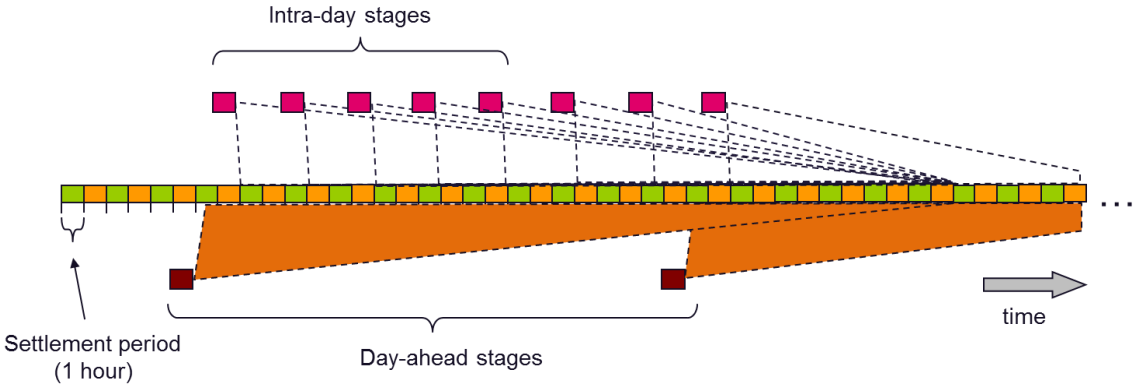



FIGURE 25: WILMAR JMM USES ROLLING HORIZON TO OPTIMIZE PLANT SCHEDULING.

Although the behaviour of reserve units is not followed by WJMM in real time, the hourly allocation of resources for provision of both frequency containment reserve for normal operation (FCR-N) and frequency containment reserve for disturbances (FCR-D) is maintained. In the Nordic system, the purpose of FCR-N is to contain normal

minute-to-minute imbalances in consumption and generation. In conjunction with a rapid frequency change to 49.9 or 50.1 Hz, the reserve shall be regulated up or down within 2–3 minutes. On the other hand, the purpose of FCR-D is to contain large unexpected imbalances. FCR-D must be of such a volume and composition that a dimensioning fault does not cause a frequency drop below 49.5 Hz in the synchronous system (ENTSO-E, 2016-3). Limits are set on the capacity offered by each plant for each reserve type and the share of the stationary response accepted on the reserve market is limited. The procurement of reserves takes places in blocks of one hour or longer. The "gate closure time" of the reserve market can also be adjusted. After the gate closure the reserve allocation for the concerned blocks is fixed. However, no explicit cost has been defined for reserve bids and the allocation is done by minimizing the cost on electricity supply.

While the manual frequency restoration reserve has long been present in the Nordic system, aFRR was introduced in 2013. Frequency restoration reserve (FRR) is not currently included in the model but could be added. FRR is procured by TSO's in hourly market.

WJMM also optimizes heat supply in the operational time scale. Especially in Nordic countries the district heating sector is an important part of the energy system, with many CHP plants present and the number of heat pumps growing. WJMM is able to simultaneously optimize also scheduling of district heat generation. The inclusion of different units in frequency, power and heat balances within the model framework is shown in Figure 26. Generally, to reduce solving time, WJMM considers only the largest units individually while other unit are grouped according to their type.

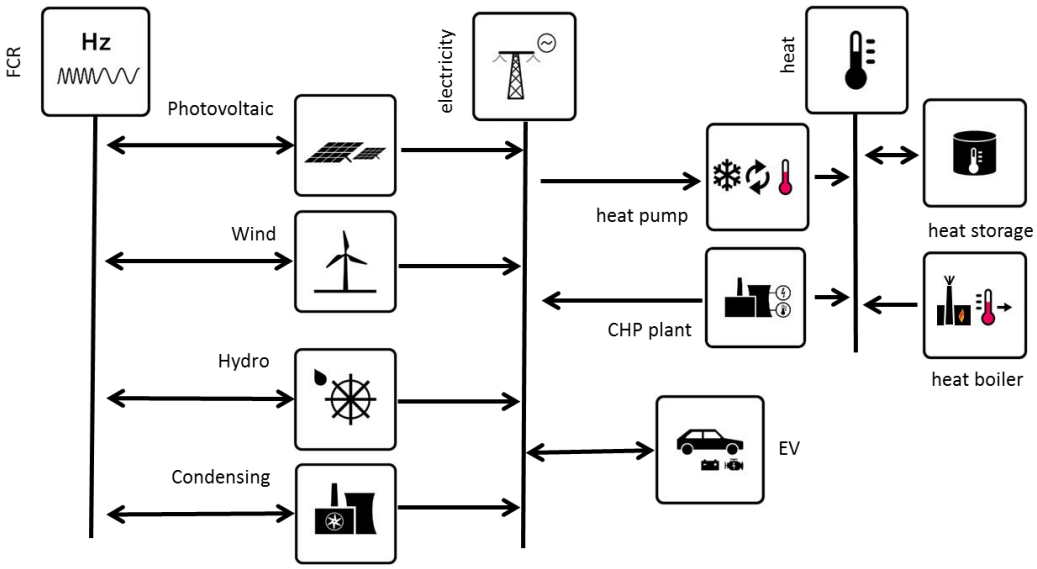



FIGURE 26: RESERVES, ELECTRICITY AND HEAT BALANCE WILMAR JMM AND THE PARTICIPATING UNIT TYPES.

As WJMM looks only maximum 36 hours ahead, other methods must be used to schedule long-terms storages. Two methods have been implemented: heuristic setting of the storage value, based on historical storage levels, and a long-term optimization model, where uncertainty of future parameters (e.g. water inflow and wind power) can be explicitly taken into account by considering a number of historical weather outcomes.

WJMM inputs include:

- time series of electrical load and district heat load;
- time series of reservoir hydro inflow and run-of-river production;
- time series wind and solar power (maximum) production;
- time series of demand response availability;
- time series of interconnector flows from the continental and Great Britain grids; and
- data of power plants, storages, interconnectors, EV and other resources.

WJMM outputs include:

- scheduled electricity production (charging when applicable) of power plants, storages, EV and other resources;
- scheduled heat production (charging when applicable) of heating plants and storages; and
- reserve allocation by plant and reserve type.

### 3.3.2 FREQUENCY STABILITY MODEL

The frequency stability model for Nordic power system is a single bus model that considers only system frequency dynamics, neglecting the coupling between system voltage and frequency i.e. assuming that the system voltage stays at 1 pu. The necessary assumptions for the model are:

- The frequency remains uniform across the system due to the tightly meshed and electrically short system with relatively low impedance between nodes. In fact the “centre of inertia frequency” is simulated, which is a weighted average of the real individual generator frequencies.

- The voltage has a negligible effect on power system balance, with no network representation included in the model. It is assumed that the AVRs on the generators maintain steady state system voltages following a contingency. Moreover, the local voltage deviations will occur near the contingency site; however these deviations are a local phenomenon with limited global manifestations.

The Nordic frequency stability model is built on the Matlab Simulink platform and is based on the numerical simulation the control system shown in Figure 27. With small deviations, frequency response of the power system can be approximated with the swing equation, which is a first-order differential equation. The corresponding transfer function between power deviation signal and system frequency is:

$$G(s) = \frac{\omega_s}{2HS_n s + K_L P}$$

where $H$ is the inertia constant of the system, $S_n$ is the summed installed capacity in the system, $K_L$ frequency sensitivity coefficient of power demand and $P$ the total load.

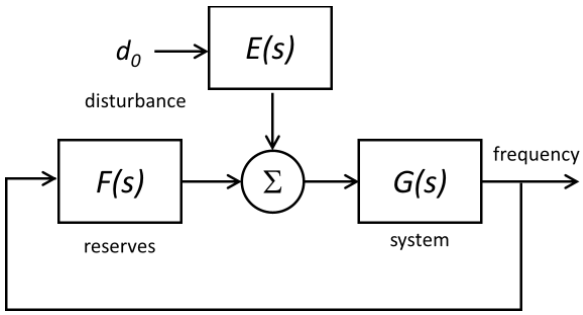



FIGURE 27: CONTROL SYSTEM FOR GRID FREQUENCY SIMULATION. THE TRANSFER FUNCTION G(S) REPRESENTS GENERATORS WHICH POSSESS INERTIA AND ELECTRICAL LOADS, AND F(S) FREQUENCY-CONTROLLED RESERVES.

The disturbance signal is sudden loss of generation as explained later in the studied operation scenarios section. The representation of operating reserves is contained in the function $F(s)$ and is different for different types of plants. For hydroelectric plants the classical model of the water turbine (Machowski, 2008) with PID type controller has been used. The turbine response is represented with water starting time $T_w$. $T_w$ has been currently set to 1 s based on (Ørum E, 2015). The constant has a very significant effect on the hydroelectric plant response and thus on the system frequency dips. The turbine–governor model for steam plants was based on the IEEE type 1 speed-governing model. A single model was used for both gas turbines and reheat plants such as fluidized bed combustion plants used as biomass-fired CHP plants. In practice gas turbines can respond faster, increasing output by several percent in one second, and differentiating their plant model can be considered.

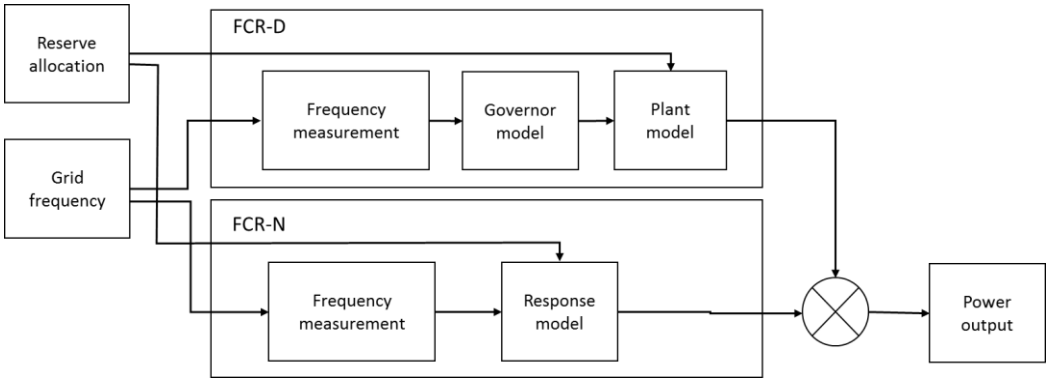



FIGURE 28: RESPONSE MODEL FOR INDIVIDUAL PLANT TYPE.

For wind turbines a simplified model where blade pitching functionality is used to modulate output power has been implemented in the model. 10 °/s for the maximum blade pitching speed has been suggested (Clark et al., 2010). A separate model block has been implemented for inertia based fast frequency response provision as shown in Figure 29. PV plants, when de-loaded, can respond immediately to power request. For them only the frequency measurement introduced a time delay. Heat pumps with continuous speed control were also included as one plant type. Other types of demand response such as chillers, pumps and electric heating could also be included if their response behaviour is known.

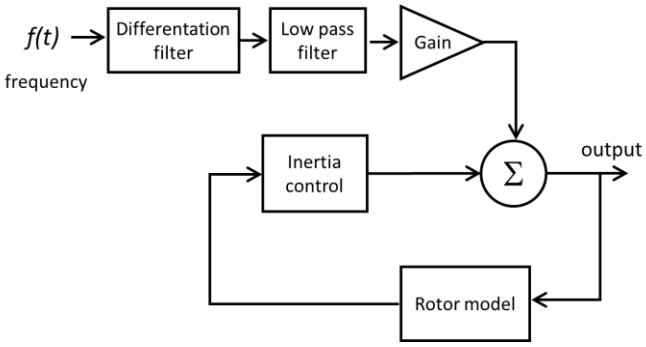



FIGURE 29: WIND INERTIA BASED FAST FREQUENCY RESPONSE MODEL IN THE NORDIC FREQUENCY STABILITY MODEL

To recap, the inputs of the Nordic frequency stability model include:

- time series of production and online capacity of different plants or groups of plants
- time series of reserve allocation by reserve type on different plants or groups of plants
- magnitude of the dimensioning fault

Outputs of the Nordic frequency stability model include:

- time series of system kinetic energy
- time series of frequency nadir and maximum rate of change of frequency

## 3.4 IRELAND AND NORTHERN IRELAND MODELS – EIRGRID AND SONI

The transmission system is operated at 400 kV, 220 kV and 110 kV in Ireland and 275 kV and 110 kV in Northern Ireland. The network is generally comprised of high-voltage overhead lines, with underground cables used mainly in areas such as Dublin, Cork and Belfast cities along with the grid connections of wind farms. The Ireland and Northern Ireland transmission systems are electrically connected by means of one 275 kV double circuit and two 110 kV tie line connections. The system is connected to GB power system via two HVDC links. The East West HVDC Interconnector (EWIC) connects Ireland and Wales by means of one 500 MW Voltage Source Converter (VSC) HVDC interconnector, while the Moyle HVDC Interconnector connects Northern Ireland and Scotland by means of one 500 MW Line Commutated Converter (LCC) HVDC interconnector.

The current Ireland and Northern Ireland system peak demand is approximately 7,000 MW. Demand in Ireland has been growing, and is expected to continue to grow, mainly driven by new large users such as data centres. A significant proportion of this extra data centre load will materialise in the Dublin area by 2030. The system demand is not expected to grow as significantly in Northern Ireland during the same period.

The installed wind capacity continues to increase year-on-year, enabling Ireland and Northern Ireland to progress towards the target of having 40% of electricity produced by renewable sources by 2020.

The current transmission map of Ireland and Northern Ireland can be seen in Figure 30. A single line diagram showing the connectivity between each transmission substation is seen in Figure 31 (Cuffe, 2018).

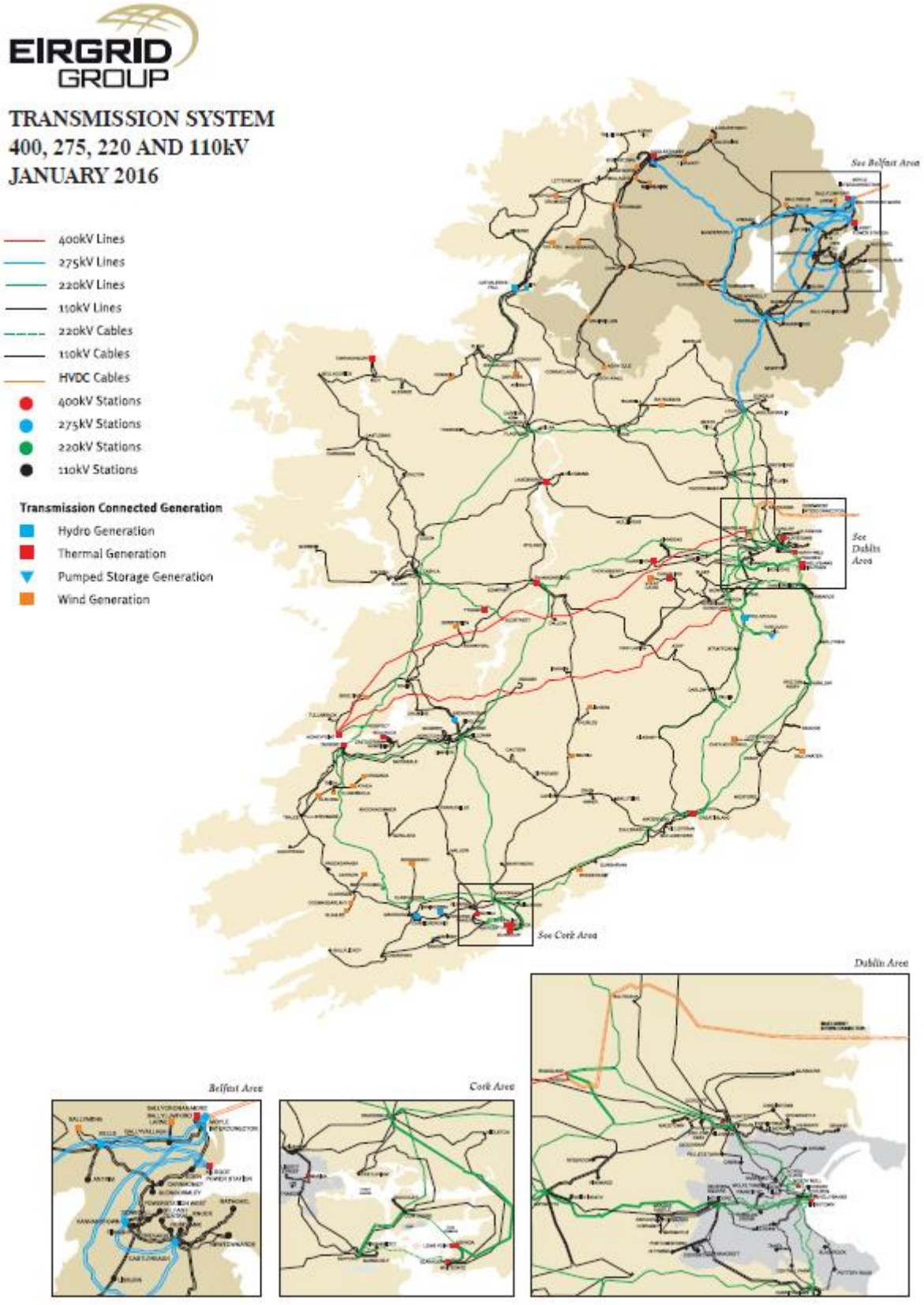



FIGURE 30: IRELAND AND NORTHERN IRELAND TRANSMISSION MAP

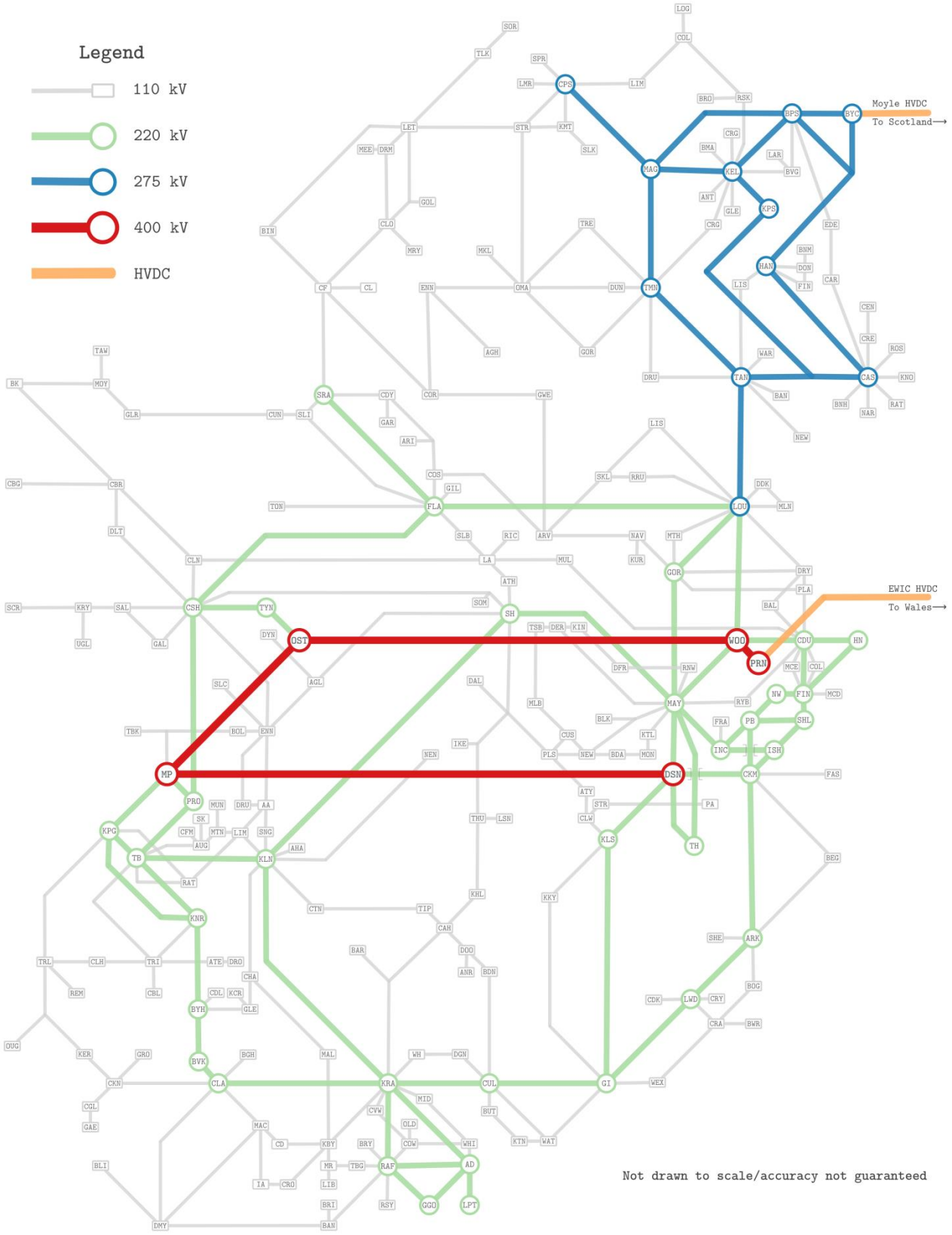



FIGURE 31: IRELAND AND NORTHERN IRELAND TRANSMISSION SUBSTATION CONNECTIVITY MAP AS OF END OF 2017 (CUFFE, 2018)

The existing 2018 transmission system model is adopted for reflecting various network configurations considered during the EU-SysFlex project. This model represents all transmission stations and circuits for Ireland and Northern Ireland down to the DSO Point of Common Coupling (PCC) typically at 38 kV.

The base model contains 1,218 AC buses, 106 synchronous and 230 non-synchronous generators, 548 loads, 772 transformers, 78 Shunts and two HVDC interconnectors represented in detail. The existing loads are represented at the DSO PCC typically at 38 kV, with contracted transmission industrial load connections such as data centres represented with their Maximum Import Capacity (MIC) at the PCC. A total of 548 individual loads are modelled in the existing base model. The base model is configured to represent the current state of the system, both in terms of system configuration and associated dynamic models as per the online Energy Management System data in EirGrid's and SONI's control centres, and the information provided by various asset owners across the system. A variety of system elements such as lines, cables, generation resources, loads, shunt compensation elements and HVDC links are included to represent various future system configurations as described below.

Detailed network models of the Ireland and Northern Ireland power system for various 2030 scenarios under consideration in the EU-SysFlex project are created by building upon the aforementioned base model. The 2030 models represent planned network reinforcements, new generation and demand connections.

The EU-SysFlex scenario and Network Sensitivities under consideration for Ireland and Northern Ireland are documented in the EU-SysFlex D2.2 report – EU-SysFlex Scenario and Network Sensitivities (EU-SysFlex, 2018-1). Further details regarding the generation and demand portfolios chosen for the Ireland and Northern Ireland Network Sensitivities can be found in the EU-SysFlex D2.2 report and in EirGrid's Tomorrow's Energy Scenarios (TES) 2017 publication (EirGrid, 2017). The locations of future generation connections vary depending on the each scenario considered. The network reinforcements are based on connection applications and the envisaged grid development.

The modelled network development is composed of following major components:

- Future grid reinforcements, e.g. overhead lines, underground cables, transformers and substations;
- Future reactive compensation, e.g. capacitors, reactors and STATCOMs; and,
- Future interconnectors, e.g. VSC HVDC Interconnector.

The updated network model includes circuit up-rates and new-build substations that are included in the system needs assessment model based on EirGrid's Multi-Year Development Program (EirGrid, 2018).

Table 9 below outlines the key new-build grid project assumptions.

TABLE 9: FUTURE NEW-BUILD GRID PROJECTS 2030

| Circuit Name |
|---|
| Cross-Shannon 400 kV Cable |
| Kilpaddoge – Knockanure 220 kV (second circuit) |
| Laois – Kilkenny Reinforcement Project |
| North South 400 kV Interconnection Development |
| Shellybanks – Belcamp 220 kV |
| Brockaghboy - Rasharkin 110kV |

The updated network model includes the assumptions listed below for future reactive compensation in Ireland, e.g. capacitors, reactors and STATCOM. It was assumed that all existing (2018) reactive compensation devices remained available to the system throughout the study time frame. Table 10 outlines the future reactive power compensation assumptions.

TABLE 10: FUTURE REACTIVE COMPENSATION ASSUMPTIONS 2030

| Compensation Device | Location |
|---|---|
| Reactor | Knockanure 220 kV |
| Series Capacitor | Dunstown 400 kV |
| Series Capacitor | Oldstreet 400 kV |
| Series Capacitor | Moneypoint 400 kV |
| STATCOM | Ballyvouskil 110 kV |
| STATCOM | Ballynahulla 110 kV |
| STATCOM | Thurles 110 kV |
| STATCOM | Coleraine 110 kV |
| STATCOM | Omagh Main 110 kV |
| STATCOM | Tamnamore 110 kV |

Future interconnector assumptions are based on the scenarios as discussed in the D2.2 report (EU-SysFlex, 2018-1). Similar to the existing EWIC interconnector, future interconnectors are assumed to be based on VSC HVDC technology. The capacity and location of future interconnectors is also scenario dependant.

### 3.4.1 UNIT COMMITMENT MODEL - PLEXOS

PLEXOS is a widely utilised tool for UCED problems, both within industry and in academia. UCED is an hourly cost minimisation problem. The algorithm in PLEXOS determines the least cost manner in which to schedule generation to meet demand for each hour of the simulation, whilst being subject to a number of operating constraints.

EirGrid and SONI have created five UCED models for the Ireland and Northern Ireland power system in PLEXOS. These five models correspond to two Core Scenarios (**Energy Transition** and **Renewable Ambition**) as well as the three network sensitivities (**Steady Evolution**, **Consumer Action** and **Low Carbon Living**) which have been detailed in D2.2 of EU-SysFlex (EU-SysFlex, 2018-1). The core scenarios for Ireland and Northern Ireland align with the core scenarios for the Continental European power system, while the Network Sensitivities were leveraged from work completed as part of Tomorrow's Energy Scenarios 2017 (EirGrid, 2017). Each of these Network Sensitivities has its own specific storyline based on potential economic, energy policy, and technical as well as consumer behaviour developments.

Across the three network sensitivities for EU-SysFlex, the installed renewable generation capacities for the Ireland and Northern Ireland power system vary between 9,000 MW and 15,000 MW by 2030. Thus, the network sensitivities for Ireland and Northern Ireland project much higher installed capacities of variable renewable generation than the EU Reference Scenario 2016 scenarios, which have approximately 6500 MW and 8300 MW of renewable generation for **Energy Transition** and **Renewable Ambition**, respectively. Consequently, the more ambitious scenarios from the Tomorrow's Energy Scenarios 2017 for Ireland plus the tailored TYNDP 2018 scenarios for Northern Ireland are the ideal sensitivities to utilise in order to stress the power system of Ireland and Northern Ireland and to identify technical scarcities.

TABLE 11: OVERVIEW OF THE SCENARIOS AND NETWORK SENSITIVITIES FOR IRELAND AND NORTHERN IRELAND

| EU-SysFlex Scenario | Scenario Name | Climate Year Selected | Interconnector Flows |
|---|---|---|---|
| Core Scenario 1 | Energy Transition | 2011 | CONTINENTAL Model |
| Core Scenario 2 | Renewable Ambition | 2011 | CONTINENTAL Model |
| Network Sensitivity 1 | Steady Evolution | 2015 | TYNDP Model |
| Network Sensitivity 2 | Consumer Action | 2015 | TYNDP Model |
| Network Sensitivity 3 | Low Carbon Living | 2015 | TYNDP Model |

#### 3.4.1.1 CONVENTIONAL AND HYDRO GENERATOR MODELLING

Each conventional generator in Ireland and Northern Ireland is modelled individually in PLEXOS utilising both technical and commercial data. The data required to fully model a conventional generator includes parameters such as: maximum capacity, minimum stable level, heat rates, ramp rates, minimum up and down times, start times, start costs and variable operational and maintenance costs. The fuel prices for the conventional plant are based on the ENTSO-E Ten-Year Network Development Plan (TYNDP) (TYNDP, 2018) fuel prices, which are consistent with the fuel prices utilised to develop the scenarios in Task 2.2.

Hydro generation is modelled with similar constraints to the conventional plants; however, there is an additional constraint on the hydro generation units. This is a daily energy limit constraint and represents the hydrological constraints that exist for run-of-river hydro generating units. Pumped hydro energy storage is modelled in PLEXOS in such a way so as to reflect how it is operated in reality on the Ireland and Northern Ireland power system.

#### 3.4.1.2 MODELLING OF VARIABLE RENEWABLE GENERATION

The historical 2011 available wind power time-series is utilised for the two Core Scenarios (**Energy Transition** and **Renewable Ambition**), so as to align with the climate year utilised in the EDF and VTT models. Wind power in Ireland and Northern Ireland had a capacity factor of 33% in 2011. Historical 2015 available wind power time series with an annual wind power data capacity factor in Ireland of 34% is utilised in the Network Sensitivities. The 2011 wind-power time-series is available on a system-level granularity, while the 2015 data is available on an area by area granularity. The historical 2015 solar data for Ireland and Northern Ireland is employed for solar PV time series.

#### 3.4.1.3 GENERATION PORTFOLIO

The generation portfolios corresponding to the five scenarios are detailed in Table 12. For additional detail on these scenarios, the reader is directed to the EU-SysFlex D2.2 report (EU-SysFlex, 2018-1).

TABLE 12: IRELAND AND NORTHERN IRELAND PORTFOLIOS FOR THE CORE SCENARIOS AND FOR THE NETWORK SENSITIVITIES

| Installed Capacity by Fuel Type ($MW_e$) | EU-SysFlex Scenarios | | IE and NI Network Sensitivities | | |
|---|---|---|---|---|---|
| | Energy Transition | Renewable Ambition | Steady Evolution | Low Carbon Living | Consumer Action |
| Solids | 855 | - | - | - | - |
| Gas | 4234 | 5657 | 5657 | 5207 | 5657 |
| Distillate Oil or Heavy Fuel Oil | 473 | 169 | 389 | 273 | 273 |
| **Conventional Fuel Generation** | **5562** | **5826** | **6096** | **5530** | **5980** |
| Wind (Onshore) | 5650 | 7268 | 6678 | 7040 | 6922 |
| Wind (Offshore) | 25 | 25 | 700 | 3000 | 1000 |
| Wind-Total | 5675 | 7293 | 7378 | 10040 | 7922 |
| Hydro | 237 | 237 | 237 | 237 | 237 |
| Biomass/LFG (including Biomass CHP) | 287 | 715 | 487 | 847 | 528 |
| Solar PV | 369 | 420 | 900 | 3916 | 2916 |
| Ocean (Wave/Tidal) | - | - | 50 | 98 | 73 |
| **Renewable Generation** | **6568** | **8260** | **9052** | **15188** | **11725** |
| Pumped Storage | 292 | 292 | 292 | 652 | 292 |
| Small Scale Battery Storage | - | - | 200 | 500 | 800 |
| Large Scale Battery Storage | - | - | 350 | 1300 | 500 |
| DSM | - | - | 500 | 750 | 1000 |
| DC Interconnection | 1650 | 2150 | 1650 | 2150 | 1650 |
| Conventional CHP or waste | 327 | 503 | 290 | 309 | 318 |

#### 3.4.1.4 LOAD MODELLING

For the two core EU-SysFlex scenarios, a single load profile is utilised to represent the entire system demand, implicitly including assumptions relating to electric vehicles, heat pumps and other large loads.

For the three Ireland and Northern Ireland Network Sensitivities, there is an annual profile for residential and commercial load. In addition, large industrial customers, heat pumps and electric vehicles are modelled individually. Demand side units are also modelled in PLEXOS for the Ireland and Northern Ireland Network Sensitivities. The units are modelled as negative generators, capable of reducing demand for a maximum for a few hours per day.

#### 3.4.1.5 MODELLING OF INTERCONNECTOR FLOWS

Inter-market HVDC interconnector flows are a fixed input to the unit commitment model. The sources of the interconnector flows are EDF's Continental model, for the Core Scenarios, and the TYNDP 2018 models for the Network Sensitivities.

#### 3.4.1.6 OPERATIONAL CONSTRAINT ASSUMPTIONS

As the aim of EU-SysFlex WP2 is to identify technical scarcities, a range of operational constraints for the Ireland and Northern Ireland system will be chosen such that these scarcities are evident. These operational constraints will be developed in Task 2.4.

Two metrics which will be used when assessing the Ireland and Northern Ireland power system: System Non-Synchronous Penetration (SNSP) and maximum instantaneous Rate of Change of Frequency (ROCOF).

The SNSP formula can be defined as follows (EirGrid and SONI, 2018):

$$\text{SNSP}(\%) = \frac{\text{Non} - \text{Synchronous Generation} + \text{Net Interconnector Imports}}{\text{Demand} + \text{Net Interconnector Exports}} \text{ x } 100$$

A constraint is included explicitly in the PLEXOS model to calculate SNSP. This constraint can also be used to set an overall SNSP limit on the power system. The current SNSP limit on the Ireland and Northern Ireland power system is 65%, with a goal of reaching 75% by 2020.

A second constraint which is explicitly implemented into PLEXOS is a ROCOF constraint which calculates the instantaneous ROCOF which would be seen on the system for the loss of any infeed or outfeed on the system.

The N-1 ROCOF constraint is calculated as:

$$ROCOF = \frac{f^{nom}.\max\{p_t\}}{2.(System\ Inertia)}$$

where:
$f^{nom}$ is the nominal frequency (i.e. 50Hz)
$\max\{p_t\}$ is the largest potential contingency at time $t$

The current ROCOF limit on the Ireland and Northern Ireland power system is 0.5 Hz/s measured over a 500ms timeframe. This is increased to 1 Hz/s in 2020. The ability to implement this constraint in PLEXOS allows for the scheduling of additional inertia on the power system to ensure the maximum instantaneous ROCOF limit is not breached. The use of this constraint will be documented in Task 2.4.

#### 3.4.1.7 AUTOMATED PLEXOS EXTRACTION (APE)

The Automated Plexos Extraction tool (APE) is a Python based tool that has been developed for quick and efficient extraction of outputs from PLEXOS. APE extracts the PLEXOS .csv files and creates a Microsoft Excel spreadsheet output detailing the dispatches for each plant for each hour of simulated year.

APE also has additional functionality for calculating a number of key metrics. These metrics include the RES-E level for the simulation year, the max ROCOF for each hour, the inertia level for each hour of the simulation and the SNSP level for each hour of the simulation.

