



Probabilistic-based cross-border capacity calculation and Cross- border flexibility pre-qualification

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List of Abbreviations and Acronyms

Acronym	Meaning
AAC	Already Allocated Capacity
ACE	Area Control Error
AGC	Automatic Generation Control
aFRR	Automatic Frequency Restoration Reserves
ATC	Available Transfer Capacity
BSP	Balancing Service Provider
DAM	Day-ahead market
DER	Distributed Energy Resources
DT	Digital Twin
DSO	Distribution System Operator
EHV	Extra High Voltage
HV	High voltage
FCR	Frequency Containment Reserves
FFR	Fast Frequency Reserves
FSP	Flexibility Service Provider
KPI	Key Performance Indicator
NTC	Net Transfer Capacity
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
TSO	Transmission System Operator
UC	Use Case

Executive Summary

This deliverable of the TwinEU project shows the implementation of the use cases developed in the TwinEU – Task 8.4: “Probabilistic-based cross-border capacity calculations and Cross-border assessment of flexibility and pre-qualification”:

- UC-Ib03. DT-enabled multi-area system dynamic behaviour assessment, implemented by the INESC-TEC;
- UC-Ib10. Probabilistic cross-border capacity allocation, implemented by R&D Nester and REN;
- UC-Ib11. Cross-border assessment of flexibility and pre-qualification, implemented by R&D Nester and REN;
- UC-Ib13. Enhancement of short-circuit models and TSO/DSO information exchange for operational planning, implemented by R&D Nester and REN.

Furthermore, it is also presented the development of the tool to compute the equivalent dynamic model of distribution grids (NEDM), which is also developed by R&D Nester and REN in the TwinEU-Task 8.4.

The use cases are shortly presented through their objectives and the focus is on their implementation, experimental results and lessons learnt. The annex includes a detailed description of the use-cases, aligned with the TwinEU deliverable [D2.2](#) “TwinEU Use Cases, pan-European scenarios and KPIs”.

The results from UC-Ib03 demonstrate deteriorating frequency Nadir and RoCoF towards 2040, especially during high-renewable spring conditions. A hybrid SC-GFM strategy is recommended, although detailed operator models and additional disturbance data are required before operational deployment.

The UC-Ib10 and the UC-IB11 show the use of Digital Twins for cross-border probabilistic capacity allocation and assessment of flexibility and pre-qualification¹.

In UC-Ib10, the scenario generation prevents the creation of unrealistic time-series and generate a compact set of representative operating scenarios. The results successfully demonstrate how uncertainty, outages, transfer limits and confidence levels can be integrated into a coherent pATC framework to support more risk-aware and transparent cross-border capacity assessment.

In UC-Ib11, simulations demonstrate the expected FFR behaviour, with rapid BESS active-power injection contributing to frequency containment following threshold activation. Overall, the developed Digital Twin provides a suitable environment for studying cross-border FFR provision between Portugal and Spain and, therefore, it is a suitable environment to assess the impact of cross-border flexibility and common arrangements concerning pre-qualification.

In UC-Ib13, the choice of short-circuit representation for wind-based generation has a decisive effect on the operational planning conclusions drawn at the TSO–DSO interface: Short-circuit models that rely on generic, technology-agnostic assumptions risk to misrepresent fault current contributions in a way that is not conservative. It reinforces the case for incorporating technology-specific short-

¹ [Innovation radar > Innovation > Use of DTs for cross-border probabilistic capacity allocation and assessment of flexibility and pre-qualification](#)

circuit representations, rather than a single generic value, into routine operational planning studies wherever wind generation forms a meaningful share of the local generation mix.

The Nester's Equivalent Dynamic Model for distribution grids (NEDM) represents the aggregated effect of the distribution grid dynamics at the TSO-DSO interface only from short-circuit transient data seen from the TSO viewpoint. The NEDM is a generic model automatically parameterized with differential evolution optimisation. The results show accurate reproduction of the dynamics of a detailed active distribution network at the TSO-DSO interface. This is especially useful when detailed data and observability is not fully available or cannot be exchanged because of privacy constraints. Therefore, the model provides a practical way to account for studies where the dynamics at the TSO-DSO interface is relevant.

The use cases' KPIs also show how the TwinEU connector-based infrastructure can support the coordination workflow represented in the Iberian combined grid-model use case for the calculation of probabilistic Available Transference Capacity (ATC). They show the usefulness of the reduction techniques through the high accuracy of the digital twin model with the reduced Iberian network model used in UC-Ib11 and its effective frequency response.

1 Introduction

This report presents the implementation of the digital twins and use-cases developed under the TwinEU project task T8.4 “Probabilistic-based cross-border capacity calculations and Cross-border assessment of flexibility and pre-qualification”.

The work addresses the usage of digital twins to support business activities in the planning and the operational planning of the electricity system. In particular, the developed digital twins enable to robustly assess the dynamics of the system following a possible large disturbance and to study use of new frequency regulation services. Furthermore, the developed digital twins allow to develop new approaches to cross-border coordination, better suited for control areas with high shares of renewable energy sources, as well as to TSO-DSO coordination, particularly to short-circuit modelling at the TSO-DSO interface.

1.1 Task 8.4

Task 8.4 “Probabilistic-based cross-border capacity calculations and Cross-border assessment of flexibility and pre-qualification” is lead by R&D Nester with the contribution of the following partners: ETRA, F4STER, Mavir, INESCTEC, REN, ANELL, CIRCE, Cuerva, REE, TT, OMIE. It ran for 30 months (M03-M33) with the following approach:

Leveraging the integrated Iberian DT continuum, a data-driven stochastic optimisation approach will be applied in order to compute the ATC for the day-ahead and intraday market drawing probabilistic scenarios of VRE generation and grid contingencies to optimize strategies using the DT and compare with BAU.

A properly tuned DT of a large multi-area control system (using the Iberian system as case-study), capable of providing the dynamic behaviour assessment, will be used to enable the identification of the type and volume and characterization of frequency ancillary services (including innovative ones like FFR, virtual inertia), which involves a set of new players like synchronous condensers, power electronic converts from batteries, power converters from RES generating units, pumps from reversible hydro power stations and dynamic load responses (EV charging and also hydrogen electrolyzers).

It will also address the problem of the optimum dimensioning and location of grid forming converters in an equivalent Iberian system for grid scenarios of 2030 and 2040 with large scale integration of power converters and reduced number of synchronous units

1.2 Outline of the Deliverable

The report is organised by use cases, with each of the following chapters depicting the use cases addressed in Task 8.4, namely

- Chapter 2: UC-Ib03. DT-enabled multi-area system dynamic behaviour assessment
- Chapter 3: UC-Ib10. Probabilistic cross-border capacity allocation
- Chapter 4: UC-Ib11. Cross-border assessment of flexibility and pre-qualification
- Chapter 5: UC-Ib13. Enhancement of short-circuit models and TSO/DSO information exchange for operational planning

Furthermore,

- Chapter 6 presents the tool to compute the equivalent dynamic model of distribution networks, while
- Chapter 7 concludes the report.

2 UC-Ib03. DT-enabled multi-area system dynamic behaviour assessment

This section presents the implementation and experimental assessment of UC-Ib03, “DT-enabled multi-area system dynamic behaviour assessment”. The use case develops a Digital Twin of the Iberian power system and its dynamic interaction with Central European system to evaluate frequency stability under current and future operating conditions. The section describes the Digital Twin workflow and equivalent dynamic model, assesses the evolution of system inertia and frequency stability indicators, and evaluates the volume and performance of new frequency ancillary services, including Fast Frequency Response, synchronous condensers and battery energy storage systems operating with Grid Forming converters. It also addresses the optimal location of Grid Forming resources for improving transient stability and concludes with a KPI-based assessment and discussion of the main results. A complete description of the use case, including its actors, information exchanges and operating scenarios, is provided in Annex A.

2.1 Objectives of the use-case

The objective of UC-Ib03 is to develop and demonstrate a Digital Twin capable of assessing the dynamic robustness of the Iberian power system under operating conditions characterised by increasing penetration of converter-interfaced renewable generation and progressively lower levels of synchronous inertia. The Digital Twin represents the dynamic interaction between Portugal, Spain and the Central European system and enables the frequency response following large active-power disturbances to be evaluated through indicators such as the frequency Nadir and the Rate of Change of Frequency.

The specific objectives of the use case are to:

- reproduce the multi-area frequency behaviour of the Iberian and the Central European systems using a calibrated equivalent dynamic model;
- identify operating periods in which reduced synchronous inertia may compromise frequency stability, providing information to system operators at the dispatch control room level;
- quantify the type, characteristics and required volumes of additional frequency ancillary services needed under future operating scenarios;
- compare the effectiveness of Fast Frequency Response, synchronous condensers and battery energy storage systems with Grid Forming controls in improving the frequency Nadir and RoCoF;
- determine suitable locations and capacities for Grid Forming converters to improve the transient stability of the Portuguese transmission system; and
- demonstrate the potential application of the Digital Twin as both a planning tool and an online decision-support platform for monitoring the degree of dynamic robustness of the Iberian power system.

Through these objectives, the use case supports system operators and planning engineers in anticipating frequency stability limitations and in selecting technically effective and economically balanced solutions for the secure operation of future low-inertia power systems.

2.2 Digital Twin Workflow

The workflow starts by collecting operational data from the ENTSO-E Transparency Platform. The data-fetching module retrieves actual generation per production type and actual total load for the countries included in each equivalent area.

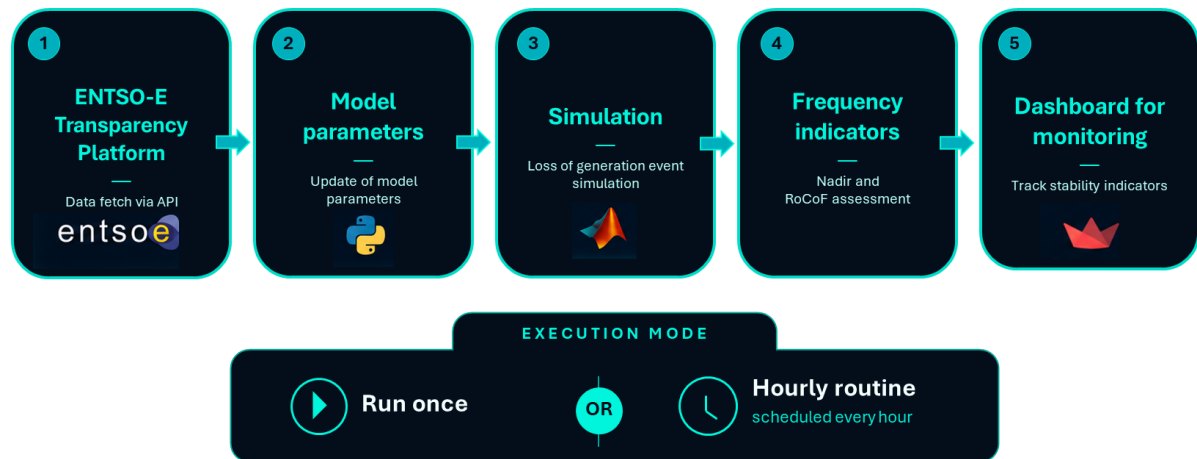


Figure 1. Workflow of the Digital Twin

If data for the target timestamp is not available for a given country, the script applies a fallback rule and selects the latest available timestamp within a predefined lookback window (5 hours). Demand is selected consistently with the generation timestamp used for each country, reducing the risk of combining generation and demand values from inconsistent operating points.

After the data-fetching stage, the parameter calculation module converts the generation and demand data into Simulink model parameter. These include equivalent nominal powers for steam, hydro and combined-cycle gas turbine generation, equivalent inertia constants, load damping coefficients, governor droops and reference load disturbance applied to the Iberian Peninsula area. The calculations use typical inertia constants and load factors by generation technology.

The simulation module reads the calculated parameter and sends them to the Simulink model using MATLAB Engine for Python. The Simulink model is then executed. Based on the resulting frequency trajectory, the module calculates several dynamic performance indicators, including the frequency nadir and the minimum and maximum Rate of Change of Frequency for 100 ms and 500 ms windows.

This script can execute the full workflow once for testing purposes, run immediately and then continue as a scheduler, or remain active and execute automatically every hour at a predefined minute. During each run, the master runner stores execution logs, appends the frequency indicators to a historical file and updates the generation-mix history used by the dashboard.

Finally, the project includes a Streamlit dashboard for monitoring the results. The dashboard displays the Iberian Peninsula generation mix for the latest runs, the frequency nadir trend and the minimum RoCoF values over 100 ms and 500 ms windows. This provides a compact interface for following how changes in the real operating point affect the simulated frequency response of the equivalent two-area system.

Overall, the workflow creates a link between real-time or near-real-time system data, automatic model parameterisation, dynamic simulation and visual monitoring of frequency stability indicators.

This makes it suitable for testing how different operating conditions, especially those involving changes in generation mix and synchronous inertia, influence the dynamic behaviour of the Iberian power system within the Continental European interconnection.

Figure 2 shows the dashboard of the Digital Twin output in on-line execution mode, running automatically every hour, for a disturbance, showing the generation mix and performance indexes (frequency nadir and RoCoF).

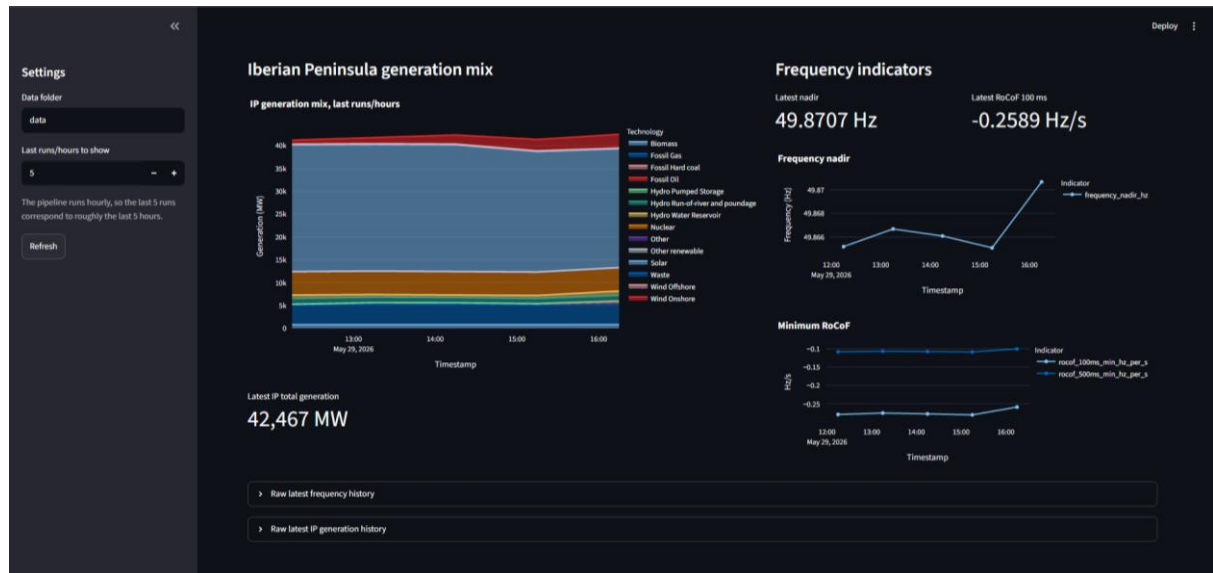


Figure 2. Dashboard of the Digital Twin output

2.3 The Iberian Peninsula-Central Europe equivalent Model

The Iberian Peninsula model, described in Figure 3, was calibrated using a parameter estimation approach, with the aim of matching the model's frequency response to that of the real system under large disturbances.

The parameter identification covers system inertia, system damping, equivalent generator technology droops, and synchronization coefficients between control areas. It was carried out by solving an optimization problem. This problem consists of minimizing the sum of the squared error between the model's frequency response and the real system response, using a metaheuristic approach based on a Particle Swarm Optimization (PSO) algorithm.

The model was tuned considering the real frequency evolutions in Central Europe (CE) and in the Iberian Peninsula (IP) recorded during a reference disturbance that took place in Spain [1]. The disturbance in case was the loss of 1 GW of Active Power, due to the disconnection of the Almaraz II Nuclear plant in January 2025. The parameter estimation process makes it possible to obtain model parameter values that closely match the real system's behaviour and are consistent with actual operating conditions.

The Annex A has a previous description of the model that the reader can be referred to.

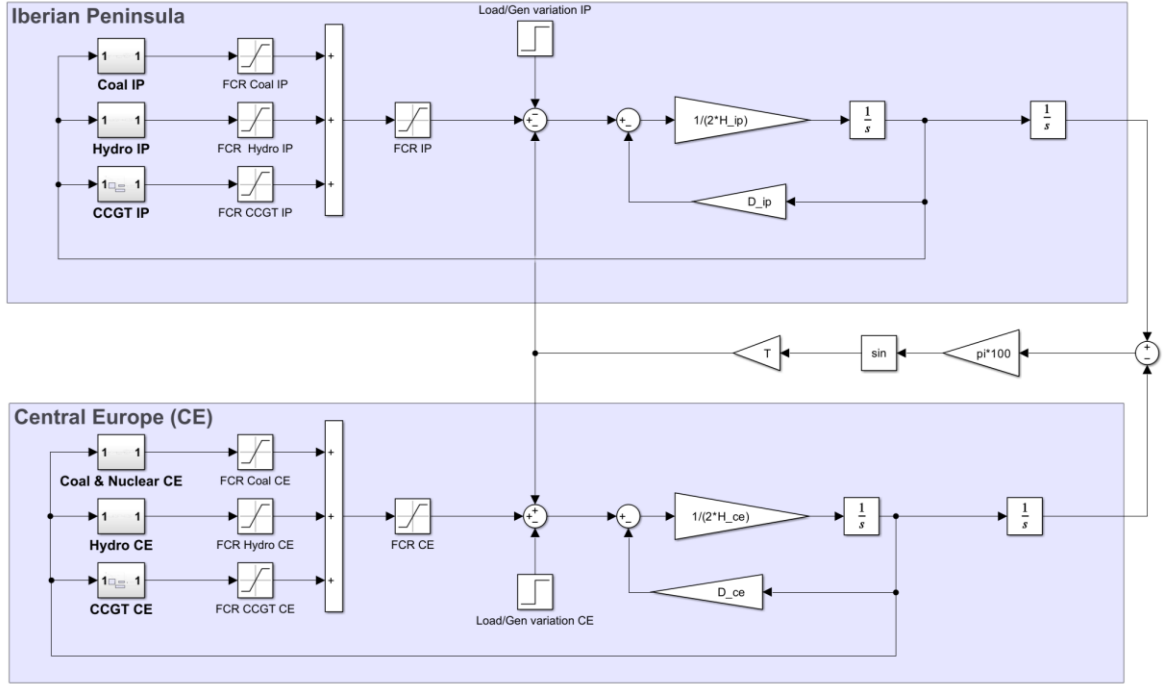


Figure 3. Digital Twin model

This model is suited for frequency stability assessment studies, providing the coherent frequency behaviour of the Iberian system and the Central European system. The Iberian system is strongly interconnected inside the peninsula, leading to large synchronization coefficients among main generation areas, which assures that frequency evolves in the same manner inside the Iberian control area.

The model parameters obtained are representative of the system's operating condition at the time of the reference event used in the estimation process (o). Therefore, they are considered as a starting point for estimating parameter values that represent the system's behaviour under alternative operating conditions (t) in the future. In this way, the parameters can be adjusted to represent a given system state as follows:

- 1) Equivalent droop of technology i ($R_{t,i}$):

$$R_{t,i} = R_{o,i} \times \frac{P_{go,i}}{P_{gt,i}} \quad (1)$$

where $P_{go,i}$ is the active power generated by technology i at the time of the reference event considered in the parameter estimation, and $P_{gt,i}$ is the active power generated by technology i at instant t .

- 2) Damping constant (D_t):

$$D_t = D_o \times I_D \quad (2)$$

Since it is foreseen that the natural damping of the system will reduce, because of the decline of synchronous machines and the increasing dominance of converter-based technologies both at generation and demand side, it was assumed that damping was progressively reduced with time. For analysing the year 2040, D_t corresponds to 25% ($I_D = 0.25$) of the initial damping value at the time of the reference event (D_o). The use of 25 % of the existing actual damping for 2040 is a reasonable pessimistic assumption for the Iberian system. Nuclear power plants and biomass plants will be kept

in operation and later the introduction of synchronous condensers will ensure that natural damping will never be zero.

3) Inertia Constant (H_{sys}):

$$H_{sys} = H_{gen} + H_{load} \quad (3)$$

$$H_{load} = l_{load} H_{sys} \quad (4)$$

$$H_{gen} = \frac{\sum_i (H_i \times S_{G,i})}{P_{load}} \quad (5)$$

where H_{sys} is the system inertia in each area, H_{gen} is the inertia of the total synchronous generation in operation in the area, and H_{load} being the equivalent load inertia, where l_{load} represents the percentage of the system inertia corresponding to the load inertia share. The inertia value related to the system load varies between 8% and 12% according to the literature [2]. Thus, l_{load} assumes a value of 12% for 2024, 10% for 2030, and 8% for 2040. Typical inertia constant values were used for the Hi generation units dispatched, in accordance with their type of generation technology [3], with $S_{G,i}$ being the sum of the rated apparent power of the i type dispatched units per technology in each area.

These calculations enable updating model parameters to assess the dynamic behavior of the three control areas in response to active power disturbances under any relevant operating condition.

2.4 Sizing Frequency Ancillary Services for future Scenarios

2.4.1 Evolution of Frequency Stability Indicators

With the foreseen generation profiles, the system parameters can be updated as described in Section 2.2, allowing simulations to be performed to assess the dynamic robustness of the Iberian Peninsula power system. The frequency behavior following the sudden loss of a 2 GW generation block was assessed for each hour of the spring scenario between 2024 and 2040, assuming the generation portfolio is going to evolve as described in Section 2.4.2. The evolution of the corresponding frequency indicators is illustrated in Figure 4. The Spring operating scenarios in Iberia are the worst-case ones, since wind generation is abundant and solar PV is also quite important, which leads to a large penetration of inverter based renewable generation units leading to more critical Nadir / RoCoF values.

One can observe that the frequency nadir and RoCoF progressively deteriorate from 2024 to 2040. This degradation is particularly evident during daylight hours, when the share of non-synchronous generation increases considerably, hence highlighting the need for additional frequency ancillary services to ensure frequency stability in future operating conditions.

It can also be observed that the Iberian system generally exhibits lower frequency nadirs and RoCoF values during nighttime periods. This behaviour is mainly due to the lower overall synchronous inertia and Frequency Containment Reserve (FCR) available in the Continental European system during these hours, which influences the frequency response of the Iberian system through the interconnection. The high penetration of wind generation across Continental Europe during the night further reduces the synchronous inertia of the Central European system, contributing to this behaviour.

Around midday, synchronous inertia in the Iberian Peninsula reaches its lowest values because of the high contribution of photovoltaic (PV) generation. Consequently, frequency deviations following a disturbance tend to be larger and the frequency nadirs lower during this period. However, owing to

the higher overall inertia of the Continental European system during daytime conditions, the resulting frequency excursions are not as severe as those observed during the night.

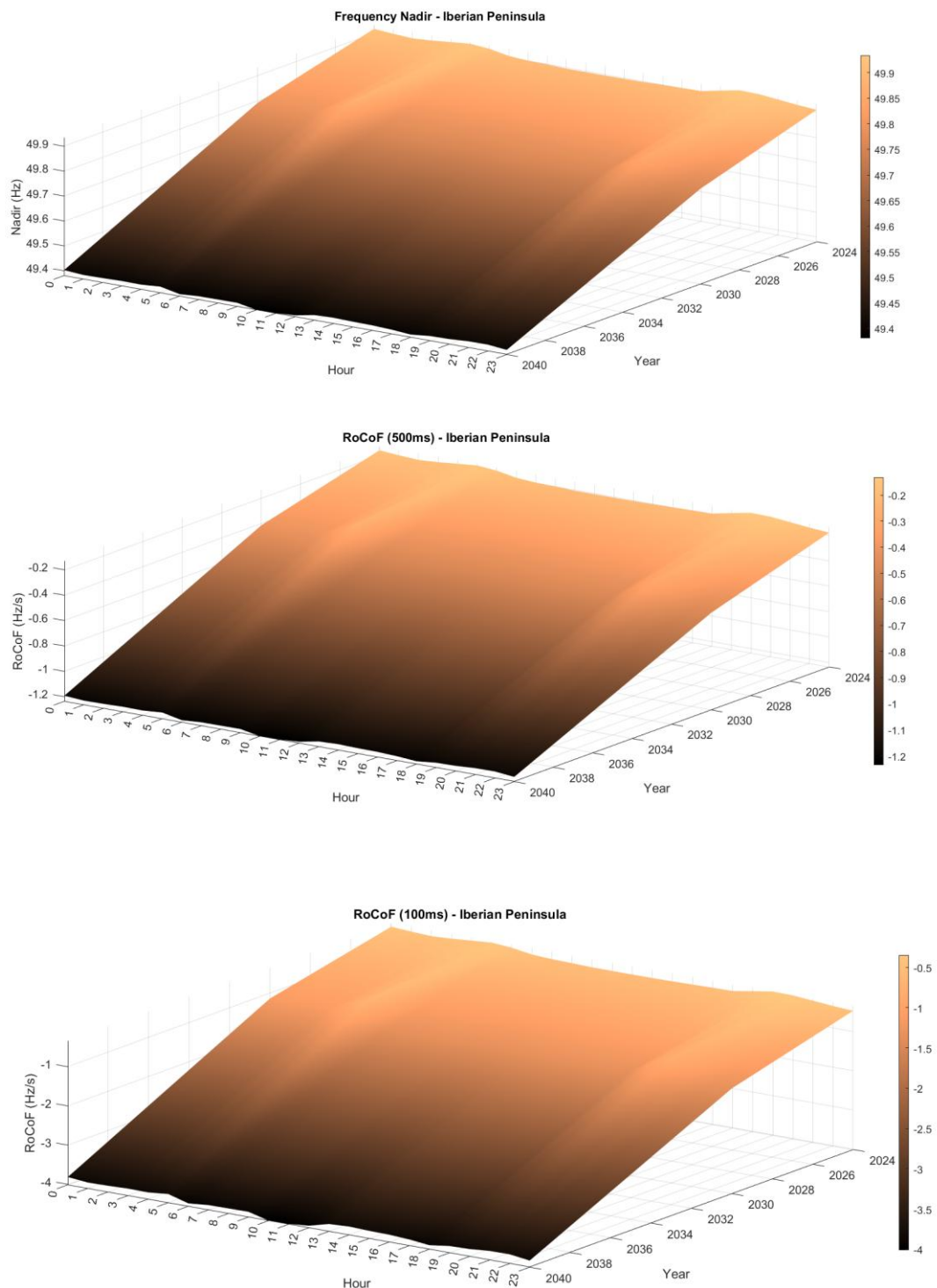


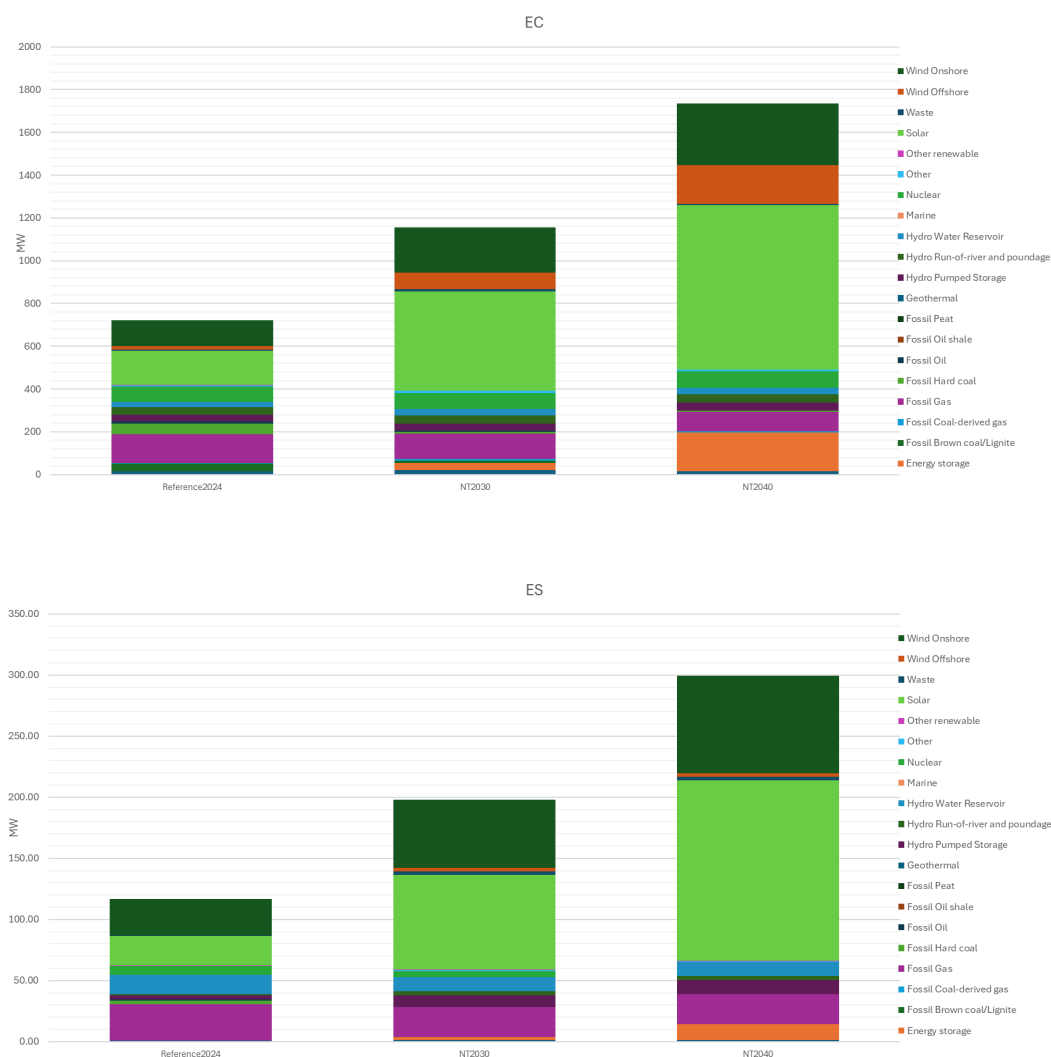
Figure 4. Iberian Peninsula's Nadir and RoCoF evolution, in the Spring Scenario evolution from 2024 to 2040

These findings indicate that the most effective way to improve the dynamic frequency performance of the Iberian power system is to implement frequency-related ancillary services within the Portuguese and Spanish power systems. Given the strong electrical coupling between Portugal and

Spain, together with the significantly larger size of the Spanish system, any frequency support service deployed in Portugal should be accompanied by a corresponding implementation in Spain. This highlights the need for close coordination in the design and deployment of future frequency support solutions across the Iberian Peninsula.

2.4.2 Evolution of the Iberian and Central Europe Power Systems

To carry out the stability studies of the Iberian system in future years, it was necessary to define the evolution of the generation portfolios of Portugal, Spain, and Central Europe up to 2040, based on the scenarios defined as National Trends (NT) in the 2024 ENTSO-E Ten-Year Network Development Plan (TYNDP) [4]. These scenarios are aligned with national energy and climate policies derived from the defined European targets. The data sets for this scenario were collected from the TSOs of the different European countries, reflecting the most recent developments in energy and market policy analyzed at the national level. These scenarios are developed for the time horizons of 2030 and 2040. Figure 5 illustrates the foreseen evolution of the installed capacity by generation technology, according to the 2024 TYNDP NT scenarios in Central Europe (top), Spain (middle), and Portugal (bottom), for the years 2024, 2030, and 2040.



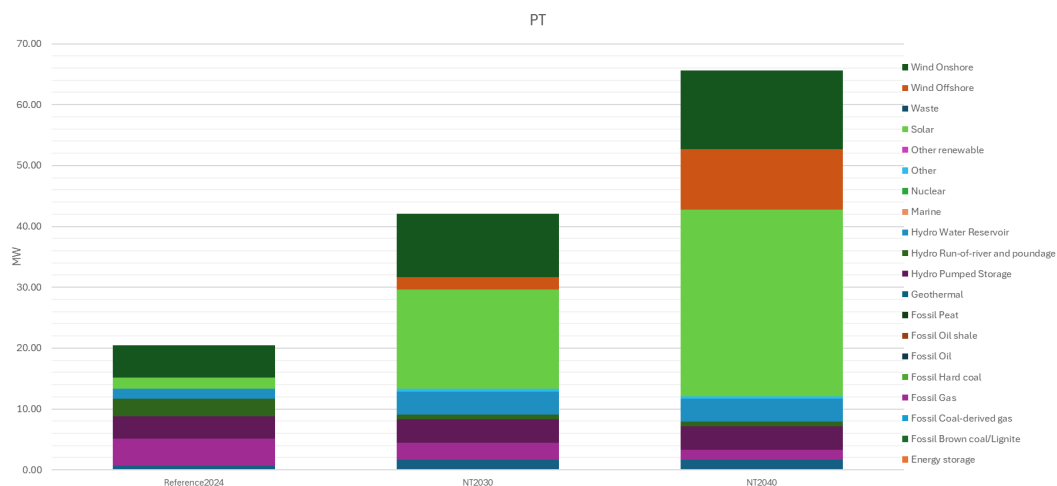


Figure 5. Evolution of installed capacity by generation technology for Central Europe, Spain, and Portugal

The peak loads and net transfer capacities (NTC) between the considered control areas are described in the next tables.

Table 1. Peak Load scenarios for UC-Ib03.

Peak Load (MW)			
Area	2024	2030	2040
PT	9705	9727	10261
SP	37937	51376	57131
CE	288667	434363	540936

Table 2. NTC scenarios for UB-Ib03.

NTC (MW)				
From	To	2024	2030	2040
SP	FR	2800	5000	6500
FR	SP	2800	5000	6500
SP	PT	2700	4200	4200
PT	SP	2700	3500	3500

2.4.3 Scenarios

The most critical days incorporating large shares of renewable generation correspond to spring scenarios due to the simultaneity of large wind generation and solar PV. Typically, these days also

correspond to weekend days with lower demand, but large integration of renewable generation, leading to very low shares of synchronous generation in the control areas of Portugal and Spain. Operating scenarios for the power systems of Portugal, Spain, and Central Europe for weekend days were then defined for the years 2024, 2030, and 2040. The generation profiles of these days in Central Europe and Iberia are described in Figure 6 and Figure 7.

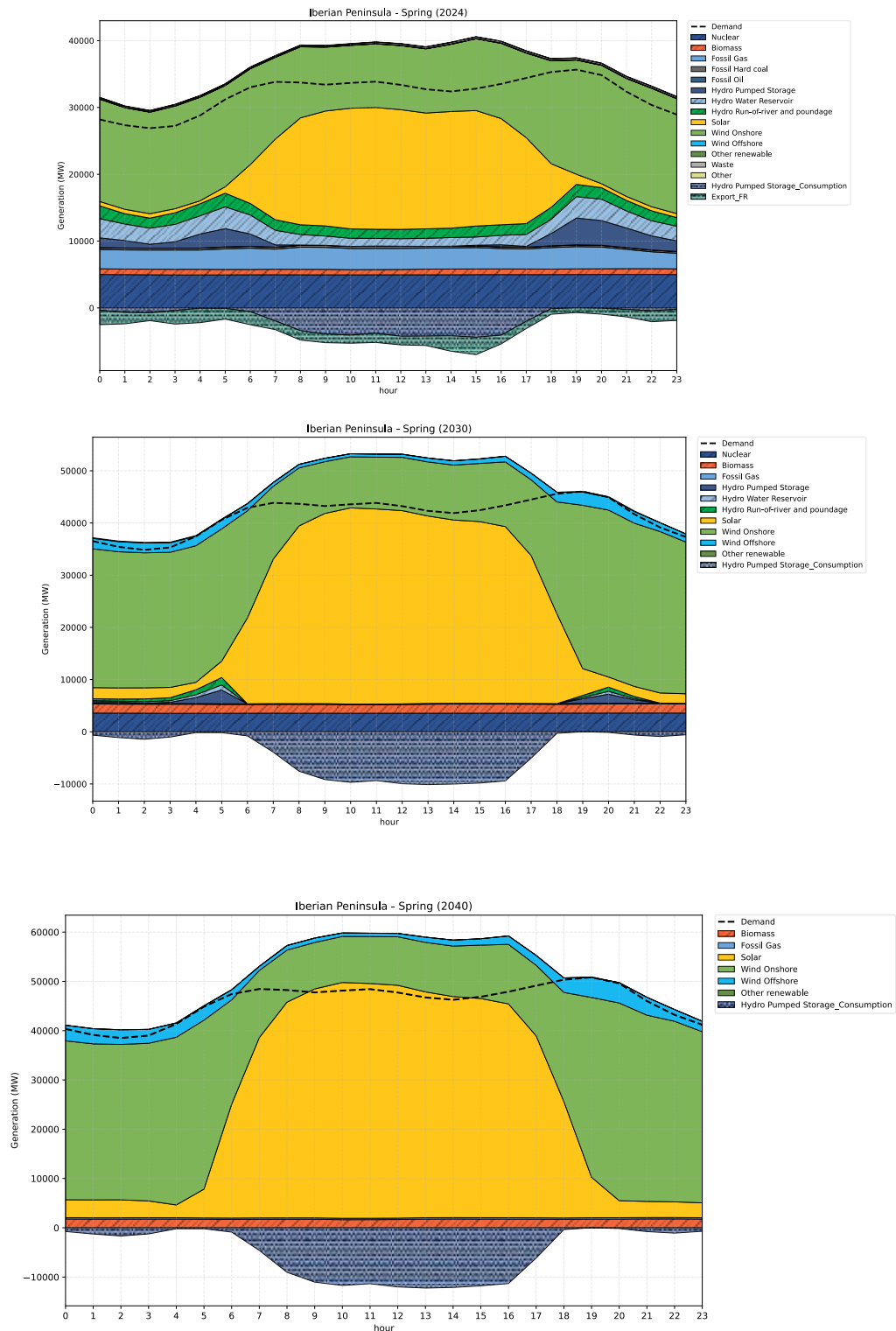


Figure 6. Generation profiles for the years of 2024, 2030, and 2040 for Iberia, Spring Scenario

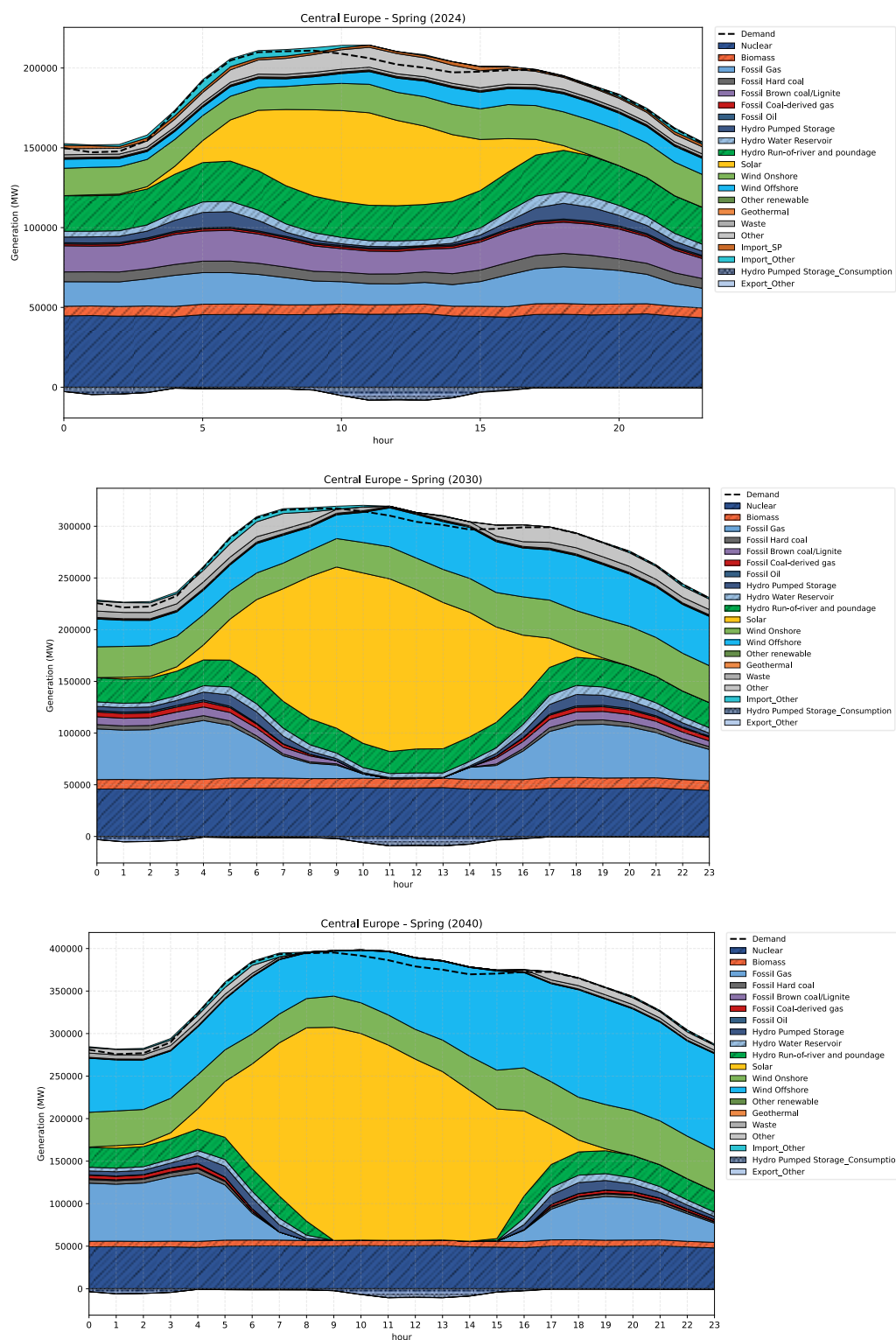


Figure 7. Generation profiles for the years of 2024, 2030, and 2040 for Central Europe, Spring Scenario

2.4.4 Evolution of System Inertia

System inertia for the Iberian Peninsula was calculated according to equations (3), (4) and (5) and exploiting the portfolios of generation and generation profiles described before.

Figure 8 illustrates the evolution of system inertia over the 24-hour period of the critical spring days for the analyzed years in the Portuguese and Spanish power systems. The dashed red line represents the minimum system inertia threshold of 2 s recommended by ENTSO-E [5].

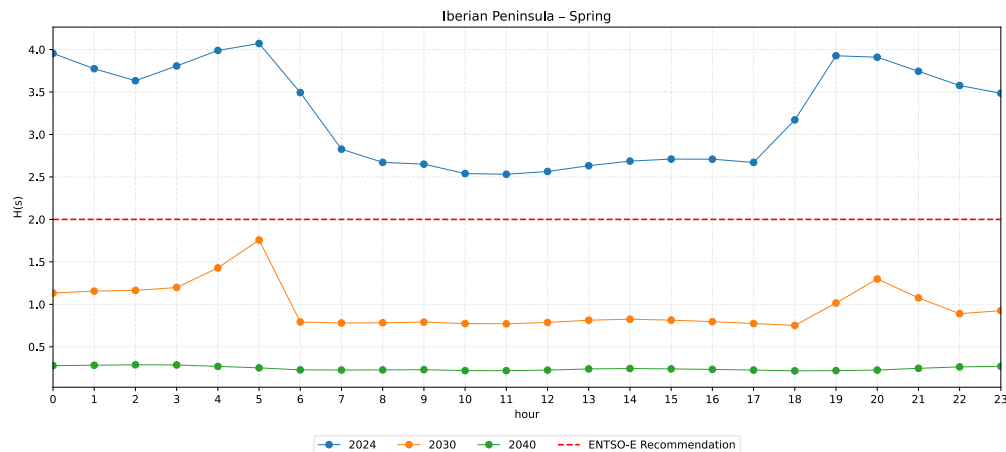


Figure 8. Evolution of the inertia of the Iberian system in the spring scenario

These figures show that synchronous inertia falls below the 2 s threshold in 2030 and 2040, particularly during daytime periods, due to the high penetration of solar photovoltaic generation.

The reduction in system inertia observed in 2030 and 2040 across the Iberian Peninsula is also partly driven by the progressive phase-out of Spain's nuclear power plants. The first nuclear plant, Almaraz, is scheduled for decommissioning before 2030, whereas the last one, Ascó, is expected to be retired before 2040.

2.5 Provision of New Frequency Ancillary Services

In face of the frequency stability problems that the Iberian system may face in the coming years, the adoption of new frequency ancillary services was tested, and their volumes were identified exploiting the simulation platform used also for the DT.

These ancillary services include Fast Frequency Response (FFR), synchronous inertia provided by synchronous condensers and synthetic inertia provided by power electronic converters of battery systems operated in Grid Forming (GFM) mode.

The assessment of the required volume of complementary frequency ancillary services was conducted for the 12:00 h operating point of the 2030 and 2040 spring scenarios, since these correspond to the most challenging operating conditions from the perspective of synchronous inertia in the Iberian power system. The analysis was performed considering, as the reference contingency, the loss of a 2 GW generation unit in the Spanish power system.

2.5.1 Fast-Frequency Response

For the adoption of the FFR product, it was necessary to characterize it properly. The implementations currently in service in the ERCOT control area (Texas, USA) [6], Fingrid (Finland) [7], and EirGrid (Ireland) [8] were used as reference cases.

The FFR service was designed to provide an active-power response faster than that delivered by conventional operating reserves, ensuring immediate support to the power–frequency balance shortly after the occurrence of an imbalance between generation and demand.

FFR requires a very fast change in active power, acting within the critical time interval that follows the initial inertial response and precedes the activation of FCR. The main objective of FFR is to reduce the magnitude of frequency excursions following a disturbance and to delay the time at which the frequency nadir occurs, i.e., the minimum frequency reached after a system event.

In general terms, FFR may be described as the rapid injection or absorption of active power by generation units or controllable loads, typically occurring within less than two seconds after a disturbance causing an imbalance between generation and demand. This product is typically characterized by a set of parameters described in Figure 9.

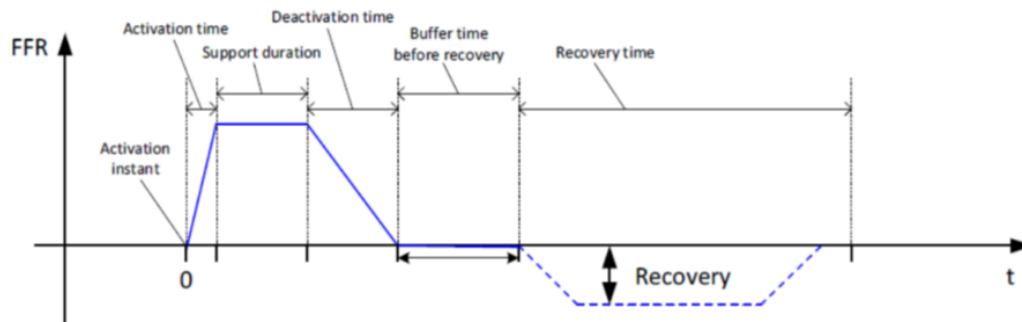


Figure 9. Characterization of the FFR ancillary service

Once the activation frequency threshold is reached, the active power output shall increase linearly until the maximum reserved power is delivered, within a period not exceeding the total activation time. This power level shall then be sustained for a predefined interval, referred to as the support time. At the end of this interval, the delivered active power shall be reduced while ensuring that the magnitude of the power reduction gradient does not exceed the specified deactivation rate.

This ancillary service can be provided by battery energy storage system (BESS) converters, hydropower units with appropriately tuned governors, gas turbines, and power electronic converters associated with wind generation operating below the maximum power point.

The modeling of this FFR ancillary service is performed by adding an injection of active power, as described above in Figure 9, in the node that feeds the swing equation block of the Iberian system in the dynamic model of Figure 3. This swing equation corresponds to the well-known differential equation that describes the behavior of the frequency, depending on the acceleration power, the total inertia and damping constants, as described by Kundur [41].

The studies performed for this FFR product assumed a reserve volume of 400 MW in Portugal and 2,400 MW in Spain. Three alternative FFR products were evaluated, differing in their activation times and activation frequency thresholds, while sharing the remaining characteristics listed in the next table.

Table 3. Characteristics of the FFR products

FFR Product	Reserve (GW)	Activation Time (s)	Support Time (s)	Deactivation Rate (p.u./s)	Activation Frequency (Hz)
FFR 1	2.4 + 0.4	1.30	5	0.2	49.90
FFR 2	2.4 + 0.4	1.00	5	0.2	49.87
FFR 3	2.4 + 0.4	0.70	5	0.2	49.85

The following figures present the dynamic response of the Iberian power system assuming the deployment of the proposed FFR ancillary service with the reserve volumes previously specified, for the reference contingency and for the 2030 and 2040 scenarios. A total of three FFR configurations were evaluated, as defined in the preceding tables.

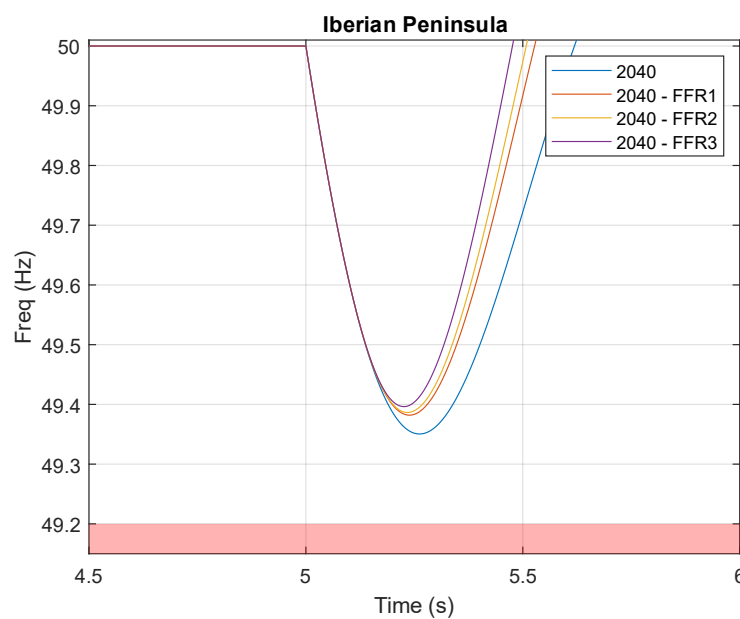


Figure 10. Frequency response in the Iberian system for the different FFR services

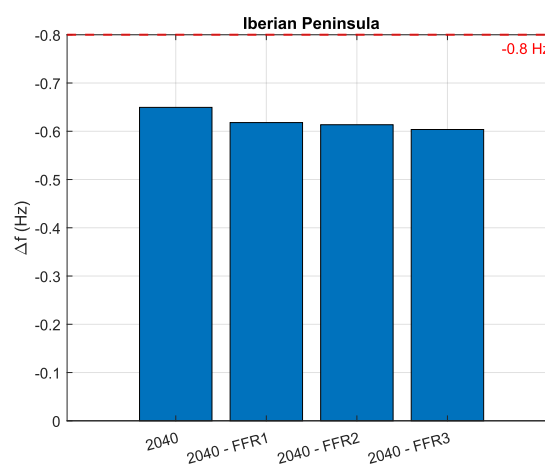


Figure 11. Nadir values of the frequencies for the different FFR services

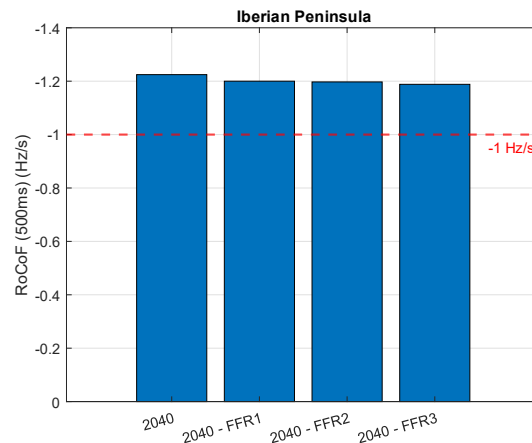


Figure 12. RoCoF (window 500 ms) values of the frequencies for the different FFR services

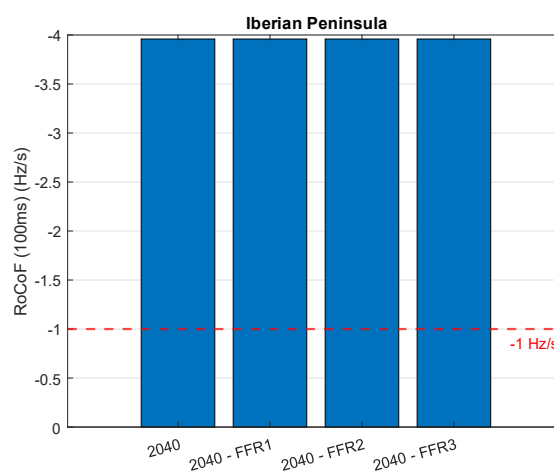


Figure 13. RoCoF (window 100 ms) values of the frequencies for the different FFR services

Figure 10 shows the initial frequency trajectories of the Spanish and Portuguese power systems following the reference disturbance. The results are presented both for the base case, in which no FFR service is available, and for the cases in which the FFR service is implemented according to the characteristics specified in the previous table.

The FFR products used are described also in the next figure.

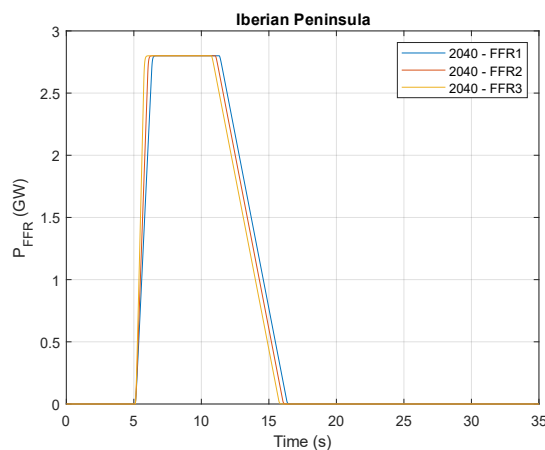


Figure 14. Characterization of the used FFR products

The analysis of the Iberian system frequency response shows that all FFR configurations provide a slight improvement in the frequency nadir. The most significant improvement is achieved by the FFR3 product, which corresponds to the shortest activation time among the products considered. Also it can be observed that the reduction in RoCoF is negligible, owing to the relatively late activation of the FFR service and the finite active-power ramp-up time, which are insufficient to significantly improve the initial rate of frequency decline. A new set of FFR products was then tried with lower activation times, as described in the next table.

Table 4. Characterization of new FFR products

FFR case	Reserve (GW)	Activation time (s)	Support duration (s)	Deactivation rate (p.u./s)	Activation Frequency (Hz)
FFR 1	2.4+0.4	1.30	5	0.2	49.9
FFR 11	2.4+0.4	0,5	5	0.2	49.9
FFR 12	2.4+0.4	0.2	5	0.2	49.9

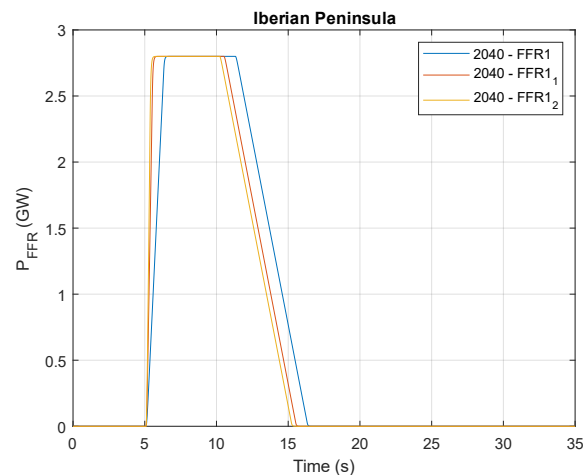


Figure 15. Characterization of the new FFR products

The following figures present the dynamic response of the Iberian power system assuming the implementation of the proposed FFR ancillary service with the reserve volumes previously specified, for the reference contingency and for the 2030 and 2040 scenarios.

The analysis of these figures shows that a significant improvement in the frequency nadir is now achieved in all cases, with an increase exceeding 20 mHz. The best performance is obtained with the FFR12 product, which features the shortest activation time among the configurations considered.

Figure 18 and Figure 19 present the RoCoF profiles corresponding to the frequency responses of the Iberian power systems for the base case without FFR, as well as for the FFR1, FFR11, and FFR12 new products. A noticeable reduction in the 500 ms RoCoF values can be observed, demonstrating that the faster-acting FFR products are effective in mitigating the initial rate of frequency decline following the disturbance.

It can therefore be concluded that the effectiveness of the FFR product decreases as the overall synchronous inertia deteriorates due to the integration of larger volumes of renewable generation. These findings highlight the need to assess alternative mechanisms, beyond synchronous inertia, that

may be more effective in ensuring robust dynamic system behavior under scenarios with high penetration levels of converter-interfaced renewable generation.

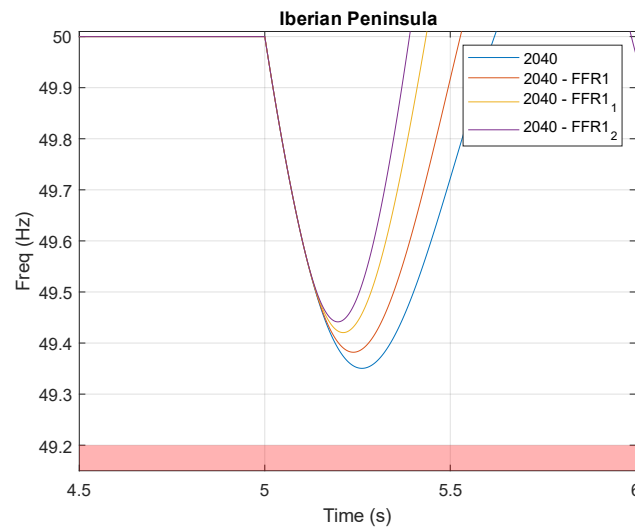


Figure 16. Frequency response in the Iberian system for the different new set of FFR services

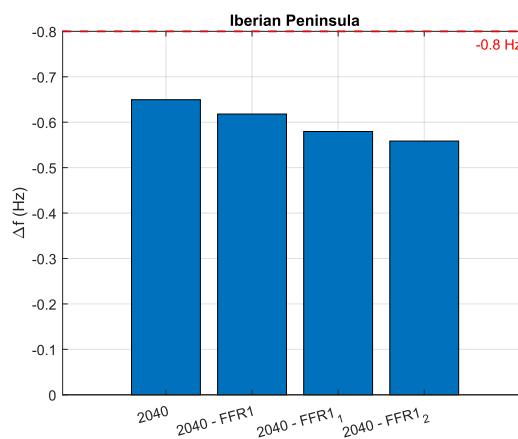


Figure 17. Nadir values of the frequencies for the new FFR services

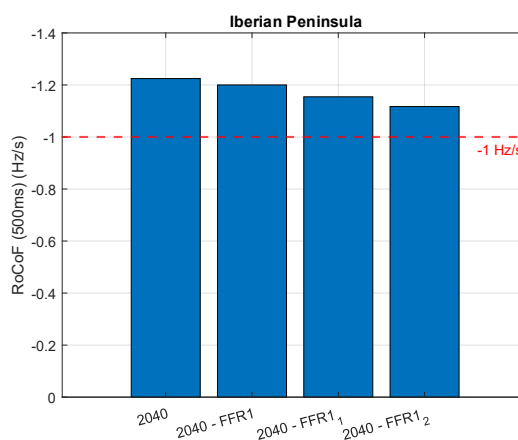


Figure 18. RoCoF (window 500 ms) values of the frequencies for the new FFR services

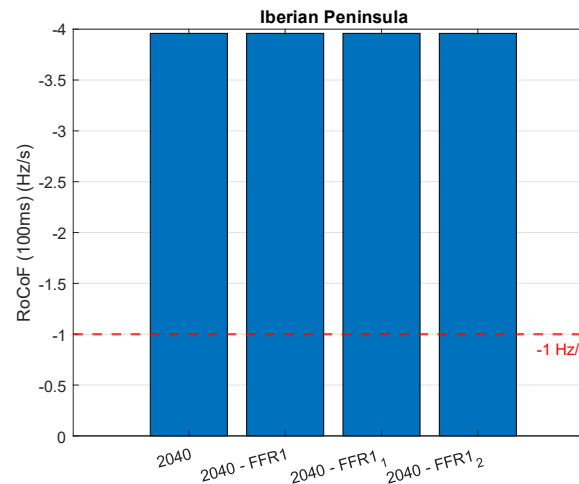


Figure 19. RoCoF (window 100 ms) values of the frequencies for the new FFR services

2.5.2 Synchronous Inertia

With regard to synchronous inertia, the assessment first focused on the dynamic performance of the solutions proposed by the Portuguese and Spanish TSOs in their respective multi-year network development plans, namely the installation of synchronous condensers (SC):

- Spain: installation of eight 250 MVA synchronous condensers, each providing an inertia constant of 6s [9];
- Portugal: installation of two 250 MVA synchronous condensers, each providing an inertia constant of 16 s (equivalent to 4,000 MW·s of stored kinetic energy) [10].

The analysis initially evaluated the dynamic performance of the Iberian power systems for the reference contingency, assuming that by 2030 two synchronous condensers would be commissioned in Spain and one synchronous condenser in Portugal.

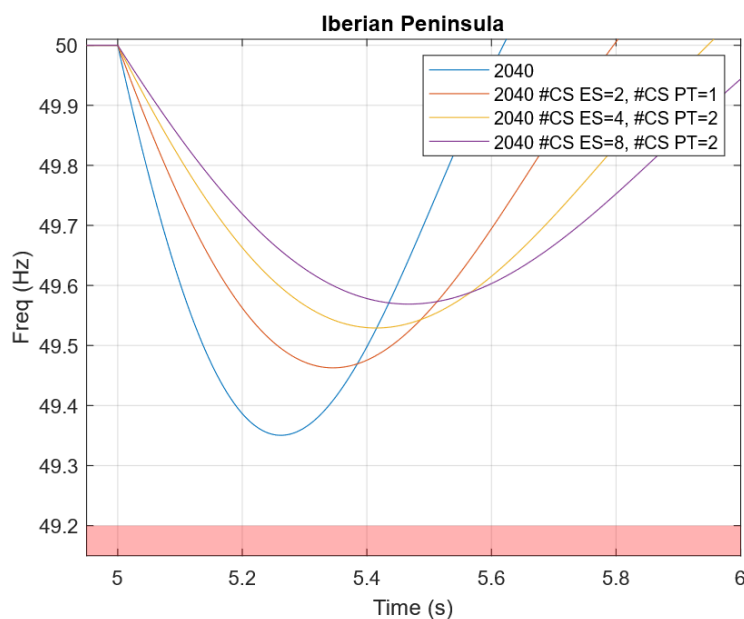


Figure 20. Evolution of the frequency in the Iberian Peninsula for a spring scenario of 2040 following a loss of 2 GW using SC

Several configurations of deployment of SC were considered for 2040, namely:

- 2 SC in Spain + 1 SC in Portugal;
- 4 SC in Spain + 2 SC in Portugal;
- 8 SC in Spain + 2 SC in Portugal.

The corresponding results are presented in Figure 20 - Figure 22, which compare the frequency nadirs and RoCoF values before and after the installation of the synchronous condensers.

These additional increases in synchronous inertia of the Iberian system will change the inertia parameter of the swing equation of the dynamic model described in Figure 3.

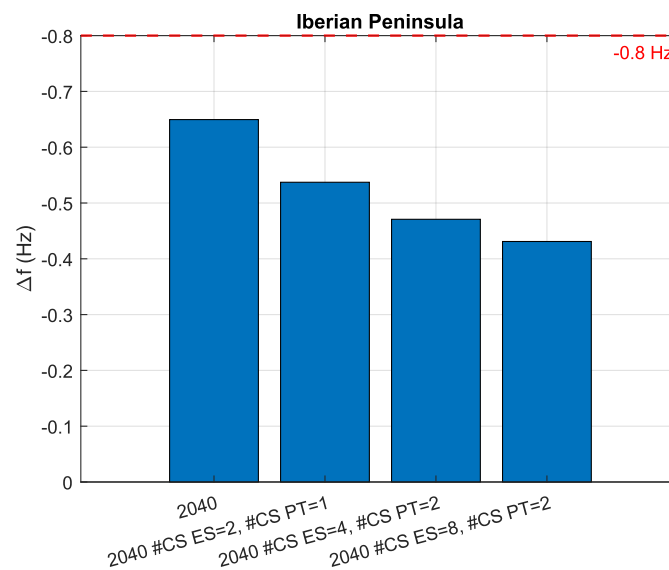


Figure 21. Iberian Peninsula's Nadir, in the Spring Scenario of 2040 following a loss of 2 GW with SC

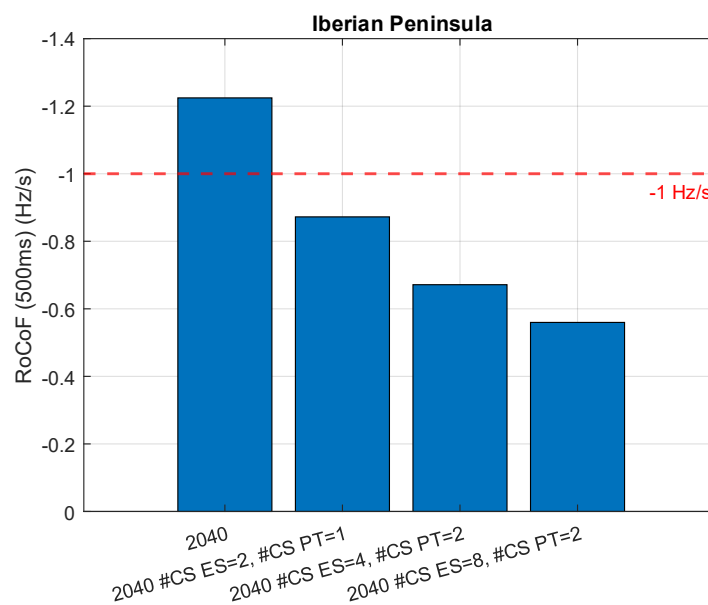


Figure 22. Iberian Peninsula's RoCoF, in the Spring Scenario of 2040 following a loss of 2 GW with SC

As shown, the deployment of synchronous condensers results in a substantial improvement in the system stability indicators for the considered scenario in 2040, assuring that the RoCoF value becomes less than -1 Hz/s.

2.5.3 Battery Energy Storage Systems with GFM controllers

The assessment of complementary frequency ancillary services was further extended to the use of Battery Energy Storage Systems (BESSs) installed in the Portuguese and Spanish power systems. These systems were assumed to operate with grid-forming (GFM) converter controls, capable of emulating the behaviour of a synchronous machine through a control loop incorporating parameters equivalent to those of the synchronous machine swing equation. This control strategy is commonly referred to as a Virtual Synchronous Machine (VSM).

Figure 23 illustrates the control structure of the power electronic converters operating in GFM-VSM mode when integrated, together with other generating units, into the primary frequency control loop of the power system.

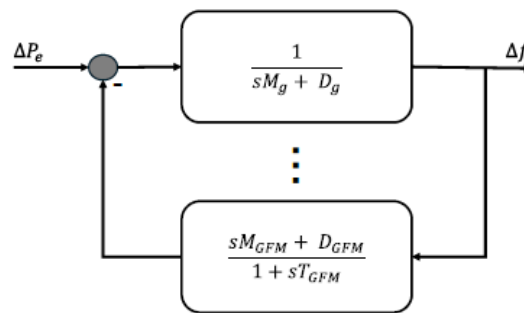


Figure 23. Converter in VSM mode integrated in the primary frequency control

The power converters operated in GFM mode, which emulate the behaviour of a synchronous machine, must have control parameters that are equivalent to those of a synchronous machine swing equation. This control strategy is therefore referred to as a Virtual Synchronous Machine (VSM). Figure 23 presents the control block of the power electronic converters operating in GFM-VSM mode [11] when integrated in the primary frequency control loop of each control area. The block of the power electronic converter, described in this Figure 23, is added to the block diagram of Figure 3, by adding an active power contribution that affects the swing equation that determines the frequency behaviour of the Iberian system part.