#### 3.4.1.8 OUTPUTS

Together, PLEXOS and APE produce a wide variety of results and outputs including:

- Least cost dispatches for all units for each hour of the simulation period
- Total net demand, taking IC flows, storage etc. into account
- Production costs
- Variable renewable curtailment or dispatch down levels
- Indication of RES-E levels for both Ireland and Northern Ireland
- SNSP levels for the All-Island power system
- Inertia levels for the All-Island power system
- Indication of reactive power capability for the All-Island power system
- Indication of system ramping capability for the All-Island power system

Some of these parameters could be utilised to identify critical times and critical snapshots for further investigation.

### 3.4.2 WIND SECURE LEVEL ASSESSMENT TOOL - WSAT

Wind Secure Level Assessment Tool (WSAT) is a combination of component computation engines designed to focus at various aspects of power system stability problem specification and solution. This suite of power system analysis tools is developed by PowerTech Labs and is used extensively for online and offline stability studies within EirGrid and SONI. WSAT is composed of three components detailed in Figure 32.

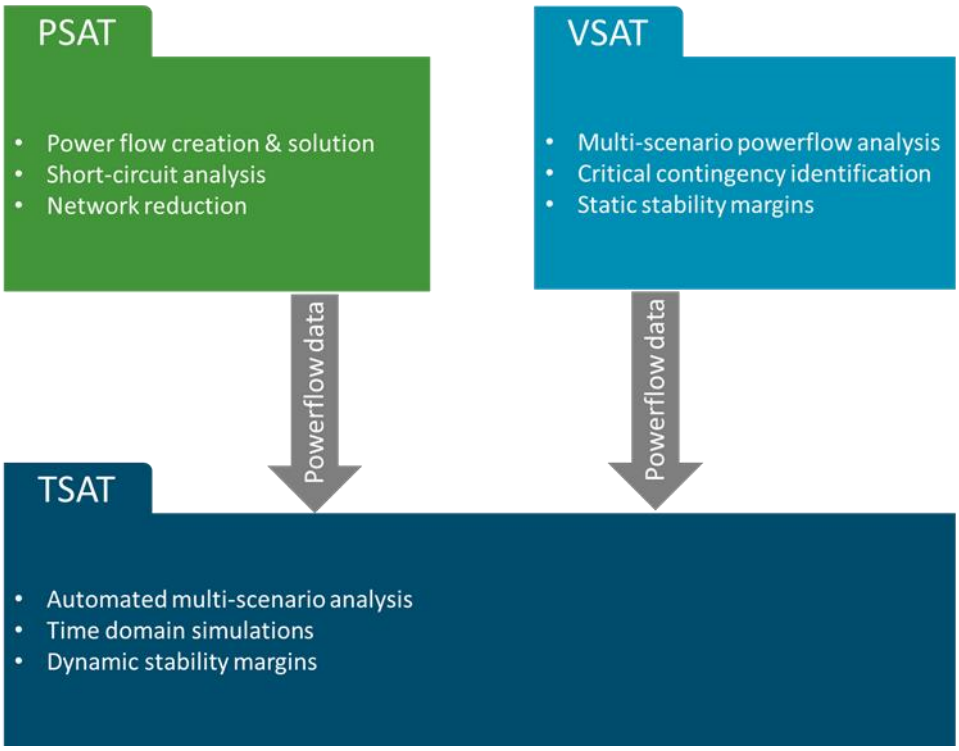



FIGURE 32: OVERVIEW OF WSAT

**Powerflow & Short-circuit Analysis Tool (PSAT):** PSAT is primarily a static stability analysis tool, designed for creation and solution of power-flow cases and classical short-circuit power calculations. The output powerflow solution can be used to initialise transient security assessment tool.

**Voltage Security Assessment Tool (VSAT):** VSAT is primarily designed to assess system voltage stability through the solution of multiple powerflow problems. It can additionally be used to determine the margins to static voltage security. VSAT concentrates on power system voltage security under steady state conditions (i.e. > 20 seconds following an event, after transient oscillations have been damped out).

**Transient Security Assessment Tool (TSAT):** TSAT is the time domain simulation engine compatible with both PSAT and VSAT. It focusses on system transient stability (frequency, dynamic voltage and rotor angle) within 20 seconds following an event while the transient oscillations are present.

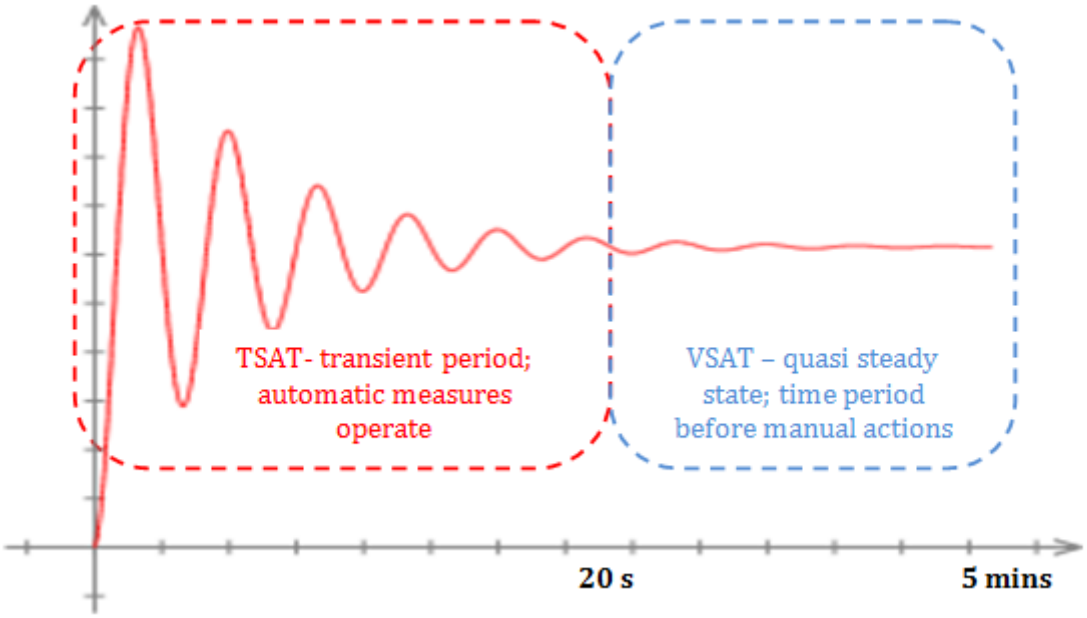



FIGURE 33: INTERACTION BETWEEN TSAT & VSAT

#### 3.4.2.1 CONVENTIONAL GENERATION MODELS

The conventional generators are modelled using the standard components representing both machine and control dynamics as appropriate. The main components associated with each generator model are the following:

a) Synchronous machine model
b) Governor/turbine model
c) Excitation system model
d) Power system stabiliser model

Various machines on the system have been modelled using various degrees of complexity, so as to get an appropriate representation of their associated behaviour in a positive sequence simulation analysis. The synchronous machine models contain a representation of machine's physical parameters such as various self and mutual inductances through impedances and time constants. The standard industry practice of modelling the synchronous machine with two circuits, representing the d and q axis is used in the model. The summation of machine electrical torque obtained from the two circuits is used in the swing equation establishing a link between the speed and the net torque acting on the machine. The network interface on the machines is established through the corresponding Norton equivalents (Weber, 2015). The common assumptions across all the synchronous machine models are well documented in literature (Kundur P. , 1994) (Anderson & Fouad, 1994). For instance, the layout of standard industry model GENROU is shown below:

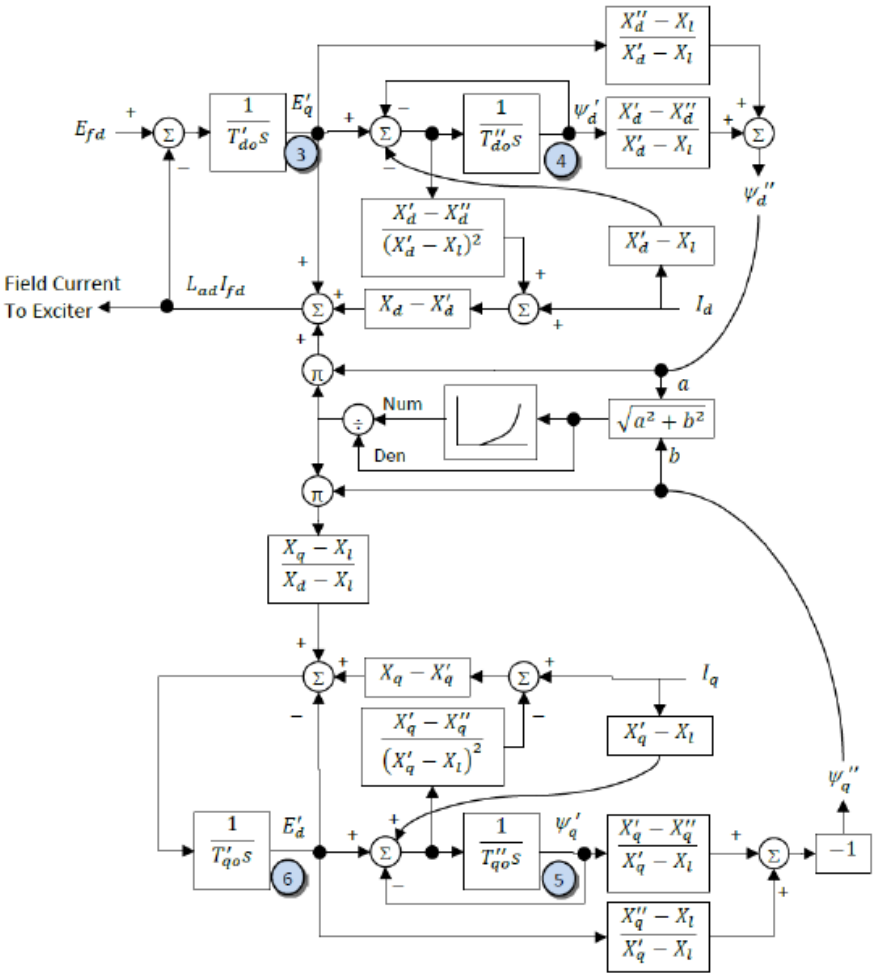



FIGURE 34: GENROU MODEL STRUCTURE

The traditional industry practice has been to have slight differences in models according to modelled units, based on:

i) Rotor type (round vs salient pole)

ii) Saturation modelling

Based on these differences, a number of models have been developed and are used to represent each synchronous machine in the model:

| Model | Rotor type | Saturation modeling |
|---|---|---|
| GENROU | Round rotor | Open circuit saturation fit to quadratic model |
| GENROE | Round rotor | Open circuit saturation fit to exponential model |
| GENSAL | Salient pole | Open circuit saturation fit to quadratic model |
| GENSAE | Salient pole | Open circuit saturation fit to exponential model |
| GENTPJ | Salient pole | Open circuit saturation fit to quadratic model |
| GENTPF | Round rotor | Open circuit saturation fit to quadratic model |

The fundamental assumptions for model derivation for GENTPJ and GENTPF are different. The rotor saliency in the sub transient time frame is not ignored and a relationship between self and mutual inductances on the d-axis is established. Further details on the difference between these model types are available in literature (Pourbeik P. , 2016). The conventional generation on the Ireland and Northern Ireland power system consists of multiple units, varying in nature and therefore the standard synchronous machine models as discussed have been used as appropriate. Figure 35 gives an indication about the percentage of units in the system utilising various model types.

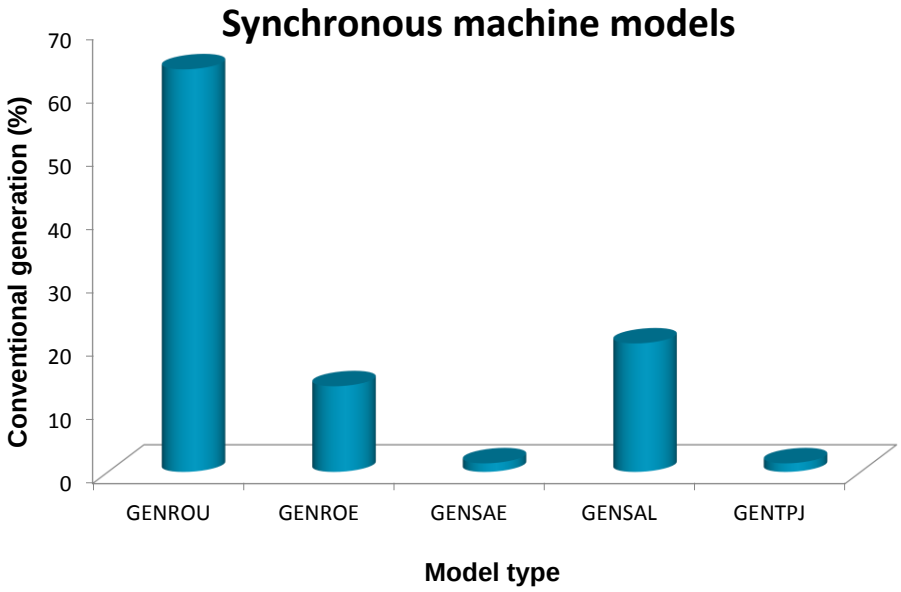



FIGURE 35: TYPES OF SYNCHRONOUS MACHNIE MODELS USED

The excitation system is responsible for voltage regulation in a synchronous machine by varying the field voltage. The excitation system model used for each generator depends on the type of excitation system. Excitation systems are generally categorised with regards to AC/DC based supply and rotational/static nature, with corresponding associated models. The conventional generation in the Ireland and Northern Ireland system model contains the exciter model associated with each generation resource on the system. Figure 36 shows various excitation models and the percentage of generators modelled for each. There are a number of standard models used for various generators, however, a large fraction of generation is modelled through user defined model (UDM), which are specific models supplied by the vendor to more accurately represent the voltage regulation characteristics.

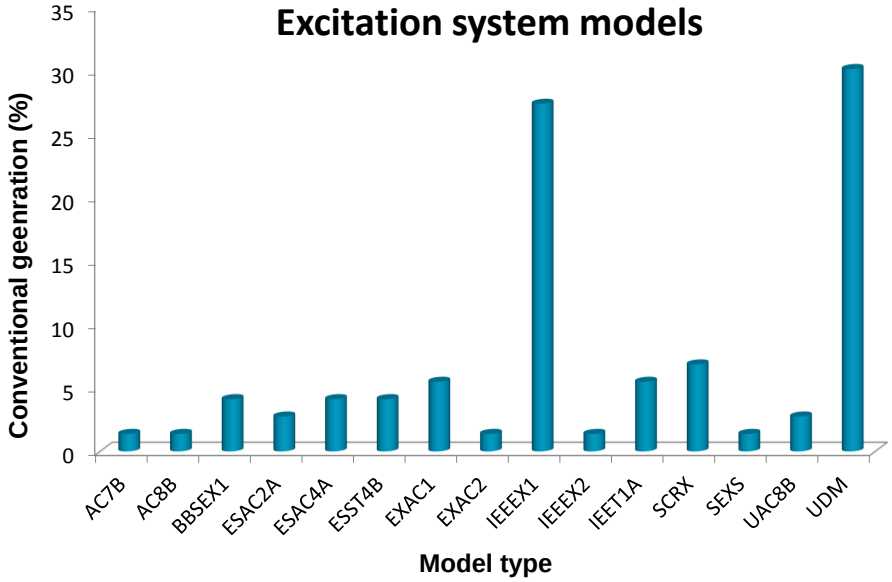



FIGURE 36: TYPES OF EXCITATION SYSTEM MODELS USED

There are a number of components of an excitation system, as shown in Figure 37. The most important component, which is usually modelled separately, is the power system stabilizer (PSS).

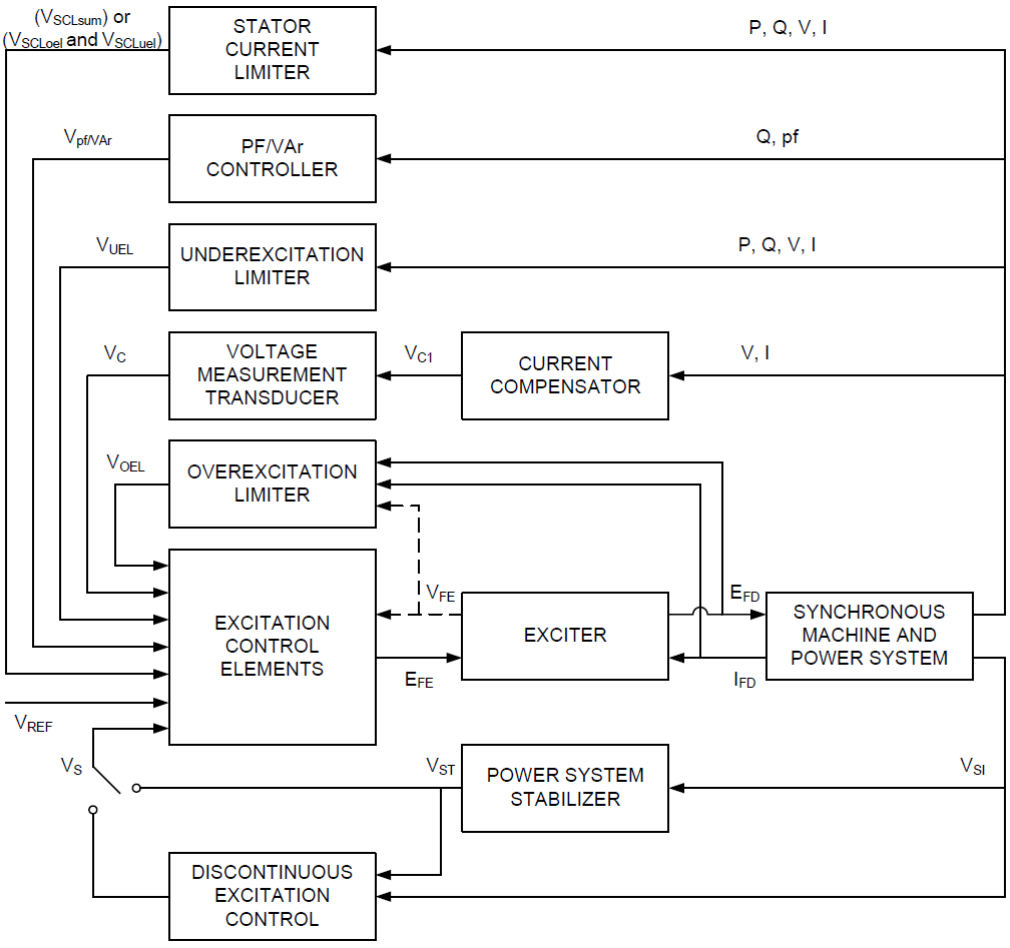



FIGURE 37: FUNCTIONAL BLOCK DIAGRAM OF AN EXCITATION SYSTEM (IEEE, 2016)

The primary function of the voltage control loop in the excitation is to regulate voltage and enhance the synchronising torque in the system. However, the voltage control loop has a very small response time due to large reactance of field windings the effect of this voltage control loop isn't transferred across to the terminals immediately, thereby potentially reducing the damping torque in the system and resulting in oscillations. The power system stabilisers are at times used to correct the phase lag and hence to introduce positive damping in the system. There are multiple PSS design philosophies mainly differing in terms of the input signal used to generate the phase correction; these input signals include speed change, system frequency, electrical power etc. Moreover, the system stabilisers can be classified in terms of a single or multiple inputs. The power system stabiliser models used for the Ireland and Northern Ireland power system are detailed in Figure 38. The percentages of generators with various PSS models, amongst the generators containing a PSS, are shown in the Figure below:

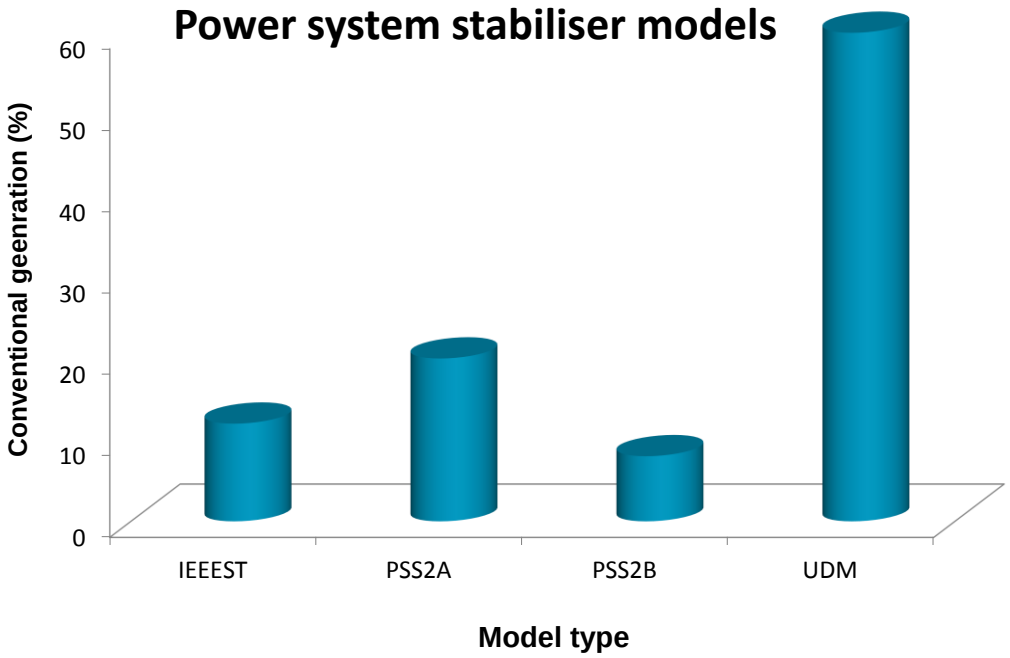



FIGURE 38: TYPES OF POWER SYSTEM STABILISER MODELS

### 3.4.2.2 RENEWABLE ENERGY MODELS

The renewable energy models are based on the generic models proposed by Western Electricity Coordinating Council's (WECC) Renewable Energy Modelling Task Force. WECC models have been chosen for their flexibility and the ability to represent a wide range of equipment from various vendors. WECC Generation 2 models are particularly suited for representing a large power park module with multiple components coordinated through a complex plant controller and the provision of primary frequency response. The renewable energy system models have the following limitations (Pourbeik, 2017):

1) The models are suitable only for balanced operation i.e. for positive sequence simulations;
2) At low short circuit ratio values, the numerical stability of the models is limited owing to their current source nature;
3) High frequency controls in converters are modelled through algebraic equations and phase locked loop (PLL) control is represented through a basic algebraic expression;
4) Detailed aerodynamics/solar irradiation is not considered, wind speed and solar irradiation is assumed constant during the simulation; and
5) Inertia based FFR is not represented for wind turbines.

The modular approach for RES models using WECC Generation 2 model structure ensures individual models for various components of a renewable energy source are available and can be combined in different ways to model any particular renewable energy resource. Following table explains the combinations of various individual models.

TABLE 13: MODEL COMBINATIONS FOR VARIOUS RES (POURBEIK, 2017)

| Renewable energy resource | Model combination |
|---|---|
| Type 1 WTG | wt1g, wt1t, wt1p_b |
| Type 2 WTG | wt2g, wt2e, wt2t, wt1p_b |
| Type 3 WTG | regc_a, reec_a, repc_a, wtgt_a, wtgar_a, wtgpt_a, wtgtrq_a |
| Type 4 WTG | regc_a, reec_a, repc_a (optional: wtgt_a) |
| Photo voltaic plant | regc_a, reec_b (or reec_a), repc_a |
| Battery energy storage system | regc_a, reec_c (optional: repc_a) |

Models for battery energy storage systems (BESS), large scale PV plant, Type 1 and Type 2 wind farms as per above configuration are used. Type 3 and Type 4 wind farms are represented by user defined models, detailed in the subsection below.

Figure 39 and Figure 40 show the model overview for a Type 1 and Type 2 wind turbine generator. Further details regarding the internal structures of pitch control and drive train blocks are available in (Pourbeik P. , 2015).

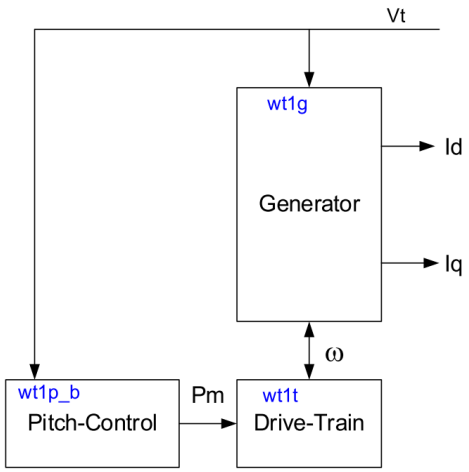



FIGURE 39: TYPE 1 WIND TURBINE GENERATOR

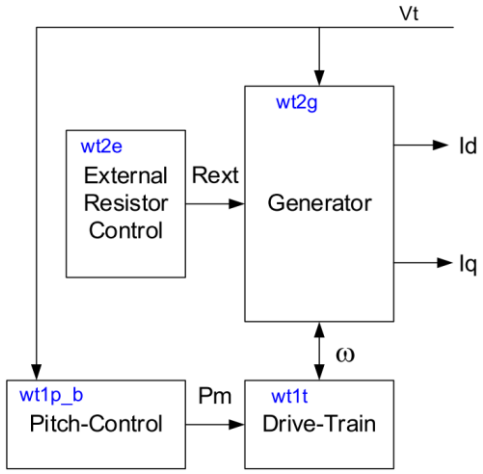



FIGURE 40: TYPE 2 WIND TURBINE GENERATOR

The generator models wt1g and wt2g are the electrical models of induction generator, as shown in Figure 39 and Figure 40. Wt1g contains the standard machine equations for a single cage induction machine, with the model parameters being the standard characteristics of an induction machine such as machine impedances, time constants and saturation parameters. Wt2g contains the induction generator model with parameters similar to Wt1g, with an externally accessible wound rotor winding.

The generator/convertor representation and plant controllers for Type 3 WTG, Type 4 WTG, BESS and PV plant are similar. BESS and PV plant differ marginally in terms of their respective electrical controllers. This common generator/convertor model regc_a receives commands for active and reactive current values from the electrical controllers and interfaces to the network through active and reactive current injections. The active current injection controls modelled in the converter block consist of a low voltage active power limiter logic used to emulate the possibility of restricting active power output at very low voltages, representing the limited ability of converters to produce active power. Furthermore, the rate of rise of active power output following a disturbance can also be controlled. The reactive current controls implemented in regc_a model limit the rate of recovery of reactive power to its initial value following a fault clearance. There are further two blocks mainly for ensuring

numerical stability and hence do not represent the physical components of a converter. This is detailed in Figure 41.

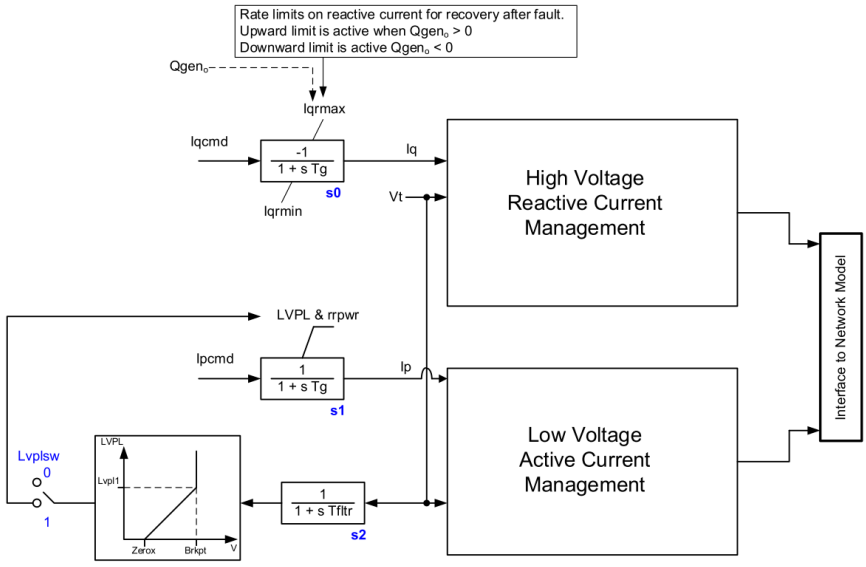



FIGURE 41: GENERATOR/CONVERTER REPRESENTATION REGC_A (POURBEIK P. , 2015)

The plant controller model repc_a is an optional component of the models and is required to coordinate the response of individual elements within a large power park models e.g. to coordinate the response of various PV panels within a PV plant. The inputs to this model are either voltage reference & regulated voltage at the plant level or reactive setpoint and measured reactive generation at the plant level. The plant controller model provides the frequency control functionality, the inputs for this control loop include a reference and measured active power, along with reference and actual frequency at the point of common coupling. The outputs of this model are fed in to electrical controllers as reference values for active and reactive control loops. Figure 42 shows the configuration for the plant controller model.

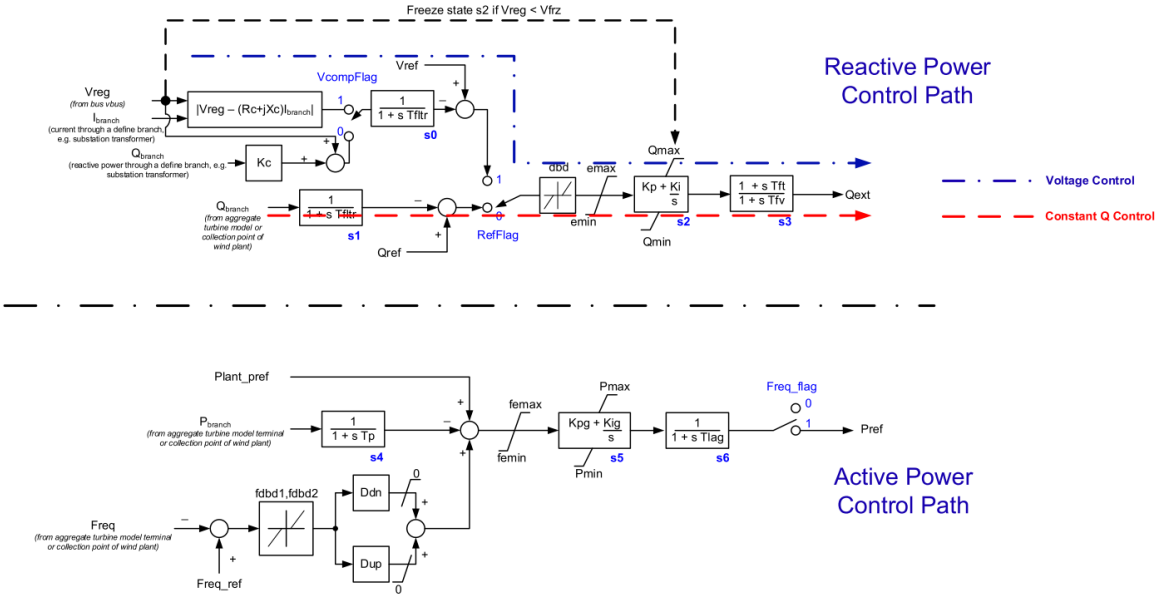



FIGURE 42: PLANT CONTROLLER REPRESENTATION REPC_A (POURBEIK P. , 2015)

#### 3.4.2.2.1 BATTERY ENERGY STORAGE SYSTEM (BESS) MODELS

The BESS model consists of generator/convertor and electrical controllers. The electrical controller model reec_c consists of the following major components:

1) Steady state active current control loop
2) Steady state reactive current control loop
3) Voltage dip reactive current control loop
4) Current limit logic

The overall structure of BESS models is shown in Figure 43. The active current control loop takes Pref from the plant control model if such a model is used; the active current command during a fault situation is frozen to the pre-fault value. For BESS models, a state of charge estimation block is added in the electrical control component shown in Figure 44, which shifts active current command to zero if the BESS runs out of charge. The reactive current command during steady state depends on whether the BESS is in voltage control mode, power factor control mode or constant Q control mode. The input to this loop is taken from the plant control model if such a model is used and is taken from a declared constant otherwise. In a voltage dip fault situation, the voltage dip reactive current control loop is activated, with the steady state reactive current control loop frozen, providing a reactive current injection in proportion to the voltage dip. The dead band and proportionality around this reactive current injection can be adjusted.

The current limit logic is implemented, so as to not breach the total available current rating of the BESS. A P-Q priority flag determines whether the BESS reverts to active or reactive current priority mode in case of a voltage fault. All the associated measurement and control delays are included, along with limits to establish credible device operation.