Assuming that the GFM-VSM converter power response is constrained by the maximum allowable RoCoF of 1 Hz/s and reaches its rated power at the maximum allowable frequency deviation of 1.5 Hz [12], the corresponding equivalent damping (DGFM) and inertia (MGFM) parameters are given by:

$$D_{GFM} = \frac{P_{GFM}}{1.5 \text{ Hz}} \quad (6)$$

$$M_{GFM} = 2H = \frac{P_{GFM}}{1 \text{ Hz/s}} \quad (7)$$

where P_{GFM} corresponds to the level of power reserve available from the battery converter. The next table shows the values of the parameters used in the equivalent GFM converter adopted as well required reserve for three GFM operating solutions, corresponding to reserve volumes from 160 to 320 MW in Portugal and from 120 to 480 MW in Spain.

Three GFM solutions were tested (GFM1, GFM2 and GFM3), that correspond to 3 solutions of combinations of synchronous condensers, as described in last column of the table below.

Table 5. Parametrization of the GFM converter solution

	Portugal			Spain			
GFM case	Reserve (GW)	D_{GFM} (p.u.)	M_{GFM} (p.u.)	Reserve (GW)	D_{GFM} (p.u.)	M_{GFM} (p.u.)	SC equivalent
GFM 1	0.16	0.5	0.8	0.12	0.4	0.6	#CS ES = 2 & #CS PT =1
GFM 2	0.32	1.1	0,8	0.24	0.8	1.2	#CS ES = 4 & #CS PT =2
GFM 3	0.32	1.1	1.6	0.48	1.6	2.4	#CS ES = 8 & #CS PT =2

The corresponding dynamic behaviour of the Iberian systems when facing the 2 GW loss of generation are presented in Figure 24 and the corresponding frequency nadirs and RoCoF values are presented in Figure 25 and Figure 26, while Figure 27 shows how the power injection from battery-based power electronic converters takes place for the different parameterizations and sizing of converters operating in GFM mode in Iberia.

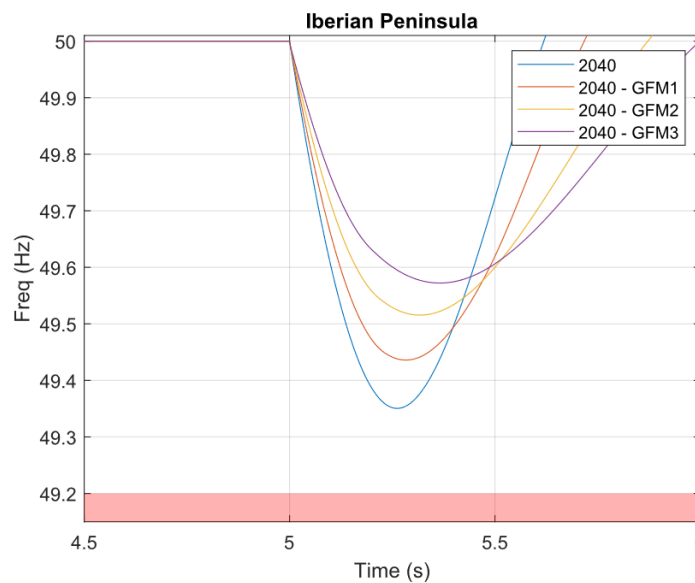


Figure 24. Evolution of the frequency in the Iberian Peninsula for a spring scenario of 2040 following a loss of 2 GW using GFM power electronic converters

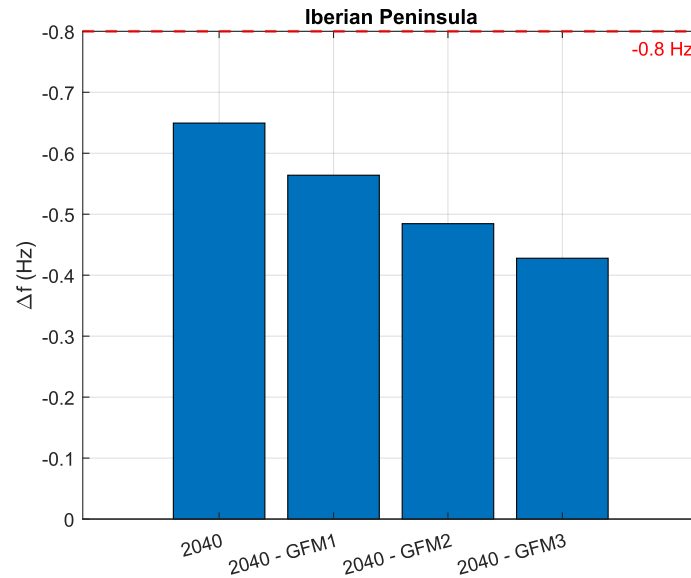


Figure 25. Iberian Peninsula's Nadir, in the Spring Scenario of 2040 following a loss of 2 GW with GFM power converters

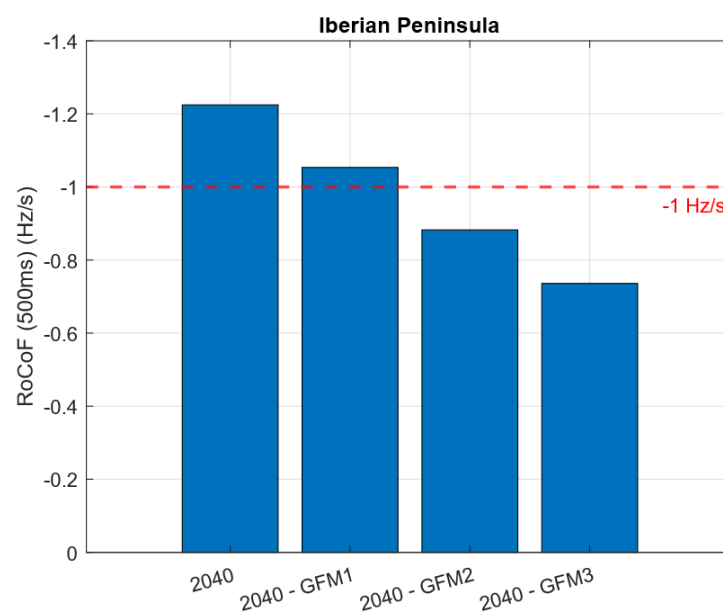


Figure 26. Iberian Peninsula's RoCoF, in the Spring Scenario of 2040 following a loss of 2 GW with GFM power converters

Figure 27 shows the active-power injection provided by the battery power electronic converters for the different parameter settings and converter ratings considered, with the converters operating in GFM mode in Iberia.

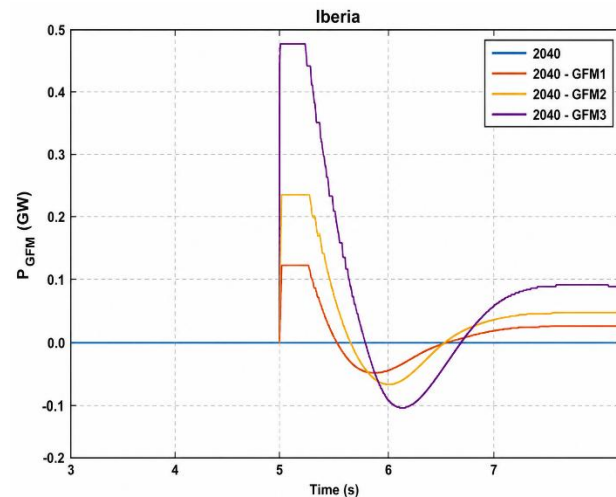


Figure 27. Active power injections from GFM converters

As shown in the above figures, a comparison between the frequency responses of the Spanish and Portuguese power systems in the base case without GFM support and in the GFM3 configuration demonstrates an improvement in the frequency nadir of approximately 200 mHz. The GFM solution GFM2 assures that RoCoF values become less than -1 Hz/s keeping in this way the grid within the pre-defined stability limits.

Overall, the dynamic performance of the GFM converter solution presents very similar results to the ones obtained by the SC solution. Assuming the installation in Iberian Peninsula of batteries converters in GFM mode with a total power rating around 600 MVA, dedicated to providing this synthetic inertia ancillary service, and with an energy capacity of 500 MWh allocated to them, if we compare the investment costs of the battery converter-based solution against the investment in 6 SC (6×250 MVA), the solution based on power electronic converters is significantly more economical. However, it is important to consider that a solution based only on power electronic converters, operating in GFM mode, does not provide short-circuit current, which can be very relevant for the overall robustness and stiffness of system.

The use of the power converter solution in GFM mode achieves a performance equivalent to the obtained with synchronous compensation. It is worth highlighting that this performance is achieved by mobilizing relatively moderate volumes of reserve power through battery converters (in the order of 320 MVA in Portugal and 240 MVA in Spain, as described in Table 5). Ultimately, it is understood that a hybrid approach, combining synchronous compensation and battery storage systems with converters operating in GFM mode, is the most technically robust and economically balanced solution to ensure the dynamic stability of the Iberian system in the long term.

2.6 Location of grid forming converters

2.6.1 Simulation Model

For this assessment, a dynamic model of the Portuguese network was developed using the Digsilent PowerFACTORY tool at INESC TEC. The static part of this model employed a PSS/E model provided by REN, which was duly adjusted to ensure the inclusion of the network reinforcements described in the Plan of Investments of the Portuguese Transmission Grid - PDIRT. For this purpose, the network description presented in the document "RNT 2025 Characterization" [13] was also used. Regarding the interconnection with the Spanish network, a network equivalent was used, consisting

of a single node representing the Spanish network, to which the interconnection buses of the Spanish network were connected through virtual impedance lines. These impedances were adjusted to meet the short-circuit power levels of the nodes of the Portuguese network interconnection, described in the document "RNT 2025 Characterization".

Regarding the dynamic network model, the generation nodes include both the corresponding generators dynamic models and their control loops, split by technology, using generic models that provided the state-of-the-art modelling for each technology, while also using typical parameter values after being properly adjusted (as for inertia values). The dynamic models used by each generation technology are described in Table 6.

Table 6. Dynamic models adopted for each type of technology

	Biomass / Cogeneration	Gas	Wind/Solar	Hydro
Model (or similar)	GENROU + IEEE ST1A	GENROU + IEEE ST1A	REGC_C + REEC_B	GENSAL + IEEE ST1A

Since this study is aiming to improve transient stability, the dynamic models of the governors were excluded from the analysis. This choice is justified by the fact that these control systems have response times exceeding the time horizon considered for the study of synchronism loss for the synchronous machines in the system. This simplification reduces the computational effort associated with evaluating dynamic security through RMS simulations, without compromising the representativeness of the phenomena of interest for the considered analysis time interval. It is important to emphasize that the contribution to the frequency stability of converters operated in GFM mode were addressed in previous sections and the problems related with frequency stability are not strongly correlated with the location of the power converters in the network, but rather with the total installed capacity. This finding justifies the focus of the location analysis developed in this part of the study related with transient stability, rather than frequency stability.

Regarding the dynamic model used for the Grid-Forming (GFM) converter, a state-of-the-art representation was adopted, considering exclusively the control dynamics associated with the AC side of the converter. This option is supported by the fact that there are several control strategies for the DC side, whose implementation depends significantly on the manufacturer and the technological solution adopted. This option avoids selecting a specific configuration that could condition the generality of the study's conclusions, ensuring that the results obtained remain applicable to a wider range of GFM solutions. The solution adopted for the AC side control corresponds to a virtual synchronous machine (VSM) with double overcurrent control via virtual impedance and current limiter.

The parameters adopted for the model are described in Table 7.

Table 7. Parameters of the Dynamic Model of the GFM Converter

	Value	Unit
Inertia Constant of the VSM	5	[s]
Damping constant of the VSM	100	[p.u.]

Cutoff frequency of the filter of the damping constant of the VSM	6	[rad/s]
Virtual resistance	0	[p.u.]
Virtual reactance	0	[p.u.]
Setpoint value for the overcurrent limitation strategy	1	[p.u.]
Proportional factor of the additional resistance	8	[p.u.]
Proportional factor of the additional reactance	8	[p.u.]

2.6.2 Scenario generation by technology type using historical data

After establishing a dynamic model for the network, a collection of 200 representative scenarios was defined, based on historical data. These scenarios were used as a starting point for positioning the GFM converters in the network.

Using normalized historical generation and load data for Portugal from 2023 and 2024, available on the ENTSO-E transparency platform, a Gaussian copula was calibrated to model the statistical dependencies between the variables. Subsequently, 200 synthetic scenarios were generated per technology, preserving the statistical characteristics of the historical data but corresponding to values not observed in the available historical data.

These 200 scenarios, characterized by the normalized values of power generated for each technology and load, were then adjusted to the installed capacity values described in the PDIRT (Portuguese Integrated Development Plan) [10]. After making the necessary adjustments, using the most recent installed capacity values to ensure a balance between the demand and the total system generation, the scenario generation phase per technology was completed. Figure 28 shows the generated scenarios by technology.

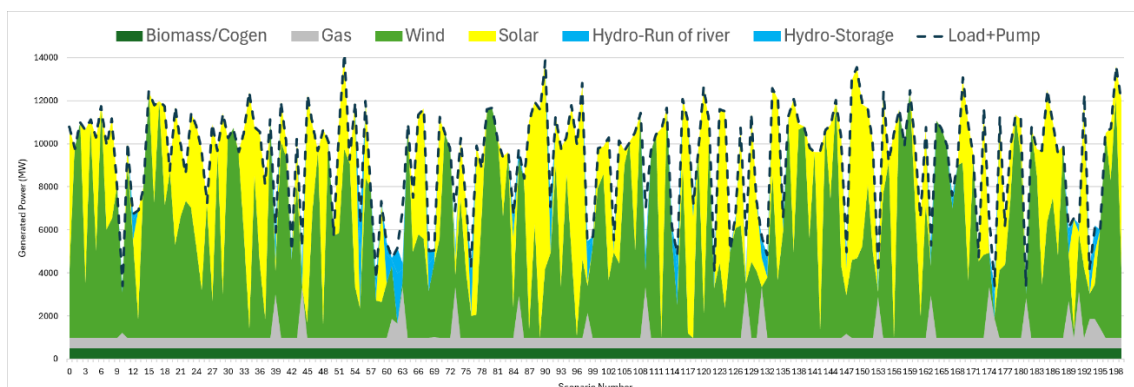


Figure 28. Overall view of the generated scenarios

2.6.3 Scenario and disturbance elimination based on similarity and severity

A scenario clustering technique was subsequently applied to the 200 scenarios, based on the similarity between the scenarios in terms of load and dispatched generation units [14]. Applying this technique, based on hierarchical clustering, the number of scenarios analysed was reduced to only those located near the centre of each cluster, resulting in the use of only a set of 49 scenarios, which are fundamentally different in terms of load and dispatched machines, thus ensuring diversity in the analysis developed.

Given that the main objective of positioning the GFM converters is to improve the transient stability of the system, three-phase short circuits were initially considered as disturbances, simulated in all busbars of the 400 kV network, excluding the interconnection busbars. This set corresponds to a total of 275 faults analysed.

Performing dynamic simulation studies using positive sequence models for all these disturbances in all scenarios and for the various possible locations of the GFM converters would translate into an extremely high computational effort, making the approach impractical. Therefore, a methodology for reducing the number of disturbances to be considered was applied, which is described in the following section.

2.6.4 Reducing the scale of the analysis by using an estimate for the evolution of the rotor's angle

In order to reduce the number of disturbances to be analysed, while simultaneously maintaining a set of situations that are representative of the system's dynamics and the most severe operating conditions, a pre-selection methodology was adopted based on the analysis of an estimate of the trajectory of the rotors' angles of the synchronous generators. For each scenario and disturbance, the evolution of each generators' rotor angle was estimated from the results of a short-circuit calculation module and the first-order Euler numerical integration method.

Having obtained the estimates of the rotor angles of all synchronous machines for all scenarios and disturbances considered, a process of scenario and disturbance elimination was carried out. This process eliminated all disturbances that, in all scenarios, led to deviations of the rotor angles from the centre of inertia of the system that were always smaller than those caused by at least one other disturbance.

After this filtering step, only 65 disturbances remained, considered to be relevant.

2.6.5 Reducing the scale of the analysis by means of dynamic simulation

In a second step to reduce the size of the problem under analysis, the remaining 65 disturbances were simulated for each of the 60 scenarios using dynamic simulation. At this stage, only the evolution of rotor angles during the occurrence of the short circuit (eliminated after 150 ms) was considered. Based on these results, a filtering method was applied that compares the distribution of rotor angles of the system for each disturbance, considering all scenarios, eliminating cases that are adequately represented by other more severe distributions.

To identify when a disturbance is adequately represented by another in all scenarios, the Wasserstein distance between the rotor angle distributions of all machines in the system was used, considering, for all scenarios, the cases corresponding to disturbances i e j .

The same process is then repeated to eliminate scenarios that represent other scenarios well in all disturbances.

After this phase, a set of 25 scenarios and 15 disturbances was reached. Table 8 describes the busbars of the transmission grid where short circuits were simulated in the 15 disturbances, and Figure 29 generically describes the composition of the scenarios by technology. Note that these scenarios differ not only in terms of generation mix, but also in terms of the machines that are dispatched.

Table 8. List of busbars in which the disturbances were simulated

Zone	Substations/Busbars
North	237 RECAEI; 407 V. N. F.COA; 445 AROUCA; 482 PEDRALVA
Douro / Trás-os-Montes	233 PICOTE; 289 LAGOAÇA; 4090 BEMPOSTA; 489 LAGOAÇA
Centre	101 ZEZEZE; 448 LAVOS
Lisbon / Tagus Valley	425 FANHÕES; 425 ALCOCHETE; 457 FALAGUEIRA; 5466 CF-BL; 5468 CF-RJ

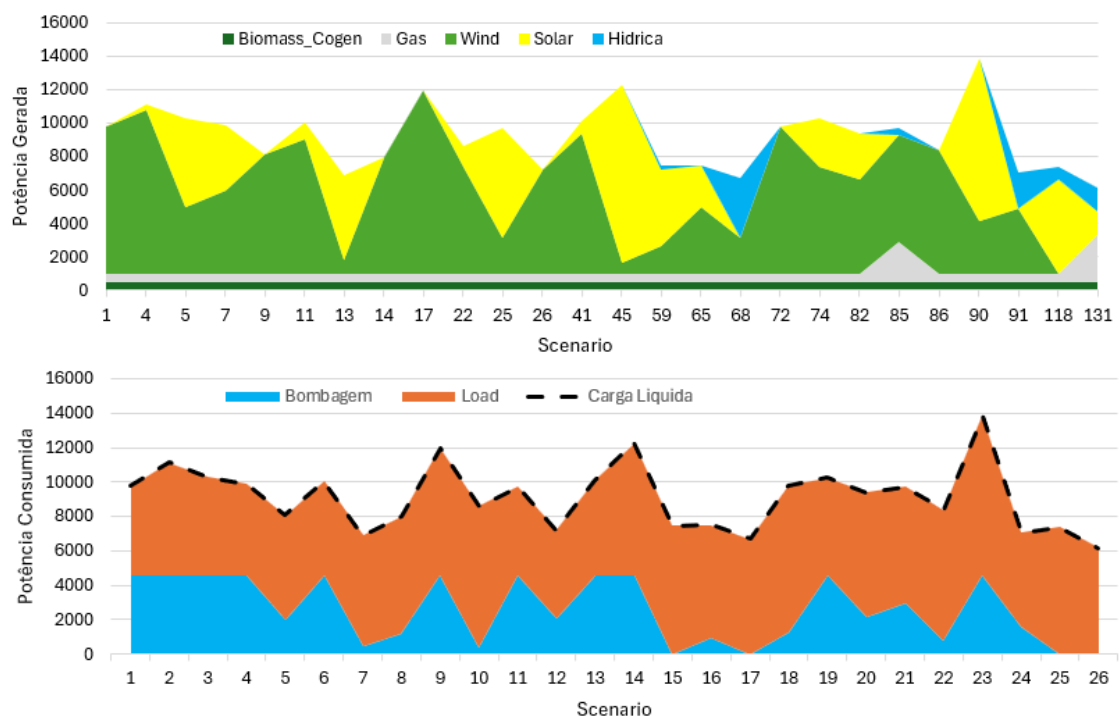


Figure 29. Final scenarios after filtering/elimination

2.6.6 Location of the grid forming converters

After defining the scenarios and disturbances to be used in determining the location of the GFM converters, an assessment was made of the impact of installing an additional capacity ΔP , in this case corresponding to 500 MVA of GFM capacity, on each busbar of the network, (overall value previously determined for the GFM converters with the reduced model of the Iberian system for the Portuguese grid – see Section 2.5.3, Table 5). To this end, in an iterative manner, a 500 MVA GFM converter was placed on each candidate busbar, subsequently simulating all disturbances for each of the selected scenarios. In each event, the maximum deviation of the rotor angle of each generator with respect to

the centre of inertia of the system was calculated during the 150 ms in which the fault develops, recording the maximum deviation between the generators.

Based on the recorded values, it is possible to quantify the performance of each solution by comparing the distribution of angular deviations obtained without GFM units and the distribution of angular deviations obtained with GFM units at the location corresponding to the solution under analysis. The comparison is made using cosine similarity.

This study identifies the busbars where integrating this capability provides the greatest improvement in system stability, and discards those whose influence is less significant. Therefore, a final subset of busbars suitable for integrating GFM converters is obtained. As an initial set of possible locations, busbars having synchronous units with installed power greater than 100 MVA, as well as all busbars in the 400 kV network, were considered. Three colour maps are presented in Figure 30, describing the improvement obtained compared to the base solution without GFM, for three positions that achieve different levels of cosine similarity.

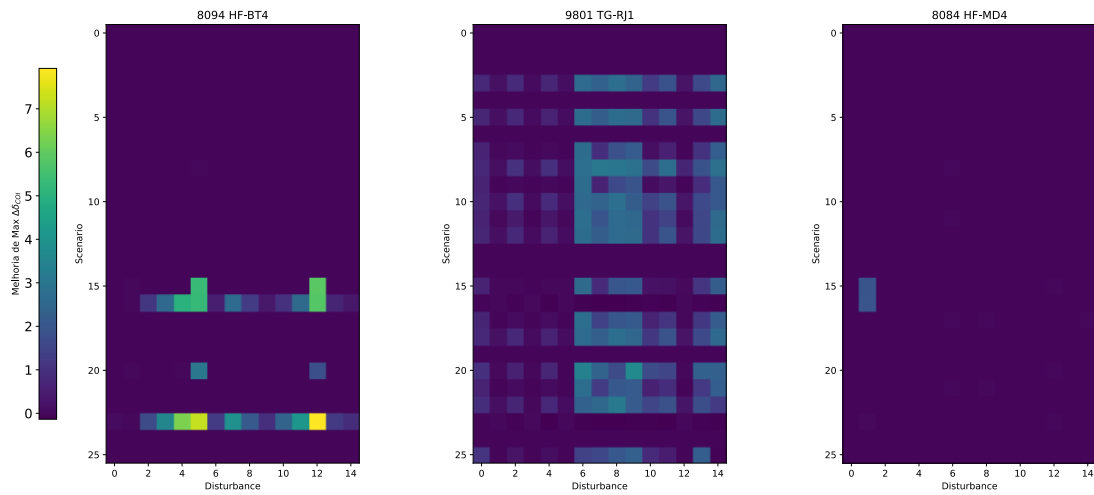


Figure 30. Colour maps showing the improvement of the stability index for different GFM locations

Once the locations where the placement of GFM converters has the greatest impact on the transient stability of the system have been defined, it is possible to determine the number and installed capacity of the power converters of the batteries, ensuring a total installed capacity close to 1100 MVA, in accordance with the solution defined in this project task - "Quantification of volumes of new system services". The problem can thus be formulated as follows:

$$\text{Min: } f(X) = \max_{m \in \Omega_m^o, d \in \Omega_d^o} \mu(X|m, d)$$

$$\mu = \max \Delta\delta_{COI}$$

$$X = [L_X, S_X] = [l_1, s_1, l_2, s_2, \dots, l_N, s_N]$$

$$\forall j, \quad 400 \text{ MVA} > s_j$$

Where:

- Ω_m^o represents the set of all scenarios considered in the optimization;
- Ω_d^o is the set of all disturbances considered in the optimization;
- $\mu(X | m, d)$ is the value of the system stability index associated with solution X , for scenario m and given disturbance d .

- $\max \Delta\delta_{COI}$ represents the maximum deviation of the rotor angle of a machine from the center of inertia among all machines.
- X is the vector of state variables of the problem, which includes the location and capacity of each of the GFM to be placed and sized.

The optimization problem described above was solved using a hybrid method that combines Bayesian optimization with the L-BFGS (Limited-memory Broyden–Fletcher–Goldfarb–Shanno) algorithm. The solution obtained is presented in Table 9.

Table 9. Location bus and capacity of the GFM converters in the optimal solution

Location	Bemposta 2	Ribatejo	Miranda
Capacity (MVA)	400	370	367

To demonstrate the impact of this solution on the system's performance, Figure 31 presents the colour map of the stability index value for all scenarios and disturbances considered in the optimization, compared to the baseline case without GFM.

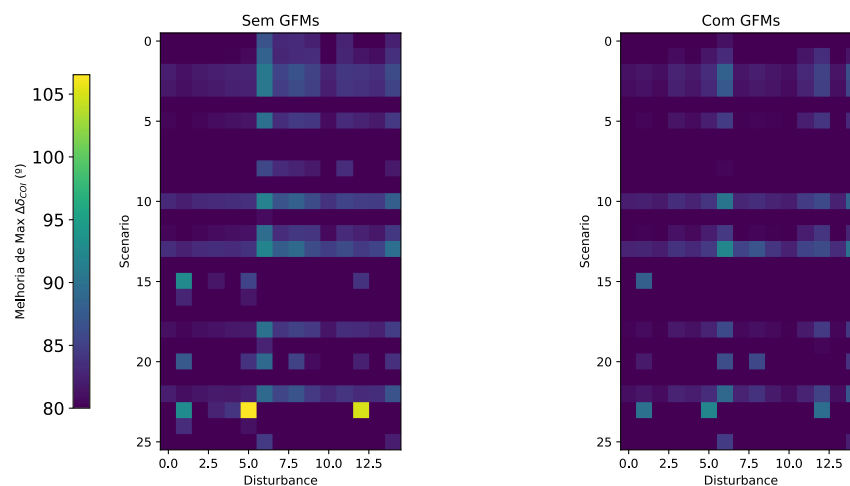


Figure 31. Colour maps showing the improvement of the stability index in all scenarios subject to optimization (right side, without GFM; left side, with GFM)

The integration of the converters operated in GFM mode results in a significant improvement in the transient stability of the system for the different disturbances analysed, particularly for the most severe ones. To clarify the role of GFM in improving the transient stability of synchronous machines, Figure 32 shows the relationship between the electrical power of the Bemposta Power Plant and the respective rotor angle, for the case without GFMs and for the solution defined previously. As can be seen, the introduction of GFM allows a significant reduction in the accelerating power to which the machine is subjected, contributing to a more contained evolution of the rotor angle and, consequently, to an improvement in the transient stability of the system.

Finally, it is worth highlighting that the identified solution allows the minimization of the accelerating power of those machines most exposed to transient stability problems in the considered future scenarios. Thus, considering other models and scenarios of the same system, and assuming that the GFM converters maintain the stability of their internal control loops, the approach should involve identifying the machines most vulnerable to transient instability phenomena in the absence of GFMs

and integrating these resources into buses electrically close to these machines, ensuring a dynamic response consistent with these generators, which tend to move away from the system's centre of inertia. Note that it is not enough for the GFM converters to be electrically close to these machines, the consistency of their behaviour must be guaranteed for the most severe scenarios.

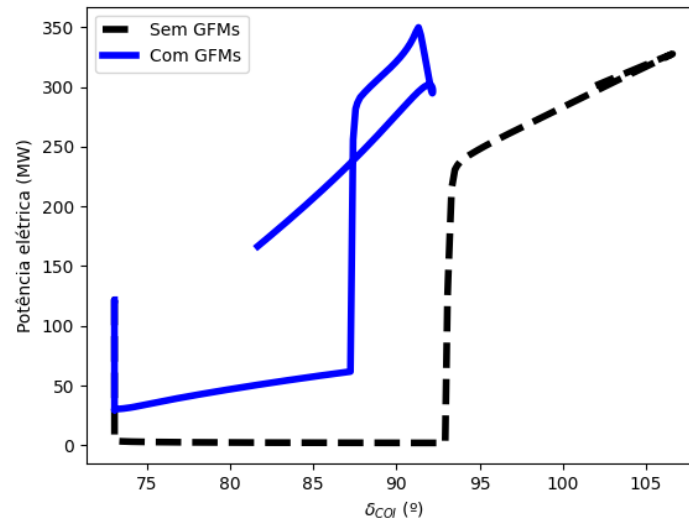


Figure 32. Power-angle curve for the unit of Miranda, with (blue) and without (dotted black) the effect of the GFM

2.6.7 Conclusions and limitations

The study carried out identified the power plants of Bemposta 2, Ribatejo, and Miranda as favourable locations for installing GFM converters. These locations make sense, since they are close to the machines that are subject to the highest accelerating powers, for the worst-case faults under analysis, in the considered scenarios.

It is important to emphasize that the conclusions presented are conditioned by the models, scenarios, and disturbances considered in this study, with the dynamic model of the system being the most critical element. As it was not possible for the system operator to provide a detailed dynamic model of the system, it was necessary to use generic models and typical parameters representative of the different generation units. This limitation naturally influences the quality of the conclusions obtained, given that the transient stability behaviour is strongly dependent on the parameters of the synchronous machines and excitation (AVR) systems.

Consequently, the results should be interpreted as a methodological demonstration of the potential of the proposed approach. Even so, the results allow us to identify relevant trends and assess the relative impact of the location and sizing of units operating in GFM mode on improving the system stability indices.

2.7 KPI assessment

Two KPIs (**KPI1 - frequency Nadir** and **KPI 2 - Rate of Change of Frequency (RoCoF)**) are the most relevant performance indicators for frequency stability and were used to assess the performance of the Iberian system following a sudden loss of 2 GW, exploiting for this purpose the Digital Twin developed for the Iberian Peninsula system.

The frequency Nadir represents the minimum frequency reached after the occurrence of a contingency and is directly related to the amount of available inertia, the speed of frequency response services and the overall capability of the system to restore the generation-demand balance. Lower Nadir values indicate a higher probability of activating under-frequency protection schemes, generator disconnections or even cascading outages. Consequently, improvements in the Nadir constitute a direct indicator of the effectiveness of any ancillary service aimed at strengthening system frequency stability. A reference values of 800 mHz is used for this purpose.

The RoCoF reflects the initial acceleration of the frequency deviation immediately after a disturbance and is primarily governed by the equivalent system inertia and by the availability of extremely fast active power injections. High absolute RoCoF values may trigger protection systems of converter-based generation and distributed energy resources, increasing the risk of widespread generation disconnections. Maintaining RoCoF below the operational limits established by TSOs (1 Hz/s) therefore represents one of the main objectives of frequency support services.

These two KPIs were employed to compare the effectiveness of the different solutions investigated to improve the dynamic performance of the Iberian power system, namely:

- Fast Frequency Response (FFR);
- Additional synchronous inertia provided by synchronous condensers;
- Synthetic inertia and fast frequency support provided by battery energy storage systems operating with Grid Forming (GFM) converters.

The two selected KPIs, also provide an objective basis for comparing the effectiveness of the three new ancillary service solutions investigated within this work. Their comparative assessment is summarized below.

Table 10. Comparison of solutions used to improve frequency stability

Ancillary Service	Nadir Improvement	RoCoF Improvement	Overall Assessment
FFR	Medium	Low to Medium	Effective only with very short activation times
SC	High	High	Very effective but infrastructure-intensive
GFM BESS	Very High	High	Best overall performance/cost compromise

The simulation results demonstrate that Fast Frequency Response (FFR) mainly contributes to improving the frequency Nadir by rapidly injecting active power immediately after the disturbance. However, its effectiveness strongly depends on the activation delay. Conventional FFR products, with activation times around one second, produce only limited improvements in the Nadir and almost negligible reductions in RoCoF because the frequency decay has already developed before the service becomes fully effective. When activation times are reduced to a few hundred milliseconds, both KPIs improve significantly, demonstrating that ultra-fast activation is essential for FFR to become an effective frequency stability service. Nevertheless, even under these improved conditions, FFR alone cannot completely compensate for the progressive reduction of synchronous inertia expected in future converter-dominated systems.

The installation of synchronous condensers (SC) produces a substantially different behaviour. By physically increasing the rotating inertia of the Iberian power system, synchronous condensers immediately reduce the initial frequency acceleration following the disturbance, leading to marked improvements in both RoCoF and frequency Nadir. The obtained results show that sufficiently large deployments can maintain the 500 ms RoCoF within the target limit of -1 Hz/s while simultaneously increasing the frequency Nadir by more than 200 mHz under the most critical 2040 operating scenarios. Besides their positive impact on the selected KPIs, synchronous condensers also contribute to increasing system short-circuit strength and voltage robustness, although these additional benefits are not directly reflected by the frequency stability indicators.

The Grid Forming (GFM) battery solution exhibits the best overall performance with respect to the selected KPIs. The virtual synchronous machine control enables battery converters to emulate inertial behaviour while simultaneously providing fast active power support. Consequently, GFM converters achieve improvements in both Nadir and RoCoF that are very similar to those obtained with synchronous condensers. The simulations show that GFM configuration with near 600 MVA (more precisely 320 MVA in Portugal and 240 MVA in Spain, as described in Table 5) is already capable of maintaining RoCoF within the adopted security threshold of -1 Hz/s. Considering that these performances are obtained with relatively moderate converter ratings and significantly lower investment costs than equivalent synchronous condenser installations (6×250 MVA = 1500 MVA), Grid Forming converters constitute a very attractive solution from a techno-economic perspective, as described in [42] [43].

From the KPI assessment, it can therefore be concluded that the three ancillary services fulfil complementary roles in enhancing frequency stability. FFR primarily limits the depth of the frequency excursion provided that extremely fast activation is available, SC directly improves both Nadir and RoCoF by increasing the physical inertia of the system, while GFM converters provide comparable dynamic performance through synthetic inertia and fast frequency support, with substantially lower investment requirements. Overall, the results indicate that a hybrid strategy, combining synchronous condensers to strengthen system inertia and short-circuit capability with Grid Forming battery systems to provide flexible synthetic inertia and fast frequency response, offers the highest dynamic robustness according to both selected KPIs.

The proposed Digital Twin can be used not only as an engineering platform for planning future ancillary services but also as an online dynamic security assessment tool capable of monitoring the evolution of system robustness throughout the day. By continuously tracking Nadir and RoCoF, the Digital Twin can identify periods of increased vulnerability associated with reduced synchronous inertia, high penetration of converter-based renewable generation or adverse interconnection conditions. This information enables TSOs to anticipate critical operating situations and proactively deploy additional frequency support services before frequency stability limits are reached.

2.8 Discussion

The results demonstrate that the proposed Digital Twin provides an effective platform for assessing the dynamic robustness of the Iberian power system under present and future operating conditions. By combining automatic parameter updating from real operating data with a calibrated dynamic equivalent model, the Digital Twin enables continuous evaluation of the system frequency response following credible disturbances. The selected KPIs, namely the frequency Nadir and RoCoF, provide clear and physically meaningful indicators of the evolution of system frequency security as the penetration of converter-based renewable generation increases.

The comparative assessment of the investigated ancillary services confirms that the Digital Twin constitutes an appropriate decision-support tool for evaluating different technical solutions to improve frequency stability. The simulations show that Fast Frequency Response effectively limits the frequency Nadir when activation times are sufficiently short, whereas synchronous condensers provide substantial improvements in both Nadir and RoCoF through additional physical inertia. Battery Energy Storage Systems operating in Grid Forming mode achieve a dynamic performance comparable to synchronous condensers while requiring significantly lower investment, making them an attractive solution for future low-inertia power systems.

An important advantage of the proposed Digital Twin is its capability to operate as an offline planning tool or as an operational decision-support platform. By continuously retrieving near-real-time generation and demand data, automatically updating the equivalent model parameters and calculating frequency stability indicators, the Digital Twin enables TSOs to monitor the instantaneous degree of dynamic robustness of the Iberian system throughout the day. This capability allows periods of reduced frequency security to be identified in advance and supports the proactive activation or procurement of additional ancillary services whenever the calculated Nadir or RoCoF approaches predefined operational security limits.

3 UC-Ib10. Probabilistic cross-border capacity allocation

This section describes the implementation and experimental validation approach for the use-case UC-Ib10 “Probabilistic cross-border capacity allocation”. This is aligned with the Methodology for coordinating operational security analysis [44]. From the TSO perspective, the use case aims to support a risk-aware calculation of available transfer capacity (ATC) for the Portugal-Spain interconnection by combining an Iberian network model with probabilistic scenarios for demand, generation and network availability. The full use-case description, including actors, information exchanges and the detailed sequence of activities, is provided in Annex B and in IEC 62559-2 use-case description.

3.1 Objectives of the use-case

The objective of UC-Ib10 is to develop a probabilistic methodology for cross-border capacity allocation that can be used by TSOs to estimate the available transfer capacity between Portugal and Spain under uncertainty. The use case addresses the fact that deterministic ATC values may not fully represent the operational uncertainty observed in real-time operation, especially when variable renewable generation, forecast demand, planned outages and forced unavailability affect the secure operating limits of the transmission grid.

The proposed probabilistic available transfer capacity (pATC) methodology builds upon the principles of the South West Europe (SWE) common capacity calculation methodology [15], while extending the conventional capacity assessment through probabilistic representation of uncertainty conditions in operational planning. In this implementation, the methodology is based on the ENTSO-E TYNDP network model [4] [16]. The Portuguese and Spanish TSO grids are retained in detail, while the rest of Europe is represented through an electrical equivalent connected to a retained slack node in France. This approach avoids reduced modelling methodology and keeps the validation closer to the tools and data formats used in TSO operational studies.

The practical objective is to calculate a probabilistic ATC (pATC) for each market time unit (by hour) and direction of exchange, and to compare the resulting transfer margin with historical physical flows, allocated capacity and security indicators of the transmission system.

- Estimate directional pATC values for the PT-to-ES and ES-to-PT exchange directions using a representation of the Iberian transmission grid.
- Represent uncertainty through a scenario set covering load, renewable generation, conventional generation availability and relevant network unavailability conditions.
- Assess whether the resulting pATC remains compatible with secure operation, considering Critical Network Elements (CNE) and contingency probabilities, including the loss or unavailability of transmission lines, and generation/production units and considering transfer capacity already allocated, as part of the final pATC assessment.

3.2 Use-case triggering event and pre-condition

The use case is triggered when the TSO initiates a cross-border capacity calculation process for a defined operational horizon, market time unit and exchange direction. In the validation environment, this triggering event is reproduced offline for selected historical timestamps. For each timestamp, the

scenario generation module provides the probabilistic operating states, and the digital twin is updated with the corresponding load, generation, exchange and availability assumptions.

The main pre-conditions for the execution of the use case are the following:

- A validated base-case DT is available, derived from the TYNDP model and adapted to retain the full Portuguese and Spanish TSO grids.
- The rest of the European network has been reduced through PSS®E electrical equivalencing, preserving the interaction with the retained Iberian grid through an equivalent external area and a retained slack node in France.
- Scenario files are available for the selected timestamps, including scenario identifiers, 24-hour trajectories of the uncertain variables and scenario probabilities.
- The relevant operational data for the selected timestamp are available, including load, solar and wind generation, net load, planned and forced unavailability of transmission assets, unavailability of production units and already allocated capacity.
- Voltage, thermal loading and angle limits are defined for the retained network elements, and the critical network elements (CNEs) to be monitored are identified from the transmission-grid unavailability data, generation-unit unavailability data and selected loss-of-line contingencies.
- The scenario set is available with sufficient metadata to associate each scenario with a timestamp, probability or weighting factor, and the corresponding uncertainty assumptions.

3.3 Use-case KPIs

To assess the effectiveness of the probabilistic approach for ATC calculation and its impact on system security, three KPIs are considered. These KPIs are calculated after the pATC results are obtained for the selected timestamps and scenarios.

Table 11. UC-Ib10 KPIs

KPI	Purpose	Assessment approach
KPI_Ib10_1: % of total cross-border capacity utilization	Measures the percentage of the calculated cross-border capacity that is actually used by the physical flow in the corresponding market time unit.	For each MTU and direction: utilization = physical cross-border flow / pATC x 100. The physical flow is compared with the pATC calculated for the same timestamp and direction, to determine if the physical flow lies between the estimated probability.
KPI_Ib10_2: % of cross-border capacity adequacy probability	Measures the probability that the calculated cross-border capacity is adequate under the probabilistic scenario set.	Calculated as the share, or probability-weighted share, of scenarios in which the calculated capacity is sufficient and the monitored security constraints are not violated.
KPI_Ib10_3: Grid Security Improvement Index (%)	Measures the effect of the probabilistic ATC calculation on the secure operation of the grid by integrating security indicators for CNE loss probabilities.	Calculated by comparing a baseline security score with the security score obtained when applying the probabilistic capacity assessment. CNEs are based on the available transmission-grid unavailability records, generation-unit unavailability records and selected loss-of-line cases.

The first KPI provides an operational view of how much of the calculated probabilistic transfer capacity is used. A low value may indicate unused transfer margin, while a value close to or above 100% may indicate that the probabilistic estimate is tight or that the physical flow exceeds the capacity level calculated for the same scenario assumptions.

The second KPI focuses on reliability under uncertainty. It is not intended to state that a single deterministic capacity value is always secure; instead, it quantifies the proportion of the probabilistic scenario space where the capacity remains adequate and compatible with operational security constraints.

The third KPI connects the capacity calculation with system security. It is important for the TSO because a higher cross-border capacity value is only useful if it does not increase the risk.

3.4 Technology development and Implementation

The grid model is built from the TYNDP network representation and adapted to create a steady-state transmission-system case suitable for cross-border capacity studies. The retained area includes the full Portuguese and Spanish TSO grids, while the rest of Europe is reduced into an equivalent representation. This is a deliberate modelling decision as the use case requires sufficient detail inside the Iberian Peninsula to detect internal Portuguese and Spanish constraints, while avoiding the computational burden and data maintenance effort associated with simulating the full European grid in detail.

The electrical equivalent is created in PSS®E by retaining the PT and ES TSO grids and selected boundary/slack elements and reducing the external area into a network equivalent. The retained slack node in France represents the interaction with the rest of Europe. The equivalent is intended to preserve the electrical influence of the external system on the retained Iberian network for steady-state studies. The external system therefore continues to provide an electrically consistent balancing and boundary condition without requiring the complete European network to remain explicitly modelled. The reduction process intentionally retains a limited set of lower-voltage buses where they are structurally necessary. In Portugal these are predominantly tertiary/auxiliary terminals of three-winding transmission transformers; in Spain a residual 63 kV structure can remain connected to the transmission network. These elements participate in the AC power flow but are not operational scenario-input nodes or primary monitored CNEs. Internal Portuguese and Spanish transmission elements become limiting CNEs, the limiting element is not restricted to the physical interconnectors. The monitored/CNE subsystem is therefore defined over the relevant PT/ES transmission network.

The implementation can be described through the main components described in Table 12.

The main technical assumptions used in the current implementation are:

- The study is performed as a steady-state transmission-system assessment. Dynamic stability and protection-system behaviour are outside the scope of this validation stage.
- The Portuguese and Spanish TSO grids are maintained with sufficient detail to capture internal congestion that may affect the PT-ES exchange capability.
- The external European grid is not modelled in full detail. It is represented by an electrical equivalent, with the retained French slack node providing the external balancing reference.
- Scenario data are applied consistently to the retained network, while external-area behaviour is represented through the equivalent model and the defined boundary conditions.
- The pATC is calculated directionally. Therefore, PT-to-ES and ES-to-PT are treated as separate studies with potentially different limiting elements and capacity values.

- Already allocated capacity is treated as an input to the assessment and is used for comparison and KPI interpretation, rather than being confused with the physical flow observed in the interconnection.

Table 12. Main components of the use-case implementation

Component	Implementation in UC-Ib10
Scenario generation	A scenario generation module produces representative operating states for each MTU. These states reflect uncertainty in load, renewable generation, conventional generation availability and relevant network conditions. Each scenario is linked to a timestamp and, where available, a probability or weight.
Digital twin	The TYNDP-based steady-state model is converted and adapted to a DT. PT and ES are retained in detail, while the rest of Europe is represented through an electrical equivalent connected through the French slack area.
Data interface	The data model with relevant case file (load, scenario, injections and exchanges, asset unavailability/outage) mapped to DT.
Joint probabilistic assessment	The operating-scenario probability is combined with the probability of CNE, asset unavailability, including loss of lines and generation units, to form the joint probability space used for pATC estimation.
pATC calculation	For each timestamp, direction and scenario, the cross-border exchange is increased until a security or operational limit is reached. The scenario results are then aggregated into a probabilistic capacity indicator.
Security screening	The retained PT-ES network is checked for voltage limits, branch/transformer loading, phase angle behaviour and CNE constraints. The monitored CNE list is built from outage/unavailability information and selected loss-of-line cases.

3.4.1 Scenario generation methodology

The scenario-generation methodology is designed to provide representative probabilistic operating states for the pATC chain [17] [18] [19]. It is data-driven and uses historical operating samples to construct coherent 24-hour trajectories, and it currently focuses on the main uncertainty variables that affect day-ahead cross-border transfer capability: load, solar generation and wind generation. Hydro and other generation are used in the filtering of comparable operating points where available, but they are not treated as independent clustering dimensions in the current implementation because their behaviour may be more dispatch-driven.

For each target timestamp, the scenario selection is conditioned on the latest observed operating point immediately before the forecast window [17] [19]. This matches the TSO operational-planning logic: at the time of calculation, the operator knows the most recent operating condition, but not the actual values inside the future horizon. Historical days are first filtered according to net-load and seasonal similarity, and then representative medoid days are selected through K-medoids clustering.

The clustering is performed in a coupled way across the selected uncertainty variables. One scenario therefore represents a coherent historical day, not an independently selected load curve, solar curve and wind curve. This is important because the correlation between demand and renewable generation affects internal flows, border exchanges and the loading of CNEs. The use of medoids also ensures that each scenario corresponds to an observed historical trajectory, which improves interpretability for TSO validation.

Scenario probabilities are calculated from the number of filtered historical samples assigned to each medoid cluster. A bootstrap or consensus logic can also be applied, so that the final selected medoids are not overly dependent on a single clustering run or random initialisation. The outputs of this module are a scenario trajectory file, a probability file and a diagnostics file with the selected medoid dates and filtering information. These outputs are then used directly by the pATC calculation workflow.

3.4.2 System Availability & Capacity Uncertainty

A separate uncertainty pre-processor reconstructs the information available at the selected operational cut-off and produces hourly state distributions for TCAA, generation availability and network availability. Known active planned or forced outages already published by the cut-off are deterministic conditions. Additional forced outages that may occur are treated probabilistically. Published TCAA is deterministic; otherwise, the model derives an empirical same-hour historical TCAA distribution. Residual outage probabilities are estimated from observed outage start events. The uncertainty model enumerates Bernoulli combinations for the selected highest-rate generation and grid assets and constructs one direction specific joint uncertainty table per hour. For an asset with N observed forced starts during H historical hours, the one-hour rate model is:

$$\lambda_a = \frac{N_a}{H}, \quad P_a(\text{new forced outage in } \Delta t) = 1 - e^{-\lambda_a \Delta t} \quad (1)$$

Where, N_a is the number of historical forced outages for asset a, H is the historical observation period in hours, and λ_a is the estimated forced outage rate.

3.4.3 Integration of scenario and CNE probabilities in the pATC calculation

For each timestamp, the pATC calculation will also consider the probability of relevant CNE and asset states, including loss or unavailability of lines, transformers and generation/production units. This means that the model will evaluate the joint probability distribution of operating scenarios and contingency states before selecting the reported pATC.

The probabilistic ATC calculation is performed at MTU level using a joint scenario-contingency probability framework. For each hour, the pATC process evaluates a probability distribution of physically distinct PT-ES system states. The methodology separates the state construction into two probability blocks. The operational block contains three forecast dimensions: Portugal operating scenarios, Spain operating scenarios, and Spain-France exchange scenarios. The uncertainty block is generated separately from Total Capacity Already Allocated (TCAA), generation availability, and transmission-grid (including lines) availability.

Each selected state is simulated independently in PSS/E 35.5. PT and ES load/generation values are applied only at retained buses. The residual (MV & LV) buses left after the network-reduction process remain in the case as fixed electrical support topology and do not receive scenario updates. The

physical transfer limit is obtained separately for PT->ES and ES->PT using incremental transfer, AC power-flow solution and deterministic N-1 security assessment. State probabilities are used when the state-specific pATC values are aggregated.

Operational Cartesian product (P_{OP}): For hour t , let i index a PT forecast scenario, j an ES forecast scenario and k an ES-FR exchange scenario. The operational state is $O(t, i, j, k)$. Under the agreed operational independence assumption, its probability is equation 1. With 10 scenarios in each operational input, the full operational Cartesian product contains $10 \times 10 \times 10 = 1,000$ operating states per hour.

Joint uncertainty block (P_{UNC}): For the same hour and transfer direction, we identify a row of the uncertainty model output. Each row carries $TCAAStateID$, $GENScenarioID$, $GRIDScenarioID$ and joint probability. The model calculates joint probability as $P_{TCAA} \times P_{GEN} \times P_{GRID}$ and records the retained probability.

Joint state probability (P_{STATE}): The combined state probability combines one operational state with one joint uncertainty row. The implementation therefore evaluates states of the form $S(t, s) = \{PT_i, ES_j, XB_k, TCAA_u, GEN_u, GRID_u\}$. This equation gives the raw system-state probability. This explicitly introduces a second modelling independence assumption: the operational forecast block is treated as independent of the TCAA/generation/grid block.

For every hour/direction, the implementation records the candidate probability mass, the uncertainty model input probability mass, and the probability mass after state reduction.

*Operational-state probability
under the agreed independence
assumption*

$$P_{OP(t,i,j,k)} = P_{PT(t,i)} P_{ES(t,j)} P_{XB(t,k)} \quad (2)$$

*Joint TCAA / generation / grid
probability produced by the
uncertainty block*

$$P_{UNC(t,u,d)} = P_{TCAA(t,u,d)} P_{GEN(t,u)} P_{GRID(t,u,d)} \quad (3)$$

Joint system-state probability

$$P_{STATE(t,s,d)} = P_{OP(t,i,j,k)} P_{UNC(t,u,d)} \quad (4)$$

$$\text{with } s = (i, j, k, u)$$

For each MTU, the generated operating scenarios represent uncertainty in load, solar and wind generation, while the CNE states represent uncertainty in line, transformer and generation-unit availability. Each operating scenario is combined with each credible CNE state to form a joint state. The joint probability is initially calculated as the product of the operating-scenario probability and the CNE-state probability, assuming independence.

Planned unavailability are treated as deterministic asset states for the affected MTUs, while forced or uncertain outages are represented through probability-weighted CNE states. For each joint state, the DT is updated, and the standard ATC calculation is performed by increasing the cross-border exchange until the first security limit is reached. The resulting set of ATC values forms a probability distribution of transfer capability for the MTU. The final pATC is selected as the maximum transfer value that satisfies a predefined security confidence level, for example 95%, meaning that the transfer remains secure in at least 95% of the weighted joint states.

The scenario-reduction procedure assigns each retained representative state an effective probability equal to the probability mass of the original states it represents within the corresponding stratum. Consequently, states removed through clustering are represented probabilistically by the selected representative rather than being treated as equally likely or simply discarded. However, the reduction targets approximately 95% retained probability mass within each stratum, meaning that a residual tail may not be explicitly represented. This has limited impact on central and 95%-secure estimates, but it becomes increasingly important for 99% and 99.9% secure capacities, since rare low-capacity states may fall within the omitted tail. The reported 99% and 99.9% values should therefore be interpreted as conditional estimates based on the reduced representative-state distribution, rather than exact quantiles of the complete unreduced scenario space. Rare adverse conditions are preserved only where they are explicitly represented by the stratification and representative-selection procedure.

Because PT, ES and ES-FR are independent forecast dimensions, an arbitrary Cartesian combination is not guaranteed to be power-balanced. The ES-FR forecast therefore cannot be treated only as a label while simultaneously allowing the French swing to settle at any value.

The implemented default uses the French external equivalent as the boundary reference and reconciles the independent ES-FR flow scenario through a distributed Spanish balancing proxy. The target is expressed through the French slack injection:

$$P_{FR,slack,target} \cong -P_{ES \rightarrow FR,scenario} \quad (5)$$

The algorithm solves the state, compares the actual French slack active power with the target, and iteratively adds a separate distributed balancing injection across eligible Spanish scenario buses until the ES-FR target is within the configured tolerance.

The main technical assumptions used in the current implementation are:

- The study is performed as a steady-state transmission-system assessment. Dynamic stability and protection-system behaviour are outside the scope of this validation stage.
- The Portuguese and Spanish TSO grids are maintained in sufficient detail to capture internal Iberian congestion that may limit the PT-ES exchange capability.
- The external European grid is represented by an electrical equivalent and a retained French slack/reference node; its internal constraints are not assessed in detail in this implementation.
- Scenario data are applied consistently to the retained network, while external-area behaviour is represented through equivalent injections, boundary conditions and corridor information.
- The pATC is calculated directionally. PT-to-ES and ES-to-PT are therefore treated as separate studies with potentially different limiting elements and capacity values.

AAC is used as an already committed commercial capacity input. It is not treated as the physical flow that occurred in the interconnection.

3.5 Description of the experimental validation

The experimental validation is structured as a staged process. The purpose is not only to obtain numerical pATC values, but also to demonstrate that the data pipeline, the reduced grid model, the scenario application process and the security checks are coherent from a TSO operational planning perspective.

Table 13. Validation stages for the pATC calculation and use-case KPIs

Validation stage	Description
Stage 1 - Data collection and harmonisation	Collect the partner data model inputs, check timestamps, units and direction conventions, and align all datasets to the same MTU resolution and time zone.
Stage 2 - Network model preparation	Build the digital twin from the TYNDP model, retain PT and ES TSO grids, reduce the rest of Europe, and verify that the equivalent case solves in steady state.
Stage 3 - Scenario generation and diagnostics	Generate probability-weighted 24-hour scenarios for load, solar and wind; check medoid dates, scenario probabilities, seasonal consistency and representativeness.
Stage 4 - Scenario application	Apply the generated probabilistic scenarios to the grid model by updating load, renewable generation, CNE states such as generation availability and network outages for the selected timestamp.
Stage 5 - Capacity search and security check	Run the directional pATC calculation and check thermal loading, voltage, angle and CNE constraints for each scenario. The search is done for both directions; PT-to-ES and ES-to-PT.
Stage 6 - Result consolidation	Aggregate scenario-level pATC outputs into timestamp-level probabilistic indicators and produce distributions, percentiles and limiting-element summaries.
Stage 7 - KPI calculation and benchmarking	Compare pATC values with physical flows, already allocated capacity and baseline security indicators to calculate the three KPIs.

This staged validation also allows intermediate issues to be isolated. For example, if a capacity value is unexpectedly high or low, the analysis can distinguish between a data issue, a scenario-generation assumption, a network-equivalence issue, a limit definition issue or an actual physical constraint in the retained Iberian grid.

3.5.1 Data required for the experimental validation

The validation requires both static network data and time-dependent operational data. The input structure follows the data collected through the TSO Partner Data Model, including the datasets used for network conditions, generation and production-unit availability, already allocated capacity and historical exchange information. The data are used to parameterise the grid model for each timestamp and to evaluate the KPI results after the simulations are completed. The historical datasets used to characterize generation and network unavailability were retrieved from the ENTSO-E Transparency Platform [20], which publishes pan-European electricity generation, load, transmission and balancing information.

Table 14. Collected Data for use-case validation

Data category	Use in validation
Network model data	Grid model base case, bus data, branch and transformer parameters, voltage levels, thermal ratings, generator connection points, load buses, interconnection branches and the retained boundary/slack representation.
Load and generation time series	Timestamped data for load, solar generation, wind generation, net load and generation schedules used to define the scenario injections for each MTU.
Total Capacity Already Allocated (AAC)	Directional already allocated capacity by timestamp, border direction and contract type.
Unavailability of line/production/generation units	Transmission-grid unavailability records and unavailability of production/generation units for Portugal and Spain. These data define scenario conditions and support the CNE/security analysis.
Scenario probability	Scenario identifiers, medoid dates, 24-hour trajectories, cluster probabilities. These provide the probability weights for the operating scenarios.
CNE/asset-state probabilities	Probabilities of line, transformer and generation-unit loss or unavailability. These are combined with operating-scenario probabilities to build the joint probability distribution used for pATC.
Observed and reference values	Physical interconnection flow, reference forecast transfer capacity, NTC/ATC values and operational limits used for benchmarking the pATC output.
Simulation outputs	pATC value, limiting element, bus voltages, branch flows, loading percentages, angle indicators, convergence status and scenario-level security flags.

A key requirement is the consistent treatment of direction. The PT-to-ES and ES-to-PT directions must be clearly distinguished in the input files, in the pATC calculation and in the KPI assessment. Physical flow is used as an observed operating result, while already allocated capacity represents capacity previously assigned to market participants and should not be interpreted as the same quantity.

3.5.2 Scenario Specific Secure Transfer Calculation

After all operating and availability components are applied, the AC power flow is solved. A state that does not converge or cannot satisfy the ES-FR reconciliation is flagged as infeasible, it is not silently treated as a normal ATC observation. For a state already insecure at zero incremental transfer, the available incremental transfer is zero. From the solved state, the pATC engine increases controlled transfer separately in the PT->ES and ES->PT directions. Source generation/load changes and sink changes are implemented through the configured PSS/E transfer method while respecting

machine/load constraints. Transfer is increased until the first monitored security limit is reached, after which a binary search refines the maximum secure incremental transfer.

At each transfer candidate, the intact state and the selected N-1 contingencies are evaluated. The probabilistic network state and the deterministic security contingency are conceptually different. If a line is already unavailable as part of the probabilistic state, the subsequent N-1 assessment is performed on that degraded topology and tests an additional eligible contingency. Monitored criteria include thermal loading, voltage limits and convergence.

$$ATC_{phys(t,r,d)} = \max_{\Delta P \geq 0} \{ \Delta P : C_{N-0}(t,r,d,\Delta P) \wedge C_{N-1}(t,r,d,\Delta P) \} \quad (6)$$

Where, t = MTU, r = representative probabilistic state, d = transfer direction PT→ES or ES→PT, ΔP = incremental transfer, C_{N-0} = adopted base-case security criteria, C_{N-1} = adopted contingency security criteria (*N-0 means the intact/base operating state, and N-1 means the system after any single credible contingency*).

TCAA is part of the probabilistic system state record but is not a physical topology uncertainty. It modifies the remaining commercial/available capacity after the physical secure headroom has been determined. Likewise, NewNTC associated with known transmission unavailability can act as an auxiliary directional cap. The model avoids automatically subtracting TCAA twice when the solved operating point already embodies scheduled interchange. When a state-specific/known NewNTC is available, the default calculation is:

$$C_{market(t,r,d)} = \max(NewNTC(t,r,d) - TCAA(t,r,d), 0) \quad (7)$$

$$pATC(t,r,d) = \min(ATC_{phys(t,r,d)}, C_{market(t,r,d)}) \quad (8)$$

After all representative states for one hour/direction have been evaluated, the set $\{pATC(t,r), P_{effective(t,r)}\}$ defines the approximate discrete probability distribution of available transfer capability.

$$E[pATC_t] = \frac{\sum_r P_{effective}(t,r) pATC(t,r)}{\sum_r P_{effective}(t,r)} \quad (9)$$

$$pATC_{\min(t)} = \min_r pATC(t,r) \quad (10)$$

$$pATC_{\max(t)} = \max_r pATC(t,r) \quad (11)$$

The minimum remains a worst-case value over the retained state set and can therefore be driven by a low-probability state. The expected value uses the probability distribution and is normally more representative of central system conditions.

In addition to minimum, expected and maximum, the methodology reports selected secure percentiles. For confidence α , the secure pATC is the largest transfer level that is met or exceeded by probability mass at least α :

$$pATC_{secure(\alpha)} = \max\{x : P(pATC \geq x) \geq \alpha\}$$

3.6 Results of the experimental validation

The scenario-generation module produces probability-weighted representative scenarios for the Portuguese system for 15 December 2025. The figures below illustrate two of the scenario outputs that will later feed the pATC DT model. These figures should be interpreted as scenario-generation results that will be coupled with CNE probabilities to introduce uncertainties for pATC computation.

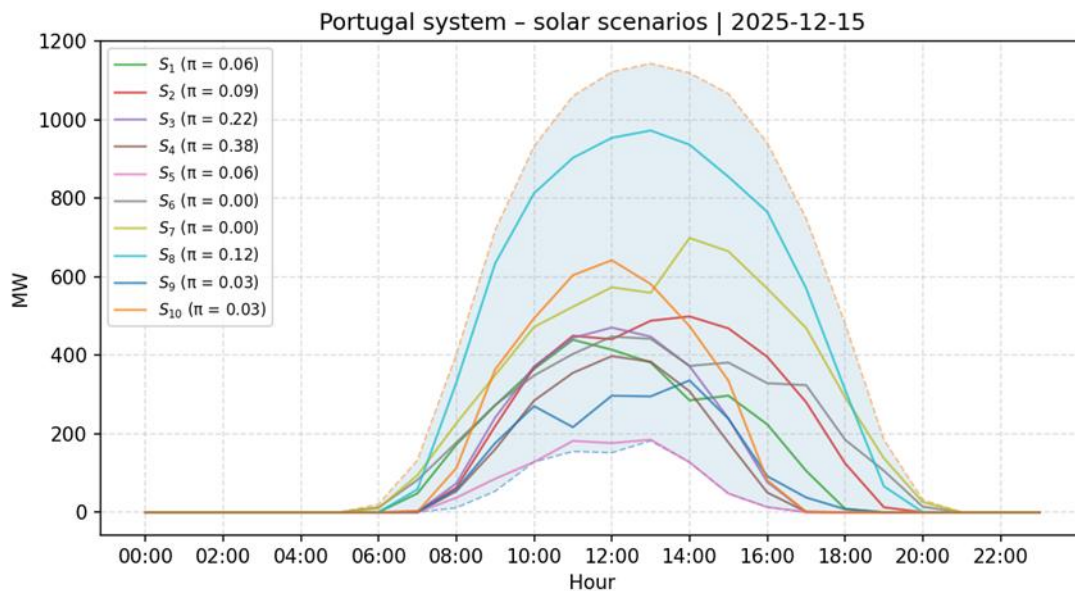


Figure 33. Portugal system solar generation scenarios for 15 December 2025. The scenario probabilities in the legend indicate the probability weight assigned to each medoid scenario.

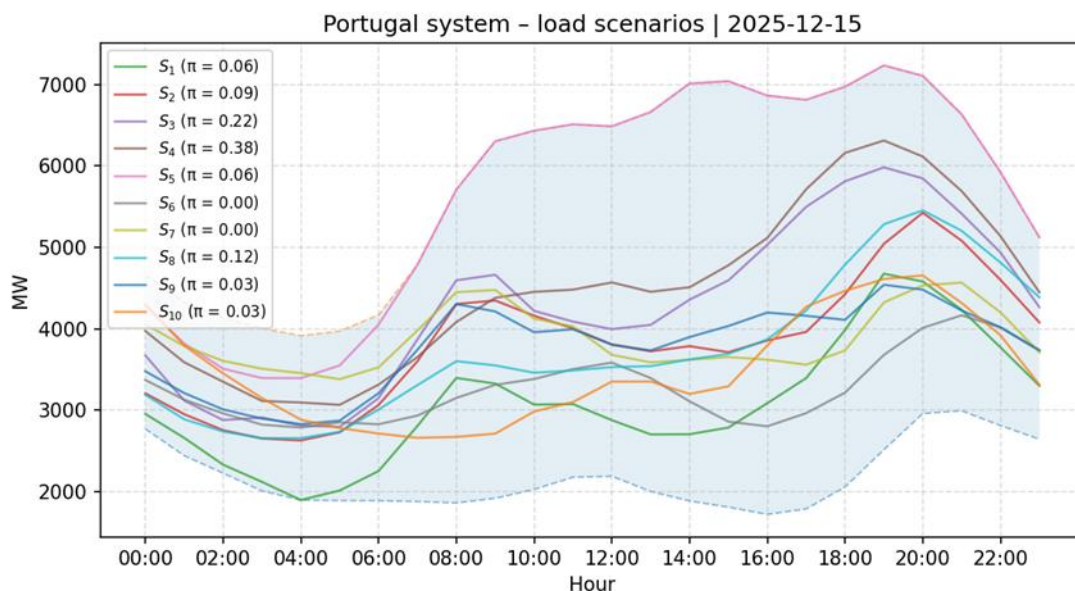


Figure 34. Portugal system load scenarios for 15 December 2025. The figure shows the range of plausible 24-hour load trajectories represented by the selected medoid scenarios.

The solar scenario plot shows the expected zero-output periods during night-time and a wide range of daytime PV trajectories. This spread is relevant for the TSO because different solar outputs modify net load, internal PT/ES flows and the available margin on monitored elements during the same

market day. The load scenario plot shows a broad envelope of possible demand trajectories, including different morning and evening ramps. These load differences are expected to influence the direction and magnitude of cross-border exchanges when the same transfer increment is applied.

Operating Scenarios: For each hour, the Portugal operational input contains multiple bus-level scenarios. Every scenario has its own probability P_{PT} and provides active load, generation and net load for the retained Portuguese PSS/E buses. The probability is repeated on the bus rows belonging to the same scenario and is validated once per MTU/scenario. Spain is represented in the same way: multiple bus-level scenarios per MTU with probability P_{ES} and load/generation values at the retained Spanish PSS/E buses. The PT and ES scenario identifiers are not interpreted as coordinated cross-country scenario identifiers. A third operational file provides independent ES-FR exchange scenarios with probability. Each state specifies net MW, absolute flow and direction. Positive and negative values distinguish the $ES \rightarrow FR$ and $FR \rightarrow ES$ exchange directions according to the source convention. The PT, ES and ES-FR forecast probabilities are intentionally treated as mutually independent. Consequently, their scenario IDs must not be joined one-to-one; the operational state set is the Cartesian product $PT \times ES \times ES - FR$.

The probabilistic ATC assessment was performed for the 24 hourly MTUs of 31 August 2026 and for both transfer directions, $PT \rightarrow ES$ and $ES \rightarrow PT$. For each MTU, the complete probabilistic scenario space was constructed from the PT, ES and ES-FR operational forecasts together with the TCAA, generation-availability and transmission-grid-availability uncertainty states. The complete scenario space contained approximately 16,000 candidate states per MTU and direction. To maintain computational feasibility while preserving the principal uncertainty combinations, stratified representative state reduction was applied according to the generation and grid availability strata. A maximum of two representative states per outage stratum was retained, targeting 95% of the probability mass within each stratum. For each representative state, the reduced PT-ES transmission model was reconstructed in PSS/E and an AC power-flow solution was obtained. The secure incremental transfer capability was subsequently evaluated in both directions through successive transfer increments and N-1 contingency analysis. Thermal loading, AC convergence and voltage-security criteria were used as the principal binding network-security constraints.

The analysis showed that the available transfer capability can vary considerably between probabilistic operating states. In particular, several states were already constrained at zero incremental transfer because of N-1 voltage-security violations. For example, in the MTU 1 representative state analyzed during model validation, contingency 100002-100120(1) resulted in a post-contingency voltage of approximately 1.169 p.u. at the 220-kV bus 100001, exceeding the adopted emergency limit of 1.10 p.u. Therefore, the physical secure transfer headroom of this particular state was 0 MW in both $PT \rightarrow ES$ and $ES \rightarrow PT$ directions.