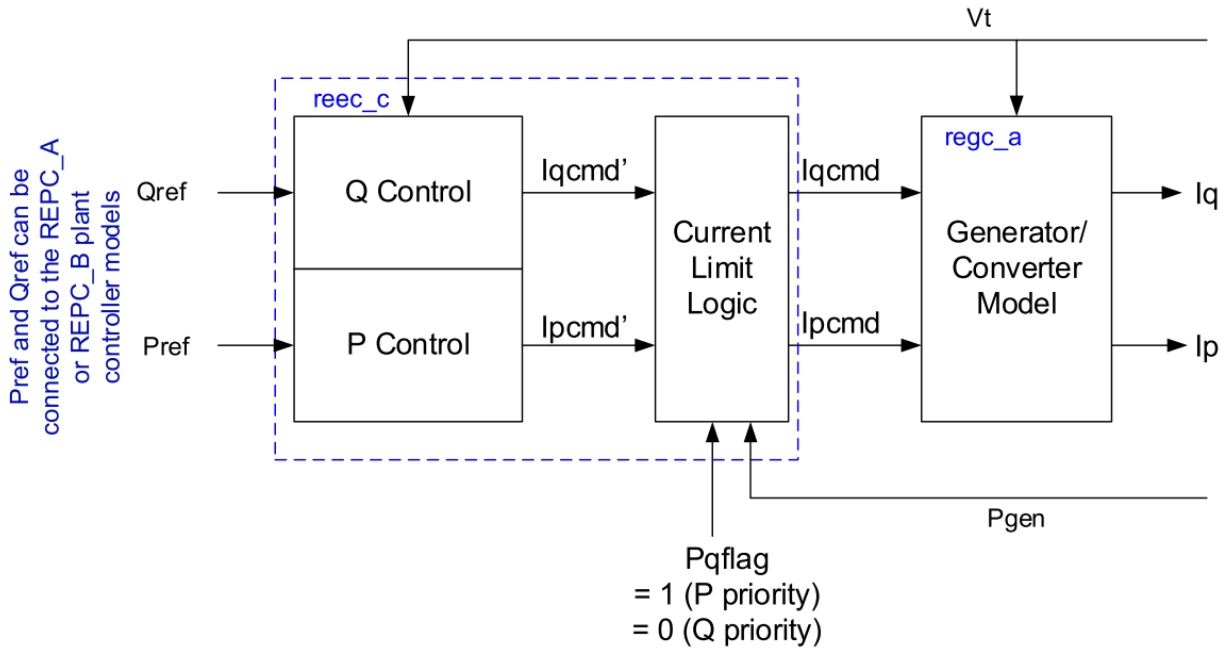



FIGURE 43: MODEL OVERVIEW FOR BESS (POURBEIK P. , 2015)

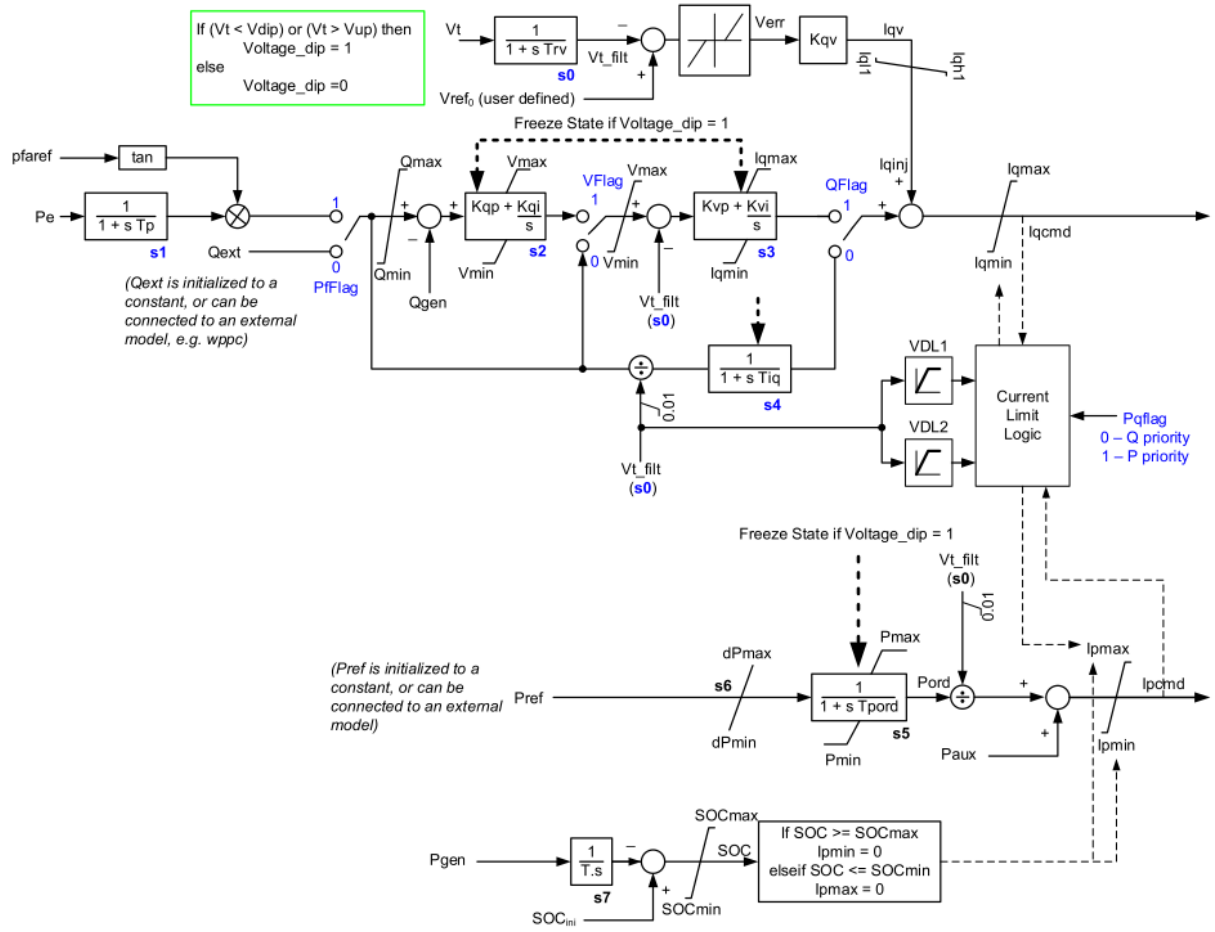



FIGURE 44: ELECTRICAL CONTROLLER FOR BESS, REEC_C (POURBEIK P. , 2015)

#### 3.4.2.2.2 LARGE SCALE SOLAR PV

Large scale solar PV models follow the same general structure as BESS, Figure 45. The plant controller and generator/convertor models are repc_a and regc_a. The electrical control model for large scale solar PV plant is a variation of the general reec_c model. The model used for PV plant is reec_b, the only difference between reec_c model used for BESS and reec_b model used for solar PV is the absence of state of charge loop in the active current command pathway of the control structure.

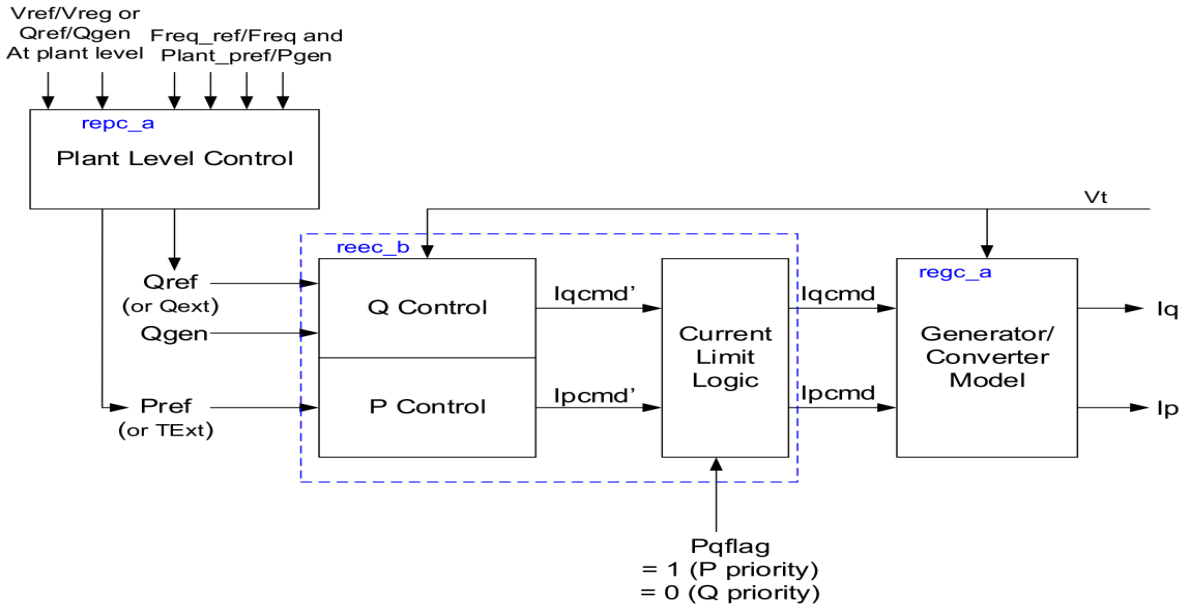



FIGURE 45: OVERVIEW OF LARGE SCALE PV MODEL (POURBEIK P. , 2015)

#### 3.4.2.2.3 TYPE 3 & TYPE 4 WIND TURBINE MODELS

User defined generic templates for Type 3 and Type 4 wind farms are utilised. As opposed to IEC and WECC2 standard models, the UDM provides enhanced flexibility options and entails more functionality. The UDM can mimic a delayed active power recovery response following a voltage dip clearance, akin to the observed response of multiple wind farms on the Ireland and Northern Ireland grid, as shown in Figure 46 below. Additionally the UDMs entail the provision of inertia based FFR in addition to the droop control. The wind farms UDMs have a general structure similar to the WECC models. The main components of the overall model include separate control loops for steady state and fault conditions corresponding to both active and reactive current. Fault detection module, P-Q priority and current limit control modules are incorporated to acquire appropriate active and reactive current commands for the network interface blocks representing the converters. Similar to WECC models, the Type 3 wind farm models contain additional blocks for torque control, pitch control, aerodynamics and drive train to establish appropriate mechanical power. The high level control layout for Type 3 and Type 4 wind UDMs is shown respectively in Figure 47 and Figure 48. Figure 46 shows an example of various types of active power responses configurable with the UDMs in case of a voltage dip.

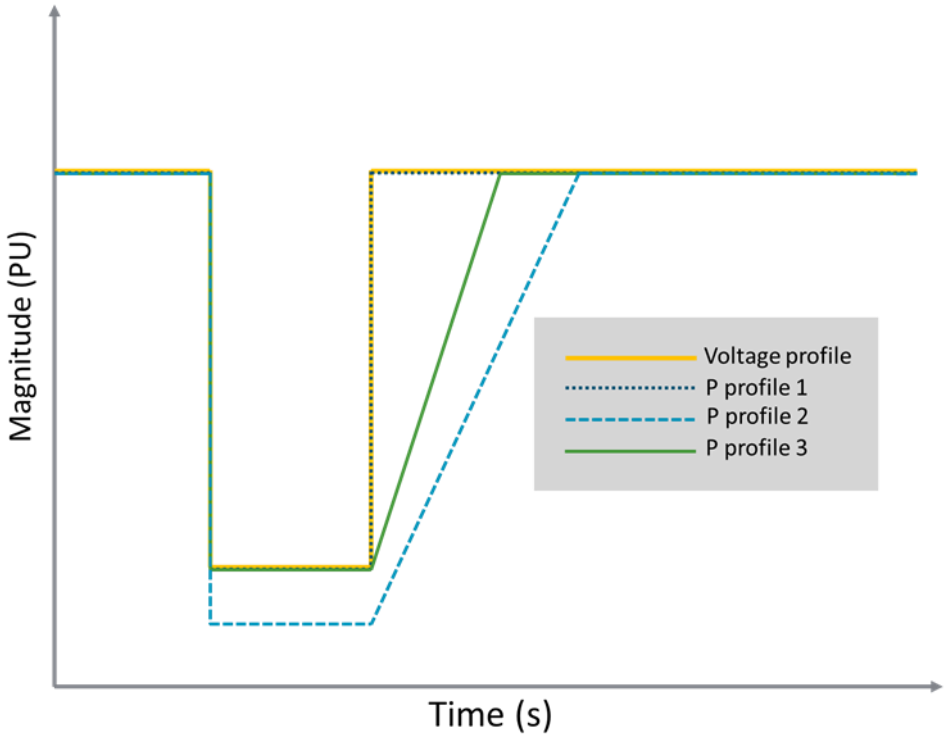



FIGURE 46: ACTIVE POWER OUTPUT VS VOLTAGE DIP

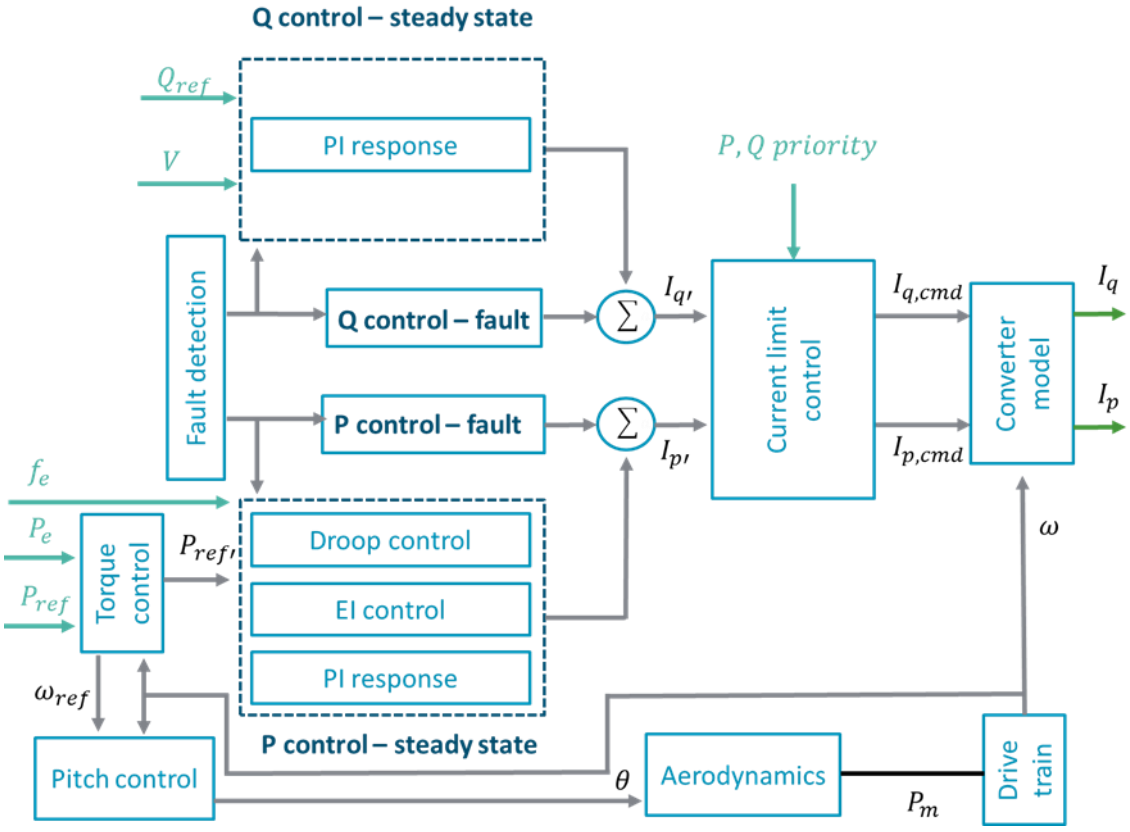



FIGURE 47: TYPE 3 WIND FARM UDM LAYOUT

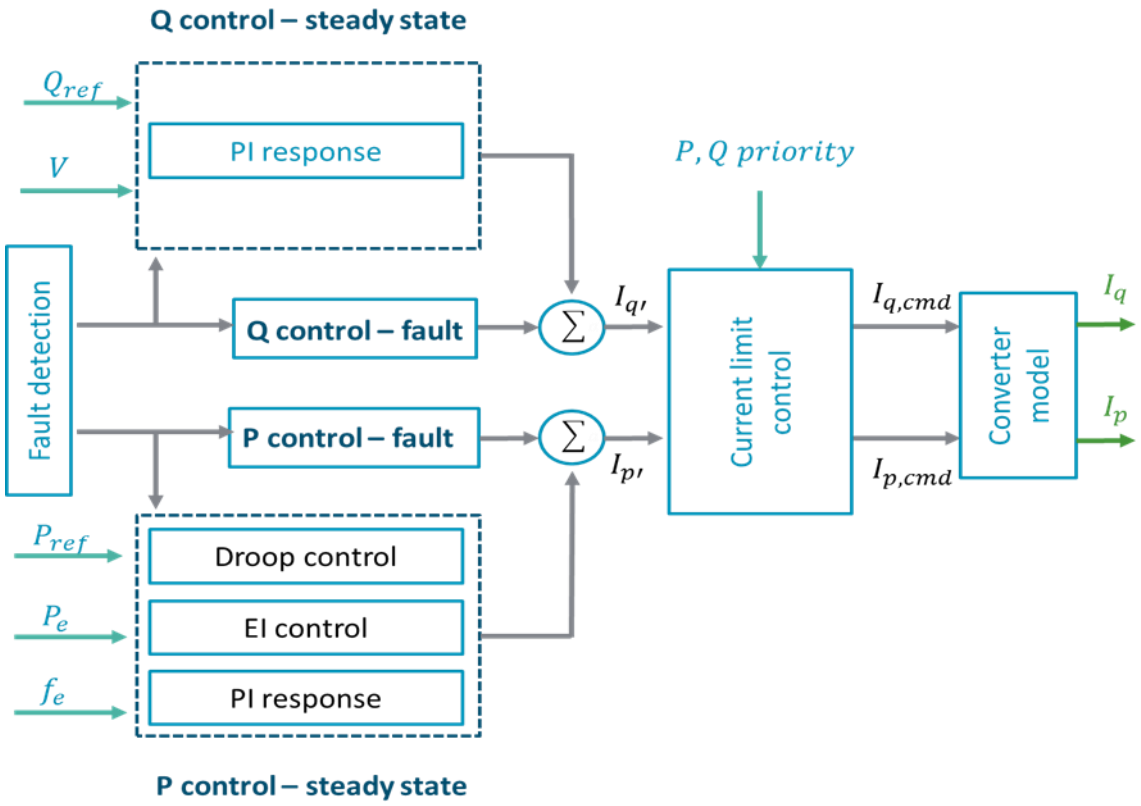



FIGURE 48: TYPE 4 WIND FARM UDM LAYOUT

### 3.4.2.3 HVDC INTERCONNECTOR MODELS

The Ireland and Northern Ireland power system has HVDC interconnections belonging to both major configurations, namely LCC type and VSC type.

The monopole VSC configuration HVDC model is a UDM. The high level control philosophy of the VSC HVDC dynamic model is shown in Figure 49 below:

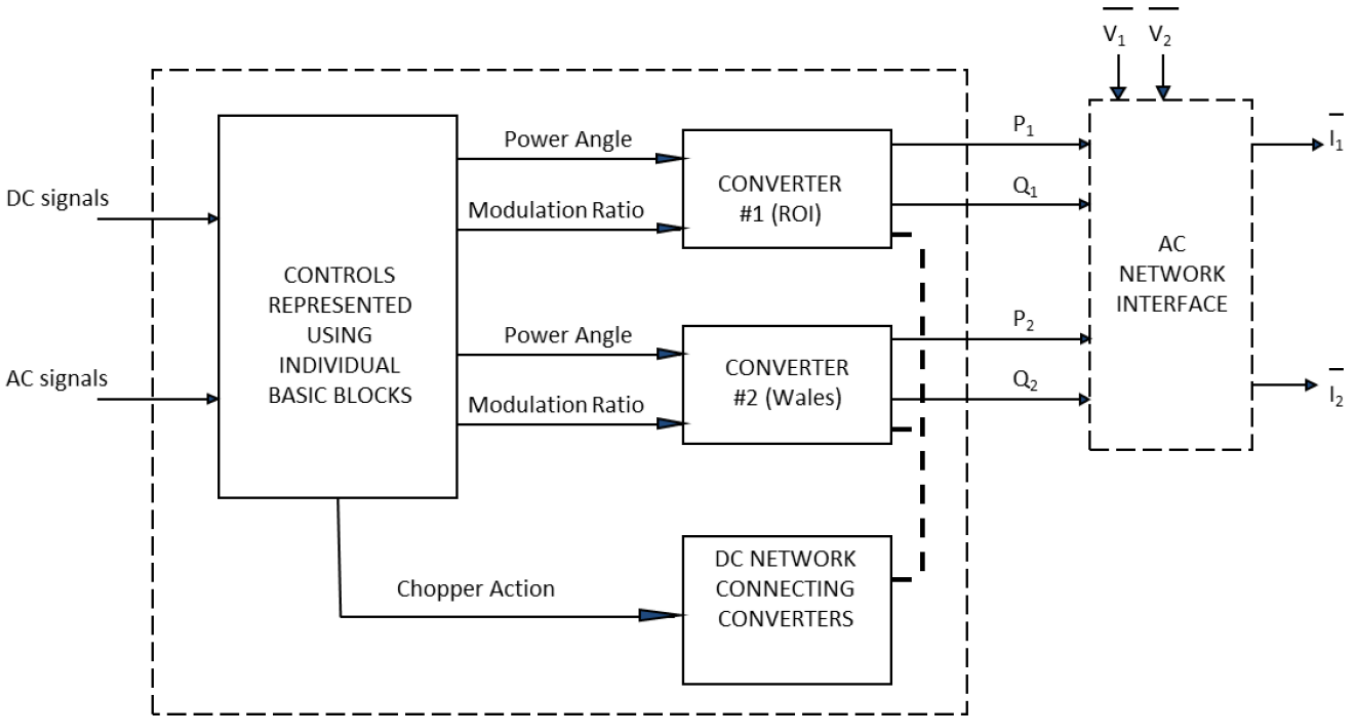



FIGURE 49: VSC HVDC MODEL CONTROL STRUCTURE

The high level control signals usually defined under station controls (CIGRE, 2014), are the control modes and set points. These signals depend on the direction of power flow and system conditions; for example, the rectifier is set to P/Vac control, while the inverter is set to Vdc/Vac control mode (Imhof, 2015). The station control signals control the active and reactive current orders in the control block, resulting in the converter power angle and modulation ratio commands being generated for converter control. Figure 50 shows a representation of such a control block configuration.

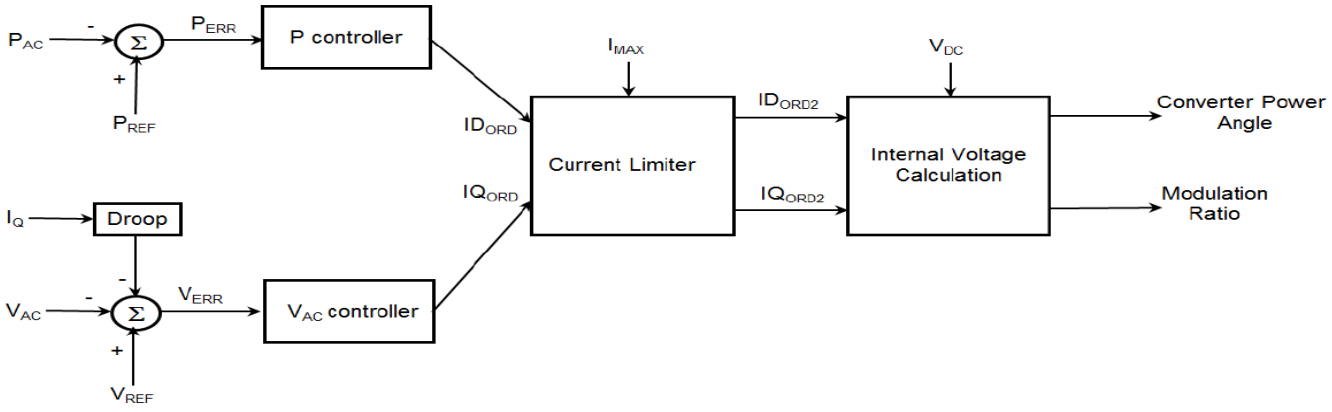



FIGURE 50: CONVERTER CONTROL STRUCTURE

The dynamic model of the voltage source converter allows the internal ac voltage control in both magnitude and angle and injects active and reactive powers into the grid through the network interface elements. The magnitude of active and reactive power generated is linked to the modulation ratio and power angle through algebraic

equations and entails the representation of associated transformer reactance. The station level control signals also include system frequency which is used to provided frequency support in the model, by modulating the interconnector active flows resulting in reserve provision. The model includes DC chopper representation which is used to limit the DC link voltage by dissipating excess energy arising when the inverter is unable to export all of energy flowing through the rectifier, in situations such as AC faults.

The LCC HVDC is a dual monopolar configuration link represented by a user defined positive sequence model. The overarching implementation structure of the LCC HVDC is given in Figure 51 and very similar to the VSC HVDC control structure. The main differences between the two models are the electrical control blocks and the converter implementation. The LCC converter model injects active and reactive power, controlled through varying thyristor firing angles.

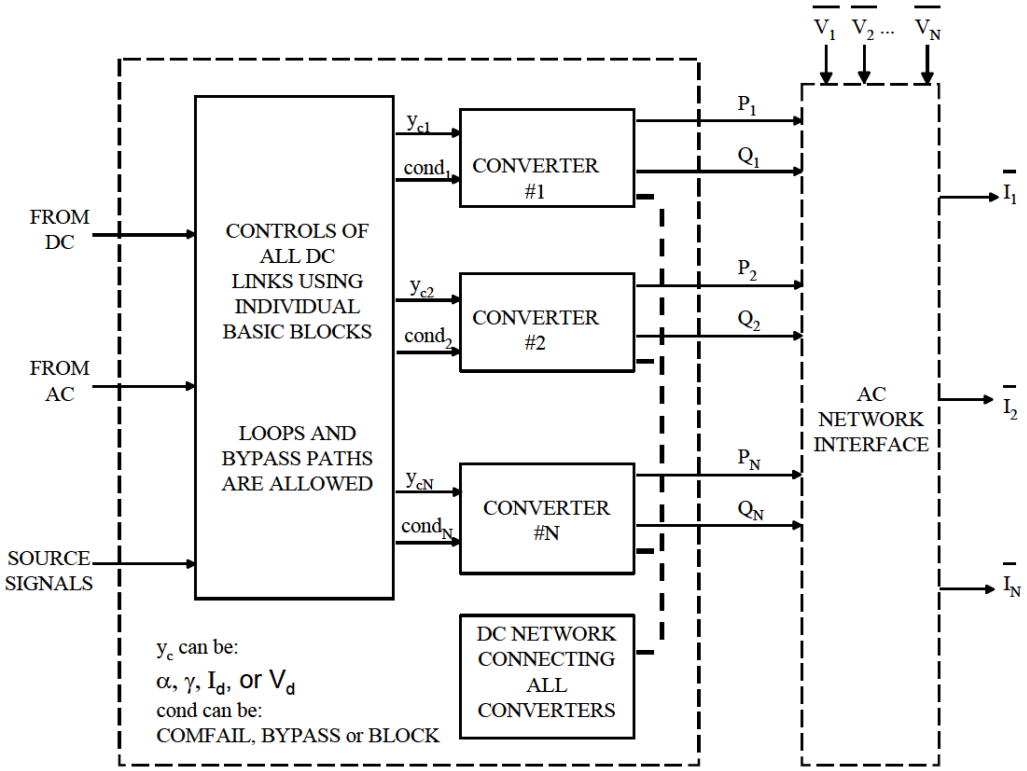



FIGURE 51: OVERVIEW OF LCC HVDC LINK MODEL

The operation of a LCC HVDC is dynamically coordinated across the various converters connected as rectifiers and inverters i.e. poles of the HVDC link. The rectifier pole maintains constant DC current across the link, while the inverter controls the dc voltage with the extinction angle control operating to ensure that minimum extinction angle is not breached. If the rectifier is unable to hold the current at the specified level the inverter abandons the voltage control and takes over the current control. The current margin is subtracted from rectifier's current reference. The choice between various control modes for each converter (current, voltage, extinction angle) determines the utilised control loop in the respective converter control block. Voltage dependent current order limiter is implemented for both the rectifier and inverter blocks in order to avoid instability during the AC network fault and aid in post fault recovery by limiting the reactive power consumption by the converters. Auxiliary

frequency control loop is included to aid in reserve provision in the event of large frequency deviations. The frequency control implementation is shown in Figure 52.

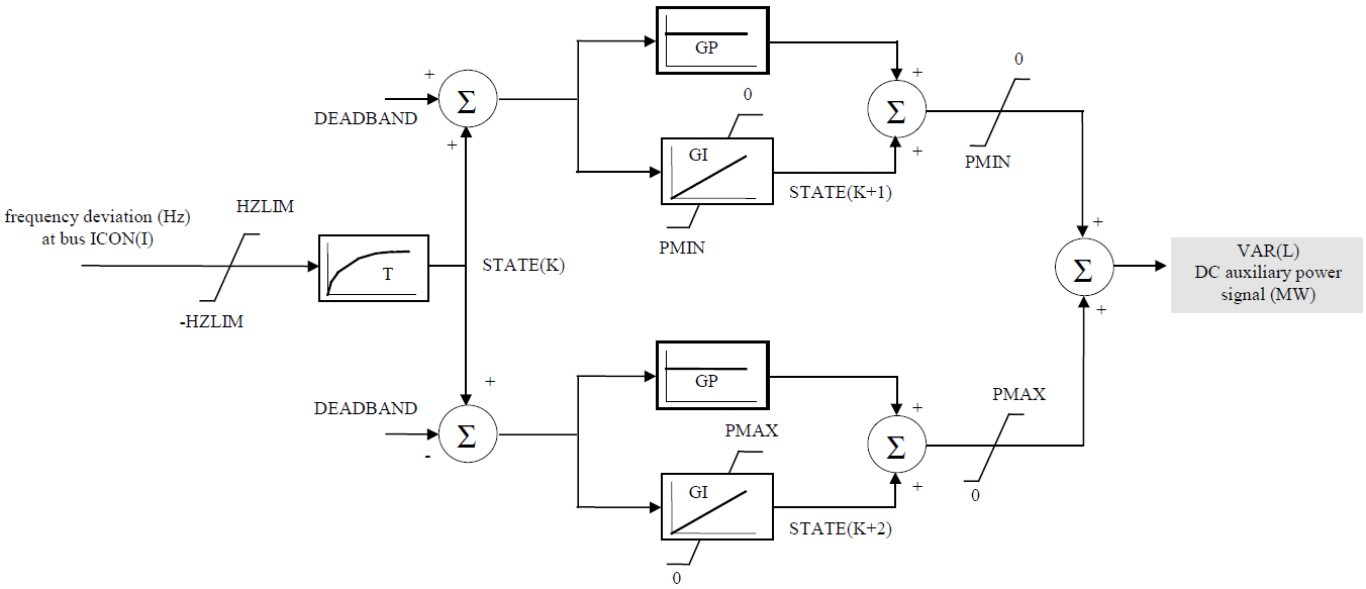



FIGURE 52: FREQUENCY CONTROL IMPLEMENTATION OVERVIEW

### 3.4.2.4 SERIES AND SHUNT COMPENSATION ELEMENTS

The main compensation elements exhibiting dynamic behaviour in the Ireland and Northern Ireland system are:

1) Static Var Compensators (SVC); and
2) Static Synchronous Compensators (STATCOM).

The SVC is a fast responding voltage control shunt device. SVCs are used for improving the voltage profile of a line, increasing power transfer capability and enhancing the steady state and transient stability limits. The SVCs have been modelled using the CSSCS1 generic model. The dynamic model consists of a double lead-lag compensator acting as the primary source of voltage control. In order to introduce damping into the SVC, a signal similar to the PSS signal in the excitation control systems can be added as model input, along with a reference voltage, measured voltage and reference susceptance, as shown in Figure 53. The associated firing delays in the valve control units etc. are represented in the first order lag.

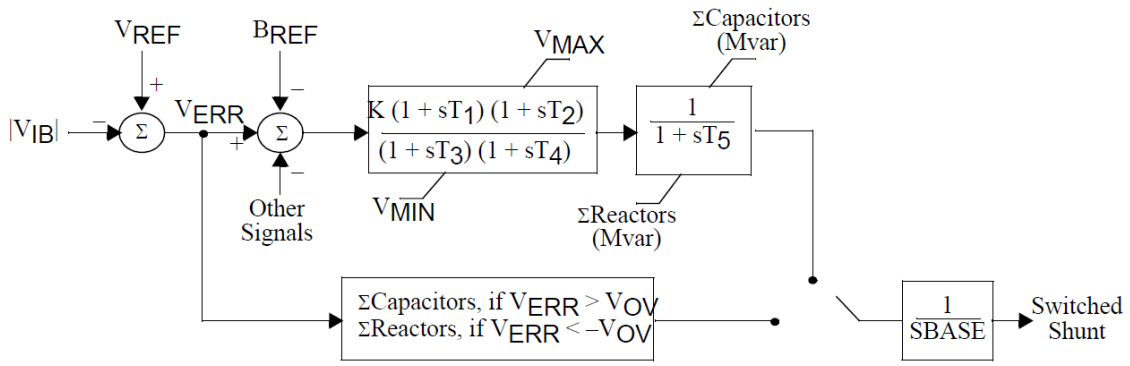



FIGURE 53: CSSCS1 MODEL FOR SVCS (SIEMENS, 2010)

STATCOMs are voltage source based shunt connected devices used to regulate the reactive power balance in the system. The main advantage of STATCOM is the relative voltage independence of the current injection. At the reactive limit, a STATCOM acts as a constant current source, as opposed to a constant susceptance. The model used for STATCOM in dynamic studies is the SVSMO3 generic model. This model consists of a PI regulator behind a first order lag to model the delays associated with firing delays. The bus voltage measurement process is represented by lead lag filter (block s0), an additional lead-lag filter to introduce damping in the system (block s5). There are three mechanisms to control the steady state output of a STATCOM, which can only be used exclusively of one another.

The first of these is a slow susceptance regulator modelled using a PI control loop (block s3), the second is the optional deadband control as can be seen in Figure 54 and the non-linear droop controller through switch flag 2. The short term rating is used to model the limits on the STATCOM current that can be attained temporarily. An over-under voltage tripping function is also implemented, which results in STATCOM switching out for excessive voltage conditions. The mechanically switched shunts (MSS) are also included in the model, along with the corresponding switching logics.