This result illustrates an important characteristic of the probabilistic methodology: a high published corridor capacity does not necessarily imply that additional transfer can be securely accommodated in every operating state. For the same MTU, the available NewNTC was approximately 4000 MW for $PT \rightarrow ES$ and 4200 MW for $ES \rightarrow PT$, but the network-security constraint was more restrictive in the analysed state.

Expected 24-hour behaviour: Based on the states examined, the final results show a mixture of:

- states with 0 MW pATC, where an N-1 security condition is already violated at the initial operating point;

- states with positive but network-limited pATC, mainly constrained by voltage or transfer-induced convergence/security limits;
- states where the physical transfer capability exceeds the remaining market capacity, in which case NewNTC – TCAA becomes the effective pATC limit.

Table 15. Summary of probabilistic and secure pATC indicators

Indicator	PT-to-ES	ES-to-PT
Maximum published NewNTC considered	~4,000 MW	~4,200 MW
Minimum scenario pATC	0 MW	0 MW
Expected pATC over the day*	~ 0-3,895 MW	~ 3,166 – 4,200 MW
Maximum scenario pATC*	~ 907 – 4,000 MW	~ 4,200 MW
95% secure pATC*	~ 0 – 2,247 MW	~ 1,481 – 3,307 MW
99% secure pATC*	~ 0 - 1,565 MW	~ 783 - 2,938 0 MW
99.9% secure pATC*	~ 0 - 1,400 MW	~ 0 - 2,523 MW

The final MTU-level results should contain four distinct quantities:

$$pATC_{min}(t, d), \quad E[pATC(t, d)], \quad pATC_{max}(t, d), \quad pATC_{secure}(t, d)$$

The minimum and maximum describe the range across the probabilistic system states, while the expected pATC represents the probability-weighted average transfer capability. The secure pATC provides the capacity that is available with at least the selected confidence level. (*Maximum*: optimistic scenario, *Expected*: probability-weighted average, *Minimum*: worst represented scenario, *95% secure*: capacity we can rely on in $\geq 95\%$ of states, *99% secure*: more conservative, *99.9% secure*: very conservative; even rare low-capacity states strongly affect it).

The results (Figure 35 and Figure 36) show a clear directional asymmetry in the estimated cross-border transfer capability. In the PT to ES direction, the expected pATC varies substantially over the day, with several MTUs showing a pronounced reduction in available transfer capability. The minimum scenario pATC reaches 0 MW, while the expected pATC ranges from approximately 0 to 3,895 MW and the maximum scenario pATC remains below the considered NewNTC ceiling of approximately 4,000 MW. The wide separation between the minimum and maximum pATC curves indicates a comparatively high sensitivity of this direction to the represented probabilistic operating and unavailability conditions. At the same time, the observed PT to ES physical flow remains low during most MTUs, meaning that the available transfer capability is only lightly utilized despite the variability in the probabilistic capacity estimate.

In the ES to PT direction, the expected pATC is generally higher and more stable, ranging from approximately 3,166 to 4,200 MW, with the maximum scenario frequently reaching the considered NewNTC ceiling of approximately 4,200 MW. Physical exchanges are also significantly higher in this direction and approach the expected pATC during several MTUs, indicating a greater utilization of the

available cross-border capacity. Table 15 complements the MTU profiles by summarizing the full probabilistic range and the derived secure capacities. As the confidence requirement increases from 95% to 99% and 99.9%, the secure pATC decreases, reflecting the increasing influence of low-capacity or adverse system states. This illustrates the main benefit of the probabilistic approach from a TSO perspective: rather than providing a single deterministic transfer value, it quantifies both the expected capability and the level of capacity that can be relied upon under progressively more conservative security requirements.

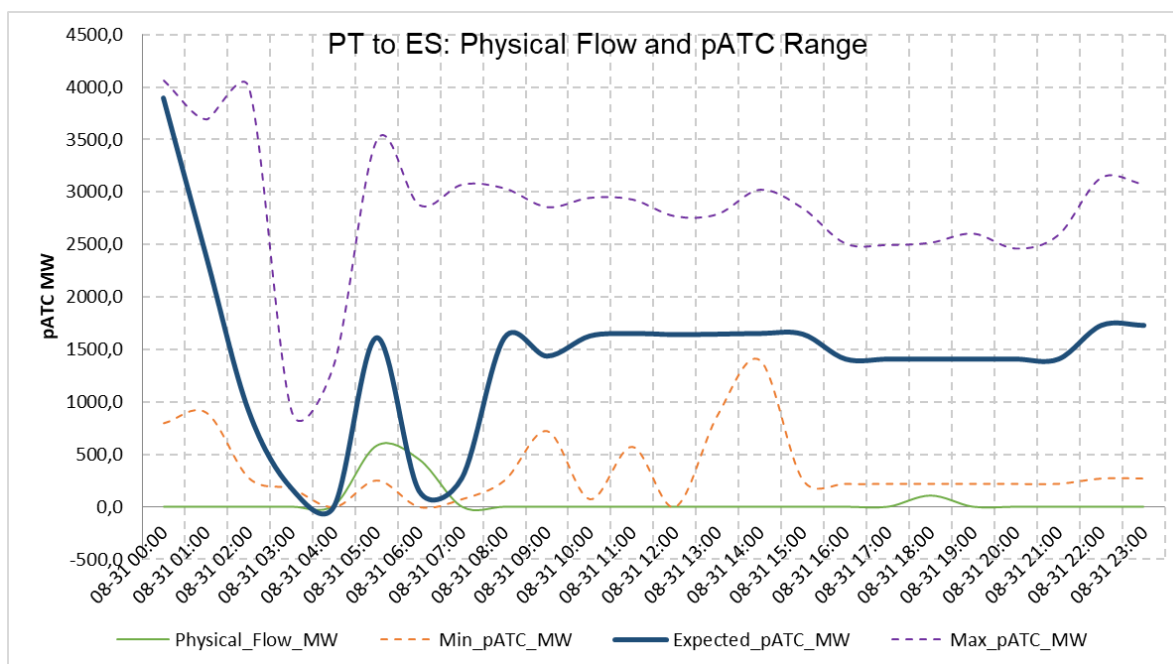


Figure 35 MTU-level physical flows and probabilistic pATC ranges for the PT to ES directions

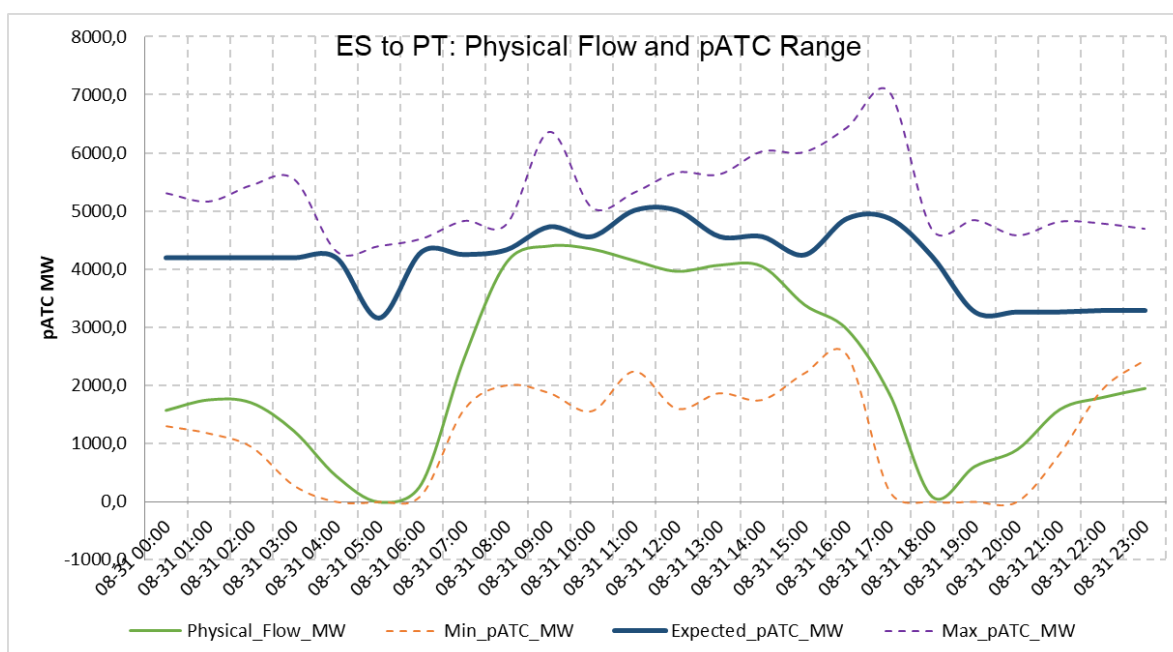


Figure 36 MTU-level physical flows and probabilistic pATC ranges for the ES to PT directions

To demonstrate the use of the TwinEU data-sharing infrastructure in support of TSO coordination for the construction of an Iberian combined grid model, a series of cross-partner data exchanges was

carried out over a one-week period, from 31 August to 6 September 2026. The exercise was structured around a 24-hour forecasting horizon, reflecting the temporal scope required for short-term operational coordination and the exchange of forecast information used in the preparation of a combined representation of the electricity grid.

Within the exercise, CIRCE emulated the role of the Spanish TSO by providing the Spanish grid-model information, while R&D Nester emulated the role of a Regional Coordination Centre, such as Coreso in the South-West Europe region, by combining the information received from the participating TSOs and performing the probabilistic cross-border capacity calculation described in this report. In this context, CIRCE acted as the data provider and R&D Nester as the data consumer, allowing the complete workflow supported by the connector-based architecture to be demonstrated: dataset registration, data-service creation, contract negotiation, transfer initiation and successful retrieval of the exchanged data on the consumer side.

For each execution, the participating parties generated and exchanged a forecast dataset covering a 24-hour operational horizon. The exercise was organised as a sequence of daily exchanges, reproducing the information flow and coordination pattern required for short-term grid operation and for the preparation of a combined grid model. This approach allowed the complete workflow—from forecast generation and publication to data exchange and consumption—to be exercised repeatedly under a consistent 24-hour forecasting framework.

The resulting log excerpts provide evidence of the successful execution of the exchange on both sides of the workflow. On the provider side, Figure 37 shows the publication of the dataset and creation of the corresponding data service, followed by contract negotiation and transfer initiation. The sequence confirms the validation of the offer, creation of the transfer process, generation of the pre-signed URL used for file access and completion of the transfer from the provider perspective.

On the consumer side, Figure 38 shows the complementary execution at R&D Nester, where the agreement is successfully enforced and the transfer is carried out through the expected HTTP PULL mechanism. The consumer retrieves the file (2026_08_31.zip) from the provider-provided endpoint, receives a successful HTTP 200 response, stores the transferred artefact in its local object storage and successfully finalises the transfer process. Together, these logs confirm the correct operation of the end-to-end exchange chain and demonstrate the capability of the TwinEU infrastructure to support cross-partner sharing of grid-related data.

Overall, the exercise demonstrates how the TwinEU connector-based infrastructure can support the recurrent exchange of 24-hour forecast datasets between independently operated systems, providing the data-sharing layer required for coordinated grid-model construction and subsequent cross-border capacity assessment. The demonstration therefore illustrates not only the technical interoperability between participating organisations, but also how the infrastructure can underpin the coordination workflow represented in the Iberian combined grid-model use case.

D8.1 Probabilistic-based cross-border capacity calculation and Cross-border flexibility pre-qualification



Figure 37 – Provider-side execution of the 24-hour forecast data exchange at CIRCE, showing dataset and data-service publication, contract negotiation and transfer initiation/completion.

08/31/2026 04:22:34 PM	31-08-2026 15:22:34.578 [http-nio-8080-exec-9] INFO i.e.d.r.p.ConsumerDataTransferCallbackController - Starting data transfer for consumerPid urn:uuid:7a89cff9-50ef-4f8a-8ba9-79d1fba4ea9 and providerPid urn:uuid:7c3a3e51-bd38-43f8-8bd4-cff2dda6cbef
	31-08-2026 15:22:34.619 [SimpleAsyncTaskExecutor-3896] INFO i.e.d.e.DataTransferEventListener - Transferring process urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef from state 'dspace:REQUESTED' to 'dspace:STARTED'
	31-08-2026 15:22:34.620 [SimpleAsyncTaskExecutor-3899] INFO i.e.d.e.DataTransferEventListener - Transfer Start message event received
	31-08-2026 15:22:34.624 [http-nio-8080-exec-9] INFO i.e.d.r.p.ConsumerDataTransferCallbackController - TransferProcess urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef state changed to dspace:STARTED
08/31/2026 04:22:34 PM	31-08-2026 15:22:34.736 [http-nio-8080-exec-1] INFO i.e.d.r.a.DataTransferAPIController - Downloading transfer process id - urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef data
08/31/2026 04:22:34 PM	31-08-2026 15:22:34.837 [http-nio-8080-exec-8] INFO i.e.n.r.api.AgreementAPIController - Enforcing agreement
	31-08-2026 15:22:34.850 [http-nio-8080-exec-8] INFO i.e.n.p.service.LocationService - Retrieving location
	31-08-2026 15:22:34.850 [http-nio-8080-exec-8] INFO i.e.n.policy.service.PurposeService - Retrieving purpose
	31-08-2026 15:22:34.857 [http-nio-8080-exec-8] INFO i.e.n.service.AgreementAPIService - Agreement is valid
	31-08-2026 15:22:34.858 [http-nio-8080-exec-1] INFO i.e.t.client.rest.OkHttpClient - Status 200
	31-08-2026 15:22:34.861 [http-nio-8080-exec-1] INFO i.e.t.client.rest.OkHttpClient - Response received: {"success":true,"message":"Agreement enforcement is ok","data":{"Agreement enforcement is valid","timestamp":"2026-08-31T15:22:34Z"}}
	31-08-2026 15:22:34.864 [http-nio-8080-exec-1] INFO i.e.d.s.api.DataTransferAPIService - Starting download transfer process id - urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef data...
	31-08-2026 15:22:34.865 [http-nio-8080-exec-1] INFO i.e.d.s.a.s.HttpPullTransferStrategy - Executing HTTP PULL transfer for process urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
	31-08-2026 15:22:34.878 [http-nio-8080-exec-1] INFO i.e.d.s.a.s.HttpPullTransferStrategy - Presigned URL: http://twineu.fcirce.es:9001/dsp-true-connector-a/urn%3Auuid%3A4ad0bdf8a-a743-45ec-a4be-23697a519b3b?response-content-disposition=attachment%3D%2031_08_2026.zip%22&response-content-type=application%2Fzip&X-Amz-Algorithm=AWS4-HMAC-SHA256&X-Amz-Date=20260831T152234Z&X-Amz-SignedHeaders=host&X-Amz-Credential=getBucketUser-c539e3af82f20260831%2Fus-east-1%2Fs3%2Faws4_request&X-Amz-Expires=604800&X-Amz-Signature=2a7190687ffbf9b2b88a591e1c3ff425deae62678ac80b2e75c53209084840
	31-08-2026 15:22:34.878 [http-nio-8080-exec-1] INFO i.e.d.s.a.s.HttpPullTransferStrategy - HTTP response code: 200
	31-08-2026 15:22:34.881 [http-nio-8080-exec-1] INFO i.e.t.s.service.S3ClientServiceImpl - Uploading file urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef to bucket dsp-true-connector-b
	31-08-2026 15:22:34.882 [Thread-12] INFO i.e.t.s.service.S3ClientServiceImpl - Starting multipart upload for key: urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
	31-08-2026 15:22:34.882 [Thread-12] INFO i.e.t.s.service.S3ClientServiceImpl - Creating multipart upload for key: urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
08/31/2026 04:22:34 PM	31-08-2026 15:22:34.989 [http-nio-8080-exec-7] INFO i.e.d.r.a.DataTransferAPIController - Fetching transfer process details for id urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
	31-08-2026 15:22:35.006 [Thread-12] INFO i.e.t.s.service.S3ClientServiceImpl - Created multipart upload for key: urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef with uploadId: ZDM2NTZjMTAtZjBjYy00ZTRhLW11YzIzTG5HTeE4ZGh0ODUwLjE4MzY0MGVmlTI0MeTNGE2MjY0MmFhLTZmNjRhY2NlMzkyYngxNzg4MTg5NzU0OTE4MzkyHjg4
08/31/2026 04:22:35 PM	31-08-2026 15:22:35.140 [Thread-12] INFO i.e.t.s.service.S3ClientServiceImpl - Uploading part 1 for key: urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef with uploadId: ZDM2NTZjMTAtZjBjYy00ZTRhLW11YzIzTG5HTeE4ZGh0ODUwLjE4MzY0MGVmlTI0MeTNGE2MjY0MmFhLTZmNjRhY2NlMzkyYngxNzg4MTg5NzU0OTE4MzkyHjg4
08/31/2026 04:22:35 PM	31-08-2026 15:22:35.430 [Thread-12] INFO i.e.t.s.service.S3ClientServiceImpl - Completing multipart upload for key: urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef with uploadId: ZDM2NTZjMTAtZjBjYy00ZTRhLW11YzIzTG5HTeE4ZGh0ODUwLjE4MzY0MGVmlTI0MeTNGE2MjY0MmFhLTZmNjRhY2NlMzkyYngxNzg4MTg5NzU0OTE4MzkyHjg4
08/31/2026 04:22:35 PM	31-08-2026 15:22:35.518 [Thread-12] INFO i.e.d.s.a.s.HttpPullTransferStrategy - Stored transfer process id - "acf7dfef1c31c991cf8a70f253cf5a0a-1" data!
	31-08-2026 15:22:35.525 [Thread-12] INFO i.e.d.r.a.DataTransferAPIController - Download completed successfully for process urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
08/31/2026 04:22:40 PM	31-08-2026 15:22:40.091 [http-nio-8080-exec-10] INFO i.e.d.r.a.DataTransferAPIController - Fetching transfer process details for id urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
08/31/2026 04:22:40 PM	31-08-2026 15:22:40.248 [http-nio-8080-exec-5] INFO i.e.d.r.a.DataTransferAPIController - Completing data transfer urn:uuid:50dc96ab-2d04-41a1-a7db-c4da98b1cbef
08/31/2026 04:22:40 PM	31-08-2026 15:22:40.307 [http-nio-8080-exec-5] INFO i.e.d.s.api.DataTransferAPIService - Sending TransferCompletionMessage to http://twineu.fcirce.es:9080
	31-08-2026 15:22:40.308 [http-nio-8080-exec-5] INFO i.e.t.client.rest.OkHttpClient - Sending request using address: http://twineu.fcirce.es:9080/transfers/urn:uuid:7c3a3e51-bd38-43f8-8bd4-

Figure 38 – Consumer-side execution at R&D Nester, showing agreement enforcement, retrieval of the 31_08_2026.zip forecast dataset and successful completion of the transfer.

3.7 KPI assessment

KPI_Ib10_1: Percentage of total cross-border capacity utilization:

This KPI measures the extent to which the probabilistically estimated transfer capability is effectively utilized by the observed cross-border power exchange. For each MTU and direction, the absolute physical flow is compared with the corresponding expected pATC. For each MTU, compare the actual physical flow with the pATC calculated for the same direction. The result indicates how much of the probabilistically calculated capacity was used.

For 31 August 2026, the resulting utilization is approximately 3.4% in the PT-to-ES direction and 56.4% in the ES-to-PT direction. Considering both directions together, the total cross-border pATC utilization is approximately, $KPI_Ib10_1 = 42.5\%$.

The large directional difference is consistent with the observed operating conditions. PT-to-ES physical exchanges were very limited during most MTUs, despite the existence of available transfer capability. Conversely, ES-to-PT experienced significantly higher physical exchanges and therefore made substantially greater use of the probabilistically estimated capacity. The KPI should therefore not be interpreted simply as an indication that a higher value is always preferable. It quantifies how much of the available probabilistic transfer capability was actually used under the observed operating conditions. Low utilization may simply reflect the prevailing market position and direction of power exchange rather than insufficient network usage.

VAL_KPI9: Data federation and interoperability coverage

This assesses the extent to which the different Digital Twin instances and associated platforms are able to exchange data through interoperable interfaces. The KPI is primarily measured as the percentage of planned data exchanges that are operational. It is therefore intended to evaluate whether the federation mechanisms developed in TwinEU are effectively enabling cross-platform and

cross-pilot data sharing in practice. For the use case considered in this report, all planned data exchanges included in the validation exercise were successfully executed through the TwinEU connector-based infrastructure over the considered reporting period of one week. The exchange between CIRCE and R&D Nester was completed successfully, including dataset publication, negotiation, transfer initiation and retrieval on the consumer side. Consequently, VAL_KPI9 achieved a score of 100%, corresponding to full operational coverage of the planned data exchanges considered in the exercise, which exceeds pilot-specific target of more than 80% coverage indicated for this KPI and confirms the interoperability of the implemented data-sharing workflow.

KPI_Ib10_2: Percentage of cross-border capacity adequacy probability

This KPI evaluates whether the calculated pATC is sufficient to accommodate the required cross-border exchange while maintaining the selected probabilistic confidence level. It is to calculate the share of scenarios where pATC is adequate and the case remains secure.

At the 95% confidence level, the criterion is fulfilled in 22 of 24 MTUs for PT-to-ES, corresponding to 91.7%, and in 16 of 24 MTUs for ES-to-PT, corresponding to 66.7%. Across the two directions, 38 of the 48 assessed MTU-direction combinations satisfy the 95%-secure adequacy requirement: KPI_Ib10_2 = 79.2%. When a more conservative confidence level is imposed, the adequacy percentage decreases. The corresponding results are approximately, KPI_Ib10_2 = 68.8% for 99 percentile secure and 50.0% for 99.9 percentile secure. This reduction is expected. Increasing the confidence requirement means that increasingly rare low-capacity system states influence the capacity considered secure. Consequently, the transferable capacity that a TSO can rely upon becomes progressively more conservative.

The results therefore show the trade-off inherent in probabilistic transfer-capacity assessment. A 95% security criterion provides adequate cross-border capacity for approximately four-fifths of the evaluated cases, whereas a 99.9% criterion significantly reduces the amount of capacity that can be considered dependable under almost all represented system states.

KPI_Ib10_3: Grid Security Improvement Index (%)

The purpose of KPI_Ib10_3 is to quantify the contribution of the probabilistic methodology to improved grid-security assessment. Conceptually, the indicator should compare the security performance obtained using the probabilistic pATC methodology against a reference or baseline assessment. The security score would ideally combine information such as CNE loading, voltage compliance, N-1 contingency results and the probability associated with secure and insecure system states. The available results provide supporting evidence of the security benefit of the probabilistic approach.

For the baseline assessment, the transfer level for each MTU and direction is taken as the available published capacity, calculated from the corresponding NewNTC after accounting for TCAA (Baseline = 53.3%). This baseline transfer level is then evaluated against the probabilistic operating, generation unavailability and grid unavailability states considered in the pATC methodology. A state is considered secure when its calculated transfer capability is sufficient to accommodate the baseline transfer level (corresponding to 95% secure adequacy). The 95% secure adequacy is the most appropriate primary estimate because it gives a reasonable balance between security and usable transfer capacity.

The methodology evaluates transfer capability across multiple operating and states rather than relying on a single deterministic operating point. For the probabilistic assessment, the transfer level is set to the 95%-secure pATC, representing the capacity that can be relied upon with at the selected

confidence level. The resulting probability-weighted security score increases from approximately 53.3% for the deterministic baseline to 79.2% when the probabilistic secure pATC is applied.

The 95%-secure adequacy assessment shows that approximately 79.2% of the assessed MTU-direction cases can accommodate the observed transfer while satisfying the adopted probabilistic security criterion. This result indicates that incorporating uncertainty explicitly into the cross-border capacity assessment improves the probability of operating within the transfer capability represented by the assessed system states by 25.9% to the deterministic baseline. The improvement is primarily associated with the PT-to-ES direction, where the probabilistic analysis identifies significant state-dependent transfer limitations that are not reflected when the available market capacity alone is considered. The ES-to-PT direction shows a smaller improvement because the available market capacity is more frequently compatible with the calculated physical transfer capability.

Table 16. UC-Ib10 KPI assessment.

KPI	Main inputs	Assessment Plan	Result
KPI_Ib10_1: % of total cross-border capacity utilization	Physical flow, pATC by MTU and direction	For each MTU, compare the actual physical flow with the pATC calculated for the same direction. The result indicates how much of the probabilistically calculated capacity was used.	For 31 August 2026, utilization was approximately 3.4% for PT-to-ES and 56.4% for ES-to-PT. Considering both directions, the overall cross-border capacity utilization was 42.5%.
VAL_KPI9: Data federation and interoperability coverage	Extent of data federation and interoperability between DT instances	Percentage of planned data exchanges operational and number of interoperable interfaces successfully demonstrated.	All planned exchanges included in the validation exercise were successfully completed through the TwinEU connector-based infrastructure. $VAL_KPI9 = 100\%$, exceeding the pilot target of $>80\%$.
KPI_Ib10_2: % of cross-border capacity adequacy probability	Scenario pATC, scenario weights, required/allocated capacity and security flags	Calculate the share of scenarios where pATC is adequate and the case remains secure.	At 95% confidence, 38 of 48 MTU-direction cases were adequate, giving $KPI_Ib10_2 = 79.2\%$. The adequacy decreases to approximately 68.8% at 99% and 50.0% at 99.9% confidence.
KPI_Ib10_3: Grid Security Improvement Index (%)	Secure pATC and capacity-adequacy results at different probabilistic confidence levels	Construct a security score for the baseline and probabilistic assessment and express the improvement as a percentage. The CNE list is based on unavailability/outage data and selected line-loss cases.	The adequacy increases from 53.3% at baseline to 79.2% at 95% secure confidence. Therefore, $KPI_Ib10_3 = (79.2/53.3) - 1 = 48.6\%$ relative improvement. The absolute increase is 25.9 %.

3.8 Discussion

The work carried out in this study demonstrates a workflow for probabilistic assessment of cross-border transfer capability between Portugal and Spain. Starting from the reduced PSS/E transmission model, operational forecast scenarios, uncertainty information and transfer-capacity data were combined to construct probabilistic system states and estimate pATC for both PT to ES and ES to PT directions. The resulting minimum, expected, maximum and secure pATC values provide a more informative representation of cross-border capability than a single deterministic value.

The probabilistic approach quantifies how transfer capability changes across acceptable system states and associates these outcomes with their probabilities. The TSO can therefore explicitly evaluate the tradeoff between cross-border capacity and security risk and select a capacity for the market. The same methodology also provides confidence values, which can support sensitivity analysis and more conservative operation under stressed conditions. The objective is therefore not necessarily to increase ATC in every MTU, but to make the security margin risk-informed, transparent and responsive to the prevailing uncertainty.

The UC-Ib10 workflow separates the probabilistic information used internally for TSO security and capacity assessment, and the single capacity value communicated to the market coupling function. Referring to the Information Exchange in Annex B, IE9 communicates the probabilistic ATC results to the CGDT, including the distribution of calculated transfer capabilities and derived indicators such as expected pATC and secure pATC at the 95%, 99% and 99.9% confidence levels. These values provide the TSO with information on the uncertainty and downside risk associated with the available cross-border capacity. IE11 does not expect communicate the complete probability distribution to OMIE. Before this information exchange, the probabilistic results are converted into a single ATC value for each MTU and direction according to the selected TSO security-confidence criterion. For the UC-Ib10 demonstration, the 95%-secure pATC is considered the primary market-facing capacity estimate.

Thus, conceptually,

$$ATC_{t,d}^{IE11} = pATC_{t,d,95\%}^{secure}$$

after application of the relevant capacity-accounting limits. The 99% and 99.9% values are retained at TSO level as sensitivity and risk indicators and are available to the TSO/CGDT, but they do not represent additional ATC values simultaneously submitted to the market. The 95% level was selected for the demonstrator as a compromise between security and efficient use of cross-border capacity. It is also the confidence level best supported by the implemented scenario-reduction approach. In a real operational implementation, the selected confidence level should ultimately be defined by the concerned TSO security policy, coordinated methodology and regulatory requirements rather than being intrinsically fixed at 95%. This approach is aligned with the European transition towards probabilistic operational risk assessment [44].

The main modelling challenge was the balance between detail and tractability. Retaining PT and ES in detail is necessary to capture internal Iberian constraints, but the rest of Europe is represented in a simplified way to keep the study manageable. The electrical equivalent is therefore a practical compromise, and is validated carefully to ensure that the equivalent does not distort the boundary conditions of the retained network. A second challenge is data consistency. The capacity calculation depends on the alignment of network cases, scenario assumptions, unavailability records, generation data, load data, allocated capacity and physical flow measurements. Differences in timestamps,

direction conventions, units or naming can lead to incorrect KPI values. For this reason, the validation includes explicit data harmonisation and quality checks before KPI calculation.

The proposed scenario generation method combines seasonally filtered historical data and k-medoids clustering to generate a compact set of representative operating scenarios for probabilistic cross-border capacity assessment. This approach captures variability in demand, renewable generation and cross-border flows while limiting the computational burden of subsequent network calculations. Jointly sampling aligned historical profiles also preserves the temporal and spatial relationships present in the selected data, which prevents the creation of unrealistic time-series. However, the reliability of the resulting scenarios depends strongly on the quality, quantity and granularity of the input data. Historical records must be sufficiently extensive and representative to cover seasonal patterns and less frequent operating conditions, while missing values, inconsistent timestamps and measurement errors require careful treatment to avoid distorting scenario probabilities. Consequently, the method's practical value depends on access to consistent, detailed and regularly updated datasets, alongside validation that the selected scenarios adequately represent both typical and stressed operating conditions.

The cross-partner data exchange was successfully demonstrated using the TwinEU connector-based infrastructure, with CIRCE acting as data provider and R&D Nester as data consumer. The test covered the complete workflow, including dataset publication, contract negotiation, transfer initiation and successful retrieval of the exchanged files. The results confirm that the infrastructure can reliably support the recurrent exchange of forecast and grid-related data between partners and could therefore be integrated into the regular result-generation workflow of this use case, enabling the automated delivery and consumption of the datasets required for combined grid-model construction and cross-border capacity assessment.

The results further illustrate the value of the probabilistic approach. For the evaluated day, the overall utilization of probabilistically estimated cross-border capacity was approximately 42.4%, while the capacity adequacy reached 79.2% at 95% confidence, decreasing to 68.8% at 99% and 50.0% at 99.9% as increasingly conservative security requirements were imposed. These results highlight the trade-off between maximizing usable cross-border capacity and maintaining robustness against rare but adverse system states. Although the reduced network model does not support a fully operational validation of all voltage and thermal security effects, the methodology successfully demonstrates how uncertainty, outages, transfer limits and confidence levels can be integrated into a coherent pATC framework to support more risk-aware and transparent cross-border capacity assessment.

4 UC-Ib11. Cross-border assessment of flexibility and pre-qualification

This section describes the implementation and experimental validation approach for the use-case UC-Ib11 “Cross-border assessment of flexibility and pre-qualification”. The full use-case description, including actors, information exchanges and the detailed sequence of activities, is provided in Annex C and in IEC 62559-2 use-case description.

4.1 Objectives of the use-case

The scope of this use case is to enable the coordination between System Operators (SOs) and Flexibility Service Providers (FSPs) for cross-border flexibility product integration particularly fast frequency reserves (FFR) in the Iberian Peninsula with the following objectives:

- Design and test the prequalification process phase between neighbour SOs, namely for a new Fast Frequency Reserve (FFR) service.
- Exchange (cross-border) grid and product prequalification information using digital twins (DTs).
- Facilitate the entry of FSPs into the various flexibility markets cross-border, namely for a new Fast Frequency Reserve (FFR) market.

4.2 Use-case triggering event and pre-condition

The use case is triggered by a sudden grid disturbance in either Portugal or Spain that creates a significant active power imbalance and causes the system frequency to fall below the selected Fast Frequency Reserve (FFR) activation threshold. This disturbance is designed to activate prequalified FFR resources and assess their capability to support system frequency stability.

The following preconditions are required for the execution of the use case:

- The ENTSO-E dynamic grid model of continental Europe V2 in PSSE [21] is considered, has been cleaned, and all simulation parameters have been configured.
- A Digital Twin with a dynamic grid model equivalent of the ENTSO-E dynamic grid model of continental Europe V2, retaining the electrical representation of Portugal and Spain has been developed and validated.
- Battery Energy Storage Systems (BESS) equipped with an FFR controller are connected to the grid model.
- The FFR controller parameters are configured according to the selected prequalification requirements.
- Initial steady-state operating conditions have been established.
- Frequency monitoring, event recording and performance assessment functionalities are available within the Digital Twin environment.
- The disturbance scenario has been designed such that the resulting frequency deviation crosses the selected FFR activation threshold of 49.7 Hz, thereby triggering the activation of the prequalified BESS assets.

- Upon occurrence of the disturbance, the prequalified BESS assets are automatically activated and provide Fast Frequency Reserve support according to the configured controller settings.

4.3 Use-case KPIs

To assess the effectiveness and impact of cross-border flexibility, a series of Key Performance Indicators (KPIs) have been defined in this use case. These indicators enable the evaluation of technical readiness, market integration, and operational efficiency associated with the deployment of FFR products in the Iberian context.

- **IB11_KPI1: Dynamic Equivalent Model Validity:** KPI tracks how accurately the reduced ENTSO-E dynamic equivalent DT reproduces the frequency response characteristics of the original system following a major generation loss event.
- **IB11_KPI2: BESS FFR Controller Prequalification Compliance:** KPI tracks whether the representative BESS FFR controller satisfies the selected FFR prequalification requirements. Since the same controller logic and prequalification criteria are used for all BESS units, the prequalification test is performed on a representative BESS model.
- **IB11_KPI3: Total system Inertia:** This KPI used to track how well a reduced network model preserves the frequency response characteristics of the original power system. The total inertia contribution is calculated from the inertia constants and rated capacities of all online synchronous machines in the grid.
- **IB11_KPI4: Volume of Flexibility by Prequalified Units:** This KPI tracks the total volume of flexibility that is available from units that have completed the prequalification process. It provides a direct measurement of the system's readiness and the technical capacity of prequalified resources.
- **IB11_KPI5: Frequency Nadir Improvement:** KPI tracks the improvement in minimum system frequency achieved through FFR activation following the sudden grid disturbance.

4.4 Technology development and Implementation

- **Dynamic Equivalent of ENTSO-E DT:** A reduced dynamic equivalent of the ENTSO-E Digital Twin (DT) was developed in PSS®E while preserving the detailed electrical representation of the Portuguese and Spanish transmission systems, the overall Continental Europe interconnections, the slack area, and identified electrically stressed buses. The implemented DT is used as an offline simulation environment and is not continuously synchronized with the physical power system through real-time or near-real-time measurements. The underlying grid model is derived from real power-system data, while grid assets such as BESS, and FFR-related information are provided as prepared input datasets and updated offline before the simulations are executed. The assessments presented in this use case therefore rely on prepared model and simulation data rather than live operational data streams. The objective was to create a computationally efficient simulation environment suitable for frequency stability studies and FFR validation while maintaining the dynamic behaviour relevant to frequency response assessment. The original static model was reduced using PSS®E Equivalence Networks, while the dynamic generator was clustered using K-means and reassigned through rule-based assignment to the reduced machine buses. The dynamic load models are also reassigned through rule-based assignment to the reduced load buses.
- **FFR Technical Requirements and Controller Response or Product Prequalification:** The FFR is triggered as an up-regulation response by either enhancing power generation of the grid or

decreasing power usage. When the frequency reaches the specified threshold, the reserve capacity must be fully activated within the required activation time. The FFR offers three different combinations of activation frequency and activation time, from which the Frequency Service Provider (FSP) can choose one. The options are listed in Table 17 [7] [22]. The BESS FFR controller was configured according to the selected FFR technical requirements. The assessment focused on the selected activation threshold behaviour, full activation time, reserve delivery capability, and deactivation limitation.

Table 17. Activation Frequency and Time for FFR

	Activation frequency	Maximum full activation time [s]
Alternative A	49.70 Hz	1.30 s
Alternative B	49.60 Hz	1.00 s
Alternative C	49.50 Hz	0.70 s

An FFR controller logic was designed and integrated into BES located in the DT: Portuguese and Spanish side within the PSS®E environment. The controller continuously monitors the system frequency and autonomously activates reserve power when the frequency falls below a predefined activation threshold.

- **FFR Product Prequalification:** To evaluate controller performance and compliance with FFR requirements, a synthetic frequency signal approach based on Nordic FFR prequalification requirements was adopted. Synthetic frequency test signals were generated according to the selected prequalification requirements and used as inputs to the BESS controller.

A simulated prequalification step response test was implemented to verify compliance of the BESS FFR controller with the selected FFR technical requirements. The assessment focused on selected activation threshold behaviour, full activation time, reserve delivery capability and deactivation limitation.

The representative BESS is integrated in Portugal grid area was modelled with a rated power of 12 MW, an energy capacity of 24 MWh, and an initial state of charge (SoC) of 50%. The controller was configured according to Alternative A of the FFR technical requirements, corresponding to an activation threshold of 49.70 Hz, a maximum full activation time of 1.3 s, and a maximum deactivation rate of 20% of the rated FFR capacity per second, corresponding to approximately 5s for complete deactivation from full output.

A synthetic frequency step test signal was generated and applied to the controller. As shown in Figure 39, the test signal consisted of three operating stages: 50.00 Hz for 120 s, 49.75 Hz for 80 s, and 49.65 Hz for 160 s. The first frequency step was used to verify that no reserve activation occurred above the 49.70 Hz activation threshold, while the second step was used to verify correct FFR activation below the threshold, using a ± 0.05 Hz test margin around the selected activation frequency. The active power response of the BESS and the state-of-charge evolution were recorded and analysed throughout the test.

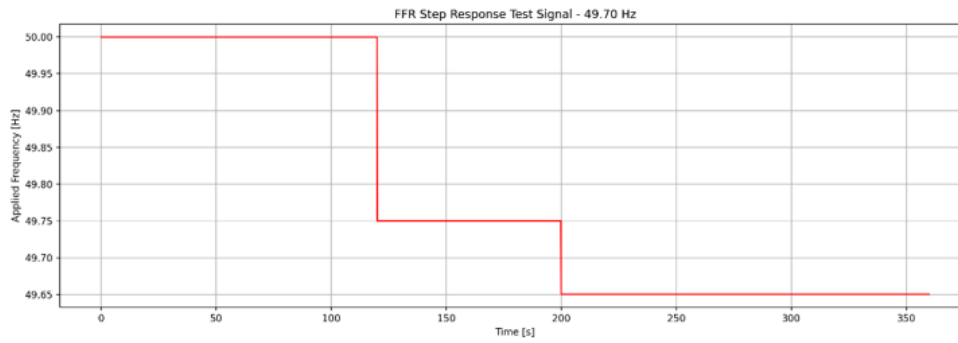


Figure 39. FFR Step Response Test Signal

- **System Equivalent Inertia:** The system equivalent inertia is calculated using Equation.(1)(2). [2]

$$E_{kin} = \sum_i H_i S_i \quad (1)$$

$$H_{eq} = \frac{\sum H_i S_i}{\sum S_i} \quad (2)$$

Where H_i is the inertia constant and S_i is the machine MVA rating. The total equivalent inertia is calculated from the inertia constants and MVA ratings of the online/in-service synchronous machines represented by the GENSAL and GENROU models in the grid model.

- **Cross-border FFR Simulation:** Following successful product and grid prequalification, the validated FFR controller (CBEST + PAUX), together with the BESS units, was integrated into the Portuguese and Spanish grid areas of Digital Twin. Dynamic simulations were performed by introducing a sudden grid disturbance designed to create a frequency deviation below the selected FFR activation threshold of 49.70 Hz. The resulting frequency evolution, BESS response, frequency nadir improvement, and reserve activation behaviour were assessed to evaluate the effectiveness of FFR support in both systems.

4.5 Description of the experimental validation

The validation process consists of the following stages:

- **Validation of the dynamic network equivalent against the original ENTSO-E dynamic network behaviour:** The reduced dynamic equivalent was validated against the original ENTSO-E dynamic network to confirm that the relevant steady-state and dynamic behaviour required for the FFR assessment was retained. The validation first considered the consistency of the reduced steady-state operating point, including preservation of the main generation, load-flow, voltage, and system interconnection characteristics. The dynamic model was then initialized and subjected to an undisturbed simulation to verify stable dynamic behaviour and the absence of immediate network divergence.

Further dynamic validation was performed by applying identical disturbance scenarios to both the original and reduced models. Major generation-loss events were applied separately in the Spanish and Portuguese grid areas, and the resulting frequency and voltage responses were recorded at common retained buses, including the disturbance bus and the system slack bus. The responses of the two models were compared using frequency RMSE, frequency nadir and nadir error, time-to-nadir error, RoCoF, voltage RMSE, and minimum-voltage error.

In addition, the equivalent system inertia was calculated for both the original and reduced models to verify that the reduction process preserved the synchronous inertia characteristics relevant to system frequency response. The combined steady-state, dynamic-response, and inertia comparisons were used to confirm that the reduced Digital Twin provides an appropriate representation of the original ENTSO-E system for subsequent FFR prequalification and cross-border FFR simulation studies

- **Execution of the FFR product prequalification test on the representative BESS controller:** A step-response prequalification test was performed according to the Nordic FFR technical requirements. The frequency signal consisted of three stages.

The initial stage at 50.00 Hz established the normal operating condition. The first frequency step was used to verify that no activation occurred above the selected activation threshold, while the second frequency step was used to verify correct activation below the threshold. The active-power response of the BESS and the state-of-charge evolution were recorded at a sampling rate of 10 Hz.

- **Cross-border FFR Simulations:** Following validation of the reduced dynamic equivalent, completion of the representative BESS controller product prequalification test and grid prequalification of all the prequalified volume of BESS a system-level dynamic simulation study was performed to quantify the contribution of BESSs providing FFR to system frequency stability following a grid disturbance. The assessment was based on a controlled comparison between otherwise identical dynamic simulation scenarios: a reference case with the BESS FFR functionality disabled and FFR-enabled cases in which the prequalified BESS controllers respond automatically to the measured frequency deviation.

Table 18 Cases Considered in Cross-border FFR Simulations

Case	Disturbed control area	Frequency Service Provider's (FSP) control area	Description
Reference Case/FFR disabled Case	-	-	A grid disturbance event affecting the whole grid model is applied, with the Portuguese and Spanish FSP FFR functionalities disabled. This provides the reference frequency response without cross-border FFR support.
FFR-enabled Case 1	Spain	Portugal	The same disturbance considered in the Reference Case is applied, while the prequalified Portuguese BESS units are enabled to provide FFR support to the Spanish system.
FFR-enabled Case 2	Portugal	Spain	The same disturbance considered in the Reference Case is applied, while the prequalified Spanish BESS units are enabled to provide FFR support to the Portuguese system.

For each operating condition, two cross-border configurations were considered. In the first configuration, there is an incident in Spain and the FFR service is provided by a Frequency Service Provider (FSP) located in Portugal. In the second configuration, there is an incident in Portugal and the FFR service is provided by an FSP located in Spain. This allows the contribution of cross-border FFR to be evaluated in both directions across the Iberian system. Table 18 shows cases considered for cross-border simulations.

The disturbance scenario was selected such that the resulting system frequency deviation crossed the selected FFR activation threshold of 49.70 Hz. The disturbance magnitude required to reach this threshold is not fixed and may vary depending on the type and location of the disturbance, as well as on the prevailing operating conditions, network topology, generation and load distribution, and system inertia. Therefore, different disturbance scenarios may require different disturbance magnitudes to achieve a comparable frequency deviation. However, for each individual assessment case, the same disturbance type, magnitude, location, and initial operating conditions were maintained between the corresponding FFR-disabled and FFR-enabled simulations to ensure a consistent comparison of the FFR contribution.

4.5.1 Data required for the experimental validation

Data required for the experimental validation:

- Dynamic equivalent grid model
- Location and capacity of the BESS units.
- Rated power and energy capacity of the BESS units in Portugal and Spain [23] [24] [25] [26] [27] [28].
- FFR controller with tuned parameters.
- Identified sudden disturbance type and magnitude in MW required to drive the system frequency below the selected FFR activation threshold of 49.70 Hz (Alternative A), as shown in Table 17 for the Portuguese and Spanish grids individually.
- Dynamic simulation parameters.
- Frequency and active power measurements obtained during simulations.

4.6 Results of the experimental validation

Dynamic Equivalent Model:

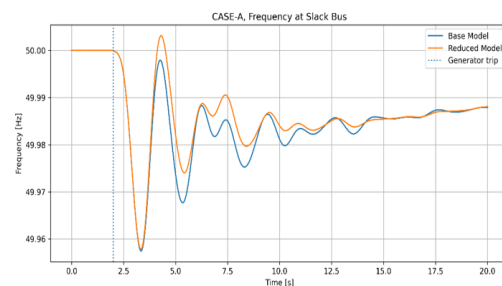
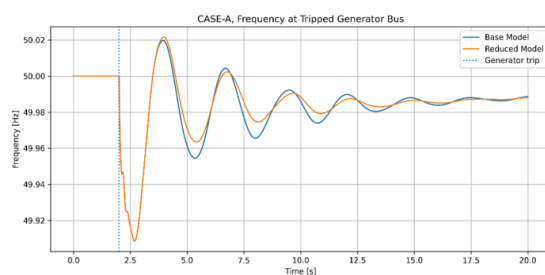
The reduced equivalent Digital Twin model was first validated against the original ENTSO-E model to ensure that the electrical and dynamic characteristics relevant to FFR studies were preserved. The reduced model decreases the network size from 25,578 to 8,525 buses, corresponding to a 66.67% reduction, while preserving the total system generation and the detailed representations of the Iberian areas, Portugal and Spain, the slack area, interconnections, boundary buses, and identified electrically stressed buses. Table 19 shows the quantitative comparison of the reduced grid model parameters and performance with the original/base model.

Table 19 Static Grid Model reduction parameter comparison.

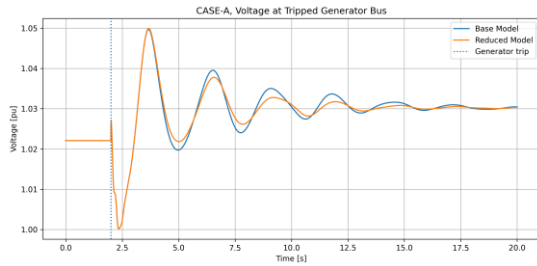
Category	Metric	Base Model	Reduced Model	Assessment
Model Size	Total buses	25578	8525	66.67% reduction
	Total loads	28745	15558	45.88% reduction
	Total machine records	21817	11675	46.49% reduction
	Total AC branches	36100	21877	39.40% reduction
Generation & Load	Total generation P (MW)	237441.2	237441.2	Exactly preserved
	PQ load P (MW)	232402.8	233103.0	+0.30% difference
	Active-power losses (MW)	4631.5	3 764.4	18.72% lower
Voltage Profile	Maximum voltage (pu)	1.2767	1.21918	Maximum voltage extreme reduced
	Minimum voltage (pu)	0.69202	0.80901	Technically ok.
Power Flow	Convergence	Yes	Yes	Both cases obtain a converged power-flow solution

Despite the substantial reduction, the load flow converges and the main characteristics of the original model are closely preserved. The model also successfully initialized with the dynamic data and completed a 2-s undisturbed dynamic simulation with a 5-ms integration time step. The reduced model remained stable for the full 2-s simulation period without any immediate network divergence. Overall, the reduction achieved a 66.67% decrease in the number of buses while preserving stable undisturbed dynamic behaviour. These results indicate that the reduced model is a strong candidate for subsequent FFR studies, subject to further validation under disturbance and contingency conditions. Further dynamic performance was validated through the following simulation cases:

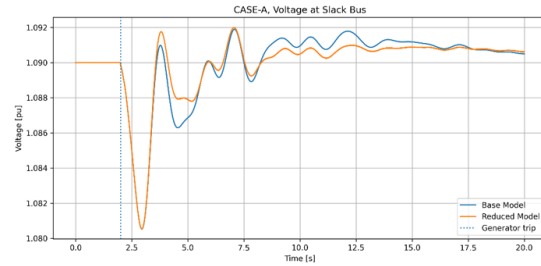
Case A- Spain: A sudden grid disturbance was introduced by disconnecting the largest online generator in the Spanish grid area, corresponding to a generation loss of 1063.64 MW. The same disturbance was applied to both the original/base model and the reduced model. The frequency and voltage responses were recorded at the tripped-generator bus and at the system slack bus and subsequently compared in Table 20. Figure 40 shows the frequency and voltage responses recorded for this case.



(a) *Case A Frequency at Tripped Generators*



(b) *Case A Frequency at Slack Bus*

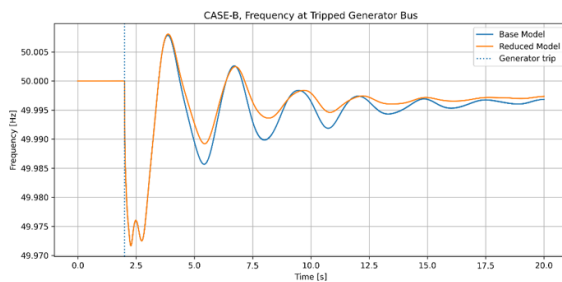


(b) *Case A Voltage at Tripped Generator Bus*

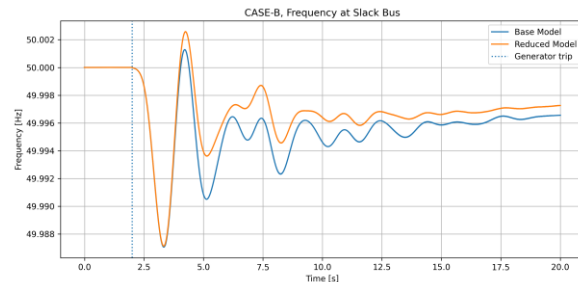
(d) *Case A Voltage at Slack Bus*

Figure 40 Case A- Frequency and Voltage Comparison

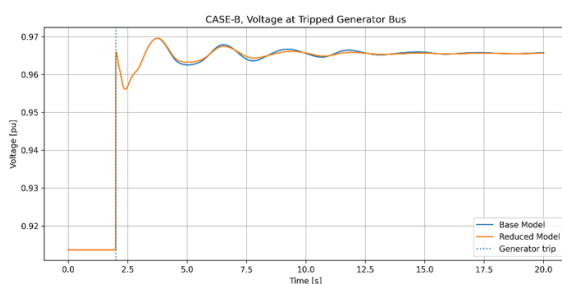
Case B- Portugal: A sudden grid disturbance was introduced by disconnecting the largest online generator in the Portuguese grid area, corresponding to a generation loss of 293.35 MW. The same disturbance was applied to both the original/base model and the reduced model. The frequency and voltage responses were recorded at the tripped-generator bus and at the system slack bus and subsequently compared in Table 20. Figure 41 shows the frequency and voltage responses recorded for this case.



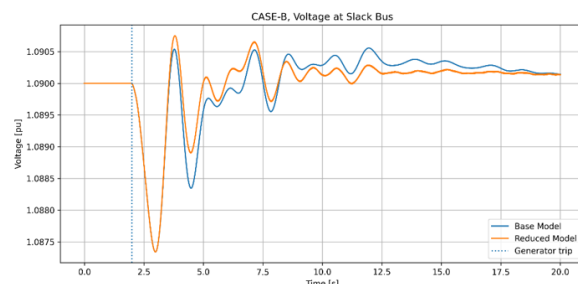
(c) *Case B- Frequency at Tripped Generators*



(b) *Case B- Frequency at Slack Bus*



(d) *Case B- Voltage at Tripped Generator Bus*



(d) *Case B - Voltage at Slack Bus*

Figure 41 Case B- Frequency and Voltage Comparison

The dynamic performance comparison was obtained using the following performance indicators: frequency RMSE, frequency nadir and nadir error, time-to-nadir error, RoCoF, voltage RMSE, and minimum-voltage error, as shown in Table 20.

Table 20 Comparison of Quantitative Parameters

Case	Location	Frequency RMSE [Hz]	Nadir Base [Hz]	Nadir Reduced [Hz]	Nadir Error [Hz]	Time-to-Nadir Error [s]	RoCoF Base [Hz/s]	RoCoF Reduced [Hz/s]	Voltage RMSE [pu]	Vmin Error [pu]
Case A – Spain	Trip bus 100325	0.003646	49.908387	49.908372	-0.000015	0.000	-1.425746	-1.425719	0.001074	-0.00000083
Case A – Spain	Slack bus 110967	0.002743	49.957446	49.957848	+0.000402	-0.005	-0.061567	-0.061231	0.000517	+0.000013
Case B Portugal	Trip bus 210501	0.001561	49.971655	49.971657	+0.000003	0.000	-1.053829	-1.053806	0.000312	+0.00000024
Case B Portugal	Slack bus 110967	0.001339	49.987060	49.987136	+0.000076	0.000	-0.020908	-0.020722	0.000192	0.000000

The comparison between the base and reduced Digital Twin models shows very close frequency and voltage dynamic responses for the Spain and Portugal disturbance cases. Across all monitored locations, the frequency RMSE remained below 0.0037 Hz, while the absolute nadir error did not exceed 0.000402 Hz, indicating that the reduced model accurately reproduces the minimum frequency response of the original system. The time-to-nadir error was negligible, with a maximum absolute deviation of only 0.005 s, and the RoCoF values showed very small differences between the two models, particularly at the disturbance buses. Voltage performance was similarly well preserved, with voltage RMSE values between 0.000192 pu and 0.001074 pu and practically negligible minimum-voltage errors.

Overall, these results demonstrate that the reduced Digital Twin model maintains the key electromechanical dynamic characteristics of the base system with very high accuracy, supporting its suitability for subsequent dynamic and FFR-related studies. The overall performance comparison demonstrates the preservation of dynamic behaviour while maintaining a substantial reduction in network size and computational complexity.

FFR Product Prequalification

The CBEST-based BESS controller logic was evaluated against the selected FFR prequalification settings using a step test. The controller was configured with an activation threshold of 49.70 Hz and a maximum full activation time of 1.30 s.

During the test, the applied frequency was first reduced from 50.00 Hz to 49.75 Hz, at which point no FFR activation was observed, confirming that the controller remained inactive above the selected activation threshold. The frequency was then reduced to 49.65 Hz, causing the controller to activate as expected. The BESS reached its full contracted reserve capacity of 12 MW within 1.20 s, satisfying the maximum full activation time requirement of 1.30 s. The BESS subsequently maintained its full FFR capacity for the required minimum support period of 5 s.

The response also complied with the subsequent deactivation constraint, with the output reduced at a rate not exceeding 20% of the prequalified FFR capacity per second. For the 12 MW representative BESS, this corresponds to a maximum permitted deactivation rate of 20% which means $0.20 \times 12 = 2.40$ MW/s. The maximum observed deactivation rate was 2.40 MW/s, therefore satisfying the selected deactivation requirement.

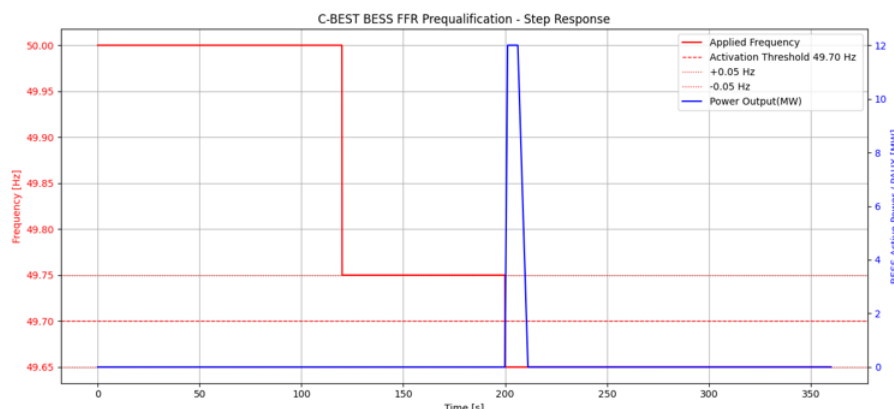


Figure 42 Frequency Signal vs Controller Response

Table 21 FFR Product Prequalification Parameter Analysis

Parameters/Conditions	Status	Unit
No-activation above threshold	PASS	
Threshold crossing time	200.00	s
Full activation time	1.20	s
Activation time requirement	PASS	
5-second latched support requirement	PASS	
Minimum support power	12.00	MW
Maximum observed deactivation rate	2.400	MW/s
Allowed deactivation rate	2.400	MW/s
Deactivation rate requirement	PASS	
Delivered FFR capacity	12.00	MW
Capacity delivery requirement	PASS	-
Initial SoC	50.00	%
Final SoC	49.89	%
SoC limit requirement	PASS	
Maximum delivered power	12.00	MW
Over delivery requirement	PASS	
No negative/recovery power	PASS	

Overall, the simulated CBEST controller response satisfied the assessed FFR prequalification criteria for the selected 49.70 Hz activation threshold and 1.30 s maximum full activation time and was therefore considered suitable for implementation in the subsequent DT cross-border FFR simulations. Figure 42 shows the controller response to the applied synthetic frequency signal, while Table 21 presents the prequalification results, showing an overall PASS for the predefined step-response test.

Grid Prequalification

The activation of the full prequalified BESS units in DT did not introduce additional network violations relative to the reference operating condition. No new undervoltage or overvoltage violations were identified following the BESS injection. In addition, no line or transformer loading violations were observed in either the Spanish or Portuguese grid areas. Therefore, no additional network congestion was identified, and the prequalified BESS capacity was considered compatible with the network for the assessed operating condition.

Total System Inertia

The ENTSO-E grid model consists of total 1422 online synchronous machines represented by GENROU and GENSAL dynamic models. The total machine M_{BASE} (S) and system kinetic energy ($H \times S$)

are calculated as 387324.88 MVA and 1418980.77 MVA.s respectively. Furthermore, the equivalent system inertia (H_{eq}) is calculated as 3.6635 s.

Volume of Flexibility by Prequalified Units:

Here, the total volume of flexibility provided by the prequalified BESS units in the Portuguese and Spanish grids is calculated. The three realistic BESS units owned by REN are mapped and integrated into the Portuguese side of the DT at medium and high voltage buses. These BESS units are prequalified assets with rated capacities of 5.96 MW, 12 MW, and 1 MW, corresponding to a total prequalified FFR capacity of 18.96 MW. Similarly, the 15 realistic BESS units are identified and integrated into the Spanish side of the DT at medium voltage level, These BESS units are prequalified assets with rated capacities of 28.8 MW (6 × 28.8 MW), 15 MW, 6MW, 5MW (3 × 5 MW), 3MW, 1.7 MW, 1.42 MW, 1.2 MW corresponding to a total prequalified FFR capacity of 216.12 MW.

Cross-border FFR Simulations

To assess the participation of Frequency Service Providers (FSPs) in cross-border Fast Frequency Reserve (FFR) provision, dynamic simulations are performed using the reduced DT for the simulation cases defined in Table 12. In all cases, the same disturbance was applied to provide a consistent basis for comparison. Following an undisturbed period from $t = 0$ s to $t = 1$ s, a sudden 10% system-wide increase in active-power demand, corresponding to approximately 22.55 GW, was applied at $t = 1$ s. This disturbance caused the system frequency to decrease below the selected FFR activation threshold of 49.70 Hz at approximately $t = 2.7$ s. Each simulation was performed for a total duration of 15 s, corresponding to approximately 14 s of post-disturbance response, in order to evaluate the complete activation, full-power support, and deactivation behaviour of the participating BESS units.

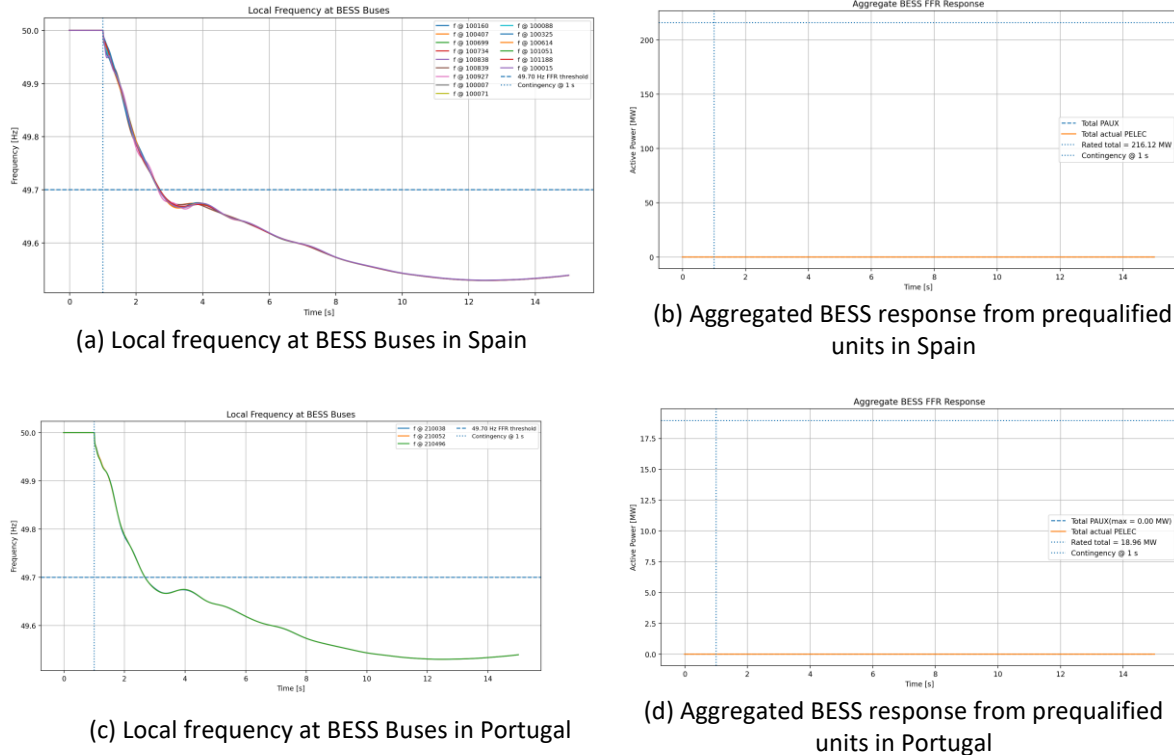


Figure 43 FFR Disabled/Reference Case: Frequency and aggregated battery response in Spain and Portugal

Reference Case/FFR-disabled: The reference simulations establish the baseline system-frequency response in the absence of FFR support. The same system-wide active-power disturbance of approximately 22.55 GW is applied at $t = 1$ s, while the PAUX command of the corresponding BESS units is maintained at zero. Consequently, although the local frequency crosses the FFR activation threshold of 49.70 Hz at approximately $t = 2.7$ s, no BESS active-power response is provided.

For the Portugal-FSP configuration, the post-disturbance frequency nadir measured at the three BESS buses ranges from approximately 49.5299 to 49.5300 Hz. For the Spain-FSP configuration, the nadir measured across the 15 BESS buses ranges from approximately 49.5297 to 49.5302 Hz. These reference simulations provide the baseline against which the FFR-enabled cases are assessed. Figure 43 presents the reference frequency and aggregated battery active-power response for Spain and Portugal; with FFR disabled, the aggregate PAUX and BESS PELEC i.e. power output of BESS that is injected into the grid remain approximately 0 MW.

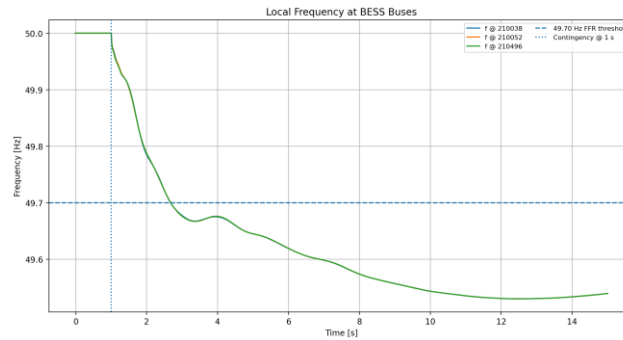
FFR-Enabled Case 1: In this case, the three prequalified BESS units located in Portugal are enabled to provide cross-border FFR support to the Spanish system. Their total available FFR capacity is 18.96 MW. Following the disturbance at $t = 1$ s, the local frequency at the BESS buses reaches the 49.70 Hz activation threshold at approximately $t = 2.68$ s. The BESS units subsequently activate and achieve approximately 99% of their contracted FFR power within 1.28–1.29 s, satisfying the selected maximum full-activation-time requirement of 1.30 s.

The batteries therefore reach full FFR delivery at approximately $t = 3.96$ s and maintain full-power support for the required 5 s, until approximately $t = 8.96$ s. They then deactivate at a maximum rate of 20% of their rated FFR capacity per second and complete their response at approximately $t = 14.0$ s.

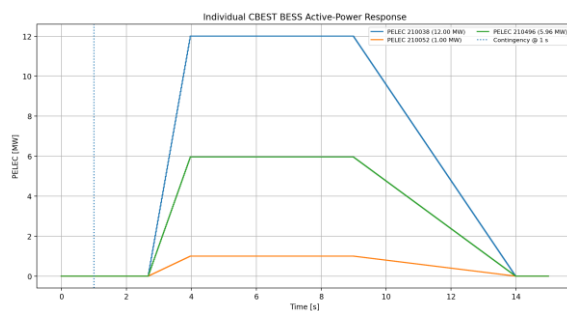
During the BESS operating period, the local frequency nadirs are approximately 49.5299–49.5300 Hz as shown in Table 22. Comparison with the corresponding FFR-disabled reference case shows no observable nadir improvement at the four-decimal precision available in the current summary results. Figure 44 presents the local-frequency responses and the individual and aggregated BESS active-power responses for this case.

Table 22 FFR Enabled Case 1: Detailed local Nadir comparison

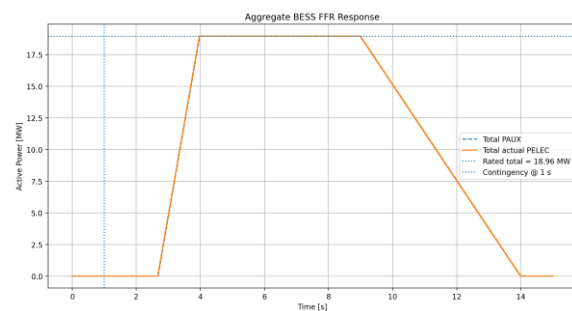
BESS bus	FFR disabled nadir [Hz]	FFR Enabled nadir [Hz]	Improvement [Hz]	Improvement [mHz]
210038	49.5299	49.5299	0.0000	0.0
210052	49.5300	49.5300	0.0000	0.0
210496	49.5300	49.5300	0.0000	0.0



(a) Local frequency at BESS Buses in Portugal



(b) Individual BESS response from prequalified units in Portugal



(c) Aggregated BESS response from prequalified units in Portugal

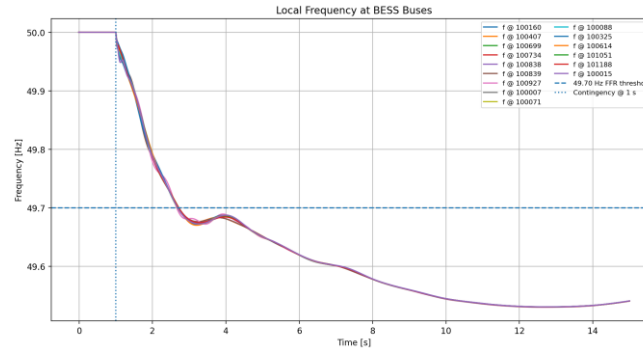
Figure 44 FFR Enabled Case 1: Frequency, individual and aggregated battery response in Portugal

FFR-Enabled Case 2: In this case, the 15 prequalified BESS units located in Spain are enabled to provide cross-border FFR support to the Portuguese system. Their aggregate available FFR capacity is 216.12 MW. Following the disturbance at $t = 1$ s, the BESS local frequencies reach the 49.70 Hz activation threshold between approximately $t = 2.67$ s and $t = 2.72$ s. All 15 BESS units activate and achieve approximately 99% of their rated FFR output within 1.28–1.30 s, satisfying the selected full-activation-time requirement.