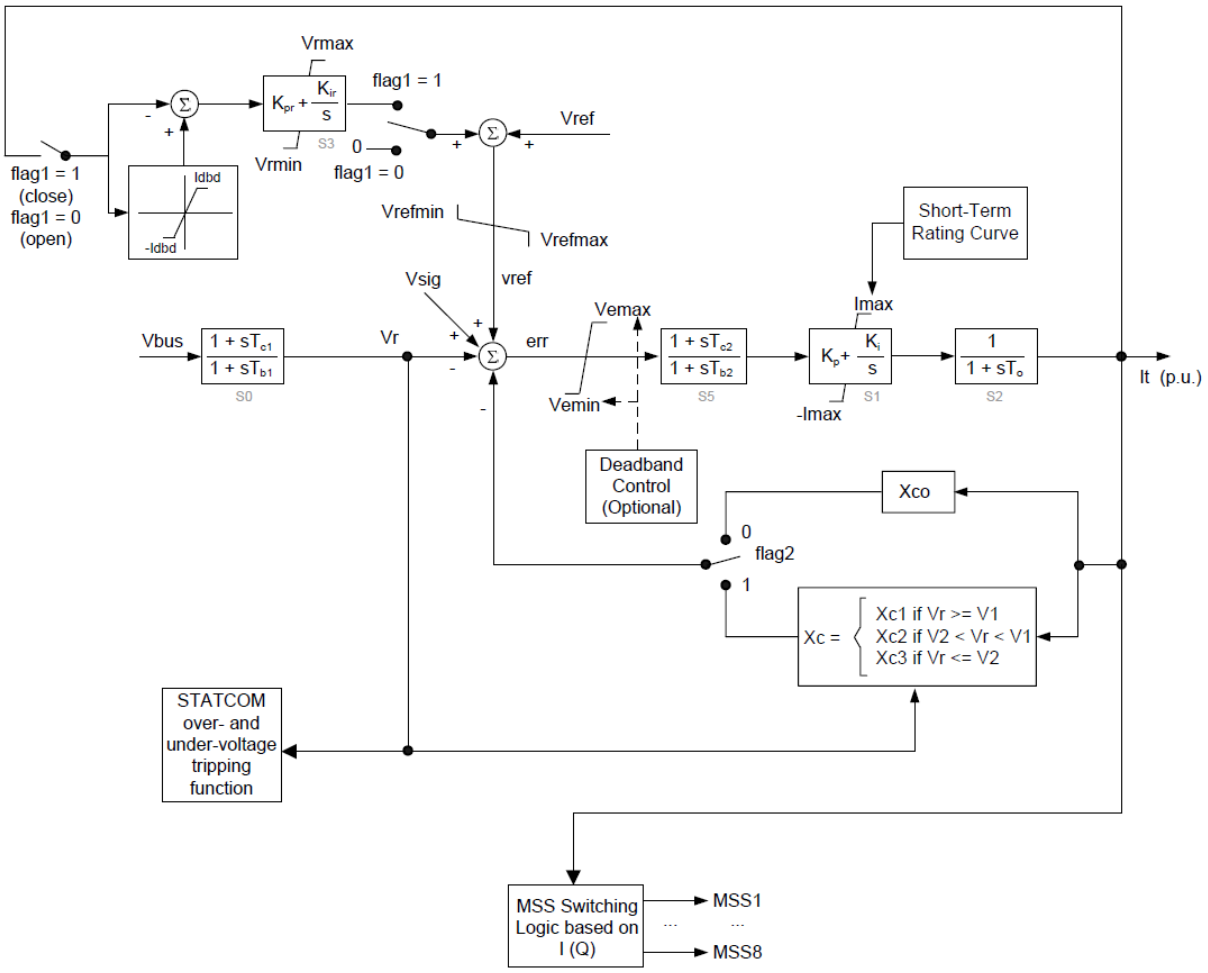



FIGURE 54: GENERIC SVSMO3 MODEL LAYOUT (WECC, 2011)

### 3.4.2.5 LOAD MODELS

There are a number of models detailed in literature for representing the loads in power system stability studies. The load models can generally be categorised into the following:

1) Static load models; and
2) Dynamic load models.

Load models establish the relationship between the active and reactive power consumption of the load and system frequency and voltage encountered. Static load models represent this relationship through algebraic equations, while the dynamic models use differential equations. Both static and dynamic load models can be used for dynamic simulations, and static load models suffice in terms of load representation in dynamic studies if the impact of load dynamics (time dependent responses) is very slow or negligible. Figure 55 shows the subcategories of static and dynamic load models:

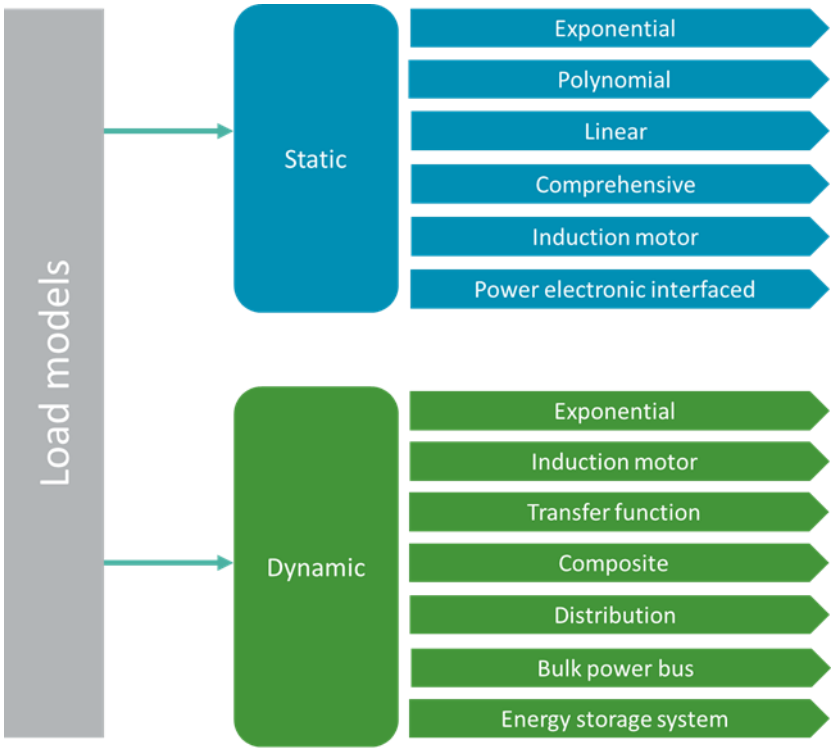



FIGURE 55: LOAD MODEL CATEGORISATION (CIGRE, 2014)

Given the nature of the current and anticipated load in the Ireland and Northern Ireland system and the scope of studies to be conducted in the EU-SysFlex WP2, it is deemed sufficient to represent the load through a static exponential model as follows:

$$P = \frac{P_0}{100}\left[K_{p1}\left(\frac{V}{V_0}\right)^{a_1} + K_{p2}\left(\frac{V}{V_0}\right)^{a_2} + K_{p3}\left(\frac{V}{V_0}\right)^{a_3} + f_p(K_{DLp}, V)\right](1 + K_{pf}\Delta f)$$

$$Q = \frac{Q_0}{100}\left[K_{q1}\left(\frac{V}{V_0}\right)^{b_1} + K_{q2}\left(\frac{V}{V_0}\right)^{b_2} + K_{q3}\left(\frac{V}{V_0}\right)^{b_3} + f_q(K_{DLq}, V)\right](1 + K_{qf}\Delta f)$$

The parameters for the exponents are varied based on the nature of connected load across various buses in the system.

#### 3.4.2.6 DYNAMIC AUTOMATION AND SIMULATION TOOL (DAST)

To enable the required studies to be performed efficiently, EirGrid and SONI have developed a suite of python based tools to automate both the creation and simulation of the required study cases in DSA Tools and the post processing and validation of the study results. This suite of tools is referred to as the Dynamic Automation Simulation Tool (DAST), and an overview of DAST is given in Figure 56.

DAST takes a set of user inputs that specify a study and based upon these it will automatically execute the simulations required for the specified study and return a set of processed result files.

The key functions that are being developed for DAST are:

- Create load flow solutions for each hour of the study year,
- Create study case files that describe the sensitivities to be incorporated in the simulations,
- Create monitor files that specify the results to be stored for each type of study,
- Create contingency files that describe the user specified contingencies to be studied,
- Create dynamic model files that specify the configuration of the dynamic models in the study (e.g. wind turbine models),
- Results analysis – this will combine the results reported by each simulation,
- Diagnostics, input verification and error reporting – these functions will ensure that the inputs provided by the user are valid and report on the execution of the simulations.

These functions will all be controlled from a single user input file, in which the user will specify the study year, sensitivities, contingencies, dynamic model, etc. An essential consideration during the development of DAST is that it be flexible and scalable, which should enable DAST to provide ongoing benefit to EirGrid and SONI post the EU-SysFlex project.

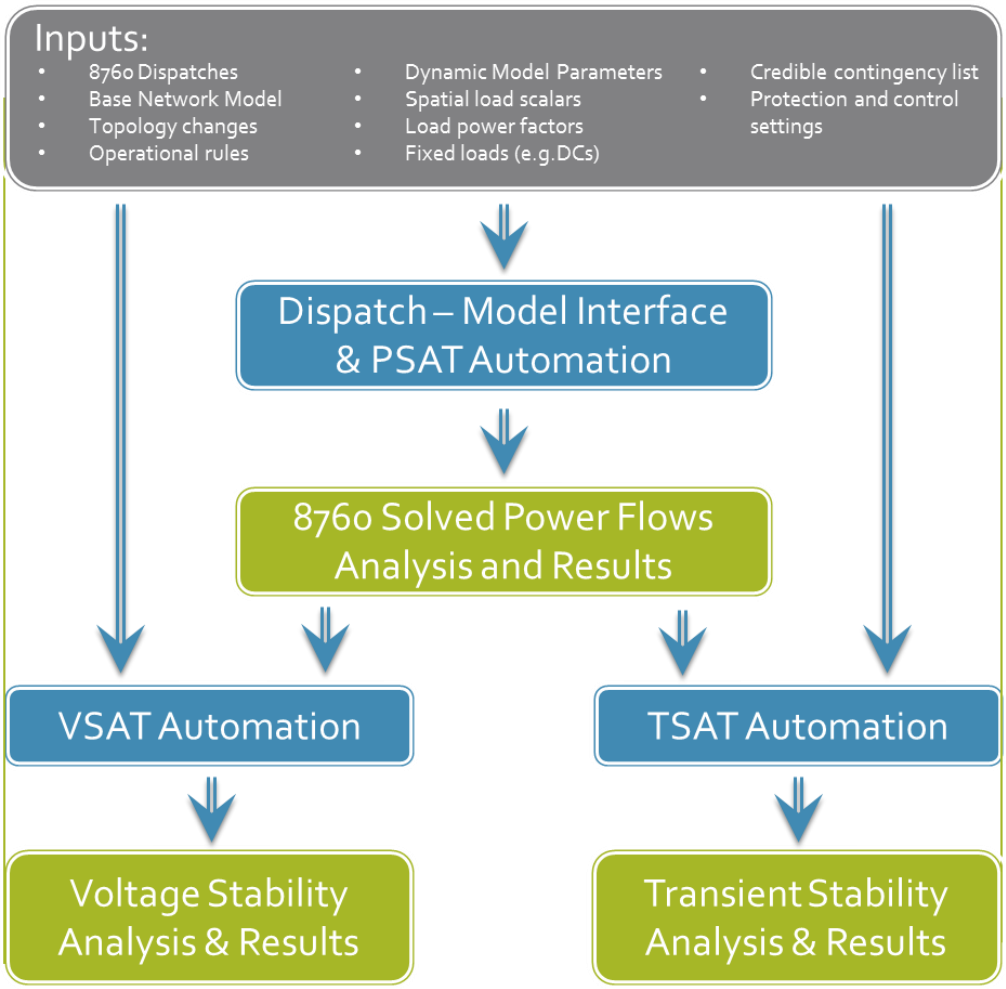



FIGURE 56: OVERVIEW OF DAST

The creation of the load flow files is the first major stage of DAST. To create the set of load flow files specified by the user (e.g. each hour of the study year) DAST requires the following inputs:

- The output of an annual PLEXOS/APE economic dispatch with an individual dispatch for every hour of the year (8760 discrete dispatches);
- Load data for each dispatch (total load and spatial distribution of the load); and
- A base network model.

The dispatch model interface uses this input data to update the base system model so that its loading, topology and dispatch reflect each hour of the year, which creates 8760 modified system models each of which reflects a single hour of the study year. These modified system models are then solved individually to create the power flow results required for further analysis and the power flow files required to perform VSAT and TSAT studies. This solving process is summarised in Figure 57 and the Dispatch – Model Interface is given in Figure 58 Summary of Input Processing in DAST, and entails:

- Applying synchronous generation dispatch (mapping PLEXOS to PSAT);
- Distributing system level wind generation (from PLEXOS) to individual wind generators in PSAT; and
- Converting system MW demand (from PLEXOS) to nodal MW and Mvar demands in PSAT.

To ensure that this process can be completed efficiently, DAST uses parallel processes to create and solve the power flow files. A summary of the execution of the power flow solving component of DAST is given in Figure 57. Much of the functionality in DAST focuses upon performing detailed and accurate diagnostics and error checking to verify that the automated process is functioning correctly. The results are then summarised to make them accessible to the user.

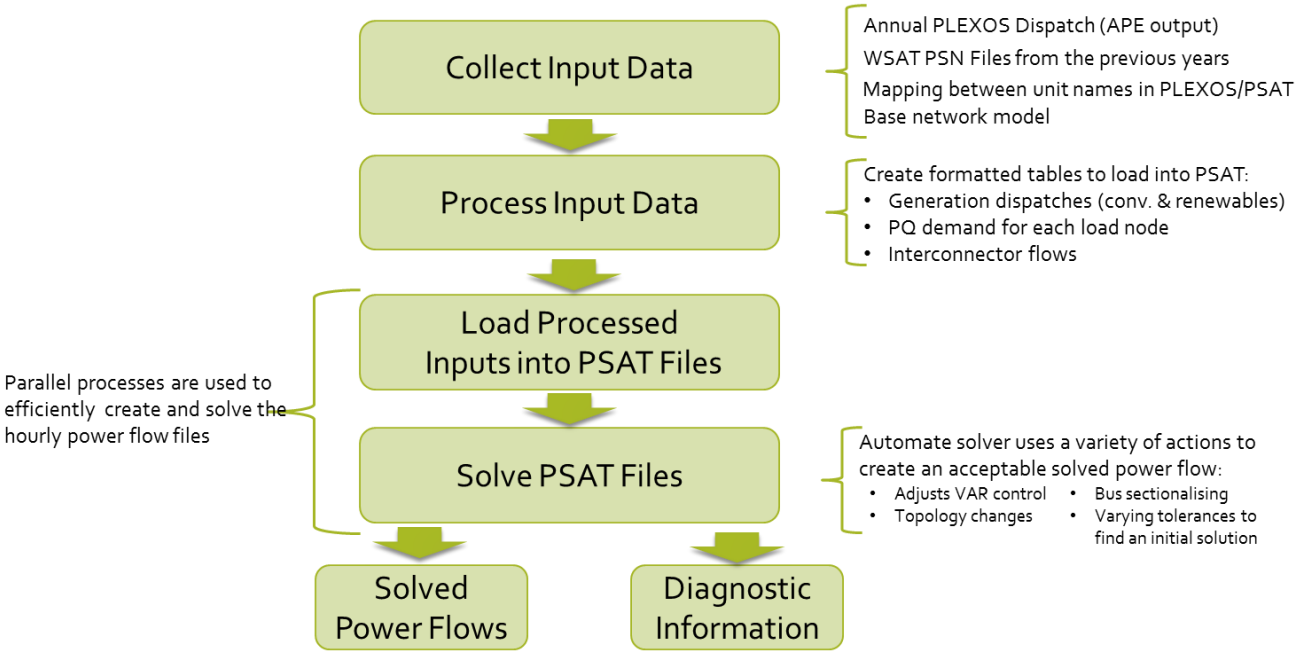



FIGURE 57: SUMMARY OF POWER FLOW SOLVING COMPONENT OF DAST

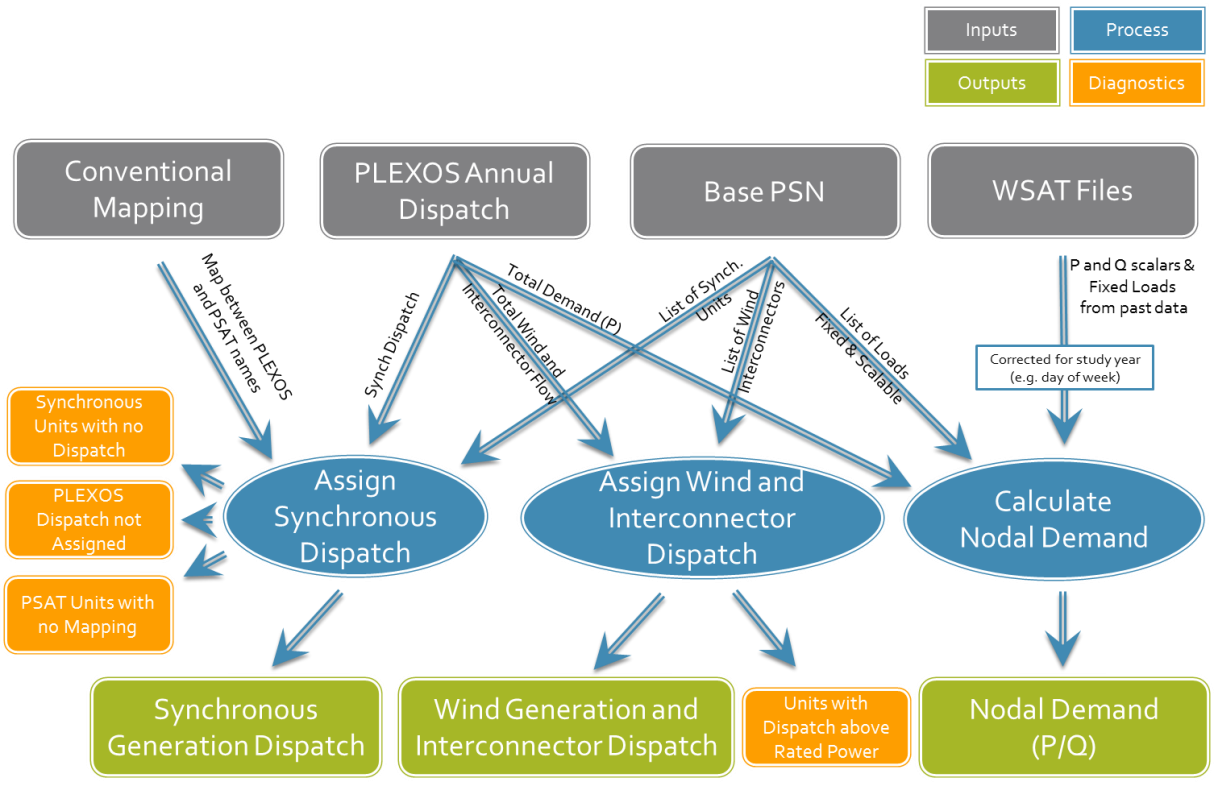



FIGURE 58: SUMMARY OF INPUT PROCESSING IN DAST

### 3.4.3 SINGLE FREQUENCY MODEL

The Single Frequency Model is a single bus model of the Ireland and Northern Ireland power system. The model considers only system frequency dynamics, neglecting the coupling between system voltage and frequency i.e. assuming that the system voltage stays at 1 PU. Due to the speed of simulation, this simplified version of Ireland and Northern Ireland power system is suitable for performing screening studies, selecting cases of interests and analysing the phenomena primarily influenced by the active power dynamics of the system. The model of the Ireland and Northern Ireland power system is a consolidated extension of two basic models previously developed for the Ireland and Northern Ireland systems respectively, with subsequent extensions and improvements. The following assumptions have been made for the model:

- The frequency remains uniform across the system due to the tightly meshed and electrically short system with relatively low impedance between nodes.

- The voltage has a negligible effect on power system balance, with no network representation included in the model. It is assumed that the automatic voltage regulators on the generators maintain steady state system voltages following a contingency. Moreover, the local voltage deviations will occur near the contingency site; however these deviations are a local phenomenon with limited global manifestations (O'Sullivan, 1996).

The model is a single bus system representation based on a feedback loop, whereby the system frequency is calculated based on the active power balance between demand, generation and the stored energy of the rotating masses in the system, as shown in Figure 59. The models have been built in SIMULINK for its flexibility, while MATLAB environment is used for data processing. The frequency measurements from system disturbance events have been used for the validation of the model. With the changing plant portfolio over the years, the augmentation and updating of the model has been carried out. The system model is composed of a number of plant types. The modelling details for individual components are explained in the following sections.

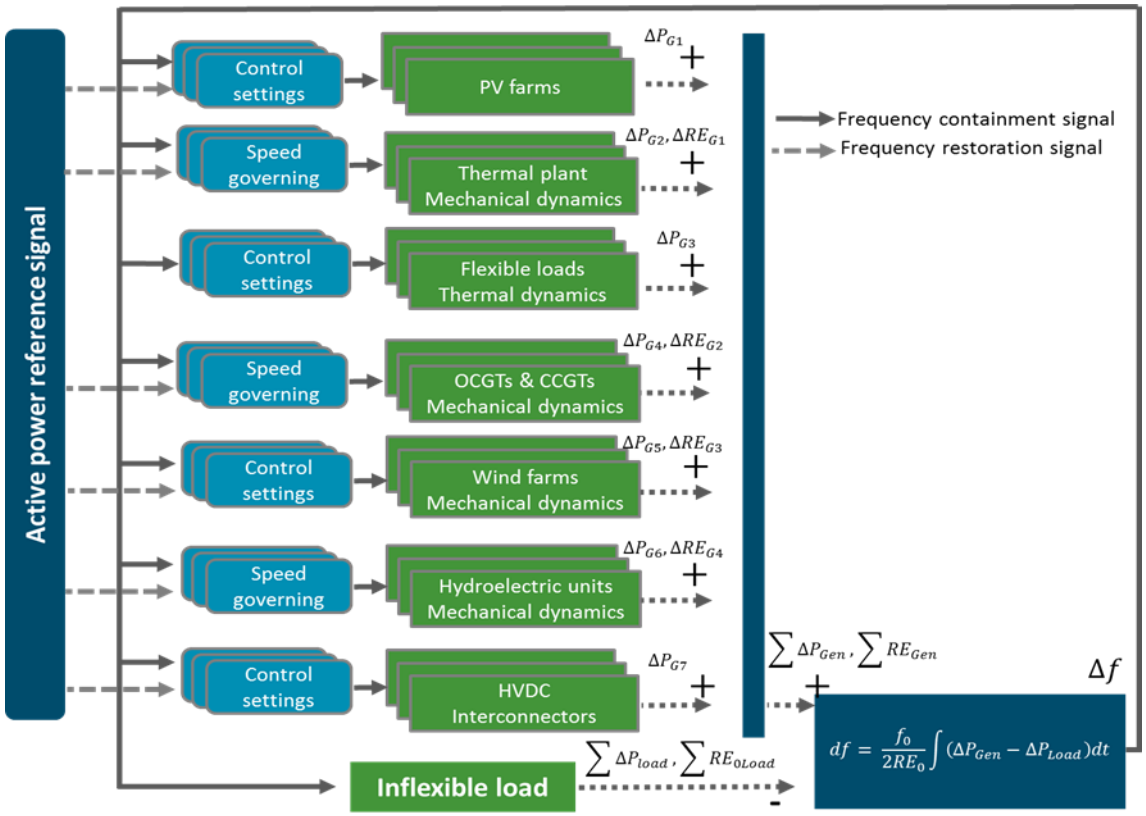



FIGURE 59: OVERVIEW OF SINGLE FREQUENCY MODEL

### 3.4.3.1 CONVENTIONAL GENERATION

Steam units are fossil fuel or nuclear fission based machines. Burning fuel in a furnace generates heat, which is transferred to water in a boiler thereby producing steam, which is subsequently used to drive a steam turbine. The behaviour of a steam turbine in response to a frequency deviation can be modelled by representing speed governor, steam turbine and boiler dynamics as shown in Figure 60. The representation of steam turbine boiler in the model has been adopted from (de Mello, 1991) and (O'Sullivan, 1996). Due to the longer duration of fuel dynamics (20 to 40s) as compared with the timescale of interest, the input heat energy is assumed to be constant. The steam flow entering the turbine determines the power generated in the turbine. The turbine model can represent both reheat and non-reheat turbine systems. The time delays for steam transport from the boiler between all turbine stages, the conversion of steam to rotational energy in all stages and the re-heater are represented. The governor model used for steam turbines is a simplified speed governor (Elgerd, 1982). The control valve signal is proportional to the inverse of the droop while the time delay due to hydraulic action is also considered.

As opposed to steam turbines where steam is the working fluid, in gas turbines, the working fluid is air. The open cycle gas turbines (OCGT) are operated by compressing air and introducing it to a combustion chamber where combustion occurs due to the addition of fuel. The combustion produces gases at high temperature, which enter the turbine stage, converting heat into rotational energy by expanding in various turbine stages. In a combined cycle gas turbine (CCGT), the exhaust gases from gas turbine enter a heat recovery steam generator, to produce

steam which in turn drives a steam turbine, resulting in a combination of an open cycle gas turbine (OCGT) and a steam turbine with a higher combined efficiency. The gas turbines operate based on three control loops, namely acceleration control, speed control and temperature control. The acceleration control is used during start-up and shut-down, and therefore is not required here, since the model investigates the system response following a contingency, assuming the online generators to be in steady state. The outputs from the speed and temperature controllers are fed, into a minimum selector and the smaller of the two signals determines the fuel flow, while the speed controller of an OCGT is a simple droop governor. The OCGT units are represented using a model adapted from (Rowen, 1983) and described in (Lalor, 2005). The OCGT power output is a product of torque and the system speed. The CCGT model developed in (Lalor, 2005) is adopted from (Rowen, 1983) by making reference to (CIGRE, 2003), (IEEE, 1994).

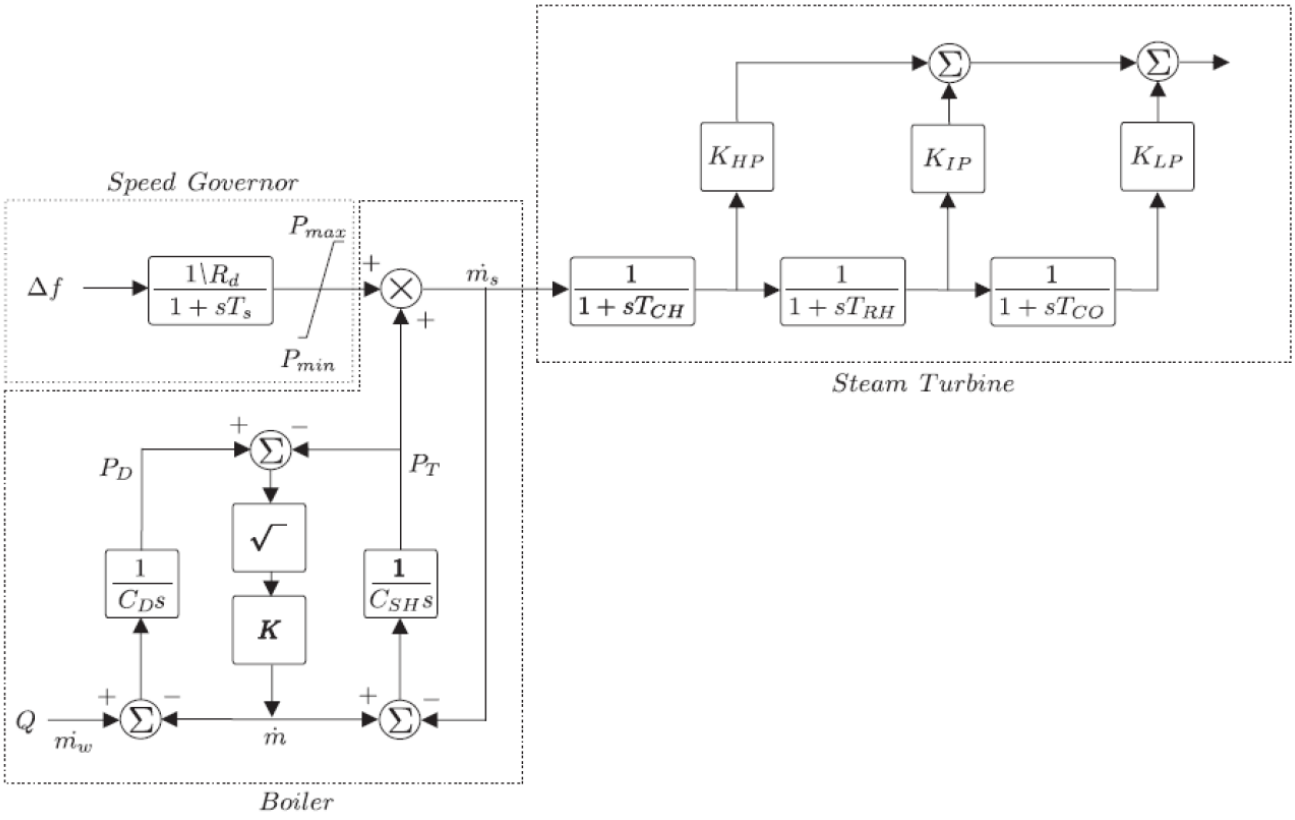



FIGURE 60: STEAM UNIT MODEL

Hydroelectric units on the Ireland and Northern Ireland power system can be classified broadly into the run-of-river hydroelectric generation and pumped storage units. Since the run-of river hydro units on the Ireland and Northern Ireland system typically operate with governors fully open, and so their dynamic contribution consists only of their inertial contribution.

There are 4 pumped hydro units currently operating in the Ireland and Northern Ireland system totalling 292 MW capacity. Each unit can operate in 4 modes:

- Generation: The unit is generating electricity with the operating point somewhere between 30 MW and rated output of 73 MW.

- Minimum generation: The unit is generating electricity with an operating point of around 5 MW at low efficiency, and mainly reserve. In case of a frequency event, the governing valve is opened fully resulting in a rapid increase in generation up to rated power.
- Spin: The turbine runner is rotating in air, with the turbine consuming energy to spin. In case of an event causing the frequency to fall beyond the unit's trigger frequency, water is released through the turbine, with the unit ramping up its power generation rapidly.
- Pump: Water is being pumped between the lower and upper reservoirs. In case of frequency exceeding a pre-allocated threshold, the load is dropped almost instantaneously providing static reserve. The classic linear model described in (Ramey & Skooglund, 1970) has been used to represent the governor dynamics of hydro turbine.

TABLE 14: SINGLE FREQUENCY MODEL COMPONENT OVERVIEW

| Plant type | Generic models used |
|---|---|
| Hydroelectric generation | HYGOV |
| Combined cycle gas turbines (CCGT) | GAST, TGOV1, GGOV1B, HN2GO1, GAST, SINGO1 |
| Open cycle gas turbines (OCGT) | GAST, GAST2A, TGOV1, IEEEG1 |
| Thermal plant | TGOV1, IEESGO, BBGOV1, IEEEG1 |
| Combined heat and power (CHP) | GGOV1B |

#### 3.4.3.2 INTERCONNECTION AND INFLEXIBLE LOAD

The interconnectors have been modelled as combination of discrete blocks of static reserves and dynamic reserves, where if the frequency reaches the allocated thresholds, the interconnectors can increase/decrease import if possible (depending on the maximum/minimum import and dispatch levels). Inflexible load can be defined as the load which does not entail an inherent demand response mechanism such as frequency dependent switching. The system load is a function of both voltage and frequency. Since the prime objective of the model is to perform frequency stability studies, coupled with the fact that the system voltage is assumed constant, only frequency dependence of the load is considered. The load frequency sensitivity is assumed to be 2%/Hz.

#### 3.4.3.3 WIND TURBINES AND PHOTOVOLTAIC PLANT

A discrete number of wind turbine generators operating at various wind speeds are modelled to approximate the wind turbine operating conditions across the system, instead of modelling all individual machines. Flexible speed and variable speed wind turbines are implemented in the model. Doubly fed induction generators are considered to represent variable speed wind turbines, with emulated inertia and droop control, modelled using (Clark et al., 2010). The generator and converters are not modelled, while turbine controls are represented to capture the active power response to frequency deviations. Fixed speed wind turbines are modelled as squirrel cage induction generators, based on (Kennedy et al., 2011). Similar to variable speed turbines, emulated inertia and droop response are modelled with turbine shaft mechanical dynamics considered. Emulated inertia provision capability

from wind turbines has also been modelled, in order to represent the post reserve provision recovery and the associated impacts on system frequency stability. The PV plant have been modelled as an aggregate unit, initialised to a MW value by the dispatch and entailing a variable droop control to provide active power injection corresponding to a frequency deviation.

#### 3.4.3.4 FLEXIBLE LOAD AND BATTERY STORAGE

The battery storage is modelled as a source of frequency reserves governed by a variable droop response curve. The flexible load representing demand responses are modelled as a net positive active power injection, with the total flexible load consisting of both static and dynamic configurations. The static flexible load is considered as a net positive injection into the grid based on a single frequency threshold. The static flexible load has the capability to be distributed into multiple steps with a configurable hysteresis between trip and recovery threshold values. Similarly, the dynamic flexible load is assumed to inject net positive active power akin to a conventional plant droop. In order to represent cold load pick phenomena, the flexible load can be configured to draw increased active power following the provision of reserves.

#### 3.4.3.5 CONNECTING SUB-SYSTEM

The connecting system is based on the fact that a change in the generation-demand balance will result in a corresponding change in the rotational energy of the system. Since the rotational energy is directly proportional to the square of the speed/frequency, a link can be established between the system frequency and the demand generation imbalance, though the system rotational energy. System demand equals generation in the steady state; however in the event of a power imbalance, the system frequency can be calculated as follows:

$$df = \frac{f_0}{2RE_0}\int(\Delta P_{Gen} - \Delta P_{Load})dt$$

Where $RE_0$ is the system rotational energy at nominal frequency $f_0$ with the aggregate system rotational energy is dependent on the inertia constant and apparent power of the units online.

### 3.5 DISTRIBUTION GRIDS GENERIC MODEL – INESC TEC

The last decades have been of considerable transformation for electrical power systems, involving a shift from the centralised and conventional generation view to the large-scale integration of distributed generation (DG) throughout the whole grid. Due to the characteristics of their applications, smaller generation units using RES were also massively connected to lower voltage levels of the grid, at the distribution network, along with other distributed energy resources (DER), such as batteries and electric vehicles. Aiming to fulfil traditional standards for grid security in face of increasing shares of DG integration, system operators have started to require these units to provide services complementary to the energy production role, and somehow in line with those services that were traditionally provided by conventional units.

Issues related with frequency and voltage stability in scenarios with massive DG connection have led to the definition of new grid codes (ENTSO-E, 2016), requiring these units to participate actively in the system regulation. Regarding the requirements for the connection of generation units to the grid, generators have been categorized per type, considering their different sizes and the voltage level at which they are connected. Even smaller units (in the network code referred to as types A and B), connected to lower voltage levels, are now required to provide over-frequency response and even fault ride-through (FRT) capabilities. Table 15 summarises some of the most significant requirements per type.