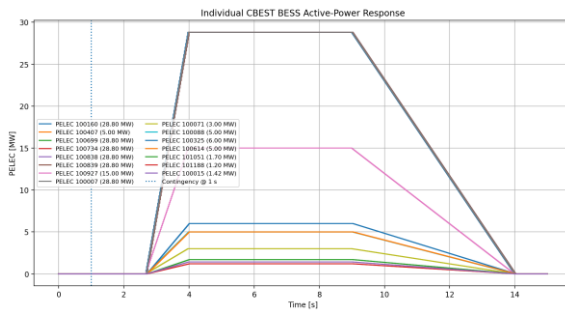
Full FFR delivery is therefore reached at approximately $t = 3.95$ – 4.02 s and is maintained for at least 5 s. The BESS units subsequently enter the controlled deactivation stage, with output reduced at no more than 20% of rated capacity per second, and complete their FFR response at approximately $t = 14.0$ s.

Table 23 shows the frequency nadirs measured at the Spanish BESS buses in the FFR-enabled case range from approximately 49.5298 to 49.5305 Hz, compared with 49.5297 to 49.5302 Hz in the corresponding FFR-disabled reference case. This corresponds to individual local-frequency nadir improvements of approximately 0.1–0.6 mHz, with an average improvement of approximately 0.43 mHz across the 15 BESS locations. Figure 45 presents the local-frequency responses together with the individual and aggregated BESS active-power response for this simulation.

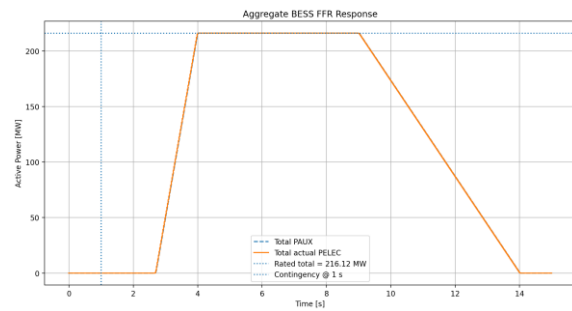
The comparison of the FFR-enabled and FFR-disabled simulations shows that the activation of the prequalified BESS units produces a positive effect on the system frequency nadir. However, the magnitude of the improvement depends strongly on the amount of available FFR capacity relative to the size of the imposed system disturbance.



(a) Local frequency at BESS Buses in Spain



(b) Individual BESS response from prequalified units in Spain



(c) Aggregated BESS response from prequalified units in Spain

Figure 45 FFR Enabled Case 2: Frequency, individual and aggregated battery response in Spain

Table 23 FFR Enabled Case 2: Detailed local Nadir comparison

BESS bus	FFR OFF nadir [Hz]	FFR ON nadir [Hz]	Improvement [Hz]	Improvement [mHz]
100160	49.5300	49.5304	0.0004	0.4
100407	49.5297	49.5303	0.0006	0.6
100699	49.5299	49.5303	0.0004	0.4
100734	49.5298	49.5303	0.0005	0.5
100838	49.5298	49.5304	0.0006	0.6
100839	49.5298	49.5304	0.0006	0.6
100927	49.5297	49.5298	0.0001	0.1
100007	49.5298	49.5302	0.0004	0.4
100071	49.5299	49.5303	0.0004	0.4
100088	49.5299	49.5303	0.0004	0.4
100325	49.5297	49.5302	0.0005	0.5
100614	49.5299	49.5303	0.0004	0.4
101051	49.5299	49.5303	0.0004	0.4
101188	49.5299	49.5303	0.0004	0.4
100015	49.5302	49.5305	0.0003	0.3

For the case in which the three BESS units located in Portugal provide cross-border FFR support to Spain, the total available FFR capacity is 18.96 MW. The local frequency nadirs in the FFR-disabled reference case are approximately 49.5299–49.5300 Hz, while the corresponding nadirs during BESS operation in the FFR-enabled case remain approximately 49.5299–49.5300 Hz. Therefore, no significant improvement can be distinguished at the four-decimal precision of the available results. This indicates that, under the considered disturbance conditions, the available Portuguese FFR capacity is too small relative to the approximately 22.55 GW system-wide active-power disturbance to produce a clearly observable change in the frequency nadir at the reported numerical precision.

A clearer improvement is observed when the 15 BESS units located in Spain provide cross-border FFR support to Portugal. In this case, the aggregate available FFR capacity is 216.12 MW. In the FFR-disabled reference simulation, the local frequency nadirs across the BESS buses range from approximately 49.5297 Hz to 49.5302 Hz. With FFR enabled, the corresponding nadirs increase to approximately 49.5298 Hz to 49.5305 Hz. The resulting nadir improvement ranges from approximately 0.1 mHz to 0.6 mHz, with an average improvement of approximately 0.43 mHz across the monitored BESS locations.

Although the absolute improvement remains small, the results consistently show a positive shift in the frequency nadir when the larger Spanish BESS portfolio is enabled. This demonstrates the expected effect of FFR: rapid active-power injection from the BESS units partially compensates for the active-power imbalance created by the disturbance and reduces the maximum frequency deviation.

Overall, the simulations demonstrate that cross-border FFR provision has a positive effect on system frequency response. However, for the very large 22.55 GW disturbance considered in this study, the available BESS capacities represent only a small fraction of the underlying active-power imbalance. Therefore, the resulting nadir improvement is modest, particularly for the 18.96 MW Portuguese FFR case. The results indicate that a larger aggregated FFR volume would be required to produce a more pronounced improvement in the Continental European system frequency nadir under a disturbance of this magnitude.

4.7 KPI assessment

KPI –1 Dynamic Equivalent Model Validity

To assess this KPI, an equivalent of the study model was developed as a DT, in which the Portuguese and Spanish grid areas were fully retained for studying the objectives of the use case. The equivalent consists of both the reduced steady-state grid model and the associated dynamic models. A K-means clustering algorithm was used to create area-wise clusters of dynamic generator models. The original system contains 1,410 in-service machines, which were represented through 82 clusters during the dynamic model reduction process. Since the original system contains 27 control areas, generator aggregation was performed independently within each area. This prevents electrically distant generators from being clustered together and preserves the geographical distribution of inertia, generation, and primary frequency response.

Similarly, load models were grouped into three different categories, including frequency-dependent loads. The reduced model preserves the frequency behaviour, generation distribution, and equivalent inertia characteristics required for FFR activation studies. The validity of the reduced model is demonstrated through the results presented in Section 4.6.

KPI –2 BESS FFR Controller Prequalification Compliance

The CBEST-based BESS controller successfully passed all selected FFR product prequalification requirements. The controller was configured to activate when the measured frequency fell to or below the selected activation threshold of 49.70 Hz. During the step-response test, the controller remained inactive at 49.75 Hz, confirming that no FFR activation occurred above the selected threshold, and activated correctly at 49.65 Hz, confirming the expected response below the threshold.

The representative BESS delivered the full contracted FFR capacity of 12 MW and achieved full activation within the maximum allowable activation time of 1.3 s. The controller also satisfied the deactivation requirement, with the FFR response decreasing from full output to zero over approximately 5 s, corresponding to the maximum permitted deactivation rate of 20% of the prequalified FFR capacity per second. The controller therefore satisfied the selected prequalification requirements and was considered qualified for subsequent FFR simulations.

KPI –3 Total system Inertia

The system equivalent inertia of the original ENTSO-E model was calculated as 3.6635 s, based on the inertia constants and MVA ratings of all online synchronous generators represented by GENROU and GENSAL dynamic models. The same methodology was applied to the developed Digital Twin model. The calculated equivalent inertia of the Digital Twin is also 3.6635 s, demonstrating that the model reduction process preserved the equivalent system inertia. This confirms that the reduced model remains suitable for Fast Frequency Reserve studies.

KPI –4 Volume of Flexibility by Prequalified Units

Here, the total volume of flexibility provided by the prequalified BESS units in the Portuguese and Spanish grids is calculated. The three realistic BESS units owned by REN were mapped into the Portuguese side of the DT. These BESS units are prequalified assets with rated capacities of 5.96 MW, 12 MW, and 1 MW, corresponding to a total prequalified FFR capacity of 18.96 MW. Similarly, the realistic BESS units identified for the Spanish mainland system were mapped into the Spanish side of the DT, providing a total prequalified FFR capacity of 216.12 MW in Spanish grid.

KPI –5 Frequency Nadir Improvement

The frequency nadir improvement was assessed by comparing otherwise identical FFR-disabled and FFR-enabled dynamic simulation cases. In both cases, the same system-wide disturbance, corresponding to an approximately 22.55 GW increase in active-power demand, was applied at $t = 1$ s. For the case in which the three prequalified BESS units located in Portugal provide FFR support, corresponding to a total available FFR capacity of 18.96 MW, the local frequency nadirs in the FFR-disabled reference case were approximately 49.5299–49.5300 Hz. The corresponding nadirs during BESS operation in the FFR-enabled case remained approximately 49.5299–49.5300 Hz. Therefore, no observable nadir improvement could be distinguished at the four-decimal precision of the available simulation results.

For the case in which the 15 prequalified BESS units located in Spain provide FFR support, corresponding to a total available FFR capacity of 216.12 MW, the frequency nadirs improved from approximately 49.5297–49.5302 Hz in the FFR-disabled case to approximately 49.5298–49.5305 Hz in the FFR-enabled case. This corresponds to individual local-frequency nadir improvements of approximately 0.1–0.6 mHz, with an average improvement of approximately 0.43 mHz across the monitored BESS locations.

The KPI results therefore show that the activation of prequalified BESS units produces a positive effect on the frequency nadir, with the magnitude of the improvement increasing with the available FFR capacity. However, the improvement remains modest because the available FFR volumes represent only a small fraction of the approximately 22.55 GW active-power imbalance introduced in the considered disturbance scenario.

Table 24 KPIs Result Summary

KPI	Purpose	Assessment Approach	Result
IB11_KPI1: Dynamic Equivalent Model Validity	How accurately the reduced dynamic equivalent model reproduces the frequency response characteristics of the original system following a major generation loss event.	The original and reduced dynamic models are subjected to identical generation-loss events. Frequency and voltage responses at common retained buses are compared using RMSE, frequency nadir and nadir error, RoCoF, time-to-nadir error, minimum-voltage error, equivalent system inertia, and steady-state consistency checks.	VALIDATED. Compared with the original model, the reduction achieved a 66.67% decrease in the number of buses while preserving stable undisturbed and disturbed dynamic behaviour. The validation resulted in $ \Delta f_{\text{nadir}} \leq 0.000402$ Hz, $0.001339 \leq \text{RMSE}(f) \leq 0.003646$ Hz, $0.000192 \leq \text{RMSE}(V) \leq 0.001074$ pu, and $0.000023 \leq \Delta \text{RoCoF} \leq 0.000336$ Hz/s.
IB11_KPI2: BESS FFR Controller Prequalification Compliance	Whether the representative BESS FFR controller satisfies the selected FFR prequalification requirements.	A synth235.etic FFR frequency test signal is applied to a representative BESS controller. Compliance is assessed against the 49.70 Hz activation threshold, ≤ 1.30 s full activation time, 12 MW reserve delivery, minimum full-power support period, deactivation-rate limitation, and SoC requirements.	Prequalification status: PASS. No activation occurred at 49.75 Hz, while correct activation occurred at 49.65 Hz. The representative BESS delivered 12 MW, achieved full activation within 1.20 s, maintained the required 5 s full-power support period, and complied with the maximum deactivation rate of 2.40 MW/s.
IB11_KPI3: Total system Inertia	It is calculated as the sum of the kinetic energy contributions of all online synchronous generators.	The total inertia-weighted capacity, $\Sigma(H_{\text{iS}_i})$, total synchronous-machine MBASE, ΣS_{i} , and equivalent system inertia, H_{eq} , are calculated for all online	PRESERVED. Original ENTSO-E model: $H_{\text{eq}} = 3.6635$ s. Reduced Digital Twin: $H_{\text{eq}} = 3.6635$ s.

		synchronous machines represented by GENROU and GENSAL models and compared between the original and reduced models.	
IB11_KPI4: Volume of Flexibility by Prequalified Units	The total volume of flexibility that is available from units that have completed the prequalification process.	The rated FFR capacity of all successfully prequalified BESS units is summed and reported by country and for the combined Iberian system.	Portugal: 3 BESS units, total capacity = 18.96 MW. Spain: 15 BESS units, total capacity = 216.12 MW. Combined prequalified FFR capacity = 235.08 MW.
IB11_KPI5: Frequency Nadir Improvement	Improvement in frequency nadir achieved through FFR activation.	Identical FFR-disabled and FFR-enabled simulations are performed using the same defined system disturbance. The frequency nadir improvement is calculated from the difference between the corresponding minimum-frequency values during the BESS operating period, supported by the frequency and BESS active-power response trajectories.	Portugal FSP – 18.96 MW: no observable nadir improvement at four-decimal frequency resolution. Spain FSP – 216.12 MW: local nadir improvement of approximately 0.1–0.6 mHz, with an average improvement of approximately 0.43 mHz.

VAL_KPI1 and VAL_KPI13 are calculated based on the results obtained for IB11_KPI1 and IB11_KPI5, respectively and are presented in Table 25.

Table 25 KPI assessment

VAL_KPI1: DT Model output accuracy			
MAPE (%) = (DT output – reference value / reference value) × 100			
IB11_KPI1: Dynamic Equivalent Model Validity	Case A Spain	Case B Portugal	Overall mean MAPE %
Frequency MAPE %	0.003648	0.002037	0.00284
Voltage MAPE %	0.049568	0.016840	0.03320

VAL_KPI13: Frequency response effectiveness			
	BESS Activation Time[s]	Response Accuracy [%]	Frequency Nadir Improvement [Hz]
Performance direction	Target typically < 2 s, Lower is better	Target: typically, > 95%, Higher is better	Higher is better
Reference Case FFR-disabled case	NA	NA	0.0000
FFR-enabled Case 1	1.28-1.29	100	≈ 0.0000
FFR-enabled Case 2	1.28-1.30	100	0.0001 to 0.0006, Average= 0.00043

For VAL_KPI1, a lower MAPE indicates a smaller deviation between the reduced Digital Twin outputs and the original/reference model and therefore represents better model accuracy. Frequency and voltage MAPE are both evaluated using a lower-is-better criterion. The reduced DT achieved a mean frequency MAPE of 0.00365% for Spain and 0.00204% for Portugal, while the corresponding voltage MAPE values were 0.04957% and 0.01684%, respectively. Across both validation cases, the overall mean MAPE was 0.00284% for frequency and 0.03320% for voltage, confirming very close performance with the original reference model.

For VAL_KPI13, lower activation time represents better performance, while higher response accuracy and frequency nadir improvement are preferred. FFR-enabled Case 1 achieved a worst-case activation time of 1.29 s and 100% response accuracy, with no observable nadir improvement at the reported precision. FFR-enabled Case 2 achieved a worst-case activation time of 1.30 s, approximately 100% response accuracy, and an average nadir improvement of 0.00043 Hz.

Overall, the KPI assessment presented in Table 24 and Table 25 confirms that the reduced Digital Twin preserves the dynamic behaviour and equivalent inertia required for FFR studies, while substantially reducing the network size. The representative CBEST-based BESS controller satisfies the selected FFR prequalification requirements, and a total prequalified flexibility volume of 235.08 MW is represented across Portugal and Spain. The cross-border FFR simulations further show that the activation of the prequalified BESS units has a positive effect on the frequency nadir, with the magnitude of the improvement increasing with the available FFR capacity. The relatively small nadir improvement observed in the present study should be considered in relation to the approximately 22.55 GW disturbance applied in the cross-border FFR simulations.

4.8 Discussion

The results demonstrate the applicability of the developed dynamic equivalent for cross-border FFR studies in the Iberian Peninsula. The validation confirms that the network reduction preserves the main steady-state and electromechanical characteristics required for frequency-response studies while substantially reducing the size of the original model. In addition, BESS models were added to the

model since the existing assets in the original ENTSO-E model do not comply with the FFR ramping requirements. The successful prequalification of the CBEST-based BESS controller confirms that the implemented control logic can provide the required FFR response and can therefore be used for the subsequent system-level simulations.

The cross-border simulations demonstrate that prequalified BESS units located in one grid area can be represented as Frequency Service Providers supporting the frequency response of the interconnected system. The results also highlight the importance of the available FFR volume. The smaller Portuguese BESS portfolio produces no clearly observable nadir improvement at the available numerical resolution, whereas the larger Spanish BESS portfolio produces a consistent positive improvement. This indicates that the effectiveness of cross-border FFR is strongly influenced by the amount of available reserve relative to the magnitude of the system power imbalance.

The simulations demonstrate the expected FFR behaviour, with rapid BESS active-power injection contributing to frequency containment following threshold activation. Overall, the developed Digital Twin provides a suitable environment for studying cross-border FFR provision between Portugal and Spain, while further studies considering larger network models, different disturbance magnitudes, operating conditions, FFR volumes, and BESS locations would support a more comprehensive assessment of the contribution of cross-border FFR to system frequency response.

Overall, the results address the three UC-Ib11 objectives at different levels. The technical aspects of the prequalification for FFR objective were demonstrated through product prequalification of the BESS controller against the selected FFR requirements and grid prequalification of the corresponding BESS capacity through voltage and congestion assessment. The resulting product and grid prequalification information provides the technical basis for information exchange between neighbouring System Operators in support of cross-border pre-qualification of FSPs. The objective related to cross-border grid and prequalification information exchange using DTs was partially addressed using prepared offline datasets, while real-time or automated synchronization was not implemented. Similarly, the objective of facilitating cross-border FSP participation was partially addressed by demonstrating, through PSS[®]E dynamic simulations, the technical provision of FFR from prequalified BESS units located in one Iberian control area to support the neighbouring system, while the complete forecasting and market process was outside the scope of the implementation. These limitations should therefore be considered when interpreting the results and in future extensions of the use case.

5 UC-Ib13. Enhancement of short-circuit models and TSO/DSO information exchange for operational planning

This section describes the implementation and experimental validation approach for the use-case UC-Ib13 “Enhancement of short-circuit models and TSO/DSO information exchange for operational planning”. The full use-case description, including actors, information exchanges and the detailed sequence of activities, is provided in Annex D and in IEC 62559-2 use-case description.

5.1 Objectives of the use-case

The use case aims to validate and enhance the assessment of short-circuit currents at the EHV/HV interface between Transmission System Operators (TSOs) and Distribution System Operators (DSOs), with particular focus on improving the representation of Wind Turbines in short-circuit studies and strengthening the exchange of technical information between network operators.

The specific objectives are:

- Improve communication, visibility and data exchange mechanisms between TSOs and DSOs to support coordinated grid planning and operational decision-making.
- Enhance the accuracy of TSO short-circuit models for wind-based generation units, enabling more reliable estimation of fault current contributions.
- Improve both TSO and DSO network planning processes by incorporating mutual short-circuit current contributions at the TSO–DSO interface.
- Increase the security and reliability of system operation through more accurate fault level assessments and coordinated planning methodologies.
- Support the integration of increasing shares of renewable generation while maintaining compliance with network security and quality-of-service requirements.

5.2 Use-case triggering event and pre-condition

The use case is triggered during the operational planning process, once per day, after the day-ahead market results are available. At this stage, the scheduled generation and consumption information for the following day can be retrieved and used as input for the short-circuit current assessment at the TSO–DSO interface. The triggering event therefore corresponds to the initiation of the day-ahead short-circuit current validation process, following market closure and the availability of the relevant operational planning data.

Before the use case can be executed, a set of technical and data-related pre-conditions must be fulfilled. First, an updated steady-state (DT) model of the transmission (in the case of the TSO) and distribution networks (in the case of the DSO) must be available, including the relevant topology, network characteristics, and interface nodes between the TSO and DSO grids.

Second, the necessary parameters of the generation units, particularly the reactance values of synchronous machines and renewable energy source generators, must be accessible. These

parameters are essential to improve the representation of generation units in the short-circuit model and to obtain more accurate estimates of fault current contributions.

Finally, the required TSO-DSO communication channels and data exchange platform are needed to support the exchange of short-circuit current forecasts. This enables both system operators to share their respective short-circuit current contributions and obtain a coordinated view of the total forecast short-circuit currents at the EHV/HV substations and TSO-DSO interface points. However, this exchange was not formally tested within TwinEU because the Portuguese DSO is not part of the project consortium. The implemented validation therefore focused on the technical validation and improvement of the short-circuit calculation methodology, while the TSO-DSO information-exchange process was addressed from a conceptual and methodological perspective.

In summary, the use case starts when the day-ahead operational planning process is initiated after market closure, provided that the network models, generation parameters, market results, and TSO–DSO data exchange mechanisms are available.

5.3 Use-case KPIs

The performance of this use case was assessed through indicators focused on the operational relevance of the short-circuit current forecasts at EHV/HV substations and TSO–DSO interface points. The KPIs evaluate how the enhanced short-circuit modelling approach affects the estimated fault levels, their relation to existing planning assumptions, and their margin with respect to equipment technical limits.

- **KPI 1 – Deviation between forecasted and TSO planning short-circuit values:** This KPI evaluates the difference between the maximum short-circuit current foreseen by the model and the reference short-circuit current value used by the TSO for planning purposes at a given EHV/HV substation. It supports the assessment of the consistency between the model-based forecast and the values considered in existing planning studies.
- **KPI 2 – Margin between forecasted short-circuit current and circuit breaker rated capacity:** This KPI compares the maximum short-circuit current forecasted by the model with the rated short-circuit breaking capacity of the circuit breaker installed at the corresponding EHV/HV substation. It supports the identification of potential operational or planning risks by indicating how close the expected short-circuit current is to the equipment technical limit.
- **KPI 3 – Impact of enhanced wind-based generator models on short-circuit current assessment:** This KPI evaluates the variation in KPI 1 and KPI 2 before and after the enhancement of wind-based generation models in the short-circuit model used within the DT. It quantifies the impact of improving the representation of wind generation units on the estimated short-circuit currents and on their relation to planning reference values and circuit breaker technical limits.

5.4 Technology development and Implementation

The technology development of this use case focuses on enhancing the short-circuit calculation capability within the steady-state Digital Twin environment, with particular attention to the modelling of wind-based renewable energy sources. The objective is to assess how improved generator modelling influences the estimated short-circuit current levels at EHV/HV substations and TSO–DSO interface points.

The implementation will use the available steady-state transmission network model as the basis for the studies. The analysis will focus on three-phase symmetrical short-circuit faults, as these represent the most severe fault condition for operational planning purposes. The short-circuit calculations will be performed in PSS®E as steady-state short-circuit studies, using the available power-flow case and the corresponding network and sequence data required by the short-circuit calculation module. Dynamic simulations fault response analysis are outside the scope of this use case.

The implementation process will include the following main activities:

- Preparation of the network model and input data

The steady-state network model will be prepared with the required topology, substation data, generation units, transformer parameters, and equivalent source information (DSO is represented with equivalent). Two relevant EHV/HV substations will be identified for the short-circuit assessment.

- Baseline short-circuit calculation

A first set of three-phase short-circuit calculations will be performed in PSS®E using the existing steady-state short-circuit modelling assumptions. In the current model, wind-based generation units are represented with a generic source reactance value, with $X_{source} = 1$ p.u. applied to all wind turbines. This simplified approach provides a uniform steady-state equivalent representation of wind generation in the short-circuit model, but it does not distinguish between different wind turbine technologies or their expected fault current contribution levels. This is particularly relevant for DFIG and full-converter wind turbines, which are not expected to contribute to short-circuit currents in the same way. Therefore, applying the same X_{source} value to all wind turbines may mask relevant differences in their equivalent contribution to three-phase short-circuit currents.

- Enhancement of wind-based generation models

The short-circuit representation of wind power plants was reviewed and updated in the DT within the scope of steady-state short-circuit calculations. The enhancement consists of replacing the generic $X_{source} = 1$ p.u. assumption with technology-specific equivalent source reactance values, distinguishing between DFIG-based (Type 3) and full-converter-based (Type 4) wind generation, instead of applying the same generic impedance to all wind turbines.

For DFIG-based units, the equivalent source reactance depends on whether the rotor-side converter remains in control during the fault or is bypassed by the crowbar protection circuit. Under normal converter control, the fault current injected at the machine terminals is actively limited by the converter, resulting in a comparatively higher equivalent reactance ($X_{source} \approx 0.4$ p.u.). When the fault is severe enough to trigger the crowbar, which protects the rotor-side converter from the high transient rotor voltages induced by the near-instantaneous change in stator flux, control of the rotor circuit is lost and the machine reverts to behaving as a directly-connected induction generator. In this condition the equivalent source reactance drops substantially ($X_{source} \approx 0.17$ p.u.), yielding a materially higher short-circuit current contribution than either the generic $X = 1$ p.u. assumption or the non-crowbar DFIG case [29], [30], [31].

Since faults applied directly at, or electrically close to, the EHV/HV substations under study (SS1, SS2) are severe enough to be expected to trigger crowbar activation on the connected DFIG units, the crowbar-active reactance ($X_{source} = 0.17$ p.u.) was adopted as the representative, conservative value for the enhanced short-circuit model, consistent with standard industry practice for wind power plant short-circuit studies, which treats crowbar-protected DFIG turbines as equivalent induction machines for this purpose [32]. The non-crowbar value ($X_{source} = 0.4$ p.u.) is retained as a secondary, less severe

reference case for sensitivity comparison, and reflects both the converter's controlled current limiting and, where relevant, additional grid-side converter current associated with DC-link voltage clamp effects during less severe voltage dips [30],[33].

For full-converter (Type 4) units, the generator is fully decoupled from the grid by a back-to-back converter, and the fault current is inherently current-limited by converter control rather than by machine impedance. Typical Type 4 fault contributions fall in the range of approximately 1.0–1.2 p.u. of rated current, depending on converter design and grid-code reactive-current-priority requirements during voltage dips. Consequently, the generic $X = 1$ p.u. assumption is a comparatively reasonable approximation for this technology, and the enhancement mainly refines the assumed value where manufacturer type-test data (e.g., IEC 61400-21 fault-ride-through current profiles) are available; a machine-specific value has not yet been confirmed for the installed units and a placeholder of $X_{source} \approx 1.2$ p.u. is used pending that data [32].

It should be noted that representing each wind turbine technology by a single static equivalent reactance is itself a simplification appropriate to steady-state, planning-level short-circuit assessment. The actual fault current of a DFIG comprises multiple components: a DC transient, an AC transient near rotor/slip frequency and, outside the crowbar-active condition, a steady-state fundamental-frequency component, which a single reactance value cannot fully reproduce [29] [30] [33]. This limitation is considered acceptable for the operational-planning objectives of this use case (breaker-duty and planning-margin assessment), but should be taken into account when interpreting the resulting KPI values.

- Post-enhancement short-circuit calculation

A second set of short-circuit calculations was carried out using the enhanced wind-based generation models. The results were compared with the baseline case.

- Assessment of operational planning indicators

The outputs were used to compute the defined KPIs, including the deviation from TSO planning reference values, the margin with respect to circuit breaker rated short-circuit capacity, and the variation introduced by the enhanced wind-based generator models.

Although the TSO-DSO information-exchange process formed part of the conceptual scope of the use case, it was not formally tested within TwinEU because the Portuguese DSO is not part of the consortium. For this reason, the DSO contribution to the short-circuit current was maintained in the simulations using the available and validated network representation. The practical implementation therefore focused on development of the short-circuit calculation methodology and assessment of the impact of enhanced wind-based generation models within the TwinEU digital-twin framework.

5.5 Description of the experimental validation

The experimental validation assessed the effect of the enhanced wind-based generation representation on steady-state three-phase short-circuit current calculations. The validation was carried out using the available steady-state transmission network model and focused on two selected EHV/HV substations.

The validation followed a before-and-after comparison. The baseline case used the existing steady-state model representation, in which wind turbines were modelled with the original short-circuit assumptions. The enhanced case used the updated wind-based generation parameters. The same

network topology, operating conditions, fault type, and selected substations were maintained in both cases so that the observed differences were attributable to the model enhancement.

The experimental validation included the following main steps:

- Definition of the study TSO-DSO substations

Two real EHV/HV substations were selected based on the generation mix in their observability area, prioritising locations with a significant presence of wind farms.

- Execution of baseline and enhanced simulations

An automatic script was developed to perform the three-phase short-circuit calculations. The baseline model with the original assumptions provided the reference case for comparison. The short-circuit simulations were then repeated with the enhanced model for the same days and substations.

- Comparison of results and KPI assessment

The short-circuit current values obtained in the baseline and enhanced cases were compared at the selected substations and interface points. The defined KPIs were computed for both configurations, including the deviation from TSO planning reference values, the margin with respect to circuit-breaker rated short-circuit capacity, and the variation introduced by the enhanced wind-based generation models.

This validation does not aim to demonstrate the accuracy of the short-circuit model against real fault measurements. Instead, it aims to evaluate the effect of improving the representation of wind-based generation on the short-circuit current calculations used for operational planning.

5.5.1 Data required for the experimental validation

The experimental validation required the data needed to perform and compare the baseline and enhanced steady-state three-phase short-circuit calculations in the Digital Twin environment.

The required data include:

- Steady-state network model: updated PSS®E model including topology, substations, lines, transformers, generators and equivalent sources.
- Wind generation short-circuit data: connection point, rated power, technology type where available and existing Xsource values.
- Operating conditions: network topology and generation/load conditions for each market time unit considered in the simulation timeframe. This includes access to market results, as these are needed to identify day-ahead, for each market time unit, the generation units expected to be active and, consequently, the machines contributing to the short-circuit currents.
- KPI reference data: TSO planning short-circuit reference values and rated short-circuit breaking capacity of the relevant circuit breakers. The TSO circuit breaker rating used for the KPI 2 assessment (31.5 kA) corresponds to the confirmed rated short-circuit breaking capacity of the installed equipment. The DSO circuit breaker rating used (25 kA) corresponds to E-REDES' documented equipment-sizing criterion for HV installations [34], generically applied across the distribution network
- DSO contribution representation: maintained according to the currently available and validated network representation. The specific as-built rating of the circuit breaker installed at the SS1 63 kV

interface has not been individually confirmed for this study and should be verified against equipment nameplate data as a follow-up action.

This data enabled the comparison between the baseline and enhanced model configurations and supported the calculation of the defined KPIs.

5.6 Results of the experimental validation

The first stage of the experimental validation has been completed with the preparation of the steady-state Digital Twin model required for the short-circuit assessment. The model includes the relevant network topology, EHV/HV substations, transmission grid elements, generation units, equivalent sources and short-circuit parameters required to perform three-phase steady-state short-circuit calculations in PSS®E. The model comprises the entire transmission network with the DSO being represented with equivalent models.

Two Portuguese EHV/HV substations, referred to as SS1 and SS2 for confidentiality reasons, were selected for the study. The selection was based on their network characteristics, generation mix and relevance for assessing short-circuit current contributions at the TSO–DSO interface. SS1 is located in the northeast of Portugal and includes relevant wind generation connected from both the TSO and DSO sides. SS2 is located in the south of Portugal and is characterised by a significant presence of distributed generation, including wind and photovoltaic generation. At SS1, three wind generation units are electrically connected to the observability area, representing a mix of turbine technologies. These comprise a direct-drive, full-converter unit and two DFIG units. This mix of Type 3 (DFIG) and Type 4 (full-converter) technologies makes SS1 particularly relevant for assessing the impact of the enhanced, technology-specific Xsource modelling described in Section 5.4, since the two DFIG units are expected to be materially affected by the crowbar-based enhancement while the full-converter unit is not. At SS2, a single DFIG unit is connected within the observability area. This substation remains a relevant test case for the enhanced short-circuit model, as it isolates the effect of the DFIG-specific Xsource update from the mixed-technology influence present at SS1, allowing the two substations to serve as complementary validation cases for the wind-generation enhancement.

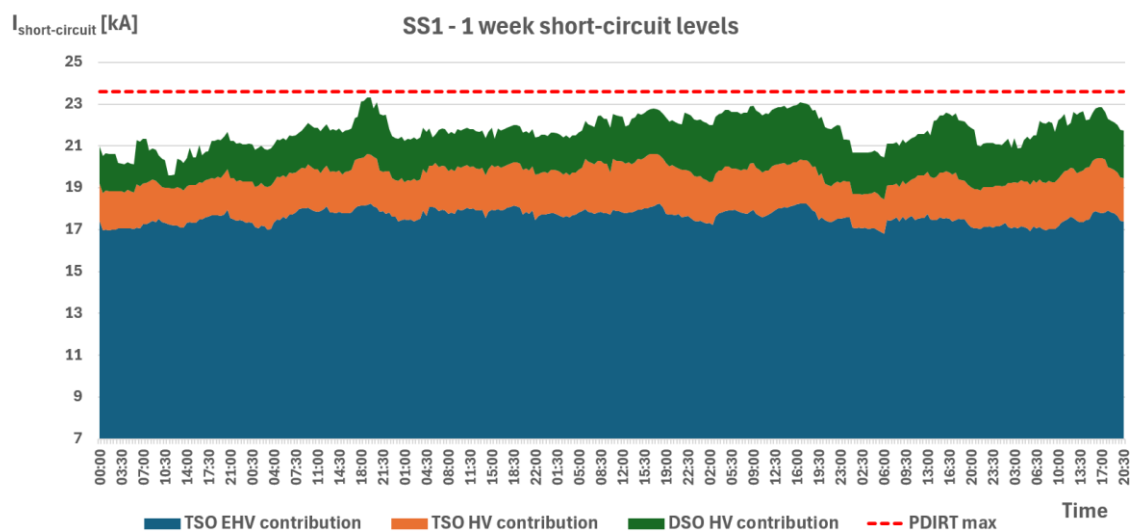


Figure 46. Short circuit levels in substation SS1 (one week)

The baseline simulations were performed using the existing DT representation and current short-circuit modelling assumptions for 1 week period. These simulations provided the reference case for

the subsequent comparison with the enhanced wind-based generation model. The calculations were carried out for three-phase short-circuit faults at the selected EHV/HV interface substations.

For SS1, the baseline results show that the total short-circuit current remains below the maximum value foreseen in the TSO planning reference, equal to 23.6 kA. The maximum total short-circuit current obtained is approximately 98% of this reference value. The DSO contribution varies between 0.61 kA and 2.82 kA, corresponding to 3% to 12% of the total short-circuit current at the interface. These results show that, although the DSO contribution is not dominant in this substation, it is still relevant for the overall short-circuit level assessment.