TABLE 15: EUROPEAN UNION'S GRID CODES REQUIREMENTS SUMMARY FOR GENERATION CONNECTION TO THE GRID

| | | Type A | Type B | Type C | Type D |
|---|---|---|---|---|---|
| Freq. ranges and *ROCOF* limits | | ✓ | ✓ | ✓ | ✓ |
| Limited FSM | Over | ✓ | ✓ | ✓ | ✓ |
| | Under | × | × | ✓ | ✓ |
| Full Frequency Sensitive Mode (FSM) | | × | × | ✓ | ✓ |
| Constant Power Output | | ✓ | ✓ | ✓ | ✓ |
| Remote shutdown | | ✓ | ✓ | *n/a* | *n/a* |
| Remote reduction of active power | | × | ✓ | ✓ | ✓ |
| Set-point control (from TSO) | | × | × | ✓ | ✓ |
| Fault Ride-Through (FRT) capability | | × | ✓ | ✓ | ✓ |
| System restoration capability | | × | ✓ | ✓ | ✓ |
| Control and protections | | × | ✓ | ✓ | ✓ |
| Simulation models | | × | × | ✓ | ✓ |
| Active Power Ramping | | × | × | ✓ | ✓ |
| *Limit for maximum capacity* | | 0.8 MW – 1 MW | 1 MW – 50 MW | 50 MW – 75 MW | > 75 MW |
| *Connection point voltage levels* | | ≤ 110 kV | ≤ 110 kV | ≤ 110 kV | > 110 kV |

This clearly establishes a new and active participation of several units located at the distribution level, influencing not only the behaviour of the distribution system itself, but also its relation with the upstream transmission network. It is evident that, in scenarios with large scale integration of RES in the electric power system, the role that DG units connected to the distribution grid have in the overall system performance, must be taken into account, once it constitutes a significant fraction of the total generated power in a given region (Hatziargyriou et al., 2017).

Considering such rationale, this section is intended to address the development of an equivalent model for the distribution grids for interfacing a substation with the upstream transmission grid. This model should be able to accurately represent the aggregated response of the whole distribution chain. The model conceptualization is generically represented by the following scheme, in Figure 61.

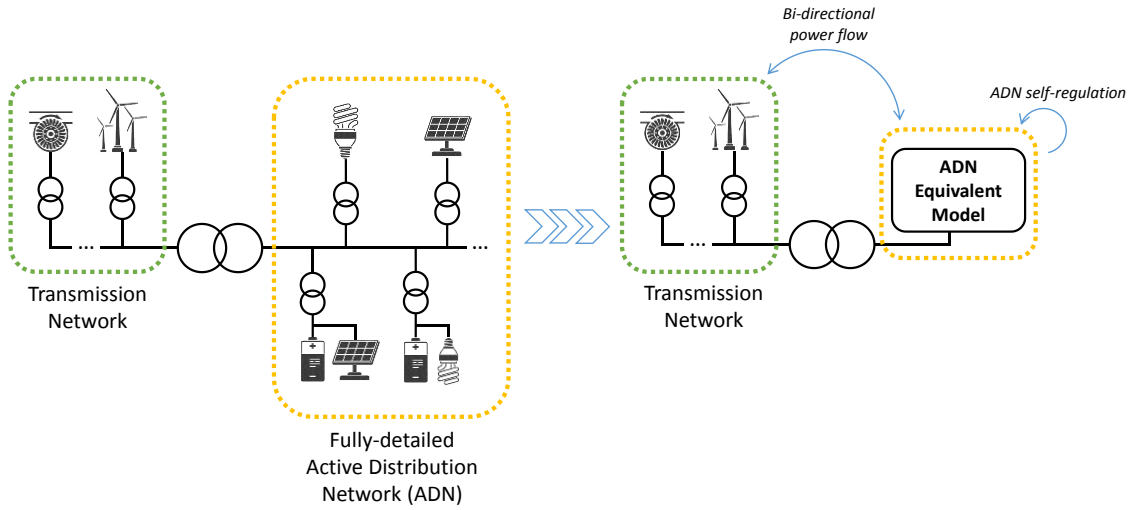



FIGURE 61: ACTIVE DISTRIBUTION NETWORKS GENERIC EQUIVALENT MODELLING APPROACH SCHEME

### 3.5.1 REQUIREMENTS FOR THE MODEL AND AVAILABLE DATA

Typically, in the past, when assessing system stability from the perspective of the TSO, the distribution networks were modelled as passive lumped loads without any dynamic response. The active nature of the distribution grid precludes this approach, requiring new models to be properly derived. However, due to the complexity of this part of the network, detailed information of all its assets and configuration is usually not available. Even if there was enough data to characterise it, a detailed modelling approach would raise computational issues that lead to time-intensive evaluation due to the systems' highly non-linear and complex behaviour. In the literature, some methods to approach the aggregation modelling of electrical grids with the aforementioned characteristics (Resende, 2013) (Kontis, 2017) can be found. Most of them recommend the use of measurement-based strategies and can be categorised as white-box, black-box and grey-box approaches.

White-box strategies require a high level of detail of the system, which is typically not available since distribution networks are very extensive and the complete mathematical characterization of these networks would also represent an immense amount of computational effort; and black-box strategies, which may be interesting due to its complete independence of the need for relevant system information, however these solutions are normally highly case-dependent, not being able to represent an extended range of system configurations and operational states (unless, beforehand, considered in the training process).

For the scenarios under study in the EU-SysFlex project, which envisions very high integration of RES-based generation into the distribution networks which are required to provide certain system services, and using power electronics to connect to the grid; grey-box strategies may be the most suitable approach to this problem, since they exploit a balance between white-box and black-box approaches.

In line with this, the rationale behind the derivation of the model structure was to lump per type every component of the system (and their respective sets of functionalities) that actively contributes to the overall

dynamic response. As soon as the model structure is known, it is then necessary to identify the most adequate parameters that best suit the model's response, in comparison with the detailed system. However, in order to achieve appropriate parametrization for the equivalent model, the complete characterization of the system to be reduced should be assured.

The accuracy of the model, in addition to how wide and flexible it is in terms of operational points' representation, is intrinsically related with the availability of the detailed characterization of the whole system. As previously mentioned, distribution networks are very extensive systems, with numerous components and their respective characteristics; meaning that it is very difficult to efficiently gather the whole data. Alternatively, a typical Portuguese distribution network configuration was used. Details are presented in the following sections.

### 3.5.2 DESCRIPTION OF THE DISTRIBUTION GRID MODEL

Regarding the model structure itself, some considerations on the equivalent configuration had to be accounted for, which are dependent on the countries' networks arrangement, in terms of voltage level. Typical configurations for the distribution network may cover not only the MV level, but also the HV level – for example, in Portugal, HV level in the distribution network starts at 60kV, while in other countries it begins with higher voltages (for instance, at 110kV for Poland). The electrical configuration of each voltage level normally differs: while the MV level of the distribution is generally operated radially downstream to the HV/MV power substation, HV networks may close electrical meshes. These concerns led to the definition of the generic equivalent model structure represented in the following scheme, in Figure 62.

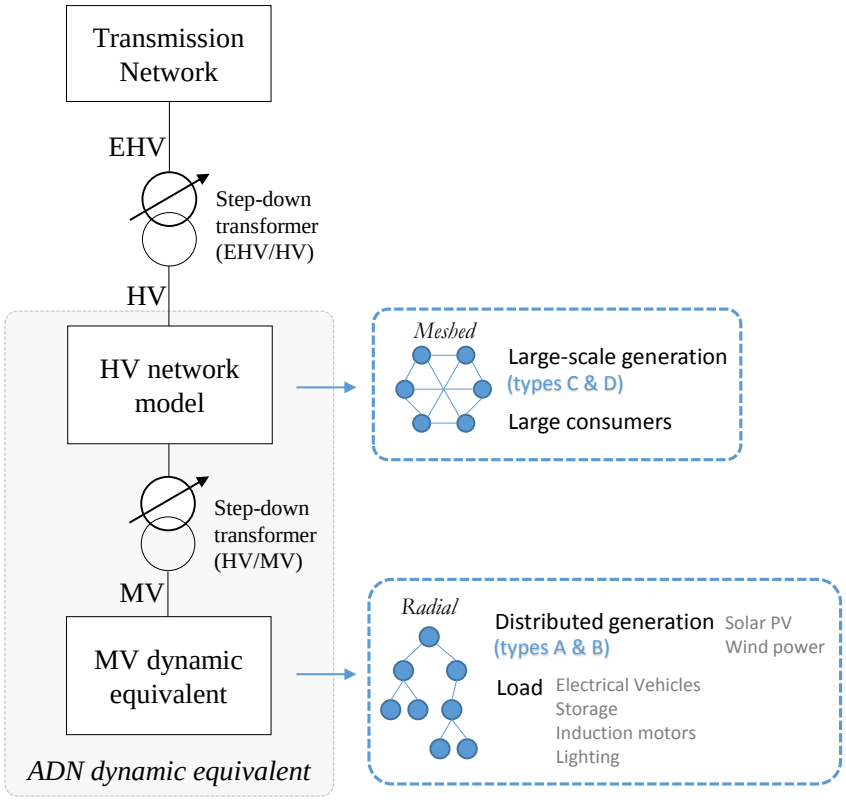



FIGURE 62: OVERVIEW OF THE ADN EQUIVALENT MODEL STRUCTURE

The HV part of the distribution is reserved for large-scale generation facilities (either RES-based converter-interfaced with the grid or synchronous conventional generation), as well as large industrial consumers. Power generation is comprised within types C and D (Table 15), providing system services that include sensitivity to full-range frequency variations as well as fault ride-through. The meshed configuration of this part of the network is very difficult to generalise, for a widely representative equivalent model. Nevertheless, and although the electrical configurations vary significantly depending on the geographical area, these networks have, in Portugal, frequently less than 10 nodes which can close one or two meshes within themselves. Due to the aforementioned lack of detailed characterization of distribution networks, a generic Portuguese HV network was opted to be part of the ADN equivalent model. This network is depicted in the following section.

At the MV level, generation units are mostly interfaced with the grid by power electronics (types A and B), and loads can cover both static types (lighting, heating and other) and dynamic types (motors, compressed air, among other). The consideration of such portfolio led to the proposed modelling strategy, downstream the HV/MV power substation, which assumes:

- an equivalent generation module, composed by a set of two power-converters connected to the same electrical point, lumping two types of generators (with, and without FRT capability – types B and A, respectively); and
- a parallel equivalent load, also composed of two aggregated loads, a static and a dynamic load.

Details on this part of the model are presented in the following sections.

The dynamic equivalent model derivation method also includes the use of a meta-heuristic optimization method for the parameters estimation, by comparing the equivalent structure's response to a fully-detailed system. The model is focused on the aggregated response of the system to voltage-related disturbances, occurring at the transmission level. The model structure, parameters estimation and respective test cases are computed recurring to the software tool of MATLAB®, in coordination with the simulation platform of MATLAB/Simulink®.

#### 3.5.2.1 HV NETWORK MODEL DESCRIPTION

For the HV part of the model, a typical Portuguese distribution network was used. The grid comprises of five buses closing a mesh, as depicted in Figure 63. A 100MVA (220/63 kV) power-substation establishes the connection to the upstream transmission network at bus 1, while 20MVA (63/30 kV) power transformers provide the interface with the MV level, making use of the MV dynamic equivalent model. The network's lines electric characteristics are presented in Table 16.

The idea for this section of the model is to define a closed electrical structure for the HV level, yet allowing some flexibility to the components to be connected to each node. A general schematic of this part of the model is depicted in the following Figure 63.

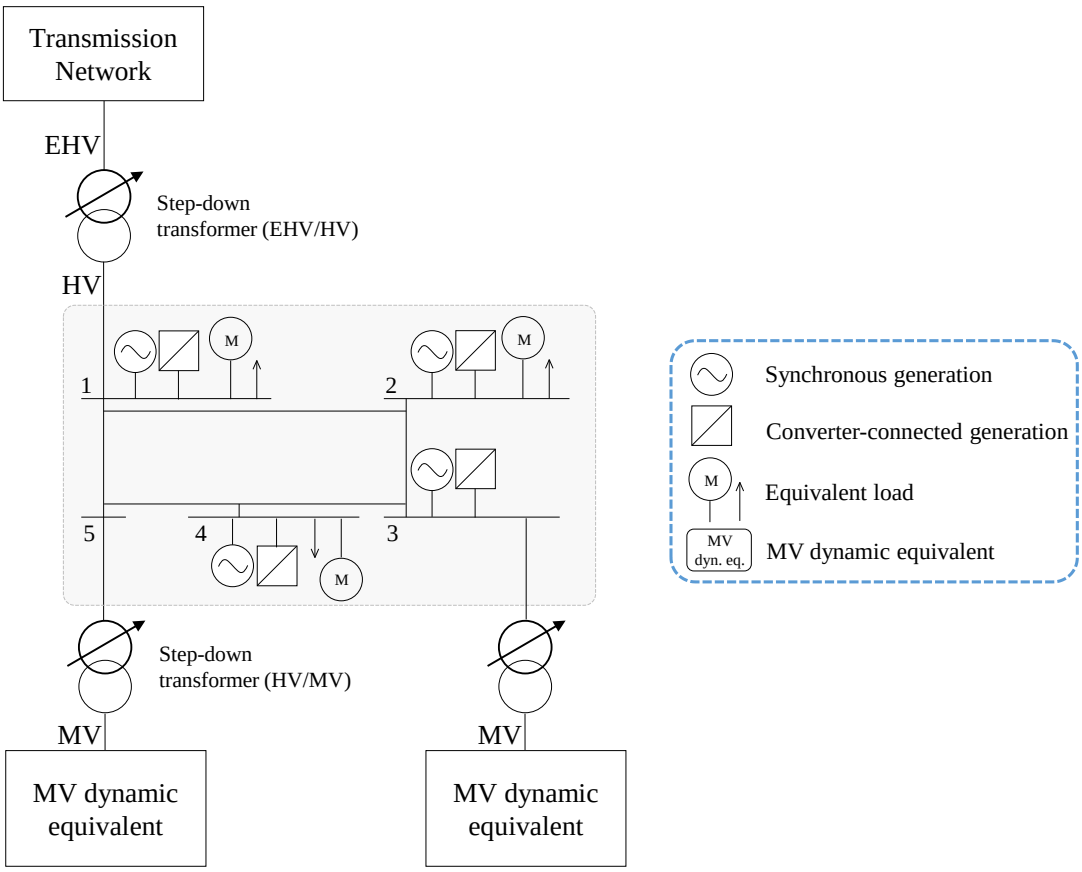



FIGURE 63: ADN EQUIVALENT MODEL FOCUSED ON THE HV LEVEL, USING A TYPICAL PORTUGUESE DIST. NETWORK CONFIGURATION

TABLE 16: HV NETWORK'S LINES CHARACTERISTICS.

| Start Node | End Node | Length (m) | R1 (Ohm) | X1 (Ohm) | C1 (microF) |
|---|---|---|---|---|---|
| Node 1 | Node 2 | 42490 | 4,8761878 | 8,4403641 | 0,764417475 |
| Node 2 | Node 3 | 14011 | 1,6070617 | 2,65438395 | 0,263305921 |
| Node 3 | Node 4 | 4669 | 0,5364681 | 0,88267445 | 0,088155389 |
| Node 4 | Node 5 | 16370 | 3,755278 | 6,284443 | 0,15070078 |
| Node 5 | Node 1 | 45352 | 5,351536 | 16,8618736 | 0,444145923 |

Although the fixed structure of the HV level may be restrictive for a wide representation of other HV distribution networks, it is believed to be representative of the HV levels for the Portuguese case. To each node of the HV network, the model may be completed with the connection of four different main components:

- Conventional, large-scale, synchronous generation;
- RES-based generation units, using electronic converters to perform the connection to the grid;
- Equivalent (passive) load, for power consumption representation; and
- MV dynamic equivalent model (explained in detail in the following section).

This approach allows the user to perform a qualitative analysis of the system aimed to be reduced, evaluating the type of generation and load present in the network – either connected directly to the HV level, or downstream to the power substations – and further define the share of each type at each of the HV network corresponding nodes. The model is hence flexible, in terms of global distribution network characterization.

The conventional synchronous generation connected at the HV level was assured by recurring to a generic three-phase salient-pole synchronous generator model available on the MATLAB/Simulink® model library. The mechanical part of the machine is represented by the swing equation whereas the electrical part is represented by a sixth-order state space model, taking into account the dynamics of the stator, field and damper windings. Reactive power control is achieved by a proportional/integrator controller of type II, by acting on the generator's field voltage recurring to a type AC4A excitation model. Both models are described in this document (IEEE, 2006). The equivalent load was represented by a composite load model, as used in the MV level equivalent. Modelling details are depicted in the following sections. Also, the power converter based RES units were modelled using the same model presented in the following sections. For fast transients, no mechanical (primary source) models are used, assuming that these units are always available for power injection, upon the period under study. Only their electric/electronic interface with the grid is then modelled. Finally, the MV dynamic equivalent model, which can be connected to each of the HV network nodes, is presented and explained in detail in the following section.

#### 3.5.2.2 EQUIVALENT MODEL STRUCTURE FOR THE MV NETWORK

The aforementioned considerations led to the generic dynamic equivalent model structure for the MV level, depicted in the Figure 64. In this part of the model, the idea was to connect, in parallel, each type of components that contribute dynamically to the behaviour of the system, by lumping each of their coherent behaviour. To do

so, the model includes two main groups: equivalent load and equivalent generation. Each of these components are connected to the point of equivalency through an equivalent impedance ($Z_{Load}$, $Z_{Gen_1}$ and $Z_{Gen_2}$) to emulate the voltage drop along the feeders.

The following subchapters depict in detail each section of the system.

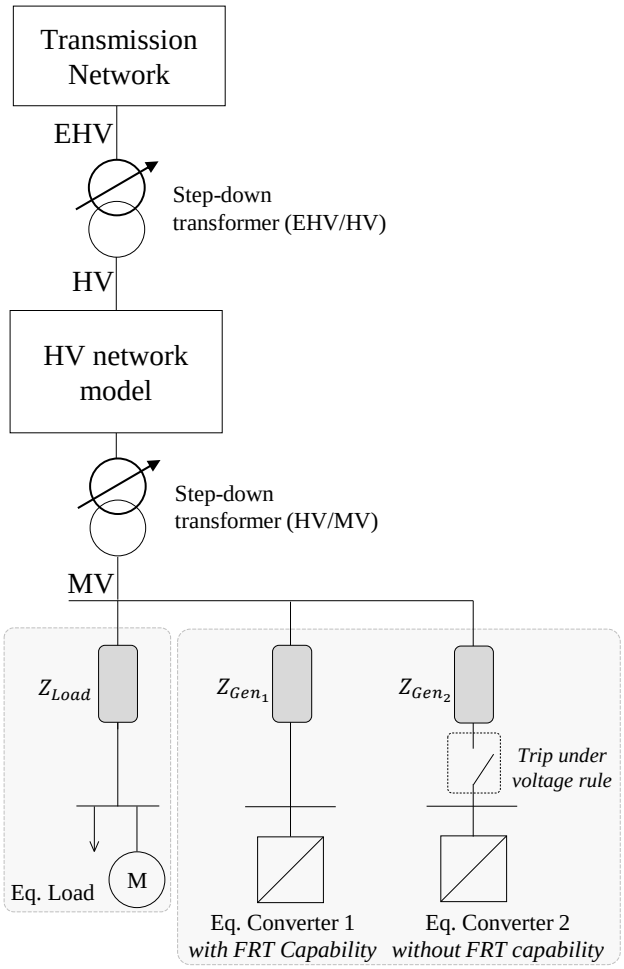



FIGURE 64: DYNAMIC EQUIVALENT MODEL FOR ADN REPRESENTATION

#### 3.5.2.2.1 EQUIVALENT LOAD MODEL

The equivalent load model is segregated into two types, considering a static and a dynamic (motor) load, connected in parallel. The use of these two representations is intended to represent the dynamic behaviour of some of the industrial and service sectors types of loads, covering heating and lighting loads for the static type, and motors for cooling/ventilation, compressed air, refrigeration and industrial appliances for the dynamic type.

The static load is represented by an exponential model of a dynamic load, where the active and reactive power consumed varies exponentially (with $n_p$ and $n_q$, respectively) as a function of the voltage, according to the following equations:

$$P(V) = P_0 \left(\frac{V}{V_0}\right)^{n_p} \quad (1)$$

$$Q(V) = Q_0 \left(\frac{V}{V_0}\right)^{n_q} \quad (2)$$

In these functions, $P_0$ and $Q_0$ are the initial active and reactive power of the model, $V$ and $V_0$ are the measured and initial voltages.

To represent the dynamic load part, a state-of-the-art representation of a three-phase asynchronous machine (squirrel cage), modelled in a dq rotor reference frame was implemented, relying on the generic model available in the MATLAB/Simulink® block library. Besides its nominal power, the model is reparametrized using the stator and rotor's resistances and leakage inductances ($R_s$, $L_{l_s}$, $R_r'$ and $L_{l_r}'$, in p.u.), as well as its mutual inductance ($L_m$, also in p.u.) and inertia constant ($H$, in seconds).

#### 3.5.2.2.2 EQUIVALENT CONVERTER MODEL

As a result of the previously depicted conditions, and particularly for the generation portfolio accounted for this voltage level, the design of the equivalent generation model has been performed in order to accommodate the FRT capability, in line with the most recent grid codes' requirements. Although most units are expected to comply with the FRT requirements in the near future, some units (those connected to the grid in the past) may not yet be able to provide this service. In case of severe short-circuits and consequent deep voltage sags, some units may trip along the feeders, justifying accounting for their dynamic impact in the distribution system combined behaviour. Because of that, as depicted in Figure 65, the equivalent generation is represented by two equivalent converters, the ones with – and the ones without – FRT capability.

The consideration of only converter-connected units in the grid led to the development of a generic equivalent converter, focusing the modelling on the embedded control and the grid-interconnection, and discarding the primary sources' electro- or electro-mechanical interactions. The model is based on a state-of-the-art representation, implemented in the *dq* reference frame, enabling decoupled control over the active and reactive components of the current. The block diagram presented in Figure 65 depicts its mathematical implementation, where it is possible to observe the inner current control loops and the outer active and reactive power settings definition.

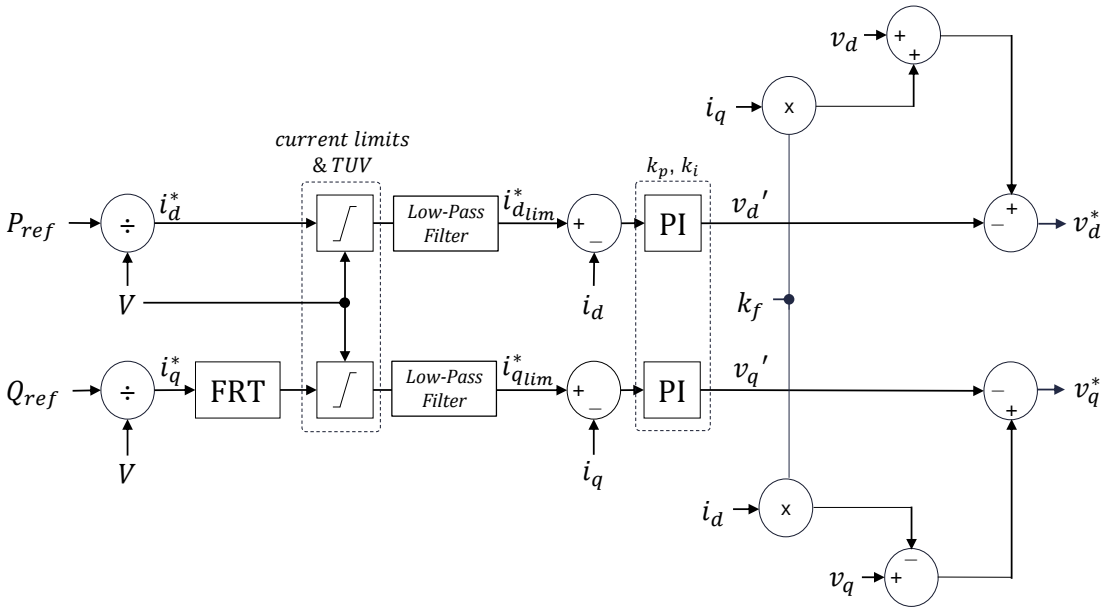



FIGURE 65: EQUIVALENT CONVERTER MODEL STRUCTURE

The inner current control acts separately on the active and reactive components of the current ($i_d$ and $i_q$) by means of a proportional and integral (PI) control – control gains were considered to be constant ($k_p = 0.5, k_i = 10$, and a feedforward decoupling gain, $k_f = 0.2$). The desired current ($i_d^*$ and $i_q^*$) is computed according to the power set-points ($P_{ref}$ and $Q_{ref}$) as a function of the measured voltage ($V$). In order to maintain the maximum admissible current ($i_{max}$), the reference current components ($i_d^{lim}$ and $i_q^{lim}$) are limited according to the following rationale.

#### *3.5.2.2.2.1* ACTIVE AND REACTIVE CURRENT LIMITS:

To provide support on the grid's voltage in case of voltage dips, the unit may be requested to significantly change its reactive power level, when voltage reaches low values. In cases this occurs, and while maintaining its maximum current ($i_{abs}$) within limits, it is given priority to the reactive current increase, by decreasing the active component, according to the following:

**If** $i_{abs} < i_{max}$

**If** $V < V_2$ (see Figure 66)

$$i_q^{lim} = i_q^*, i_q^* \leq i_{max} \quad (3)$$

$$i_d^{lim} = \sqrt{i_{max}^2 - i_q^{*2}} \quad (4)$$

**Else**: $i_q^{lim} = i_{max} \sin\theta \; AND \; i_d^{lim} = i_{max} \cos\theta$ (5)

**Else**: $i_q^{lim} = i_{abs} \sin\theta \;\; AND \;\; i_d^{lim} = i_{abs} \cos\theta$ (6)

With $i_{abs} = \sqrt{i_d^2 + i_q^2}$, and $\theta = \arctan\left(\frac{i_q^*}{i_d^*}\right)$. The resultant active and reactive components of the current are also limited by a low-pass filter – 1st-order transfer function with a 10ms time constant – in order to damp extremely fast (and physically unfeasible) set-point changes.

#### *3.5.2.2.2.2* FAULT RIDE-THROUGH (FRT) AND TRIP UNDER-VOLTAGE (TUV) RULE:

The injection of reactive current, upon significant low voltage values in fault operation is achieved by applying the characteristic curve presented in Figure 66. The parameters for the curve were set beforehand, leaving the maximum reactive current set-point ($i_{q_{max}}^*$) available for re-parametrization upon the equivalent model tuning, for the respective voltages steps ($V_0, \dots V_5$). For the purposes of this work, and considering voltage disturbances with a duration in the range of 150ms, a simplified rectangular voltage-versus-time FRT curve was considered. However, a simple TUV rule was implemented for both equivalent converters 1 and 2 (Figure 64), considering these would trip if the minimum voltage threshold was violated, respectively, at $V_{TUV_1} = 0.1\ p.u.$ and $V_{TUV_2} = 0.85\ p.u.$. The forced unit disconnection was achieved by setting $i_{max}$ to zero.

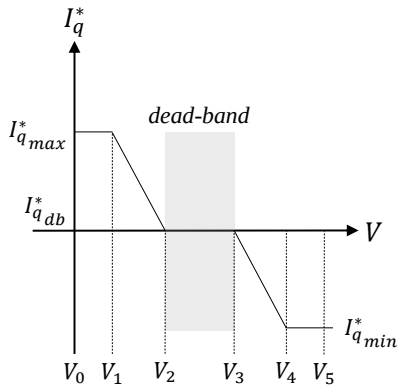



FIGURE 66: VOLTAGE TO REACTIVE CURRENT INJECTION CHARACTERISTIC CURVE

#### 3.5.2.2.3 EQUIVALENT IMPEDANCE

The integration of the expected voltage drop along the feeders was modelled by a classic π-section line. In line with the approach for the other parts of the models, it was considered one equivalent impedance per each component of the model. The model receives an equivalent resistance, inductance and capacitance (R, L and C), as well as its length. The adjustment of these variables was considered for the equivalent derivation.

### 3.5.2.3 METHOD FOR PARAMETERS IDENTIFICATION

Subsequent to the definition of the model structure, it was implemented a methodology for the model's parameters estimation. The idea is to apply the same disturbances to the detailed and the equivalent models, evaluate and compare their dynamic responses at the point of equivalency, and finally re-parametrize the equivalent model to reduce the error between them. In this sense, the equivalent should be initially trained for a given system within a set of conditions, and afterwards, tested in similar conditions. This process should endow the dynamic equivalent with the ability of properly representing untrained operational conditions. Besides its

representativeness facing trained operational conditions, the model's robustness for cases inter/extrapolation is of upmost importance. The estimation is based on measurements of the active and reactive power flow read immediately downstream to the transmission/distribution interface power substation, as illustrated in Figure 67.

In order to achieve an agreement between the two models' responses, an evolutionary particle swarm optimization (EPSO) algorithm was used. As a PSO variant, the EPSO algorithm is a meta-heuristic method that exploits, additionally to the PSO, a self-adaptive mechanism that explicitly evolves its weights of movement (inertia, memory and cooperation) for better performances. Details on the method can be found in this document (Miranda, 2002).

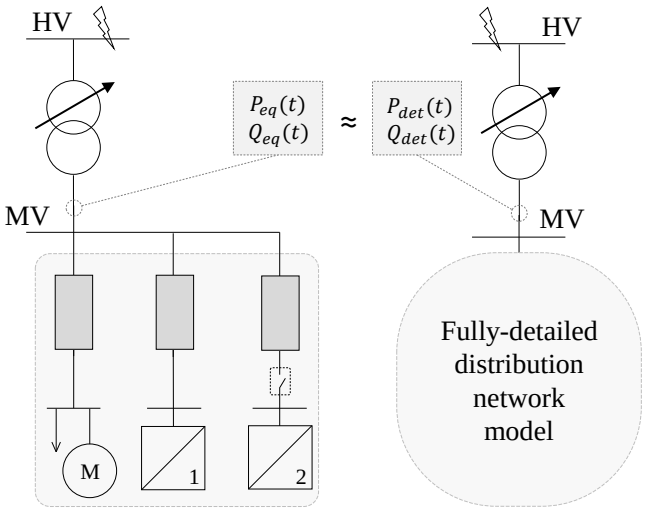



FIGURE 67: SCHEMATIC FOR THE DETAILED VS EQUIVALENT IMPLEMENTED APPROACH

Generically, the algorithm is structured according to the following steps, at a given iteration, while considering a set of solutions (particles): replication, mutation, reproduction, evaluation and selection. The evolutionary principle of "survival of the fittest" prevails, leading eventually to a close-to-optimum solution. Also, for improved robustness, when assessing the solutions' fitness, the evaluation process considered the accumulated error of several disturbances, instead of one disturbance only, aiming for a *best-fits-all* solution.

The problem formulation can be translated by the following equations, for a number of disturbances under study ($nr_{dist}$), at the $i^{th}$ disturbance:

$$\text{Min: } \epsilon_{FFT}(\theta) = \epsilon_{FFT}{}_P^2(\theta) + \epsilon_{FFT}{}_Q^2(\theta) \qquad (7)$$

With:

$$\epsilon_{FFT\,P}(\theta) = \sum_i^{nr_{dist}} P_{eq}{}_{FFT}(\theta, i) - P_{det}{}_{FFT}(i) \qquad (8)$$

$$\epsilon_{FFT\,Q}(\theta) = \sum_i^{nr_{dist}} Q_{eq}{}_{FFT}(\theta, i) - Q_{det}{}_{FFT}(i) \qquad (9)$$

Where $P_{eq}{}_{FFT}(\theta, i)$ and $P_{det}{}_{FFT}(\theta, i)$ are the single-sided amplitude spectrums of the Fast Fourier Transforms (FFT) of the normalized signals of the measured active and reactive power for the equivalent and the detailed models, respectively. The FFT is an algorithm that transforms a given time-domain signal into a frequency-domain

signal, decomposing the original signal into its frequency components – each with a given magnitude and phase. The use of a Fourier transform improves the quantification of the transient dynamics of the signals, enabling a more significant assessment and consequent comparison of the signals under study. The active and reactive power FFT errors ($\epsilon_{FFT_P}(\theta)$, $\epsilon_{FFT_Q}(\theta)$) compute the total frequency-domain error between the detailed and the equivalent responses, for a given solution – represented here by the state-variables vector ($\theta$) – for each and all the $i$ disturbances considered. Parallel computation was implemented, allowing the allocation of several simulations to different cores of the computer's processor unit at the same time. Also to be noted is the fact that, although all the simulations were performed with a variable step, the signals were normalized – using the resample function of MATLAB® – upon error calculation and comparison.

To maintain the computational time within acceptable limits, the state-variables vector ($\theta$) was decided to include 31 parameters. These are summarized in the Table 17. This group of variables allows the adjustment of most important sections of the dynamic transients, enabling the equivalent model to be properly adjusted, depending on the operational conditions.

TABLE 17: PARAMETERS FOR ADN OPTIMIZATION PROBLEM

| Model | Description | Variable | No. of variables |
|---|---|---|---|
| Converters 1 & 2 | Maximum injected reactive current | $I^*_{q_{max}}$ | 2 |
| | Initial active and reactive power set-point | $P_{ref}, Q_{ref}$ | 4 |
| | Share of converter 1 vs converter 2. | $Share_{TUV}$ | 1 |
| | Total generation apparent power | $S_{n_{gen}}$ | 1 |
| Impedances | Resistance, inductance and capacitance | $R, L, C$ | 9 |
| | Lines lengths | $LineLength$ | 3 |
| Load | Total load apparent power | $S_{n_{load}}$ | 1 |
| | Ratio of power for the static load over total load power | $Load_{ratio}$ | 1 |
| | Static load exponents, for load nature definition | $n^p, n^q$ | 2 |
| | Static load power factor | $pf_{static}$ | 1 |
| | Dynamic load resistances and inductances | $R_s, L_{l_s}, R'_r, L_{l_r}', L_m$ | 5 |
| | Dynamic load inertia constant | $H$ | 1 |

### 3.5.3 COUPLING WITH TRANSMISSION SYSTEM MODELS

In terms of the modelling process, it is known that, typically, the representativeness of such equivalent models is highly case-dependent, leading to the need of fully characterise the system aimed to be reduced. This means that, subsequently to the model structure definition, its actual application in system stability studies should be done carefully, considering the range of its application.

In line with this, two main approaches can be considered, when coupling the proposed model structure to the transmission system, depending on the level information on the grid that is available to the user, either employing a:

- quantitative analysis, or;
- qualitative analysis.

The first approach assumes that most of the relevant information on the technical aspects of the grid is available. Full characterisation of the distribution network is accessible, from generation units' electrical and electro-mechanical systems parametrizations and their respective controllers, storage systems detailed characteristics, the parametrization of all the types of loads operating in the network, as well as all the other system components (lines and transformers). This method assures a high level of confidence in terms of behaviour representation once it may consider a wide range of operational points of the system into the process. These can afterwards be fully integrated in the equivalent model, by adjusting its parametrization accordingly (see Section 3.5.2.3). However, distribution networks can be very extensive, and the full technical characterization is not easily available. Such an approach requires significant coordination between DSO and TSO, with very detailed data sharing capabilities, which is typically not available.

To overcome this major drawback, a qualitative analysis can also be applied. In this approach, the user is required to evaluate qualitatively the system, regarding the shares of each type of component operating in the network and able to be represented in the equivalent model – by assuming generic parametrizations for each part of the model. For instance, the TSO may be aware that along the transmission network buses, some of the downstream distribution feeders hold larger shares of RES, while others are significantly less expressive in that sense. Additionally, information regarding the amount of units able to comply with FRT at a certain part of the network may be available, meaning this can be adjusted to improve the equivalent response's accuracy. Moreover, the user can take advantage of the two voltage levels represented in the equivalent structure, leading to a more diverse and wide representation of the system.

# 4. FREQUENCY STABILITY AND CONTROL

## 4.1 HIGH LEVEL OVERVIEW OF FREQUENCY STABILITY SCARCITIES

Frequency stability is the ability of a power system to maintain steady state frequency, following a severe system upset, resulting in a significant imbalance between generation and load (Kundur, 2004). Large imbalances are caused by severe system disturbances, such as large load or generation tripping, tripping of HVDC interconnectors, or system splits. Deliverable D2.1 of EU-SysFlex details all frequency control scarcities identified in the literature (EU-SysFlex, 2018). Below is an overview of the prominent phenomena:

- Decrease of system inertia: due to an increasing share of non-synchronous generation and a decreasing share of synchronous generation, the available system inertia decreases. If inertia is reduced then, for a given disturbance, the frequency containment reserves must be activated faster to reach the same frequency nadir /zenith.

- Behaviour of power electronics-connected generators and loads in frequency containment: preferably no load or generation shall trip unintentionally as long as frequency remains within the predefined band for the respective synchronous area. The unplanned disconnection of DG units and loads following high or low frequency events could worsen the frequency event, and increase/decrease the frequency zenith/nadir. In the case of a frequency deviation, participation in frequency containment by providing FCR or in Limited Frequency Sensitive Mode at Over-frequency (LFSM-O) or Under-frequency (LFSM-U) is beneficial. Another issue identified is the possibility of a voltage dip-induced frequency deviation (VDIFD). This issue refers to the recovery phase of active power after short-circuit events. The impact of VDIFD is strongly dependent on the size of the synchronous area together with its inertia and the penetration of Type-3 & 4 wind power turbines.

- Lack of reserves: The increasing levels of renewables on the power system may challenge the capability to balance active power.
    - Short term reserves: the Frequency Containment Reserve (FCR) is the most widely used method to restore active power balance. This category typically includes operating reserves with the activation time up to 30 seconds. New fast frequency response products have been designed in response to the reduction of system inertia and potential increase of ROCOF values on the island of Ireland (Fast Frequency Response: FFR), and in Great Britain (Enhanced Frequency Response: EFR). There is still the question whether it would be necessary to set out this kind of enhanced frequency service at the continental European level.
    - Long term reserves: they include ramping reserves and aFRR, with an activation time typically between 30 seconds up to 15 minutes. In Ireland, new ramping-up services were designed to cope with the uncertainty and variability of VRES. At European level, it would be worth assessing the order of magnitude of aFRR procurement increase for the future decades.

## 4.2 FREQUENCY STABILITY INDICATORS

On the simulation results from each frequency stability models, different indicators will be analysed to assess the potential scarcities of the system.

### 4.2.1 FREQUENCY NADIR/ZENITH

The frequency nadir/zenith is the most common frequency stability indicator, as it shows the worst deviation from 50 Hz. Inertia, initial frequency before the incident, volumes of FCR and aFRR, and dynamic characteristics of generators and loads have an important impact on the frequency nadir/zenith.

Common incidents up to and including the size of the reference incident shall be managed without Under frequency Load Shedding (UFLS). UFLS disconnects large groups of customers, without prior notice to the customer, as a last resort before system collapse and is therefore an emergency operating measure only used during extremes situations.

The frequency deviation is the main metric which determines UFLS and should therefore be above the minimum acceptable frequency. Typical range of minimum Nadir to respect on the Continental Europe system is 49 Hz to 49.2Hz.

In the Nordic system, the minimum acceptable frequency nadir is 49.0 Hz to maintain a margin from the highest load-shedding step, 48.8 Hz.

In Ireland and Northern Ireland, the normal operating range of the system frequency is 49.8 to 50.2 Hz and a frequency event is deemed to have occurred if the frequency falls below 49.5 Hz. The maximum acceptable frequency deviation for the Ireland and Northern Ireland system is in the range of ±0.7 to 1 Hz, while the first stage of UFLS relays operate at 48.85 Hz.

EDF, VTT and EirGrid and SONI will use this indicator for their frequency stability study.

### 4.2.2 ROCOF (RATE OF CHANGE OF FREQUENCY) AND KINETIC ENERGY

Following an incident, the gradient of the frequency ROCOF is inversely proportional to the overall system kinetic energy $E_k$:

$$ROCOF = \frac{\Delta P_{Imbalance} * f_0}{2 * E_k}$$

With:

$f_0$ = 50 Hz

$\Delta P_{Imbalance}$ [MW]: Active power imbalance following the incident

Analysis of the synchronous areas in Europe by ENTSO-E show that the size of a contingency required to cause a ROCOF of either 1 Hz/s or 2 Hz/s on each synchronous area will decrease over time as further renewables connect on the power system. The analysis indicates that small synchronous areas, such as Ireland and Northern Ireland, Great Britain, or the Baltic synchronous area, would see rapid and large frequency excursions following a normal generation loss. However, larger synchronous areas such as Continental Europe would not see the same extent of frequency excursions unless a significant disturbance occurs such as a system split.

For severe incidents such as system splits into regions initially exchanging high amounts of power, the main objective would be the prevention of a total collapse of the system. In these cases, the system stability does not rely only on the frequency reserves but also on Under-frequency load shedding and LFSM-O. The relevant criterion for these incidents is the ROCOF. Under-frequency load shedding devices as well as activation of units with LFSM-O require a certain time for frequency measuring and acting. Therefore, the ROCOF must not exceed a certain value (several Hz/s).

According to ENTSO-E publications (ENTSO-E, 2016-1), a future system split could generate local imbalances amounting to 40% of the local load. In this case, the maximum acceptable ROCOF would be 2 Hz/s. This value of 40% needs to be challenged by numerical simulations of the European system.

The ROCOF standard for the Ireland and Northern Ireland system is 1 Hz/s measured over a 500 ms timeframe.

EDF, VTT and EirGrid and SONI will use these indicators for their frequency stability study.

### 4.2.3 FREQUENCY RISE/DROP DURATION INDEX

The frequency rise/drop duration index quantifies the amount of time the frequency is outside an acceptable frequency envelope following a frequency deviation. This index quantifies the ability of the system to attain post contingency restoration and is the amount of time the frequency deviation exceeds a pre-set threshold i.e. > ±0.7 Hz, for 5 second timeframe.

EDF and EirGrid and SONI will use this indicator as well for their frequency stability study.

## 4.3 OPERATION SCENARIOS TO BE STUDIED

This section presents the simulations that will be run on each European power system in Task 2.4.

### 4.3.1 CONTINENTAL EUROPE

In the EU-SysFlex approach, the EDF model PALADYN will be used to assess the frequency stability on the Continental Europe system with the EU-SysFlex core scenarios following incidents.

Normative Incidents have been defined by ENTSO-E, one for interconnected operation and one for system split.

- Interconnected operation: The reference incident for interconnected operation in Continental Europe is the tripping of two of the largest generating facilities connected to the same busbar. The reference incident, which defines the required primary reserves in the system, is 3000 MW. Many years of interconnected operation show that this normative contingency is well suited. No load shedding is allowed during the normal system operation.

- System split: As system splits are not predictable, the size of the islands and the amount of the imbalance may vary considerably. A generalised approach covering any split scenario has to be used. Therefore, the maximum imbalance shall be expressed as a percentage of the load in a region. Future system enforcements and deployment of generation technologies will increase the power exchanges throughout Europe. As a result, system split could lead to higher imbalance. From this perspective, maximum ROCOF criteria could be set to 2 Hz/s by ENTSO-E. System split scenarios have been identified by ENTSO-E as the most severe ones (ENTSO-E, 2016-1), compared to tripping of loads, HVDC-links, and generation during interconnected operation. As a result of a system split an over frequency island and an under frequency island will be formed.

  In the under frequency island, load shedding is used to restore the balance between load and generation. Load shedding requires a time delay in order to measure and detect the under frequency and to open circuit breakers. Therefore, the success of load shedding depends on the ROCOF in combination with the time delay of load shedding.

  In the over frequency island, the characteristics of the LFSM-O function of non-synchronous generating facilities play a crucial role. Three parameters are of particular interest:
  - the steepness of the frequency change (ROCOF),
  - the starting frequency point of the LFSM-O (50.2 Hz or higher),
  - the power reduction droop.

PALADYN can be used to simulate both the reference incident for interconnected operation, and a system split with several zones having to absorb high imbalances. Those events will be simulated for each hour of the year.
The interconnected incidents can be tested in each of the zones defined in PALADYN. The reference incident is 3000 MW on the CE power system. Power losses in some zones could be lower than this value, depending on their own national reference incident.

For system split simulations, several locations will be studied. The most obvious simulation cases will be the separation of electrical peninsulas, such as the Iberian Peninsula (Spain + Portugal) and Italy from the rest of the Continental Europe system. The outage of interconnections between Continental Europe and non-synchronous systems (Great-Britain, Nordic system) will also be simulated.

Finally, a case close to the 2006 grid separation will also be simulated, corresponding to the separation of the grid in at least two zones:

- France, Spain, Portugal, Italy
- The rest of the CE power system

### 4.3.2 NORDIC SYSTEM

Similar to CE, frequency stability will be simulated with the EU-SysFlex scenarios in two types of incidents: interconnected operation and system split.

In interconnected operation the dimensioning incident is set by Nordic TSOs according to the largest generating unit, which will likely be Olkiluoto 3 nuclear plant, entering operation in 2019. In system split, any of the interconnectors between the continental system and Nordic system may be disconnected, leading to an over frequency island and an under frequency island. The analysis focuses on the case where the Nordic system becomes an under frequency island.

The frequency stability will be simulated for all hours of the chosen climate year. This allows for the effect of different transmission scenarios, e.g. high flow from north to south or vice versa, on frequency stability to be investigated.

### 4.3.3 IRELAND AND NORTHERN IRELAND SYSTEM

The frequency stability analysis conducted for the Ireland and Northern Ireland power system will be conducted across every hour of the year. The year-long analysis will be carried out for all the EU-SysFlex Scenarios and Network Sensitivities. The analysis carried out is a two-step procedure, with the following steps:

1. Inter scenario analysis
2. Intra scenario analysis

#### Inter scenario analysis

Stability indices described in section 4.2 will be calculated for every system operating point and across all the EU-SysFlex Scenarios and Network Sensitivities to obtain a measure of relative system scarcities as available with changing plant portfolio, network and seasonal variations. Figure 68 shows a conceptual visualisation of inter

scenario analysis relative to a chosen stability index. The stability indices to be used for inter scenario analysis are detailed in section 4.2.

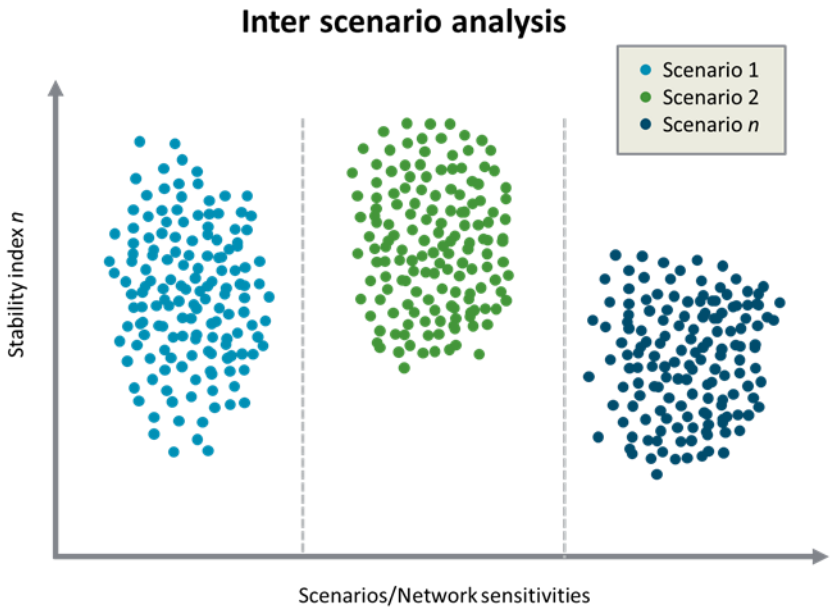



FIGURE 68: OVERVIEW OF INTER SCENARIO ANALYSIS

### Intra-scenario analysis

The intra scenario analysis will be carried out for the purpose of the evaluation of a specific EU-SysFlex Scenario or Network Sensitivities in greater detail. This analysis activity will consider specific system snapshots most representative of a scarcity to demonstrate the factors influencing an expected scarcity, propose possible mitigations and to further analyse any unforeseen system scarcity. The intra-scenario analysis is likely to focus on the following type of system operating points:

i. Operating points at extremity
ii. Expected scarcity operating points
iii. New scarcity operating points

An operating point could describe a combination of factors (e.g. VRES penetration and largest infeed) or a single factor (e.g. inertia). The nature of the three types of operating points for the system will vary according to the type of system analysis being carried out (e.g. frequency stability, transient stability etc.), perceived operating conditions as per EU-SysFlex Deliverable 2.1 and operating experience; which may demonstrate a system scarcity (e.g. high ROCOF, extreme frequency deviations). Figure 69 conceptually demonstrates the aforementioned intra-scenario analysis overview.

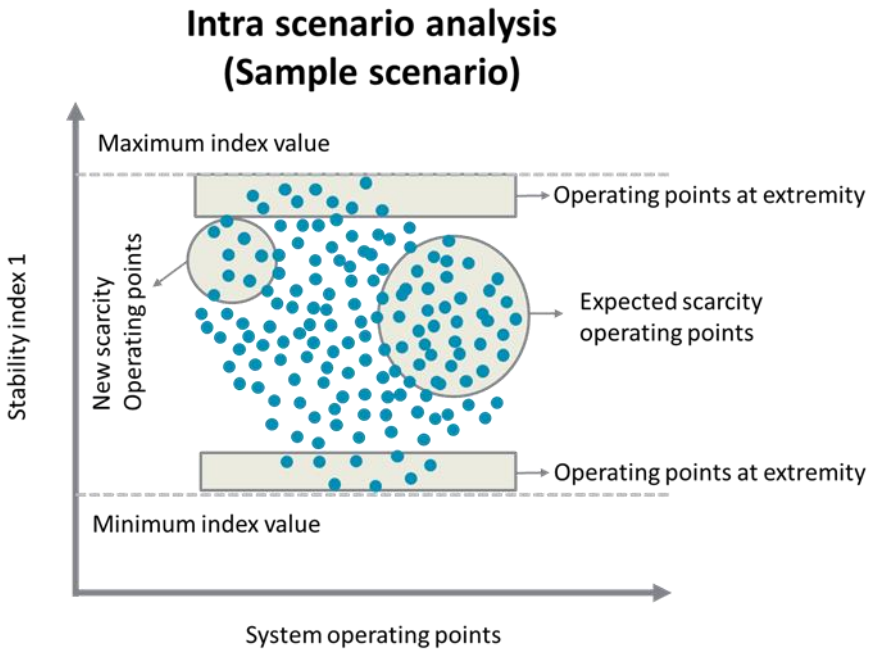



FIGURE 69: INTRA SCENARIO ANALYSIS OVERVIEW

The extremity operating points can only be known upon the completion of yearlong simulations and their categorisation as per the stability index being considered. However, the expected scarcity operating points may include a selection of operating points with low system inertia coupled with large largest infeed/outfeed levels. Similarly for the voltage dip induced frequency dipped investigation, the expected scarcity operating points are most likely to be period of high wind generation level coupled with low system inertia and reduced fixed shunt compensation on the system. Similar to “operating points at extremity”, the “new system scarcity operating points” can also only be obtained once the simulations are completed and an unforeseen scarcity manifests itself.

# 5. VOLTAGE CONTROL

## 5.1 HIGH LEVEL OVERVIEW OF VOLTAGE CONTROL SCARCITIES

The system voltage is determined by the balance of reactive power production and absorption. A power system becomes unstable when the voltage increases or decreases beyond a particular limit. Voltage stability can be classified into two subclasses (Kundur P. , 1994):

1. Large disturbance voltage stability: The system's ability to control voltage after a large disturbance such as a system fault, the loss of a generator or circuit.
2. Small disturbance voltage stability: The system's ability to control voltages following small disturbances such as switching or a change in load/generation.

Deliverable D2.1 of EU-SysFlex details all voltage control scarcities identified in the literature (EU-SysFlex, 2018). Below is an overview:

- Short-Circuit Power: The inherent capability of a power system to withstand voltage disturbances is measured through the short-circuit power. It provides an indication of the local dynamic performance of the system and behaviours in response to a voltage disturbance (National Grid, 2016). This, in practice, can be measured as the fault current contributed by all system generators during a fault, and essentially indicates the behaviour of a power system in response to voltage disturbances. With an increasing renewable generation mostly interfaced through power electronics, the short circuit power on the system is likely to reduce.

- Steady State Voltage Control: Steady state voltage control refers to steady state operation and is concerned with the reactive power management in real-time to account for fluctuations. This action ensures efficient power transfer (i.e. reduced active power losses) (ENTSO-E, 2016-2). It is also responsible for ensuring stable operating conditions. Depending on the given voltage level, severity and timescale of the fluctuation, a set of reactive power resources may be needed to address it. Voltage control becomes more challenging as reactive power supply and demand balance is disrupted due to penetration of renewable generation and displacement of synchronous generators (which traditionally provided the reactive power required). The changing nature of reactive power capability may lead to increased system losses, and compromised system security. (EirGrid and SONI, 2011).

- Dynamic Voltage Control: The reactive power imbalance, following a large disturbance is addressed through reactive power injection from various sources in the system. With increasing power electronic interfaced generation, connected at various voltage levels in the network, the reactive power injection may be negatively influenced. Additionally, dynamic voltage stability is also influenced by loads, in particular by their dynamic behaviour with respect to active and reactive power consumption in response to this disturbance (MIGRATE, 2016) (Van Cutsem, 2000)).

## 5.2 STABILITY INDICATORS

### 5.2.1 SHORT CIRCUIT LEVELS

Calculation of short-circuit power is important from the point of view of assuring a reliable operation of protection relays, keeping power quality requirements as well as maintaining power system stability.

The transmission system is operated such that the actual short circuit levels do not exceed the rated short circuit levels of equipment on the system.

TABLE 18: SYSTEM MAX SHORT CIRCUIT LEVELS

| EirGrid | SONI | PSE |
|---|---|---|
| 400 kV: 45 kA, | 400 kV: 50 kA, | 400 kV: 63 kA, |
| 220 kV: 36 kA, | 275 kV: 40 kA, | 220 kV: 63 kA, |
| 110 kV: 23.4 kA (or 28.35 kA at designated 110 kV locations) | 110 kV: 40 kA, | 110 kV: 63 kA |

Additionally a minimum level of short circuit power is required on the system to enable proper operation of protection relays to isolate faults. The short circuit power provided by power electronics interfaced renewable generation is limited by the component ratings of the converter. The short circuit levels of the system will therefore be used as stability indicator.

Short circuit power values will be also used in a simplified method assessing conditions for voltage stability (for busbars supplying loads). If the power system is represented by a voltage source equivalent including short-circuit reactance, a load supply can be ensured with required voltage stability margin (Machowski J. , 2015)

$$S_{\mathrm{K}}^{''} \geq 2k_V(1+\sin\varphi)S_{\mathrm{load}}$$

where:

- $S_{\mathrm{K}}^{''}$ – three-phase short-circuit power
- $S_{\mathrm{load}}$ and $\varphi$ – apparent power of load and its angle
- $k_V$ – required voltage stability margin.

This index will be used by PSE for the voltage stability study of the CE power system.

### 5.2.2 DYNAMIC VOLTAGE PROFILE

A voltage dip and recovery after a severe disturbance is a significant issue for busbars to which generation units

are connected. Large generation units must remain transiently stable and connected to the power system without tripping while system voltage remains within a defined time profile following a fault on the transmission system. It is therefore imperative for system stability that a dynamic voltage profile is maintained such that various generation resources on the system stay connected following a fault recovery.

#### 5.2.2.1 FAULT-RIDE THROUGH

Voltage-against-time-profile will be analysed based on time-domain simulation performed together with transient rotor angle stability analysis (see Section 6.2.1). Obtained voltage waveforms will be compared with the FRT profiles required by RFG network code (and more specifically – their national implementations).

FRT capability will be analysed by PSE as a voltage stability index. The Polish implementation of RFG network code requires parameters of FRT capability profiles as shown in Figure 70-Figure 73.

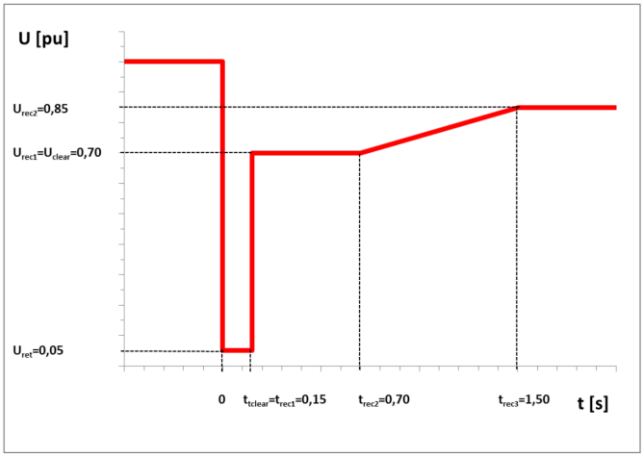



FIGURE 70: FRT CAPABILITY FOR SYNCHRONOUS GENERATION UNITS – TYPE B AND C

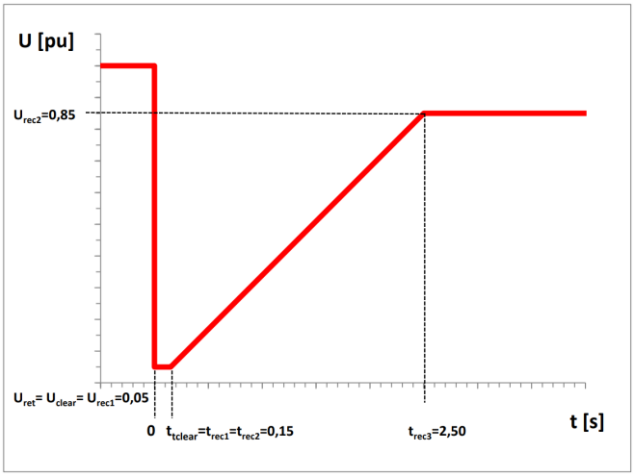



FIGURE 71: FRT CAPABILITY FOR NON-SYNCHRONOUS GENERATION UNITS – TYPE B AND C

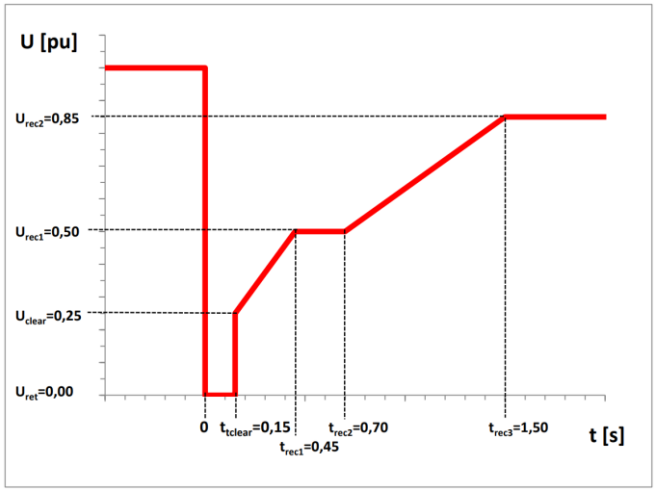



FIGURE 72: FRT CAPABILITY FOR SYNCHRONOUS GENERATION UNITS – TYPE D

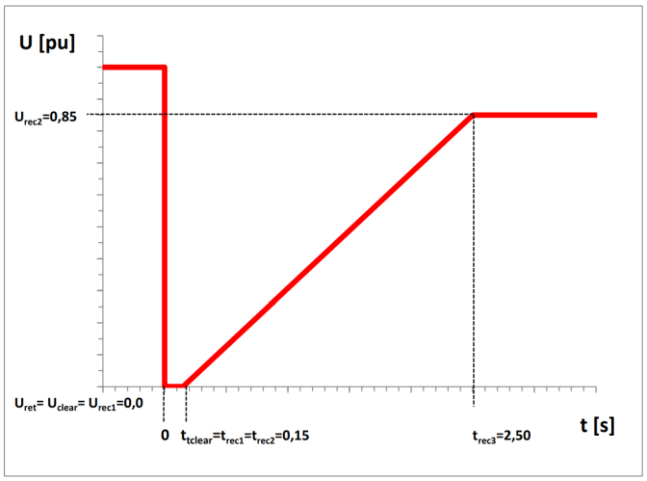



FIGURE 73: FRT CAPABILITY FOR NON-SYNCHRONOUS GENERATION UNITS – TYPE D

### 5.2.2.2 DYNAMIC VOLTAGE PROFILE INDEX

The dynamic voltage stability for various cases can be assessed using a dynamic voltage profile index. This index quantifies the maximum duration of time for which the dynamic voltage profile breaches the permissible voltage range. Figure 74 provides further clarification regarding the proposed index.

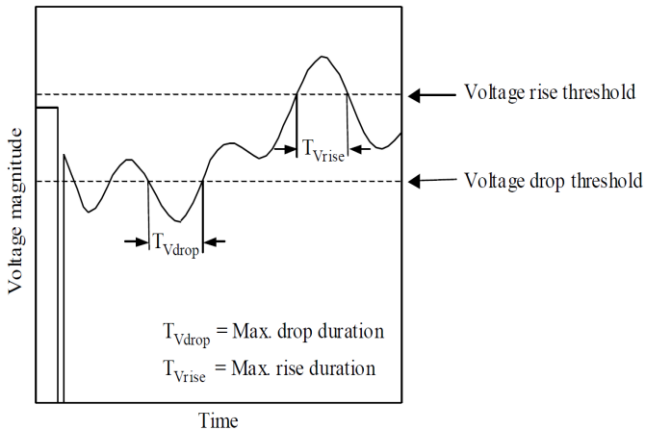



FIGURE 74: VOLTAGE DROP/RISE DURATION INDEX DEFINITION (POWERTECH, 2016)

It must be noted that instead of defining the voltage thresholds and maximum allowable breach time thresholds, a user-defined voltage profile can be specified. Therefore, this index can be used to evaluate specific voltage ride through requirements. The decision to utilise either of the above approaches will be made after taking the low voltage ride through requirements and the voltage connection levels among others into consideration.

The dynamic voltage profile index will be used by EirGrid for the voltage stability study.

### 5.2.3 VOLTAGE SECURITY

Voltage security can be divided into two sub problems.

A. Steady State Voltage Deviation – Voltage level outside predefined ranges.
B. Voltage Instability - An uncontrolled voltage decline.

#### 5.2.3.1 STEADY STATE VOLTAGE DEVIATIONS

Steady state voltage deviations (Pre and Post Contingency) are used as a voltage security index. In order to evaluate steady state voltage deviation, EirGrid's Transmission System Security and Planning Standards (TSSPS) and PSE Standard on operation of Polish power system are applied (EirGrid, 2016) (PSE, 2015). The system is planned so the voltage shall remain within the limits shown in the Tables below. It is acceptable for the voltage to fall within the post-contingency limits for the duration of an outage or contingency. For the Ireland and Northern Ireland model, for an intact network, the maximum voltage step from switching is 3.0%. The maximum voltage step change for contingency is 10%.

TABLE 19: REQUIREMENTS FOR THE VOLTAGE STABILITY ANALYSIS IN IRELAND AND NORTHERN IRELAND MODEL

| Nominal Voltage | Base Case Limits | Post Contingency Limits |
|---|---|---|
| 400 kV | 370 - 410 kV | 360 - 410 kV |
| 275 kV | 260 - 300 kV | 250 - 303 kV |
| 220 kV | 210 - 240 kV | 200 - 240 kV |
| 110 kV | 105 - 120 kV | 99 - 120 kV |
| Voltage Step | 3 % | 10 % |

TABLE 20: REQUIREMENTS FOR THE VOLTAGE STABILITY ANALYSIS IN CE MODEL

| Nominal Voltage | Base Case Limits | Post Contingency Limits |
|---|---|---|
| 400 kV | 380 - 420 kV | 360 - 420 kV |
| 220 kV | 210 - 245 kV | 200 - 245 kV |
| 110 kV | 105 - 121 kV | 99 - 121 kV |

#### 5.2.3.2 VOLTAGE INSTABILITY

### Voltage Stability Margin & Voltage Stability Limit

Large steady state voltage deviations do not necessarily imply voltage instability, neither does the absence of large steady state voltage deviations imply voltage stability, therefore voltage stability margin and voltage stability indices are required to evaluate the voltage security.

The stability of the system can be analysed by using a number of static analysis techniques. Two types of analysis are typically required to study voltage instability:

- Power - Voltage (P-V) Curve; and
- Reactive Power – Voltage (Q-V) Curve.

### Voltage Stability Margin

Steady state voltage deviation and load flow sensitivity analysis will be performed to obtain the weakest busbars in the system model. A detailed P-V analysis on pre-selected system buses/areas can yield the voltage stability margins (Figure 75) which are calculated as follows:

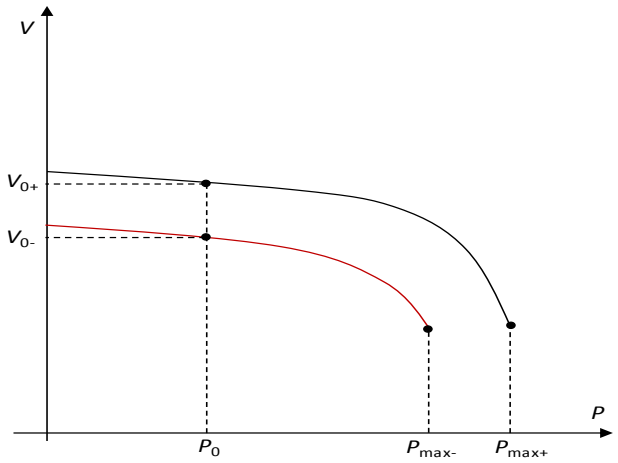



FIGURE 75: P-V CURVES WITH (+) AND WITHOUT (-) A CONTINGENCY

Voltage stability margin will be calculated as follows:

$$k_V = \frac{P_{\max} - P_0}{P_{\max}} \quad (5.1)$$

The standard safety margin to be retained between the transmission loading in an area and the voltage collapse point as per EirGrid's operating security standards should be above 5% of the total load value at the bifurcation point (applicable to meshed local areas and non-global voltage collapse phenomenon). PSE's criteria for voltage stability margin are given in Table 21.

TABLE 21: REQUIREMENTS FOR THE VOLTAGE STABILITY ANALYSIS IN CE MODEL

| Contingency | Voltage stability margin |
|---|---|
| None | 10% |
| Loss of any element such as:<br>• one generator<br>• one line (including double-circuit)<br>• one transformer<br>one HVDC pole | 5% |
| Loss of busbar system (section) in a substation | 2,5% |

### Voltage Stability Limit

As per the P-V analysis, the voltage stability limit for a certain active power transfer for the areas/buses under consideration is the P-V curve bifurcation point. Further Q-V analysis on selected critical buses may yield information regarding the reactive loading capability limit for such buses over a range of voltage values.

This analysis reveals the minimum voltage level at which the reactive stability limit is not breached. In case of a deficiency of reactive compensation in the system, this minimum voltage level for the bus under consideration (Figure 76) increases and vice-versa. This voltage stability limit will be calculated to indicate voltage stability.

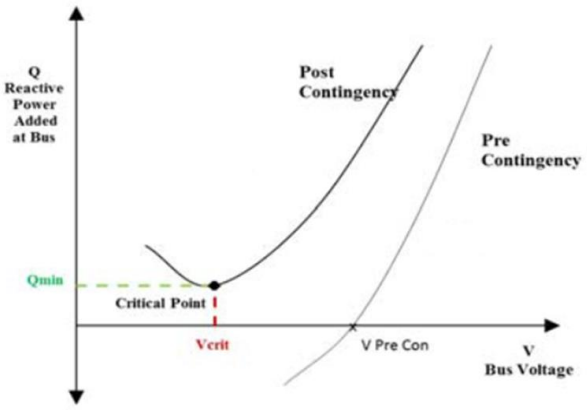



FIGURE 76: REACTIVE POWER - VOLTAGE (QV) CURVE

## 5.3 OPERATION SCENARIOS TO BE STUDIED

### 5.3.1 CONTINENTAL EUROPE

For the purpose of voltage stability analysis, assumed operation scenarios will consider the following two criteria: maximum power demand and minimum power reactive margins for the synchronous generation in the CE power system. Below, both criteria are briefly described.

#### Maximum power demand

Maximum power demand is one of the relevant operating conditions in voltage stability analysis. High active and reactive power demand causes high load on transmission lines. Thereby more reactive power is consumed by lines. Voltage stability depends on relationship between transmitted active and reactive power, current and receiving voltage. Such relationship is presented in Figure 77.

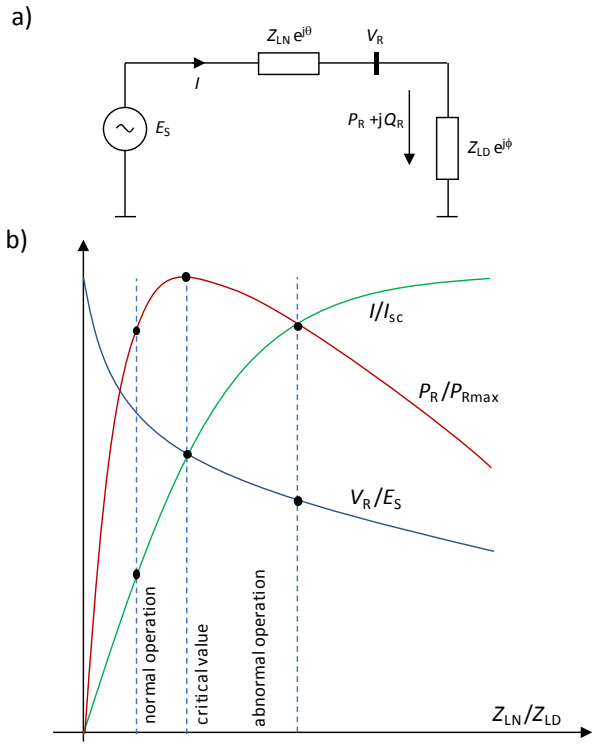



FIGURE 77: CHARACTERISTICS OF SIMPLE RADIAL SYSTEM; BASED ON (KUNDUR P. , 1994)

Looking at Figure 77 one can see that higher load demand (lower $Z_{LD}$) causes decreasing end voltage as well as moving the operation point to the area of instability. The criterion of maximum power demand can be considered from the point of view of the reactive power demand side.

### Minimum reactive power margins for the synchronous generation

A minimum reactive power margin for the synchronous generation is a criterion looking at the side of reactive power supply. Synchronous generators are the most important sources of reactive power and means of voltage control in the power system. Under normal conditions the terminal voltages of generators are maintained constant. During conditions of low voltage in the power system, the reactive power on generators may exceed their field current. When the reactive power output is limited, the terminal voltage is not longer maintained constant (Kundur P. , 1994).

Let a round-rotor synchronous generator with a step-up transformer be considered. Equivalent steady state circuit diagram and phasor diagram is shown in Figure 78. A limit in the voltage and reactive power control of the generator is that rotor (field) current must not cause overheating of the field winding. In the P–Q plane, it corresponds to a circle which the relevant fragment is marked by the dashed line along points G and F in Figure 79.

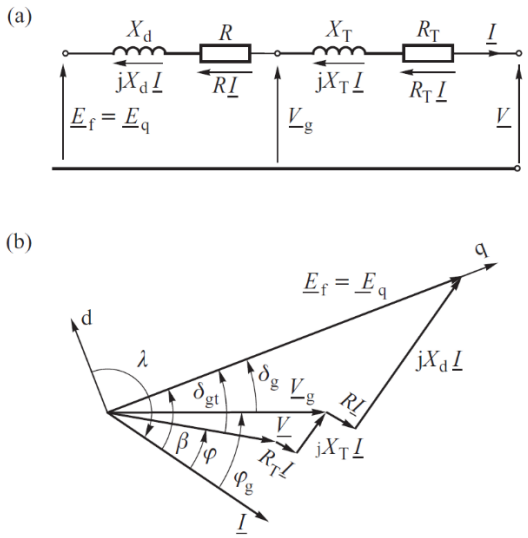



**FIGURE 78: EQUIVALENT STEADY STATE CIRCUIT DIAGRAM AND PHASOR DIAGRAM OF THE ROUND-ROTOR GENERATOR WITH A STEP-UP TRANSFORMER (MACHOWSKI, 2008)**

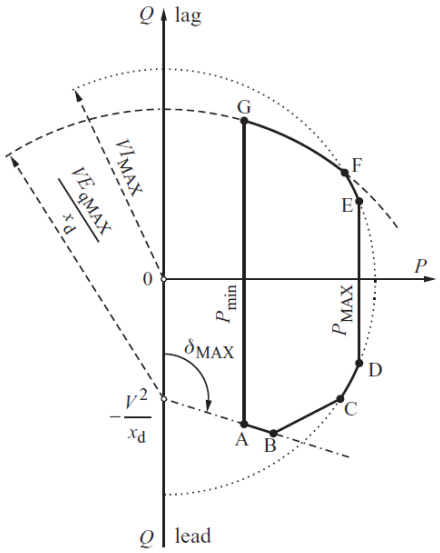



**FIGURE 79: REACTIVE POWER CAPABILITY CURVE ASSUMING A GIVEN VOLTAGE (MACHOWSKI, 2008)**

Voltage instability occurs when demand for reactive power is not met. In this way, the limitations of reactive margins for the synchronous generation approaches to the worst case scenarios for voltage stability analysis.

### 5.3.2 IRELAND AND NORTHERN IRELAND SYSTEM

The voltage stability analysis conducted for the Ireland and Northern Ireland power system will be conducted across every hour of the year. The year-long analysis will be carried out for all the EU-SysFlex scenario and Network Sensitivities as described in Table 11. The analysis carried out is a two-step procedure, with the following steps as discussed in 4.3.3.

Inter scenario analysis - Stability indices described in section 5.2 will be calculated for every system operating point and across all the scenarios/sensitivities to obtain a measure of relative system scarcities as available with changing plant portfolio, network and seasonal variations.

Intra scenario analysis - The intra scenario analysis will be carried out for the purpose of the evaluation of a specific scenario/network in greater detail. This analysis activity will consider specific system snapshots most representative of a scarcity to demonstrate the factors influencing an expected scarcity, propose possible mitigations and to further analyse any unforeseen system scarcity. The intra-scenario analysis is likely to focus on the following type of system operating points:

i. Operating points at extremity
ii. Expected scarcity operating points
iii. New scarcity operating points

# 6. ROTOR ANGLE STABILITY

## 6.1 HIGH LEVEL OVERVIEW OF ROTOR ANGLE STABILITY SCARCITIES

Rotor angle stability refers to the ability of synchronous machines directly coupled to the grid to remain in synchronism after being subjected to disturbance. This entails that each synchronous machine must maintain or restore equilibrium between its electromagnetic and mechanical torque whenever a disturbance in power system occurs. Otherwise, whenever equilibrium is disturbed by a perturbation, the machines accelerate or decelerate which can lead to the loss of synchronism as the result of increasing angular swings and synchronous generator will be disconnected from the system (Kundur P. , 1994).

The change of the electromagnetic torque of a synchronous machine after a disturbance consists of two components which affect the damping of oscillations:

- Synchronising torque component (in phase with rotor angle deviation)
- Damping torque component (in phase with speed deviation)

Rotor angle stability depends on the existence of both components, though insufficient synchronising torque leads to non-oscillatory instability through a non-oscillatory or aperiodic drift, while lack of the damping torque results in oscillatory instability due to increasing amplitude of oscillations.

Depending on the scale of disturbance and analysed phenomena, rotor angle stability is classified as small-signal stability or transient stability. Small-signal stability depends on the initial operating state of the system, while transient stability is concerned with the ability of a power system to maintain synchronism after a severe disturbance. The system response in such a disturbance would involve large excursions of generator rotor angles from the pre-fault operating point and instability would occur due to insufficient synchronising torque (Machowski, 2008).

Increasing penetration of renewable generation based on power electronics–interfaced connections affects rotor angle stability in various and interdepending ways, and the absolute impact could be negative or positive depending on the superposition and interaction of different influencing factors listed below, presented in details in the EU-SysFlex D2.1 report (EU-SysFlex, 2018):

- Impact of renewables penetration:
  Moderate penetration rate of PE-interfaced renewable generation can improve transient stability of the power system thanks to the decreased loading of conventional power plants as well as of transmission lines. However, a higher penetration can reverse this impact, as the displacement of synchronous generators can reduce the system transient stability margin.

- Impact of dynamic voltage support:

The impact on transient stability could be positive if renewable generators remain connected during system faults and provide dynamic voltage support. Due to high levels of penetration of non-synchronous generation, when there are relatively few conventional (synchronous) units left on the system, the synchronous torque holding these units together as a single system is therefore weakened. It can be mitigated by an increase in the dynamic reactive response (DRR) of wind farms during disturbances.

- Impact of pre-fault operating point:
  The loading and pre-fault operating point of all generation sources impact the transient stability, whereby lightly loaded generation resources have a larger transient stability margin. Similarly, for PE-interfaced renewable generation a lower load factor of wind or PV generators allows better voltage support by injecting higher reactive current without reducing the active currents.

- Impact of renewable generation's location:
  The voltage support provided by PE-interfaced generation installed electrically close to synchronous generators can enhance the overall system transient stability. Furthermore, the location of renewable generators could impact the system power flows. Increasing power flows, respectively increasing voltage angle differences among synchronous generators would have negative impacts on transient stability, especially in case of long distance transmission.

- Impact of control and protection schemes:
  The under voltage protection system of variable renewable generators could have a significant impact on transient stability. In the absence of dynamic voltage support from renewable generators, the ability of renewable generators to keep on providing active power during the fault can result in an acceleration of the synchronous generation in the vicinity. However, the provision of dynamic reactive support by renewable generation, during the fault contributes to a reduction in voltage depression and improvement in transient stability margins.

## 6.2 STABILITY INDICATORS

### 6.2.1 TRANSIENT STABILITY INDICATORS

Maintaining transient rotor angle stability is a necessary condition for safe power system operation. In order to maintain synchronism in power system two main conditions must be fulfilled:

i. A power system maintains synchronism with an assumed margin when subjected a severe disturbance event; and
ii. Power oscillations after severe disturbance are efficiently damped within acceptable limits.

Accurate analysis of transient rotor angle stability requires detailed models for generating units and other equipment which is presented in Sections 3.4.2 and 3.2.2 for the Ireland and Northern Ireland transmission systems and Continental Europe power system respectively.

A method of transient stability analysis is time-domain simulation representing electromechanical phenomena in which the nonlinear differential equations are solved by using step-by-step numerical integration techniques.
Severe system disturbances such as faults on transmission facilities have to be selected as a set of fault event scenarios. Only most probable fault events should be considered such as short-circuit faults eliminated by tripping the faulted elements (opening the suitable circuit-breakers).

For each fault event it is necessary to run a dynamic simulation covering time of analysed transient:

- (10-15) seconds, when local (inter-plant) power oscillations are investigated
- (15-20) seconds, when inter-area power oscillations are investigated.

During time-domain simulations, some signals should be observed, such as rotor angle, rotor speed, rotor slip, active power of generators and voltage on generator terminals.

#### 6.2.1.1 CRITICAL CLEARING TIME

In order to assess transient rotor stability in quantitative terms, the use of critical clearing times and followed transient stability margin are proposed:

$$k_{\mathrm{t}} = \frac{t_{\mathrm{cr}} - t_{\mathrm{f}}}{t_{\mathrm{f}}} \cdot 100\%$$

where $t_{\mathrm{cr}}$ and $t_{\mathrm{f}}$ are the critical and actual clearing times.

The critical clearing time (CCT) is the longest clearing time for which a generator will remain in synchronism. CCT is a widespread transient stability index. It shows a resultant impact of RES operated in the power system on its transient stability. CCT is impacted by the composition of RES technology as well as its penetration and location.

Transient stability margins will be calculated and compared to the required values, i.e. 20% to 10% depending on pre-fault conditions (such as contingencies) and the type of simulated fault. The permissible values of transient stability margins result from PSE's internal operation guidelines.

The CCT is obtained through a binary search method, whereby, a fault clearance range and set threshold levels are pre-specified. The stability margin and its threshold applied to check for instability are based on the angle margin index as described above.

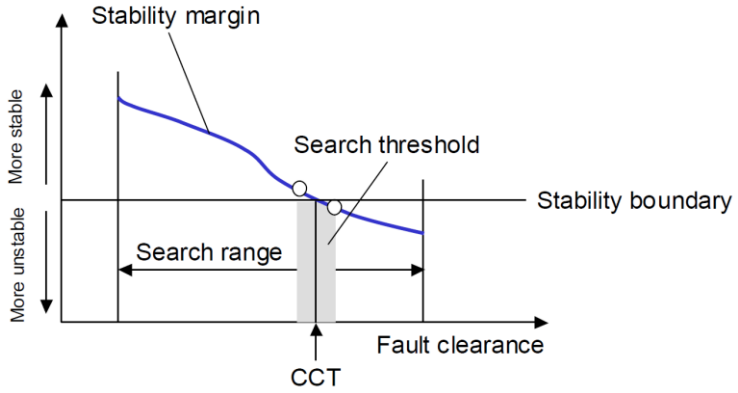



FIGURE 80: COMPUTATION OF CRITICAL CLEARANCE TIME (POWERTECH, 2016)

The calculation of critical clearing time is computationally intensive in addition to being time intensive. The critical clearing times will be computed for specific cases of interest.

The CCT as a stability index will be used by PSE, EirGrid & SONI for their transient stability study.

#### 6.2.1.2 SHORT-CIRCUIT POWER

Short circuit power values will be also used in simplified methods assessing conditions and rotor angle stability (for busbars to which synchronous generation units are connected):

$$S_{\mathrm{K}}^{''} \geq 6P_{\mathrm{n}} \tag{6.1}$$

where: $S_{\mathrm{K}}^{''}$ – three-phase short-circuit power (without generators connected to the bus), $P_{\mathrm{n}}$ – total nominal active power of synchronous generators connected to the busbar.

The relationship (6.1) results from a very simplified analysis based on equal-area criterion applied to a single-machine infinite bus system with typical values of reactance, mechanical time constant and clearing time (Machowski, 2008).

#### 6.2.1.3 ANGLE MARGIN INDEX

The evaluation of first swing stability is carried out through an angle margin index. The index compares the relative rotor angles of various generators to evaluate the current level of synchronism in the system and the margin to loss of synchronism. The index is defined as follows (Powertech, 2016):

$$\eta = \frac{360 - \delta_{max}}{360 + \delta_{max}} \times 100 \tag{6.2}$$

where δ_max is the maximum difference between the relative rotor angles across all generators within the simulation timeframe. The proposed index value can vary between -100 to 100, whereby for index values of less than or equal to zero, the system is first angle instable i.e. the generation loses synchronism following a contingency. The core benefits of the proposed index are the relatively short computation times and the intuitive nature of the index, especially as a system wide parameter.

The angle margin indices will be calculated for all analysed system snapshots. This index will be used by EirGrid and SONI for the transient stability study.

### 6.2.2 OSCILLATORY STABILITY INDICATORS

Oscillatory stability can be assessed as a small signal stability problem. For a power system, small signal stability refers to the ability of the power system to remain stable after small disturbances. Oscillatory instability in power systems is usually associated with poorly damped electromechanical oscillations that can be separated into local modes and inter area modes:

- **Local Modes**:
  These modes usually occur at frequencies of 0.8 to 2 Hz and are associated with the behaviour of a small part of the system (e.g. a single generator oscillating against the rest of the system or a single generator oscillating against another single generator that is electrically close to it).
- **Inter Area Modes**:
  These modes usually occur at frequencies of 0.2 to 0.8 Hz and are associated with a group of generators in one part of the system oscillating against another group of generators in a different part of the system.

The strict definition of stability simply requires that the system must not be in an unstable state (i.e. it will eventually reach a new steady state). However, in practical applications it is common to also require that this new steady state is reached in a reasonable amount of time (e.g. within 20 seconds). This leads to a more general requirement that any oscillations are not only stable but are also well damped – with the definition of well damped being a matter of engineering judgement.

Small signal stability is best assessed using Eigen value analysis of a linearized system model. The Eigen values of the system can then be used to directly determine the frequency, damping ratio and stability margin of each mode of oscillation that exists in the system under study. However, power systems are frequently subjected to large disturbances (e.g. line faults and generator trips) and modes that are small signal stable may not be stable after these large disturbances. Therefore, it is ensuring the stability of an oscillatory mode in the aftermath of a credible large disturbance that will be the binding constraint on system operation and not the small signal stability of the oscillation. Unfortunately, Eigen value analysis is not well suited to assessing the stability of the system after it has been subjected to large disturbances, as it depends upon linearized models.

Therefore, instead of Eigen value analysis, Prony's method will be used to decompose the time domain response of the system to a large disturbance into the dominant oscillatory components. Then, the stability of each of these components will be assessed individually. Prony's method has been widely used in the past for this form of stability assessment and it is described briefly in the ANNEX I of the report.

Finally, whilst common mode oscillations (usually observed as a modulation of the system frequency at an oscillatory frequency of below 0.1 Hz) are an oscillatory phenomena that may be observed in power systems, they have rarely been associated with system stability issues and will not be considered as part of these studies.

#### 6.2.2.1 IMPLEMENTATION OF PRONY'S METHOD IN TSAT

In TSAT, a Prony analysis algorithm is implemented to identify the worst damping ratio ζ from modes that satisfy the following conditions:

- They are within a specified frequency range
- They have sufficiently large amplitudes
- They are most visible from a set of generators

In the worst damping identification algorithm, the Prony method is applied simultaneously to the relative rotor angles of up to four generators in a time window you specify. The generators to-be-included, as well as the reference generator used for the relative angle calculation, should be specified in subsystem definition associated with criteria data. In case of reference generator not specified, reference generator that is specified in the monitor data will be used. The subsystem definition associated with criteria data should at least contain one valid generator for this damping calculation.

Damping ratio ζ is used as the damping index to determine the degree of small-signal stability for a contingency. Also, TSAT supports the use of decay time constant, which allows the users to apply the decay time constant τ as the damping index for all categories instead of damping percentage.

#### 6.2.2.2 DECAY TIME CONSTANT

The EirGrid Grid Code specifies the following with respect to oscillatory stability for generators (EirGrid, 2015):

"A **Generation Unit** is adjudged to be stable if the various machine states and variables, including but not limited to rotor angle, active power output, and reactive power output, do not exhibit persistent or poorly damped oscillatory behaviour, when the **Generation Unit** is subjected to a **Fault Disturbance** or other transient event on the **Transmission System"**.

Given this definition and the fact that ENTSO-E identify the time period of interest for these oscillations as being up to 20 seconds, it is assumed here that the oscillations studied can be classified as stable if they reach an

approximate steady state within 20 seconds. Here, an approximate steady state is defined as the peak to peak magnitude of the oscillation remaining below 15 % of its maximum peak to peak magnitude (i.e. the first cycle peak to peak magnitude).

There are two obvious ways to determine if an oscillation satisfies this requirement. The first is to directly measure the peak to peak magnitude of the oscillation and compare it to the maximum peak to peak magnitude. The second is to use the decay time constant of the oscillation calculated using Prony's method. The decay time is the most convenient way of performing this assessment, as it is directly calculated by the TSAT implementation.

The decay time constant ($\tau$) of an oscillation is a function of its natural frequency and damping ratio and is equivalent to the time constant of the exponential decay. Therefore, the oscillation reaches 36.8 % of its initial value after this time. As such, requiring $\tau$ to be less than a third of the target settling time would seem an effective index for assessing the stability of each oscillatory mode.

This index will be used by EirGrid and SONI for the transient stability study.

#### 6.2.2.3 SETTLING AND HALVING TIMES

In order to evaluate electromechanical oscillation damping after severe disturbances, results of time-domain simulation and Prony's application will be used. A regulation time for the rotor angle signal can be calculated as time, after which the observed signal does not extend beyond an assumed control band. Usually, a percent of the first amplitude (peak) is used as a width of the reference control band. The following time measures will be used for damping performance in the time-domain simulations (PSE, 2015):

- settling time $t_{15\%}$ corresponding to the control band of 15% width of reference
- halving time $t_{50\%}$ corresponding to the control band of 50% width of reference

The idea of settling and halving times are shown in Figure 81.

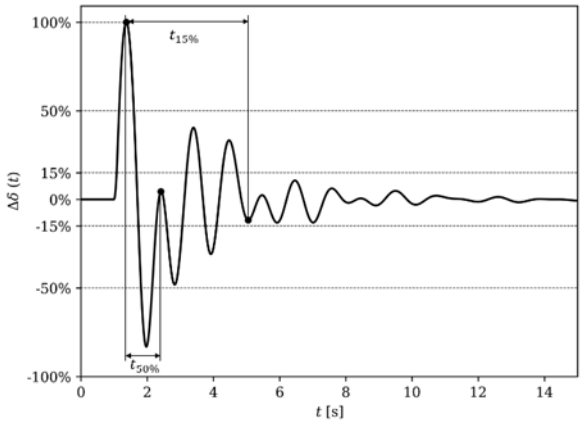



FIGURE 81: DEFINITION OF SETTLING AND HALVING TIMES USED TO OSCILLATION DAMPING PERFORMANCE.

The settling and halving times will be calculated for simulations in which actual clearing times are assumed. Requirements for damping performance are presented in Table 22.

TABLE 22: REQUIREMENTS FOR DAMPING OSCILLATIONS (PSE, 2015)

| Type of oscillations | Frequency | Halving time (50%) | Settling time (15%) |
|---|---|---|---|
| inter-plant | about 1-2 Hz | ≤ 5 s | ≤ 5 s |
| Inter-area | about 0,3 Hz | ≤ 7 s | ≤ 20 s |

This index will be used by PSE for the transient stability study.

## 6.3 OPERATION SCENARIOS TO BE STUDIED

### 6.3.1 CONTINENTAL EUROPE

For the purpose of transient stability analysis, assumed separate operation scenarios will consider the following two criteria: minimum inertia and maximum power demand in the CE power system. Below, both criteria are briefly described.

#### Minimum inertia in the power system

Minimum inertia in the power system can be found as follows:

$$\min \sum_{i \in C} H_i S_{\mathrm{n}i} \tag{6.3}$$

where $C$ is the set of selected countries in CE power system, $H_i$ – inertia constant in the $i$-th country, $S_{\mathrm{n}i}$ – total apparent nominal power of synchronous generation.

A reason for choosing such criterion as a worst case scenario is presented below.

Let a synchronous generator (or aggregated generators) operating in the single-machine infinite bus system be considered. According to Newton's second law, the rotor motion can be expressed as (neglecting the component of damping power):

$$\frac{T_{\mathrm{m}} S_{\mathrm{n}}}{\omega_{\mathrm{m}}} \frac{\mathrm{d}^2 \delta_{\mathrm{m}}}{\mathrm{d}t^2} \cong P_{\mathrm{m}} - P_{\mathrm{e}}(\delta) \tag{6.4}$$

where $T_{\mathrm{m}} = 2H$ – mechanical time constant (s), $H$ – inertia constant (s), $S_{\mathrm{n,}}$ – apparent nominal power of synchronous generator (MVA), $\omega_{\mathrm{m}}$ – rotor shaft velocity (mechanical rad/s), $\varepsilon = \mathrm{d}^2\delta_{\mathrm{m}}/\mathrm{d}t^2$ – angular acceleration of rotor (mechanical rad/s$^2$), $P_{\mathrm{m}}$ – net shaft power input to the generator (MW), $P_{\mathrm{e}}(\delta)$ – electrical air-gap power (MW).

When the three-phase short-circuit located on the generator terminals is considered, then $P_{\mathrm{e}}(\delta) \cong 0$. Assuming this, the rotor moves by uniformly accelerated motion with the angular acceleration:

$$\varepsilon = \frac{\mathrm{d}^2\delta_\mathrm{m}}{\mathrm{d}t^2} \cong \frac{P_\mathrm{m}}{S_\mathrm{n}}\frac{\omega_\mathrm{m}}{2H} \tag{6.5}$$

For the uniformly accelerated motion, the rotor angle $\delta_\mathrm{m}$ varies according to:

$$\Delta\delta_\mathrm{m} = \frac{\varepsilon t^2}{2} \tag{6.6}$$

Looking at (6.6) it can be seen that decreasing the product $HS_\mathrm{r}$ (kinetic energy of rotational masses) increases the angular acceleration $\varepsilon$. Assuming constant $P_\mathrm{m}$ and the same time moment $t$, a generator for which the kinetic energy is lower, achieves higher angle deviation and is closer to the instability point of operation.

In practical operation scenarios in power systems, the minimum inertia case can be obtained when minimum number of synchronous generation units is run ("must run" units). Such case occurs when low power demand or high RES generation is forecasted. Considering a generator operating in the single-machine infinite bus system, an equivalent reactance seen from the generator terminals is higher when the number of bulk generation units approaches minimum in the power system. Hence, the synchronizing torque is decreased.

In general, the higher the inertia, the slower the rate of change of angle. This reduces the kinetic energy gained during fault (Kundur P. , 1994).

### Maximum power demand

Maximum power demand is usually correlated with a number of highly loaded synchronous generators. Let a synchronous generator (or aggregated generators) operating in the single-machine infinite bus system be considered. For this generator, let two pre-fault generator loads $P_\mathrm{m1}$ and $P_\mathrm{m2}$ be analysed as is shown in Figure 82.

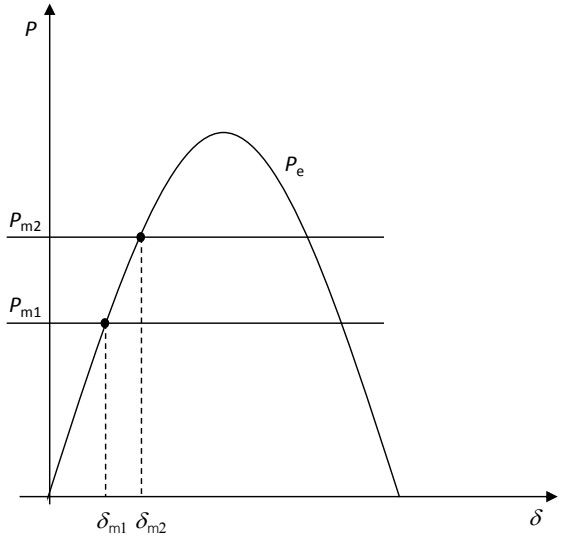



FIGURE 82: EXEMPLARY POWER-ANGLE RELATIONSHIP AND TWO DIFFERENT PREFAULT LOADS.

Assuming a three-phase fault located on the generator terminals and cleared after certain time, two different acceleration areas are obtained as presented in Figure 83 and Figure 84.

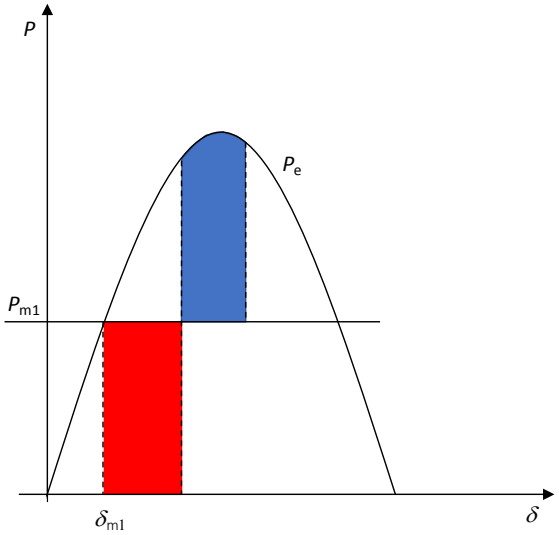



FIGURE 83: ACCELERATION AND DECELERATION AREAS FOR PREFAULT LOAD $P_{M1}$.

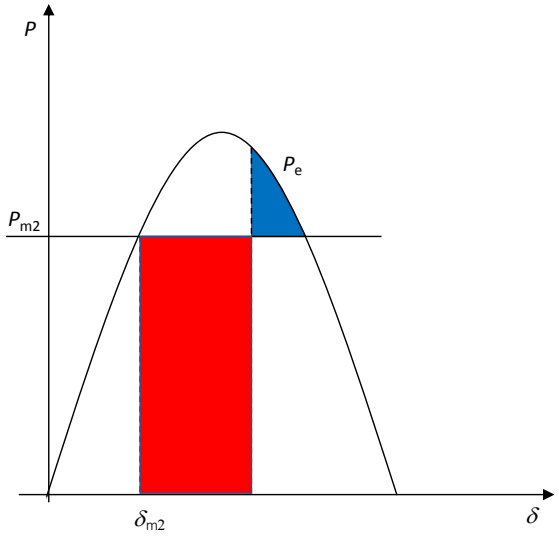



FIGURE 84: ACCELERATION AND DECELERATION AREAS FOR PREFAULT LOAD $P_{M2}$.

Looking at Figure 83 and Figure 84, one can observe that the acceleration area corresponding to $P_{\mathrm{m1}}$ is much lower than the acceleration area when the generator operates at load $P_{\mathrm{m2}}$. In the latter case, corresponding deceleration area is smaller than the available acceleration area and the system is unstable.

The pre-fault loading is an important factor with regard to determining the critical clearing time and generator stability. The higher the load, the lower the CCT (Machowski et al., 1997). Therefore, the criterion of maximum power demand is considered as a one of the worst case scenarios.

### 6.3.2 IRELAND AND NORTHERN IRELAND SYSTEM

The transient stability analysis for the Ireland and Northern Ireland power system will be conducted across every hour of the year. The year-long analysis will be carried out for all the EU-SysFlex scenarios and Network Sensitivities as described in Table 11. The analysis carried out is a two-step procedure, with the following steps as discussed in 4.3.3.

Inter scenario analysis - Stability indices described in section 6.2 will be calculated for every system operating point and across all the scenarios and Network Sensitivities to obtain a measure of relative system scarcities as available with changing plant portfolio, network and seasonal variations.

Intra scenario analysis - The intra scenario analysis will be carried out for the purpose of the evaluation of a specific scenario/network in greater detail. This analysis activity will consider specific system snapshots most representative of a scarcity to demonstrate the factors influencing an expected scarcity, propose possible mitigations and to further analyse any unforeseen system scarcity. The intra-scenario analysis is likely to focus on the following type of system operating points:

i. Operating points at extremity
ii. Expected scarcity operating points
iii. New scarcity operating points

# 7. CONGESTION

## 7.1 HIGH LEVEL OVERVIEW OF CONGESTION SCARCITIES

The EU-SysFlex Deliverable 2.1 review defines congestion occurring whenever system and network constraints prevent grid users from transmitting as much power as they would like or that would otherwise be economically efficient (EU-SysFlex, 2018). This can occur due to physical congestion where forecasted or realised power flows violate thermal limits on elements of the grid, or violate the voltage or angular stability limits of the power system (ENTSO-E, 2015).

The review reveals that congestion management will pose risks in the operation of both distribution and transmission systems and thus requires due attention to ensure that the European power system will be secure and reliable as the penetration of renewable energy resources increases. Increase in penetration of distributed generation will stress the networks towards their thermal limits, while increases in non-synchronous generation will lead to voltage and angular stability challenges. Traditionally, the solution to congestion was an investment in network reinforcement; however the review highlighted new solution techniques such as enhanced voltage control strategies, and the utilisation of smart network reconfiguration techniques and flexible technologies.

Congestion Management is complicated in many countries as renewable generation resources are often located far from load centres, which results in increased power flows in areas with weak networks. Additionally, as an increasing level of renewable generation connects to the distribution system, there are areas of the distribution network which were historically importers of power from the transmission network to meet demand, and which may now be net exporters for many times of the day and year. An important metric for TSOs and DSOs to identify the areas of congestion is the level of renewable energy being constrained in particular areas to relieve network congestion.

Additionally, cross-border interconnection will play a vital role towards the creation of a unified European energy market. However, the energy market needs to evolve in allowing network congestion issues as a result of renewable generation to be mitigated in a cost-reflective manner. For example, studies reviewed in Deliverable 2.1 indicate that cross-border bottlenecks may be created; e.g. cold spells in the Nordic region during the winter can create congestions from the West to the East of Norway and from the North to the South of Sweden (EU-SysFlex, 2018).

## 7.2 STABILITY INDICATORS

### Continental Europe system

The Continental Europe system will be assessed for congestion based on thermal limits for each interconnection. CONTINENTAL model takes into account the limitations on each border to generate the country dispatches. A post processing tool will then derive the occurrences of border congestions over the year.

### Nordic system

The analysis for system congestion will take place on bidding zone level (in some cases using groups of bidding zones). Especially power transfer in north-south direction will be considered, given the wind and hydro resources in the northern part of Sweden and Norway.

### Ireland and Northern Ireland

The Ireland and Northern Ireland power system will be assessed for congestion using the thermal limits criteria defined in the Transmission System Security Planning Standards (TSSPS) (EirGrid, 2016). The thermal limits for different types of equipment are shown in Table 23.

TABLE 23: THERMAL LIMITS OF EQUIPMENT IN IRELAND AND NORTHERN IRELAND PLANNING CRITERIA

| Equipment | Emergency Rating | Minutes |
|---|---|---|
| **Overhead Line** | 110% Normal Rating | 30 |
| **Cable and Transformer** | within half hour equipment limit | 30 |
| | within two hour equipment limit | 120 |

Thermal limits on equipment shall be as determined by the assumed ambient conditions for each item of equipment individually. Auxiliary and ancillary equipment (such as switchgear, bushings, instrument transformers, tap-changers, etc.) on a branch shall be adequately rated to permit such overloading; if such equipment in existing branches is inadequately rated and cannot be replaced, the lowest such rating shall be the limiting rating on the branch. No overloading on equipment shall be acceptable for normal or emergency operation except in the immediate aftermath of a disturbance (while corrective action, either automatic or manual, is being taken).

The system will also be assessed for congestion using the system voltage ranges in the TSSPS. The system must remain within the limits set out in Table 24. It is acceptable for the voltage to fall within the post-contingency limits for the duration of an outage or contingency.

TABLE 24: ALLOWABLE VOLTAGE RANGES IN THE IRELAND AND NORTHERN IRELAND SYSTEM

| Nominal Voltage | Base Case Limits (meshed network) | Post-Contingency Limits (all buses) |
|---|---|---|
| **400 kV** | 370 – 410 kV | 360 – 410 kV |
| **275 kV** | 260 – 300 kV | 250 – 303 kV |
| **220 kV** | 210 – 240 kV | 200 – 240 kV |
| **110 kV** | 105 – 120 kV | 99 – 120 kV |

In addition to these ranges, for base case operation, i.e. with all lines in service, the voltage step resulting from reactive compensation switching shall not exceed 3%. For system outage contingencies, the maximum step change between pre- and post-contingency steady state voltages shall be no more than 10%.

Voltage collapse analysis, as set out in Chapter 5 will also be considered in the assessment of congestion. A safe margin should be provided between the transmission loading in an area and the voltage collapse point as the transmission loading is increased.

Using these stability indicators, an overall view of system congestion will be given through an estimated percentage of renewable generation which will be constrained off as a result of these congestion issues. Flexibility solutions to this level of system congestion will be assessed within Task 2.6 of WP2 in EU-SysFlex. This will examine solutions such as the implementation of energy storage devices, demand side management solutions, and smart network devices to alleviate some of the congestion seen.

## 7.3 OPERATION SCENARIOS TO BE STUDIED

### 7.3.1 CONTINENTAL EUROPE SYSTEM

The thermal constraints will be hourly assessed for the two EU-SysFlex core scenarios, on each border and for base case operation.

### 7.3.2 NORDIC SYSTEM

Thermal constraints will be assessed for the two EU-SysFlex core scenarios for each hour of the chosen climate year.

### 7.3.3 IRELAND AND NORTHERN IRELAND

The congestion assessment of the Ireland and Northern Ireland power system will take account of the thermal limits for system equipment and allowable voltage ranges for the system using PSAT. These indicators will be assessed for base case operation and for single contingency conditions (N-1 or N-G). Where thermal overloads

occur, or transmission system voltages go outside of the allowable voltage ranges, this will identify areas of congestion in specific circumstances.

The assessment will consider the EU-SysFlex scenarios and Network Sensitivities for Ireland and Northern Ireland as outlined in Table 11. It will focus on 8760 hour analysis for each of the five cases for thermal and voltage limit assessments. System snapshots will be chosen to assess possible risks for voltage collapse and will set power transfer limits accordingly.

In addition to localised issues related to network limitations, an assessment of overall system curtailment will take place using the outputs of the PLEXOS production simulations for the two core scenarios and the three Network Sensitivities for the Ireland and Northern Ireland system. This curtailment may be a result of system operational constraints relating to reserve provision, minimum inertia requirements, or maximum penetration levels of non-synchronous sources in the synchronous system of Ireland and Northern Ireland.

These five cases will be reassessed in Task 2.6 to identify possible flexibility solutions to any congestion discovered.

# 8. SYSTEM RESTORATION

## 8.1 HIGH LEVEL OVERVIEW OF SYSTEM RESTORATION SCARCITIES

Power systems are now regularly being pushed closer to their operational limits as a result of de-carbonisation and a drive towards greater utilisation of system assets. The increased extreme weather events together with large penetrations of variable generation resources can cause various voltage and frequency disturbances. These events can lead to wide-area blackouts. Power system restoration is the process required to restore the system to steady state operation following a partial or complete collapse causing an extensive loss of supply.

The EU-SysFlex review of system scarcities (EU-SysFlex, 2018) indicates that as the penetration of variable renewable generation (both in transmission and distribution systems) becomes higher, the need for ancillary services, including system restoration, will accordingly increase. The review highlighted three stages concerning system restoration (Liu, Fan, & Terzija, 2016) (Holttinen et al., 2012):

- Black Start or preparation stage (also called re-energisation);
- Network reconfiguration; and
- Load restoration (or synchronisation).

Black Start (or preparation stage) – System restoration services have been traditionally provided by large-scale synchronous generators (e.g. hydro or coal plants), which have Black Start capability. However, the transition to systems with high share of renewable and non-synchronous generation will result in a reduction in the number of synchronous generation capacity and thus a reduction in traditional system restoration capability. As such, new restoration strategies should be designed that leverage the flexibility of other providers such as HVDC interconnectors, battery energy storage systems, or even non-synchronous renewable generation.

Network Reconfiguration – Once the initial Black Start has begun, system restoration plans traditionally seek to restore larger conventional generation sources on the system to initiate provision of power to bulk supply points. However, increasing levels of zero marginal cost generation may mean some of these conventional generation plants will no longer be operational in the future due to decreases in energy market revenue. In this situation, network reconfiguration paths will need to be refined.

Load Restoration – Similarly, as more embedded renewable generation connects to the distribution system, such as rooftop solar PV, there will be increased challenges in managing load restoration. Where historically distribution system networks would have energised load to maintain the generation – load balance, in the future much of this load will also have substantial levels of embedded generation. Depending on the time of day, and time of year, the restoration is taking place; the re-energised load could result in a net increase in generation and further complicate the restoration process.

## 8.2 SYSTEM RESTORATION ASSESSMENT OVERVIEW

### 8.2.1 IRELAND AND NORTHERN IRELAND – OVERVIEW OF EXISTING SYSTEM RESTORATION PLAN

Ireland and Northern Ireland's current Power System Restoration Plans seek to restore a continuous supply of electricity, as quickly and as safely as possible to Generation, Transmission, Distribution and Customer Systems in the event of a total system blackout. The Power System Restoration Plans assume a total loss of electricity supply to the Transmission System with no damage to the Transmission System and the current plans are not cognisant of any Generation or Transmission unavailability. The plans are designed so relevant sections can also be implemented to deal with other scenarios such as a partial system blackout.

The existing Power System Restoration Plan outlines a framework of actions to achieve the above objective. In Ireland, the foundation of this plan is the Black Start capability of four hydro stations, one pumped storage station, one thermal station and one HVDC Interconnector. The Ireland plan also addresses how to use supply from Northern Ireland should this be available. In Northern Ireland, the majority of conventional generator units have Black Start capability. The Power System Restoration Plans are intended to be flexible and relies heavily on Generation Stations and the DSO preparing specific Black Start plans and procedures and the training of all relevant staff to rigorous standards.

The existing plans adopt a strategy of restoring four independent subsystems in Ireland and three in Northern Ireland from a total blackout situation. These subsystems are in the North, South, East and West of Ireland, and split across the country surrounding the three main generation stations in Northern Ireland. Restoration of supply to all generation units in each subsystem is initiated by using the capability of the blackstart generator(s) in that subsystem and/or by getting supply from Northern Ireland (if available) across the interconnectors for Ireland. These subsystems would proceed with their restorations concurrently, before synchronisation occurs between subsystems.

When subsystems are synchronised, further restoration of 400 kV, 275 kV and 220 kV facilities are progressed, paying careful attention to the Mvar capacities of individual feeders and the capacity of synchronised generators to absorb Mvars. The voltage on the 220 kV system is kept low during restoration, preferably at 205 kV or lower.

The objective of getting as many generators as possible on load, while avoiding a second collapse of the subsystem, is carefully considered in the plan. The plan is structured such that system stability takes precedence over speed of restoration.

The structure of the subsystems has been chosen to take account of:

(a) Capacity of the primary base stations;

(b) Ease and flexibility of choice in subsequent synchronisation of the four subsystems;

(c) Time required by non-blackstart units to re-sync following loss of external supply; and
(d) Network location of non-blackstart units relative to the system configuration and primary base stations.

At the early stages of restoration the first priority is to stabilise the running of the Black Start units. Therefore, very small blocks of load which require the fewest switching steps, will be selected for reconnection. During these initial stages of restoration, the TSO works closely with the DSO to carefully coordinate load restoration from critical supply points. Careful consideration should apply to all load restoration with small blocks of load being introduced to each delicate blackstart path as directed by the TSO. Once additional generators synchronise to the subsystem, priority loads (as determined by both the TSO and the DSO) should be reconnected. Priority loads include the control centres themselves, hospitals, airports and other loads of national importance. As restoration progresses and subsystems become more established load reconnection will take place at a pace dictated by the availability of the generation connected to the system. Once each subsystem has been stabilised and/or synchronised to a larger system, the DSO control centres will coordinate the load restoration effort.

### 8.2.2 IRELAND AND NORTHERN IRELAND – 2030 SYSTEM RESTORATION ASSESSMENT

An assessment of the existing Ireland and Northern Ireland Power System Restoration Plans for the three stages of system restoration will be carried out using the 2030 EU-SysFlex scenarios and Network Sensitivities.

This assessment will take account of the following considerations in the existing plan:

- Black Start stage:
  - Availability of existing Black Start generator units under each scenario;
  - Additional new sources of Black Start capable technologies such as additional interconnectors and battery energy storage devices; and
  - Assessment of the possibility of non-synchronous generation offering Black Start capability.

- Network reconfiguration:
  - New network devices which can support network reconfiguration and system voltages; and
  - Enhanced capabilities of generation and demand technologies to provide support for network reconfiguration.

- Load restoration (or synchronisation):
  - Likely transmission system loads which will be seen under each EU-SysFlex scenario and network sensitivity;
  - Time of day and the time of year variance on load due to new technologies such as embedded renewable generation and the electrification of heat and transport; and
  - Assessment of capability of distribution connected generation to provide Black Start services.

The assessment will consider the EU-SysFlex scenarios and Network Sensitivities for Ireland and Northern Ireland as outlined in Table 11. It will focus on these overall demand and generation portfolios and also focus on different system restoration strategies for different times of the year and day in each scenario.

# 9. COORDINATION BETWEEN MODELS FOR SYSTEM SCARCITY SIMULATIONS PREPARATION

## 9.1 INTERACTIONS BETWEEN MODELS

The inter-model interactions between all models are illustrated in Figure 85.

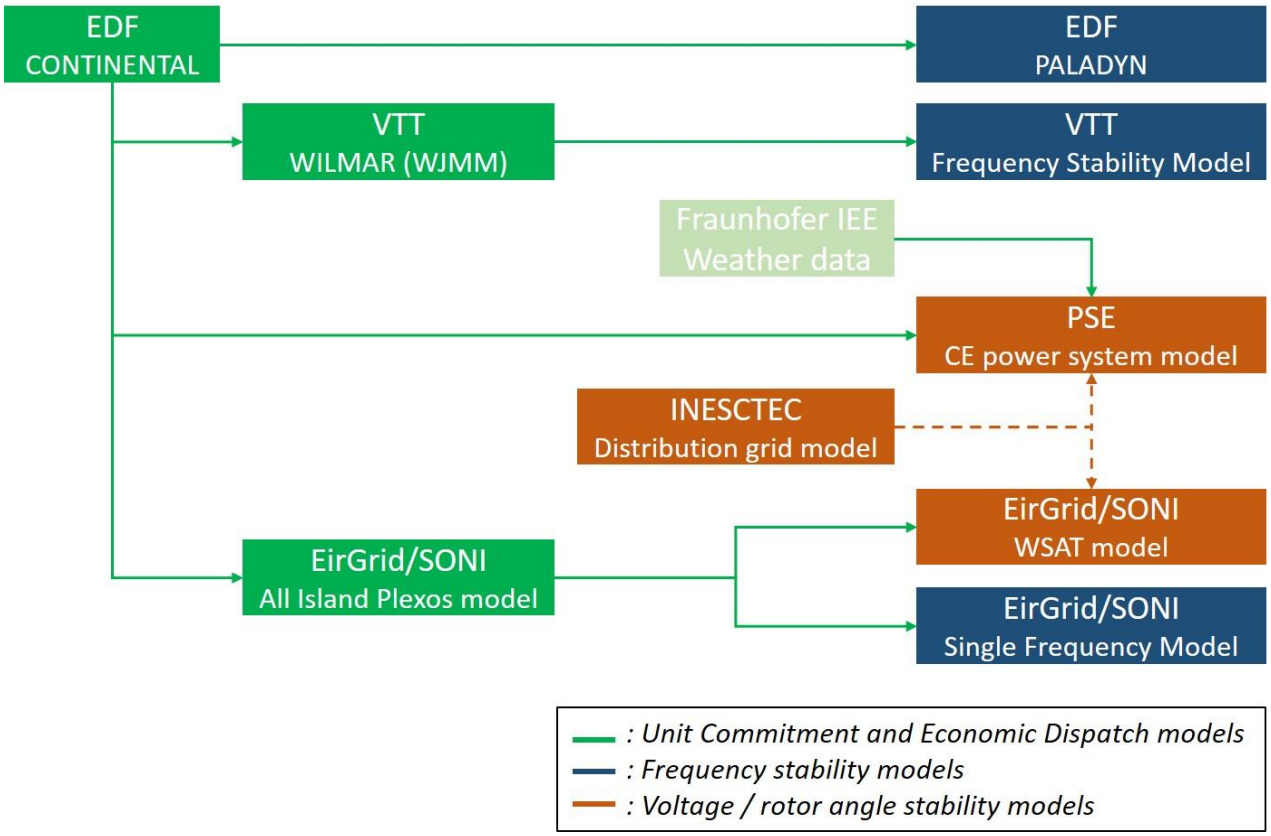



FIGURE 85: SUMMARY OF INTERACTIONS BETWEEN PARTNERS MODELS

Some details on these interactions are listed below:

- The EDF tool CONTINENTAL (3.1.1) will simulate the EU-SysFlex scenarios developed in Task 2.2, and provide the following hourly data for most European countries:
  - Load [MW]
  - Generation dispatch for each technology [MW]
  - Reserves (FCR, aFRR) for each technology [MW]
  - Kinetic energy [MVA.s]

  Generation technologies considered by CONTINENTAL are:
  - Nuclear
  - Hydro
  - Coal
  - Combined cycle gas turbine
  - Open cycle gas or oil turbine
  - Biomass
  - Cogeneration
  - Wind
  - Solar

The EDF model PALADYN (3.1.3) will use CONTINENTAL data to run frequency stability simulations on several hours of the year. VTT will simulate one year with a more detailed Nordic model WILMAR (3.3.1), taking the hourly exchanges from CONTINENTAL model, and using the same scenario for generation and load in Sweden, Denmark and Norway. EDF will send some snapshots of CONTINENTAL data to PSE for several worst hours in the year, previously identified with stability indicators later described in 5.3.1. Finally, interconnector flows will be provided by CONTINENTAL to EirGrid/SONI for the study on Ireland and Northern Ireland with PLEXOS.

- The VTT model WILMAR (WJMM) will provide data to conduct simulations on VTT's frequency stability model (3.3.2) for each hour of the year. WJMM outputs include:
    - scheduled electricity production (charging when applicable) of power plants, storages, EV and other resources
    - scheduled heat production (charging when applicable) of heating plants and storages
    - reserve allocation by plant and reserve type

- Fraunhofer IEE will produce spatial distribution of weather data (solar radiation, wind speed and temperature), that will be used by PSE to assess the repartition of wind and solar power inside the Eastern Europe countries.

- INESC TEC distribution grid model (3.5) will be integrated in PSE and EirGrid transmission models. The aim is to represent the impact of distribution grids on transmission level, and to assess the role of distribution flexibilities for the system stability.

- The EirGrid model PLEXOS (3.4.1) will provide unit commitment data according to the EU-SysFlex core scenarios and Ireland sensitivities:
    - Least cost dispatches for all units,
    - Total net demand,
    - Production costs,
    - VRES curtailment or dispatch down levels,
    - Indication of RES-E levels for Ireland and NI,
    - SNSP levels,
    - Inertia levels,
    - Indication of reactive power capability,
    - Indication of system ramping capability,

  This data will be used to run simulations on the Ireland and Northern Ireland system with two models: WSAT suite of tools for voltage and rotor angle stability (3.4.2), and Single Frequency Model for frequency stability (3.4.3).

## 9.2 SUMMARY OF SIMULATIONS PLANNED TO DEMONSTRATE SYSTEM SCARCITIES

The dynamic models will be used to perform simulations that will be described in details within Task 2.4 of EU-SysFlex, which will determine the technical scarcities associated with high levels of renewable generation on European system. Table 25 provides an overview of the models applications, and the stability indicators that were chosen for each stability issue.

TABLE 25: SUMMARY OF SIMULATIONS TO BE RUN IN TASK 2.4

| Category | Power System | Scheduled simulations | Indicators |
|---|---|---|---|
| **Frequency Stability and Control** | Ireland & Northern Ireland | Loss of infeed, loss of load/export for each hour of the year | Frequency nadir/zenith, ROCOF, frequency rise/drop duration index |
| | Continental Europe | Simulation of events for each hour of the year:<br>- Interconnected incidents<br>- System splits | |
| | Nordic system | Simulation of events for each hour of the year:<br>- Interconnected incidents<br>- System splits | Frequency nadir/zenith, ROCOF |
| **Voltage Control** | Ireland & Northern Ireland | Series of faults in Ireland and Northern Ireland on each hour of the year | Short circuit levels, voltage drop/rise duration index, voltage security index, voltage stability margin, voltage stability limits |
| | Continental Europe | Series of 3-phase short-circuits for the worst hours of the year following criteria:<br>- Maximum power demand<br>- Minimum reactive power margins | Short circuit levels, FRT capability profiles, voltage security index, voltage stability margin, voltage stability limits |
| **Rotor Angle Stability** | Ireland & Northern Ireland | Series of short circuit faults in Ireland and Northern Ireland on each hour of the year | Angle margin index, critical clearing time, stability margin, decay time constants |
| | Continental Europe | Series of short circuit faults in Poland and neighbour countries, for the worst hours of the year following criteria:<br>- Minimum inertia<br>- Maximum power demand | Transient stability margin, settling time and halving time |
| **Congestion** | Ireland & Northern Ireland | Congestion assessment for base case operation and single contingency conditions | Thermal limits of equipment, compensation switching, voltage collapse margin |
| | Continental Europe | Base case operation, congestion assessment on borders | Thermal limits of equipment |
| | Nordic system | Base case operation, congestion assessment between bidding zones | Thermal limits of equipment |
| **System Restoration** | Ireland & Northern Ireland | Assessment of the 2030 system restoration plan | |

# 10. CONCLUSION

This report provides the outcome of the dynamic model development for the EU-SysFlex project (Task 2.3 of the EU-SysFlex project). Three European power systems are modelled: Continental Europe power system, Nordic power system and Ireland and Northern Ireland power system.

### Classification of models

Due to the increasing penetration of non-synchronous VRES, the European power system is likely to face exceptional challenges over the coming decades. These challenges, or scarcities, have been summarised in EU-SysFlex D2.1 deliverable into five following main categories (EU-SysFlex, 2018). Based on this work, a classification of major stability issues was developed.

TABLE 26: CLASSIFICATION OF STABILITY ISSUES USED IN TASK 2.3

| N° | System Scarcities and Stability Issues | Category |
|---|---|---|
| 1 | Rate of change of frequency | Frequency stability and control |
| 2 | Frequency containment | |
| 3 | Inertia levels | |
| 4 | Voltage dip induced frequency dip | |
| 5 | Adequate reserve provision | |
| 6 | Ramping margins and reserve sizing | |
| 7 | Short circuit levels | Voltage control |
| 8 | Fault-Ride-Through | |
| 9 | Reactive power levels | |
| 10 | Power oscillations | Rotor angle stability |
| 11 | Oscillation modes | |
| 12 | Transient stability margins | |
| 13 | Network congestion | Congestion management |
| 14 | Black-start analysis | System Restoration |

In order to further investigate the aforementioned issues, relevant models capable of addressing these issues are developed in Task 2.3. The table below shows the model capability compared to the stability issue to be investigated. The complementary nature of the models enables the coverage of a broad range of stability studies on the three European power systems under consideration.

TABLE 27: SCOPE OF THE MODELS DEVELOPED IN TASK 2.3

| | Developer | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | EDF | | PSE | VTT | | EirGrid & SONI | | |
| | CONTINENTAL & OPIUM | PALADYN | CE power system model | WILMAR (WJMM) | Frequency stability model | PLEXOS | WSAT | SFM |
| 1 | | X | | | X | | X | X |
| 2 | | X | | | X | | X | X |
| 3 | X | | | | X | X | | |
| 4 | | | | | | | X | |
| 5 | X | | | X | | X | | |
| 6 | X | | | | | X | | |
| 7 | | | X | | | | X | |
| 8 | | | X | | | | X | |
| 9 | | | X | | | | X | |
| 10 | | | X | | | | X | |
| 11 | | | | | | | X | |
| 12 | | | X | | | | X | |
| 13 | X | | | X | | | X | |
| 14 | | | | | | | X | |

| | |
|---|---|
| | Continental Europe power system |
| | Nordic power system |
| | Ireland and Northern Ireland power system |

For the modelling of the Continental Europe power system, the UCED model used is CONTINENTAL (3.1.1), associated with OPIUM (3.1.2) for the assessment of reserve levels in the future system. CONTINENTAL performs a hydro and thermal dispatch optimization to match load profiles developed for the EU-SysFlex scenarios in Task 2.2 and caters for novel technologies such as EV and heat pumps. Generation technologies that are considered by CONTINENTAL for the dispatch are nuclear, hydro, coal, combined cycle gas turbine, open cycle gas or oil turbine, biomass, cogeneration, wind and solar.

Subsequently, PALADYN (3.1.3) is used for frequency stability studies, as it represents the Continental Europe system as a multi-zone model with individual inertias, generation technologies' frequency responses and loads. Additionally, the Continental Europe power system model (3.2) is used for voltage control and rotor angle simulations. It comprises a detailed model of the Poland transmission system and adjacent countries, while the

remaining counties in the CE power system are represented in a simplified manner. A distribution grid model (3.5) is appended to represent the TSO-DSO interfaces in the grid.

Three stability issues are not studied for the Continental Europe power system:

- Voltage dip induced frequency dip: this topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016),
- Oscillation modes: available data and working time are insufficient to run accurate simulations on this issue,
- Black-start analysis: additional black start means are not likely to be needed on most of the Continental Europe countries, which can already rely on multiple hydro power plants. This topic is not considered by the Continental Europe TSOs as a priority issue (MIGRATE, 2016).

The Nordic system study uses the UCED model WILMAR (WJMM, 3.3.1)) for dispatching and congestion assessment. The model simulates the hydro-thermal dispatch of a multi-area system for every hour of the year, given the interconnection constraints between the areas. It provides scheduled electricity production of power plants, storages, EV and other resources, scheduled heat production of heating plants and storage, and reserves allocations. The dynamic study on the Nordic system will focus on frequency stability, using a specific model (3.3.2). Similar to the Ireland and Northern Ireland Single Frequency Model, the frequency stability model for Nordic power system is a single bus model providing time series of system kinetic energy and frequency stability indicators.

The study on Ireland and Northern Ireland will be extensive, a broad variety of issues will be investigated in a sequence of models, including PLEXOS, a Unit Commitment and Economic Dispatch model (3.4.1), followed by two dynamic models:

- WSAT: A suite of tools used for performing quasi steady state and time domain simulations (3.4.2). It is suitable for investigating classical voltage stability, frequency stability, dynamic voltage stability and rotor angle stability. The models contain a detailed model of the Ireland and Northern Ireland transmission system, and a representation of the TSO / DSO border with the implementation of the generic distribution grid model (3.5) at certain locations, subject to study requirements.
- Single Frequency Model (3.4.3): developed in Matlab, it is a simplified version of Ireland and Northern Ireland system model assuming perfect voltage regulation and uniform system frequency. This is mainly suitable for screening type studies pertaining to active power balance in the system and hence frequency stability.

### Interactions between models

The inter-model interactions between all models are illustrated below.

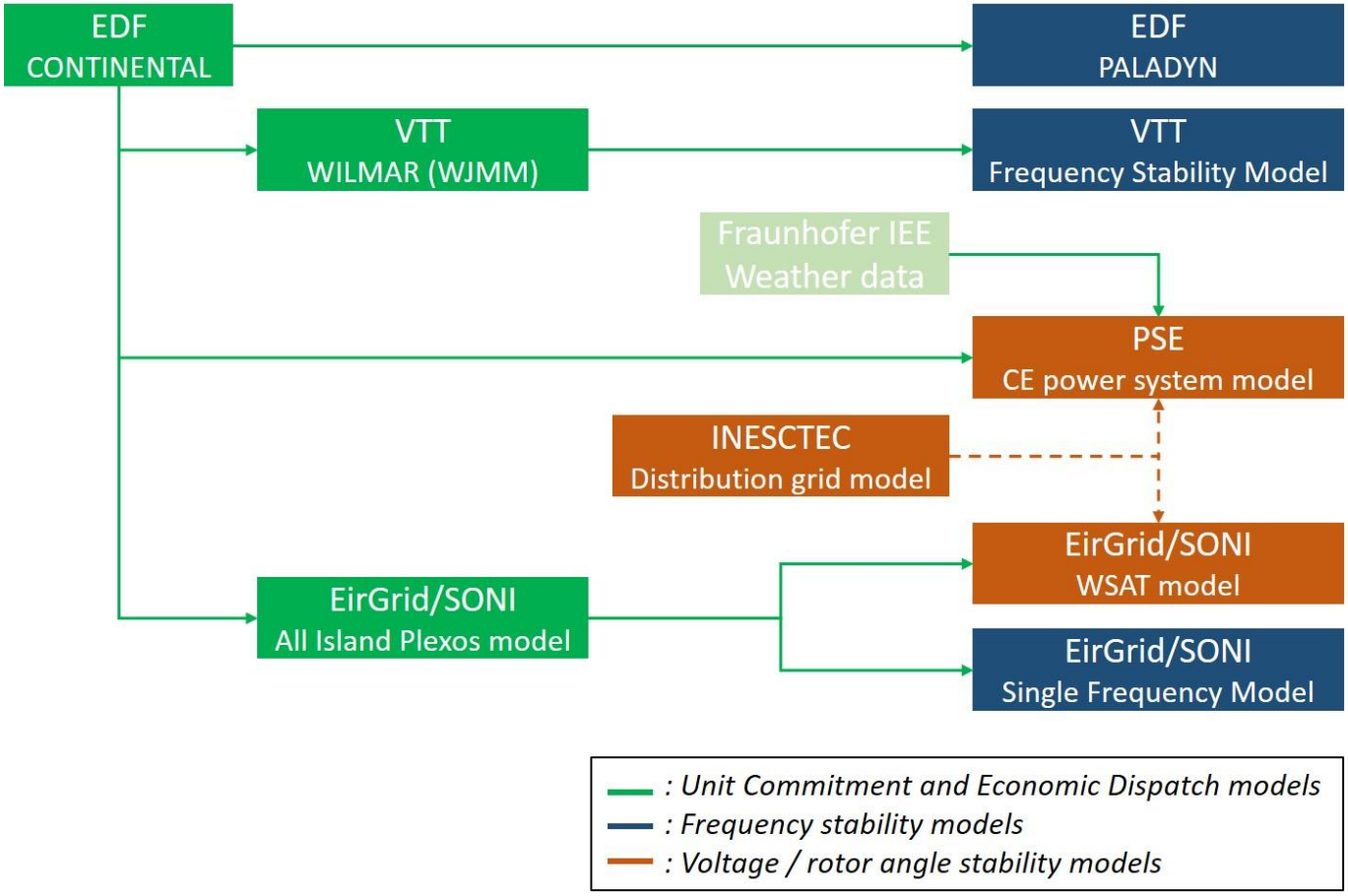



FIGURE 86: SUMMARY OF INTERACTIONS BETWEEN PARTNERS MODELS

### Stability indicators

The **frequency stability** results on the three power systems will be compared through analysis of the frequency nadir/zenith (worst deviation from 50 Hz), and the ROCOF (frequency gradient) on each incident. In addition, EirGrid/SONI and EDF will use the frequency rise/drop duration index to quantify the amount of time the frequency is outside an acceptable envelope.

With those indicators, the behaviour of each power system after a disturbance will be assessed and compared.

**Voltage control** simulations will lead to an assessment of short circuit levels on Ireland and Northern Ireland and Continental Europe systems. The dynamic voltage profiles will be simulated, to ensure that generation resources stay connected following a fault recovery.

Steady state voltage deviations will be assessed for Ireland and Northern Ireland and Continental Europe, the requirements being different on those two systems. Finally, voltage stability margins (with P-V curves) and voltage stability limits (with Q-V curves) will be used on the two systems to assess voltage stability.

**Rotor angle stability** study will consist in:

- Time-domain transient stability simulations on the Ireland and Northern Ireland system and Continental Europe system will be undertaken, leading to critical clearing time and short circuit power assessment on both systems, along with angle margin index in Ireland and Northern Ireland.
- Oscillatory stability analysis on the Ireland and Northern Ireland system and Continental Europe system will be carried out, with an analysis of the oscillation modes damping.

**Congestion assessment** on Ireland and Northern Ireland, Continental Europe and Nordic system will be based on an evaluation of thermal limits of equipment. EirGrid and SONI will also check the voltage step resulting from reactive compensation switching, and evaluate the voltage collapse margin.

**System restoration study** will consist of assessing the existing Ireland and Northern Ireland power system restoration plans for the three stages of system restoration (black start, network reconfiguration and load restoration).

### Minimum requirements for models

The following table gives an overview of minimum time and space granularity requirements for each type of model developed in Task 2.3.

TABLE 28: REQUIREMENT FOR TASK 2.3 MODELS

| Model attribute | UCED | Frequency stability | Voltage / rotor angle stability |
|---|---|---|---|
| Time granularity of the model | [15 min; hour] | < 1s | < 100 ms |
| Minimal time horizon of the study | Several climatic year scenarios | Snapshots corresponding to the “worst” hours of the year | Snapshots corresponding to the “worst” hours of the year |
| Geographical resolution | Country / bidding zone | Country or zone with several homogeneous countries | Nodes of the transmission system |

### Perspectives and applications of the models

The dynamic models are used to perform simulations that will be described in detail within Task 2.4 which will determine the technical scarcities associated with high levels of renewable generation on European system. The results obtained for each scenario, stability issue and power system will be analysed and compared.

EU-SysFlex Task 2.6 will take learnings from the demonstration projects within the EU-SysFlex project (i.e. WP6 – WP9) and integrate them, along with other solutions, to show the impacts of deploying different mitigation measures to address the various scarcities identified. In this Task, models developed within Task 2.3 could be adapted and enriched with innovative solutions modelling.

The description of models can also be helpful for other WPs. In WP3, these models may be of support in particular to Task 3.4 – 'Impact analysis of market and regulatory options through advanced power system and market modelling'. Finally, the work detailed in this report will be of benefit to WP4 and principally Task 4.1 – 'Integration of System Services from new technologies into System Operator scheduling and decision support tools'.

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# ANNEX I. PRONY'S METHOD

Prony's method decomposes a time domain signal into the sum of a number of damped oscillatory components. For assessing small signal stability, Prony's method can be applied to the time domain response of the system to a disturbance and then the stability of each component can be assessed independently. For example, Figure 87 shows how an oscillatory response can be decomposed into two dominant oscillatory components.

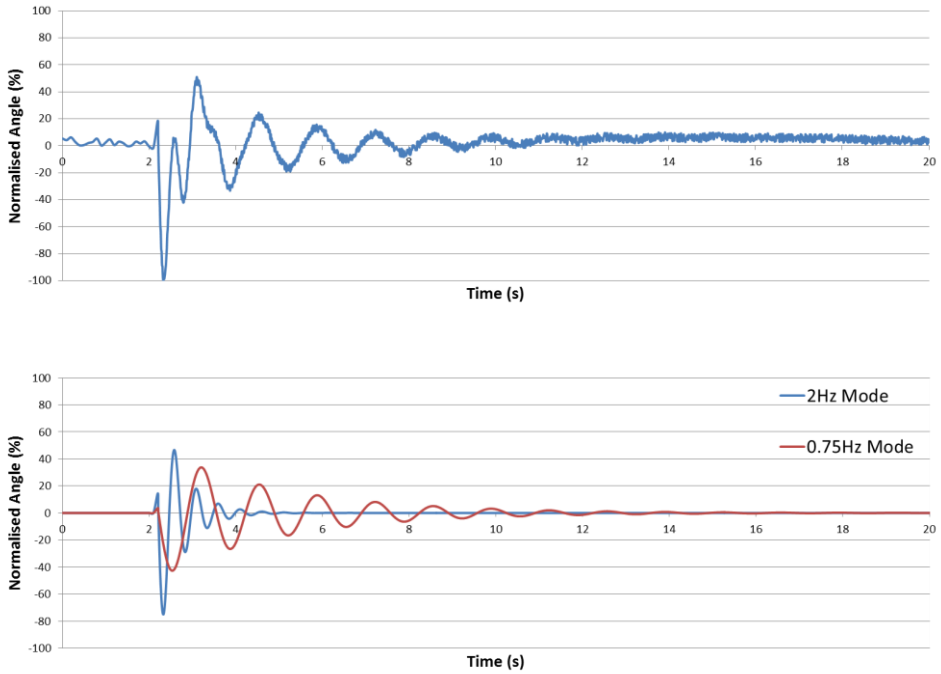



FIGURE 87: DECOMPOSITION OF A SIGNAL INTO ITS DOMINANT OSCILLATORY MODES

Each of these oscillatory components is defined according to its amplitude ($A$), damping ratio ($\xi$), natural frequency ($\omega_0$) and phase ($\varphi$). Where the damping ratio is less than 1 this can be described as follows:

$$f(t) = \mathrm{A}e^{-\xi\omega_0 t} sin\left(\sqrt{1-\xi^2}\omega_0 t + \varphi\right)$$

Furthermore, each component can also be expressed in terms of the relaxation time ($\tau$) and angular frequency ($\omega_1$):

$$f(t) = \mathrm{A}e^{-t/\tau} sin(\omega_1 t + \varphi)$$

The damping ratio describes the behaviour of an oscillatory system as the ratio between the damping of the system and the critical damping of the system, where the critical damping of the system is the level of damping required for the system to reach a steady state as quickly as possible without oscillating. As such, a critically damped system (where $\xi = 1$) will reach a steady state without oscillating but an underdamped system (where $\xi < 1$) will oscillate after any disturbance. The step responses of a critically damped and under damped system are compared in Figure 88.

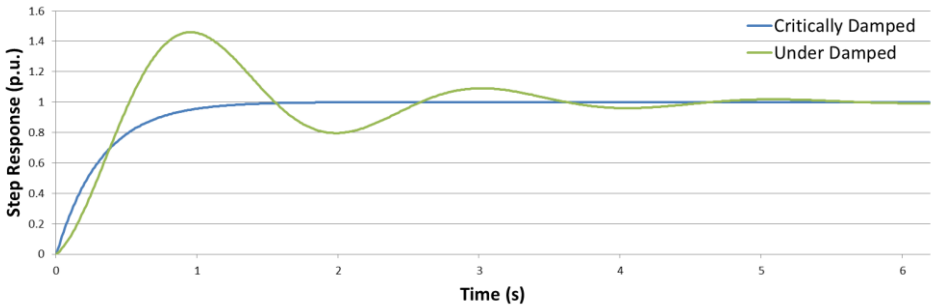



FIGURE 88: STABLE, UNDER DAMPED SYSTEMS WILL OSCILLATE BEFORE REACHING A NEW STEADY STATE

If the oscillation is stable (i.e. $0 < \xi < 1$) then the system will oscillate prior to reaching a new steady state. However, if the system is unstable ($\xi < 0$) it will oscillate with increasing magnitude and not reach a new steady state. Whilst oscillatory instability is the focus of this assessment, Prony's method can capture any asynchronous instability by including a single term that contains only the damped exponential and not the oscillatory component ($\mathrm{Ae}^{-\mathrm{t}/\tau}$).

As such, if an oscillatory mode is critically damped ($\xi = 1$) or over damped ($\xi > 1$) then it cannot be assessed using Prony's method, as it will decay exponentially and this decay cannot be distinguished readily from any other exponential decays that are occurring immediately after the disturbance. So all of these decays will be captured by the single term that is a damped exponential that is included. This limitation is not a concern for this analysis, as if the mode is either critically or over damped then it does not exhibit an oscillatory response and, obviously, cannot pose a threat to the oscillatory small signal stability of the system.