For SS2, the baseline results show a more significant contribution from the DSO side. The maximum value foreseen in the TSO planning reference is 14.5 kA, while the maximum total short-circuit current obtained in the simulation reaches 15.3 kA. For 61% of simulated time horizon the total short-circuit current exceeded the planning reference value. The DSO contribution varies between 0 kA and 3.34 kA, corresponding to 22% of the total short-circuit current at the interface.

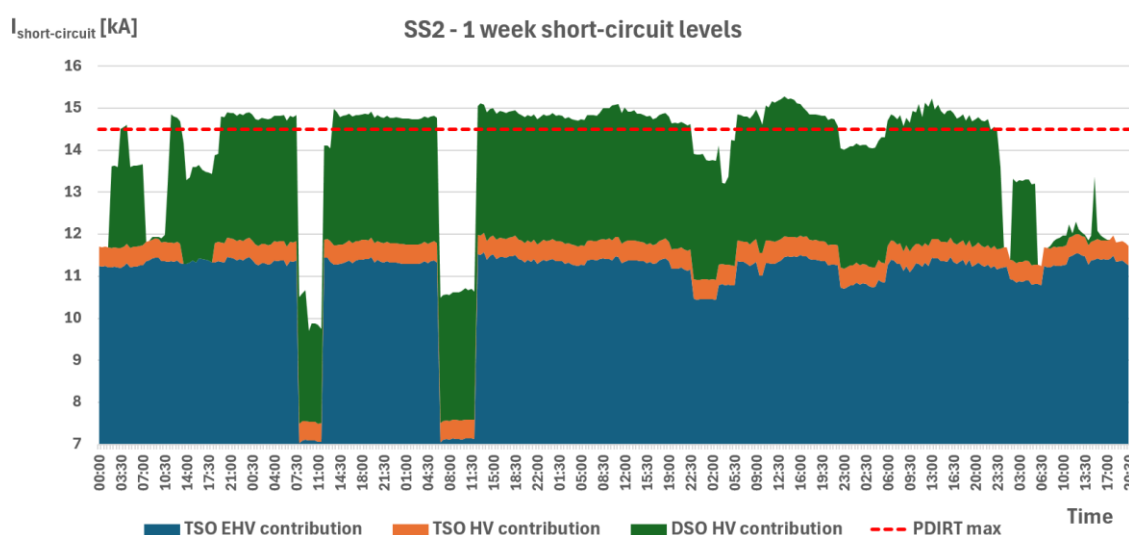


Figure 47. Short circuit levels in substation SS2 (one week)

The baseline results confirm the relevance of considering the contribution from both the transmission and distribution sides when assessing short-circuit currents at EHV/HV substations. In SS1, the DSO contribution has a moderate but visible impact on the total value. In SS2, the DSO contribution is more significant and directly influences the comparison with the planning reference value.

Overall, the completed baseline simulations demonstrated that the steady-state Digital Twin was functional for the intended operational-planning assessment and contained the data required to perform the short-circuit calculations for the selected substations. These results established the reference case for the enhanced-model stage, in which the wind-based generation parameters were updated and the same simulations were repeated under equivalent network and operating conditions.

Following completion of the baseline simulations, the enhanced short-circuit simulations were performed using the technology-specific Xsource values described in Section 5.4, replacing the generic $X = 1$ p.u. assumption previously applied to all wind turbines. For the DFIG units connected at SS1 and SS2, the crowbar-active equivalent reactance ($X_{source} = 0.17$ p.u.) was applied, consistent with the

assumption that faults occurring at or electrically close to the substations are severe enough to trigger crowbar activation. For the full-converter unit connected at SS1, the placeholder equivalent reactance $X_{source} \approx 1.2$ p.u. was applied.

The enhanced simulations were carried out for the same one-week period, the same network topology and operating conditions, and the same three-phase fault type as the baseline case, ensuring that any differences observed between the two sets of results are attributable solely to the updated wind-generation modelling rather than to changes in the underlying network or scenario assumptions. The simulations were executed for both selected EHV/HV substations, SS1 and SS2, using the same automated short-circuit calculation script applied to the baseline case, modified to apply the technology-specific X_{source} values to the relevant wind-generator buses before each fault calculation. The DSO contributions were kept from the baseline simulation.

Figure 48 presents the enhanced short-circuit simulation results for SS1 over the one-week period, decomposed into the TSO EHV contribution, TSO HV contribution and DSO HV contribution, consistent with the presentation format used for the baseline results. The TSO EHV contribution remains comparatively stable throughout the week, at approximately 17–18 kA, reflecting the fact that this component is dominated by the upstream 220 kV network and is largely insensitive to the local wind-generation modelling update. The TSO HV contribution, in contrast, exhibits noticeably greater variability across the week, consistent with it being the component most directly affected by the enhanced, technology-specific X_{source} values applied to the DFIG and full-converter wind units connected at this voltage level. The DSO HV contribution remains a comparatively minor share of the total throughout the period.

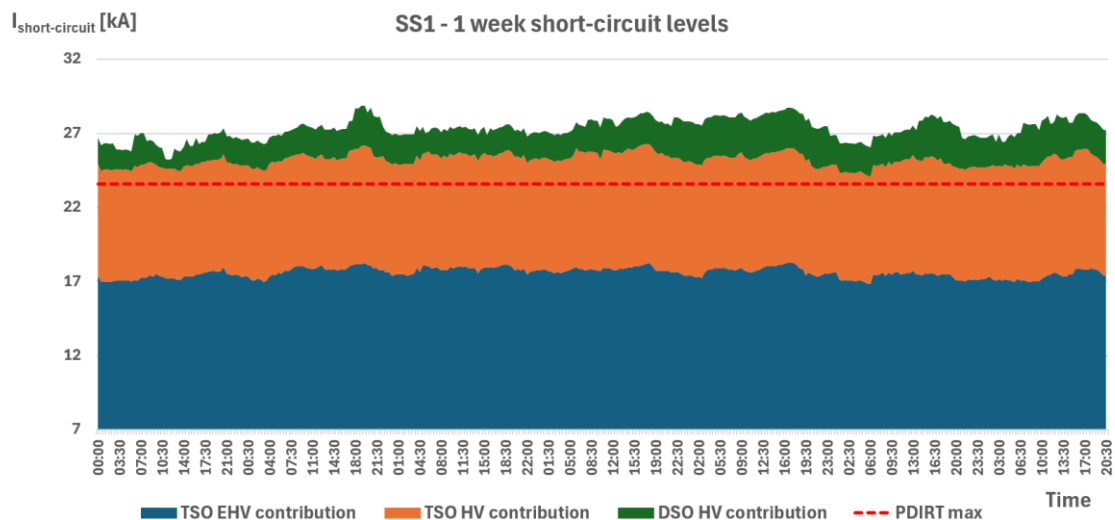


Figure 48 – Short circuit levels in substation SS1 (one week) with enhanced model

The most significant observation from the enhanced simulation is that the total short-circuit current at SS1 (the sum of all three contributions) remains consistently above the TSO planning reference (planning max = 23.6 kA) for essentially the entire one-week period, with the total fluctuating in the approximate range of 25 to 29 kA. This contrasts markedly with the baseline results (Figure 46), where the maximum total short-circuit current remained below the planning reference, reaching approximately 98% of that value. This shift is consistent with the crowbar-active DFIG X_{source} enhancement described in Section 5.4, replacing the generic $X = 1$ p.u. assumption with the lower, crowbar-active equivalent reactance (0.17 p.u.) increases the fault current contribution from the DFIG units, and the resulting increase is sufficient to move SS1 from an apparently compliant

condition under the baseline model to a condition that persistently exceeds the planning reference under the enhanced model.

At SS2, the decomposition shows a markedly different profile from SS1. The TSO EHV contribution stays close to 11 kA for most of the week, and the TSO HV contribution adds a fairly steady 2–2.5 kA on top. The DSO HV contribution, however, is far more variable here than at SS1, both in magnitude and over time, and makes up a substantially larger share of the total, consistent with the stronger DSO presence already noted for SS2 in the baseline results.

The total short-circuit current fluctuates roughly between 13 and 17 kA over the week, spending a substantial share of the time above the 14.5 kA planning reference, at times by 1.5–2.5 kA. This is a significant shift from the baseline case, where the total marginally exceeded the reference in 61% of market time units. In the enhanced model the total short-circuit current exceeded the planning reference during 78 % of the periods.

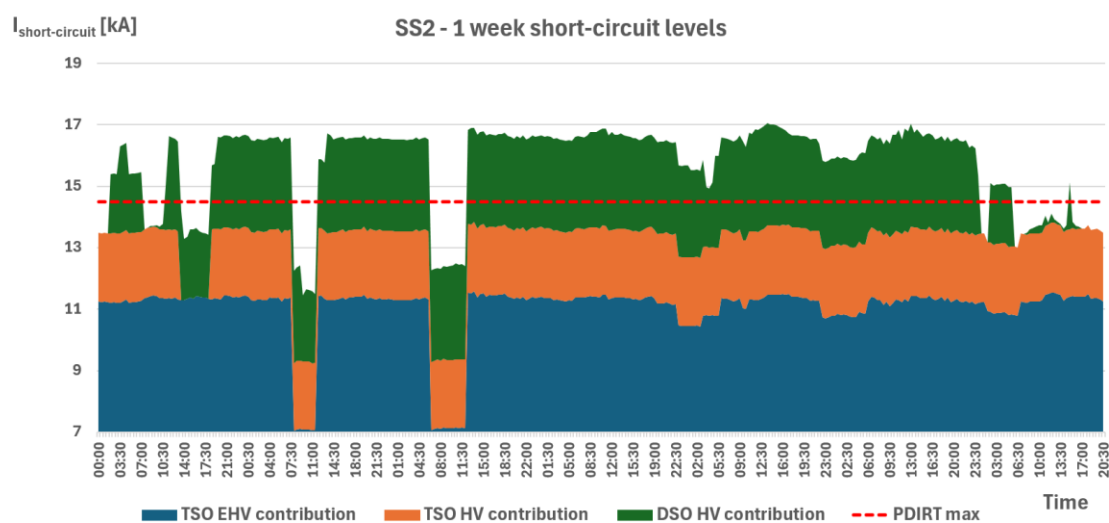


Figure 49 – Short-circuit levels in substation SS2 (one week) with enhanced model

The enhanced simulation results presented above for SS1 and SS2 have now been compared against the corresponding baseline values for each substation over the same one-week period. As shown, the effect of the enhancement differs markedly between the two substations: at SS1, the total short-circuit current shifts from remaining below the planning reference under the baseline model to persistently exceeding it under the enhanced model, while at SS2 the total moves from exceeding the reference in 60 % market time units to exceeding it across a more substantial share of the week, punctuated by a small number of sharp drops (due to generation that is disconnected). These substation-level comparisons form the basis for the KPI assessment presented in the following section, where KPI 1 and KPI 2 are recalculated for the enhanced model and KPI 3 is used to quantify the resulting shift relative to the baseline.

5.7 KPI assessment

The KPI assessment evaluates the results obtained from the baseline steady-state three-phase short-circuit simulations for the two selected EHV/HV substations, SS1 and SS2. Next are computed the KPIs for the baseline and the enhanced model short circuit simulations.

- **KPI 1 – Deviation between calculated and TSO planning short-circuit values**

Baseline

This KPI compares the maximum short-circuit current obtained from the steady-state simulation with the corresponding TSO planning reference value. For SS1, the maximum calculated short-circuit current remains below the planning reference value of 23.6 kA, reaching approximately 98% of that value. For SS2, the maximum calculated value reaches 15.3 kA, exceeding the planning reference value of 14.5 kA. This shows that, in SS2, the full short-circuit contribution at the TSO–DSO interface can lead to values above the planning reference. This result highlights the importance of considering DSO-side contributions in planning studies and reinforces the need to define adequate observability areas and information exchange mechanisms between TSOs and DSOs.

Enhanced model

At SS1, the enhanced model produces a total short-circuit current that exceeds the TSO planning reference (23.6 kA) at every timestamp across the simulated week, ranging from approximately 25.2 kA to 28.9 kA (mean 27.3 kA), corresponding to 107–122% of the reference value (mean 116%). This represents a substantial reversal from the baseline case, where the maximum total short-circuit current remained below the reference, reaching approximately 98% of it. At SS2, the enhanced model shows the total short-circuit current exceeding the 14.5 kA reference during approximately 78% of the week, with values ranging from 11.5 kA to 17.1 kA (mean 15.7 kA) and reaching up to 118% of the reference. This is also a marked change from the baseline case, in which the reference was exceeded during 60% of the market time units.

- **KPI 2 – Margin between calculated short-circuit current and circuit breaker rated capacity**

Baseline

This KPI evaluates the margin between the calculated short-circuit current and the rated short-circuit breaking capacity of the relevant circuit breakers. In both substations, the calculated short-circuit currents remain below the TSO and DSO circuit breaker ratings of 31.5 kA and 25 kA (not to all, some are also 31.5kA), respectively. In SS1, the total short-circuit current is closer to the DSO circuit breaker rating, highlighting the importance of monitoring the short-circuit level at the interface. In SS2, despite the slight exceedance of the planning reference value, the calculated short-circuit current remains far below the circuit breaker ratings.

Enhanced model

At SS1, the enhanced total short-circuit current remains below the TSO circuit breaker rating of 31.5 kA throughout the week, with a margin ranging from 2.6 kA to 6.3 kA (mean 4.2 kA). However, it exceeds the DSO circuit breaker rating of 25 kA at every timestamp in the simulated week, with the shortfall ranging from 0.2 kA to 3.9 kA (mean 2.3 kA). This is a materially different outcome from the baseline case, where the total short-circuit current at SS1 remained below both circuit breaker ratings, albeit closer to the DSO rating than to the TSO rating. At SS2, the enhanced model shows comfortable margins to both circuit breaker ratings throughout the week, a minimum of 14.5 kA to the TSO rating and 7.9 kA to the DSO rating, indicating that, despite the more frequent exceedance of the planning reference described under KPI 1, SS2 does not approach either equipment technical limit under the enhanced model.

- **KPI 3 – Impact of enhanced wind-based generation models on the short-circuit assessment**

The comparison between the baseline and enhanced simulations, performed timestamp-by-timestamp over the full one-week period for both substations, confirms that the wind-generation

model enhancement has a substation-dependent impact on both magnitude and operational significance.

At SS1, the enhancement increases the total calculated short-circuit current by a consistent 5.4–5.8 kA (mean 5.6 kA) across every timestamp in the week, moving the mean value from 21.7 kA under the baseline model to 27.3 kA under the enhanced model. In relative terms, this shifts SS1 from a mean of 92% of the TSO planning reference (with the reference never exceeded under the baseline model) to a mean of 116% (with the reference exceeded at every timestamp under the enhanced model), a mean deviation shift of +23.7 percentage points. The effect on KPI 2 is more significant still: the enhancement reduces the DSO circuit breaker margin from a mean of +3.3 kA under the baseline model (never exceeded) to a mean of –2.3 kA under the enhanced model (exceeded at every timestamp in the week). The TSO circuit breaker margin also narrows, from a mean of 9.8 kA to 4.2 kA, but remains positive throughout.

At SS2, the enhancement increases the total calculated short-circuit current by 0.0–1.8 kA (mean 1.7 kA), moving the mean value from 14.0 kA to 15.7 kA. This raises the proportion of timestamps exceeding the planning reference from 60% under the baseline model to 78% under the enhanced model, and the mean deviation from the reference from 96% to 108% (a mean shift of +11.9 percentage points). Unlike SS1, the SS2 circuit breaker margins remain comfortably positive under both the baseline and enhanced models, the TSO margin falls from a mean of 17.5 kA to 15.8 kA, and the DSO margin from 11.0 kA to 9.3 kA, with no exceedance of either rating recorded at any timestamp in either simulation.

Taken together, KPI 3 shows that the wind-generation model enhancement is quantitatively significant at both substations, but only becomes an equipment-adequacy concern at SS1, where it converts a previously adequate DSO circuit breaker margin into a sustained deficit across the entire simulated week. At SS2, the enhancement meaningfully worsens the KPI 1 planning-reference picture without translating into a comparable KPI 2 equipment risk.

This result should be interpreted as a signal for verification of the DSO-side equipment rather than a confirmed inadequacy. The TSO circuit breaker rating (31.5 kA) is confirmed and retains a positive margin throughout; the DSO circuit breaker rating used (25 kA), however, is a generic assumption, and the calculated fault current at SS1 approaches or exceeds it under the enhanced model. This should be checked against the specific circuit breaker actually installed at that interface before any conclusion is drawn about DSO-side equipment adequacy. Notably, this is precisely the kind of finding that the TSO–DSO short-circuit forecast exchange described in this use case is intended to surface, enabling the DSO to confirm or rule out an equipment-adequacy concern using its own asset data, rather than the TSO having to assume it either way.

Table 26 summarizes the peak-condition results of the KPI assessment for both substations, taking the single highest total short-circuit current recorded during the simulated one-week period as the reference point for KPI 1 and KPI 2, and comparing this peak value between the baseline and enhanced simulations for KPI 3. This peak-based view complements the weekly averages presented above by identifying the most demanding operating condition observed in each dataset, which is the condition most relevant for assessing whether the circuit breaker (CB) and planning reference, at each substation, retains an adequate margin under the full range of simulated operating states.

Table 26 – UC-Ib13 KPIs table

	SS1 baseline	SS1 enhanced	SS2 baseline	SS2 enhanced
IB13 KPI 1 (Deviation from planning reference)	-0.29 kA	5.29 kA	0.78 kA	2.55 kA
IB13 KPI 2 (Margin vs. TSO CB (31.5 kA))	8.19 kA	2.61 kA	16.22 kA	14.45 kA
IB13 KPI 2 (Margin vs. DSO CB (25 kA))	1.69 kA	−3.89 kA	9.72 kA	7.95 kA
IB13 KPI 3 (Shift in max Short- Circuit current)	5.57 kA		1.78 kA	
VAL_KPI6	24h ahead			

* Negative KPI 1 = below the planning reference;

* Negative KPI 2 = the circuit breaker rating is exceeded.

5.8 Discussion

The experimental validation carried out for UC-Ib13 demonstrates that the choice of short-circuit representation for wind-based generation has a decisive effect on the operational planning conclusions drawn at the TSO–DSO interface. Replacing the generic $X_{source} = 1$ p.u. assumption with technology-specific values, distinguishing DFIG and full-converter wind turbines, and accounting for the crowbar-driven regime change within DFIG behaviour, produced a substantial increase in the calculated short-circuit current at both selected substations. This increase was large enough to change the planning conclusion at SS1 from compliant to non-compliant with the TSO reference value.

The results also show that the practical significance of the enhancement is not uniform across substations. At SS1, the enhanced model moves the total short-circuit current from below to persistently above the TSO planning reference, and, more importantly, from a comfortable margin to a sustained deficit against the DSO circuit breaker rating used in this study. At SS2, the enhancement increases both the magnitude and frequency of exceedance relative to the planning reference, but the resulting current remains within both circuit breaker ratings throughout the simulated week. This contrast illustrates that the value of improving short-circuit modelling accuracy is substation-specific and depends on the local generation mix, the relative weight of DFIG versus full-converter contributions, and the existing margin between planning assumptions and equipment technical limits.

The SS1 finding regarding the DSO circuit breaker margin should be read as a signal for verification rather than as a confirmed equipment inadequacy, since the 25 kA rating used in this study is a generic assumption and has not been individually confirmed against the as-built equipment at that interface. This limitation does not diminish the relevance of the result, on the contrary, it is a direct illustration of the coordination gap that UC-Ib13 is intended to address. A TSO-side short-circuit model, however

accurate, cannot by itself confirm the adequacy of DSO-owned equipment, since that confirmation can only come from the DSO's own asset data. The result obtained here shows exactly the kind of finding that would benefit from the short-circuit forecast exchange process described in the use case: the TSO model flags a condition worth checking, and the DSO is positioned to close the loop with equipment-specific information the TSO does not hold. Since the TSO–DSO information exchange could not be formally tested within TWIN-EU, as the Portuguese DSO was not part of the consortium, this aspect of the use case was addressed conceptually and methodologically. The SS1 result nonetheless provides a concrete, real-data example of the kind of case such an exchange mechanism would be expected to resolve in practice.

More broadly, the validation confirms the underlying premise of the use case: as wind generation capacity connected at the distribution interface increases, short-circuit models that rely on generic, technology-agnostic assumptions risk understating fault current contributions in a way that is not conservative. This has direct implications beyond the two substations studied here, since any TSO/DSO interface with a comparable share of DFIG-based generation could be subject to a similar gap between planning assumptions and actual fault levels, particularly where crowbar-active behaviour is the relevant operating condition. This reinforces the case for incorporating technology-specific short-circuit representations, rather than a single generic value, into routine operational planning studies wherever wind generation forms a meaningful share of the local generation mix.

Some limitations of the present study should be acknowledged. First, the enhanced model still represents each wind turbine technology by a single static equivalent reactance. The actual fault current response of a DFIG unit is a multi-component transient that a static value cannot fully capture, and the crowbar-active reactance adopted here represents a conservative, worst-case simplification rather than a complete dynamic characterisation. Second, the full-converter Xsource value (1.2 p.u.) remains a placeholder pending manufacturer type-test data for the specific units installed at SS1; should such data become available, the enhanced model should be updated accordingly. Third, as noted above, the DSO circuit breaker rating used for SS1 is a generic assumption rather than a confirmed value, and the KPI 2/KPI 3 conclusions for that substation should be treated as provisional until verified. Finally, the validation was limited to steady-state, symmetrical three-phase faults; dynamic fault response and unbalanced fault types were outside the scope of this use case and would require separate analysis.

Taken together, these results support continued development of technology-specific short-circuit modelling within the TwinEU digital-twin framework and reinforce the operational value of establishing a structured TSO-DSO short-circuit information exchange. In UC-Ib13, that exchange was evaluated from a methodological standpoint rather than through live synchronization with the physical TSO-DSO system, and the SS1 result illustrates the type of operational issue that such an exchange could help resolve in practice.

Beyond the use-case-specific KPIs discussed above, this use case also contributes to the project-level KPI VAL_KPI6 (Operational decision lead time gained by DT). For UC-Ib13, this was interpreted as the forecast horizon between availability of the day-ahead short-circuit current assessment, generated once daily following market closure, and the operating conditions evaluated by the study model. The use case produced short-circuit forecasts for all market time units of the following operating day, giving a representative lead time of approximately 24 hours compared with a baseline in which short-circuit adequacy is assessed only through periodic planning studies using generic assumptions and without a day-specific early-warning mechanism. The effective lead time varies across the operating day, ranging from a few hours for the earliest periods to close to 48 hours for the

latest, with 24 hours adopted as the representative reporting value, consistent with the approach used for VAL_KPI6 in other pilots. This lead time was obtained from prepared operational-planning inputs and should not be interpreted as evidence of continuous synchronization with the physical grid.

6 Equivalent dynamic model of distribution networks

This section details the Equivalent dynamic model of distribution networks developed in the TwinEU Iberian Pilot.

6.1 Scope and objectives of the tool

The work addresses the need to represent Active Distribution Networks (ADN) in transmission-level dynamic studies. Distribution grids are increasingly integrating Distributed Generation (DG), particularly PV and Battery Energy Storage Systems (BESS), which are commonly connected through inverters, also known as Inverter-Based Resources (IBRs). As a result, the behavior observed by the Transmission System Operator (TSO) at the TSO-DSO interface can no longer be represented accurately using only static passive load representations.

The main objective was to develop a compact Equivalent Distribution Model (EDM) capable of reproducing the dynamic behavior of a detailed ADN while using fewer elements and requiring less grid information. The EDM was designed to reproduce voltage, active power, and reactive power behavior at the TSO-DSO boundary under disturbance conditions. This responds to practical limitations such as low observability, data privacy constraints, and the difficulty of building complete combined transmission-distribution dynamic models. In addition, many other country specific requirements, such as Fault-Ride Through capabilities and reactive current injection, directly affect the behavior observed in the TSO-DSO interface [35].

A second objective was to tune the EDM through a parameter-estimation process. Instead of manually adjusting the model, the work combines dynamic simulation with a metaheuristic optimization process so that the model parameters are selected by minimizing the error between the EDM's response and the reference response of the detailed ADN being studied. In this sense, the EDM can be interpreted as a Digital Twin (DT) representation of the distribution grid at the interface with the transmission system as it is "a high-fidelity (...) virtual representation of a physical system and its underlying characteristics and operational state" [36].

6.2 Description of the tool

The EDM represents the aggregate behaviour of a detailed active distribution network using a simplified electrical structure. As seen in Figure 50, it includes a 110/30 kV transformer connected to a 30 kV busbar, two outgoing lines, a static load, a dynamic load represented as an induction motor, and two IBRs: one representing PV and one representing BESS.

The model is intentionally compact. Its purpose is not to reproduce every busbar, feeder, load, or inverter of the original network, but to reproduce the resulting dynamic behaviour at the interface with the transmission system. The previous aligned with industry guidelines that established recommendations for representing aggregated IBRs in dynamic studies of power systems [37]. The measured variables used for the comparison are the voltage at BUS1, representing the TSO-DSO interface, and the active and reactive power flow from the transmission system towards the distribution grid. Negative values can represent reverse power flow.

The second component of the tool is the Parameter Estimation Algorithm. The selected algorithm is Differential Evolution [38], a stochastic population-based optimization method. Each candidate solution represents a possible set of EDM parameters. For each candidate vector of parameters, the tool runs a load flow and dynamic simulation of a disturbance, compares the simulated curves with

benchmark reference curves, and evaluates the quality of the candidate vector of parameters using RMSE values for voltage, active power, and reactive power.

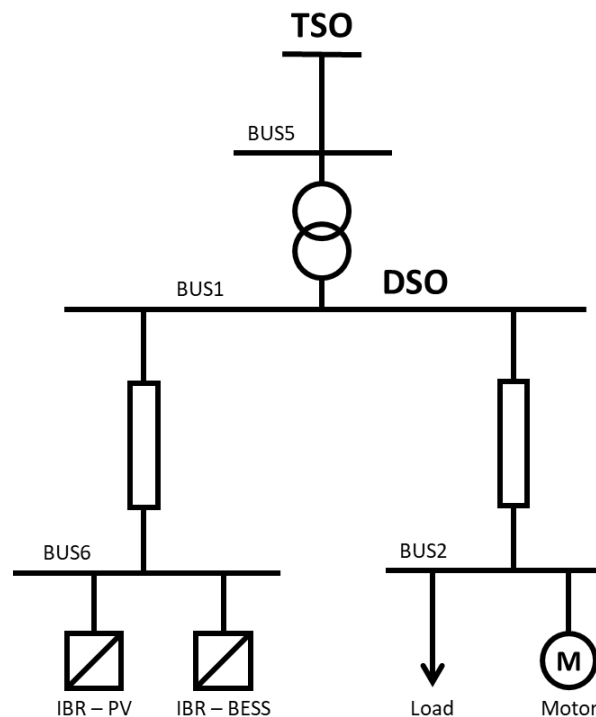


Figure 50. Equivalent Distribution Model schematic diagram.

6.3 Inputs and outputs

The main inputs are the reference curves of voltage, active power and reactive power from ADN being analysed. Also, the tool's inputs include the model parameters as seen in Table 27.

Table 27. Equivalent Distribution Model input parameters.

Asset	Description	Parameter	Units
Load	Active power	P_load	MW
	Reactive power	Q_load	MVar
IBR – PV	Active power	P_PV	MW
	Maximum reactive current injection	I _{max_PV}	p.u.
IBR – BESS	Active power	P_BESS	MW
	Maximum reactive current injection	I _{max_BESS}	p.u.

Motor	Active Power	P_motor	MW
	Inertia	M_intertia	p.u.
	Damping	M_damping	-

The outputs of the tool are the calibrated EDM parameter set, the dynamic response curves generated by the EDM, and the RMSE values obtained by comparing against the benchmark grid.

6.4 Implementation

The tool evaluates different possible dynamic parameters by using a simulation software to perform load flow and dynamic simulation of disturbances. The different possible dynamic parameters are analysed by the optimization algorithm developed. This approach is suitable because the relationship between the model parameters and the resulting dynamic response is multivariable, nonlinear, and not directly differentiable due to the load-flow and dynamic-simulation steps included in the loop.

The optimization process starts with a population of candidate parameter vectors. For each vector, the parameters are applied to the EDM, and a dynamic simulation is executed. The resulting voltage, active power, and reactive power curves are compared with the benchmark reference curves. The objective function is based on the RMSE values of those three physical quantities. Across generations, mutation and recombination move the population toward regions of the search space that produce lower errors.

The stopping criterion is based on convergence of the objective function. The process is terminated when the relative variation of each RMSE value between two consecutive generations falls below a predefined threshold. The final parameter set is therefore a globally consistent solution that allows the compact EDM to reproduce the detailed benchmark response at the TSO-DSO interface.

For robustness, the parameter estimation was performed using the most severe voltage disturbance considered in the study: an 80% voltage sag. The resulting global solution was then applied to all other scenarios without re-estimating the parameters. This implementation choice tests whether one parameter set can be generalized to less severe faults and to steady-state operation.

6.5 Test Case

The methodology was demonstrated using a fully detailed CIGRE medium-voltage benchmark grid [39]. The original benchmark system contains 14 busbars, 15 lines, and 14 loads – 2 of them are a 250-kW induction motor each. The total active power demand of the benchmark grid is 1.84 MW. The grid is connected to the transmission system through a 110/30 kV transformer, which is consistent with the interface represented in the EDM.

To transform the original benchmark into an ADN, 5 PVs (400 kW) and 2 BESS (160 kW) installation were added at different busbars. These IBRs represent 30% of the initial grid demand. After their inclusion, the total active power requested from the transmission system decreases from 1.84 MW to 1.28 MW, while the active load remains 1.84 MW and DG contributes 0.56 MW, i.e. 30% penetration rate with respect to the load.

The reference curves were obtained by applying a three-phase fault in the transmission system. The fault starts at 1.0 seconds and is cleared at 1.1 seconds. Because the fault is applied in the transmission system, it affects both the detailed benchmark grid and the EDM in the same manner. As seen in Table 28, different disturbances were considered. Scenario 1, corresponding to an 80% voltage sag, was used to estimate the global parameter solution. The same solution vector of parameter was then applied in the EDM and the rest of the scenarios were applied.

Table 28. Scenarios for Parameter Estimation and Validation.

Scenario	Voltage sag	Comment
1	80%	Parameter Estimation executed
2	60%	Validation scenario
3	40%	Validation scenario
4	20%	Validation scenario
5	-	Validation Scenario in Steady State

6.6 Results and KPI assessment

The parameter estimation process produced a single final solution under Scenario 1. The resulting active power balance of the EDM is consistent with the modified benchmark grid, i.e., the load active power minus the active power of the PV and BESS resources gives the same 1.28 MW active power demand observed after the inclusion of IBRs in the benchmark system.

Figure 51 show the comparison between the curves of the signals measured both in the benchmark grid and in the EDM after performing parameter estimation using scenario 1. Respectively, the graphs correspond to voltage, active power and reactive power.

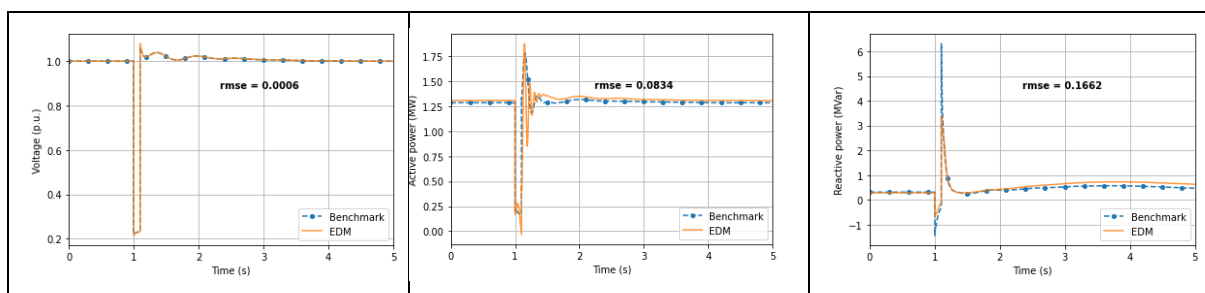


Figure 51. Voltage, Active Power and Reactive Power behavior in Scenario 1 in the EDM (solid orange) in comparison to the Benchmark (dashed blue with markers).

The RMSE values obtained across the scenarios confirm that the EDM reproduces the benchmark behavior with low errors, especially for voltage. Voltage RMSE remains very close to zero in all scenarios, indicating that the voltage response of the EDM is almost identical to the benchmark response. Active power errors remain low and comparable between scenarios. Reactive power

presents the largest deviation, mainly due to differences during the fault and during the post-fault stabilization behavior. Table 29 collects all the RMSE values collected in all the scenarios.

Table 29. Results per scenario

Scenario	Voltage RMSE (p.u.)	Active Power RMSE (MW)	Reactive Power RMSE (MVar)
1	0.0006	0.0836	0.1662
2	0.0007	0.0651	0.1740
3	0.0006	0.0444	0.1272
4	0.0003	0.0309	0.0723
5	0	0.0210	0.0298

Scenario 2 presents the highest RMSE values after Scenario 1 was used for parameter estimation. This is expected because Scenario 2 is the most severe case that was not used during the estimation process. Nevertheless, the errors remain comparable to the remaining validation scenarios. In general, the RMSE values decrease for less severe voltage sag cases, showing that the selected parameter set provides consistent performance across the analysed operating conditions.

6.7 Discussion

The results show that the EDM can reproduce the behavior of a detailed ADN at the TSO-DSO interface with good accuracy. The most relevant result is that the parameters estimated for the worst-case voltage disturbance were also suitable for less severe disturbances and for steady-state operation. This supports the use of the 80% voltage sag scenario as a robust calibration case.

The EDM reduces the amount of information needed about the distribution grid to be analysed during dynamic studies while still representing the aggregate effect of the dynamics that can be attributed, among other effects, to the presence of IBRs. This is especially useful when detailed data and observability is not fully available or cannot be exchanged because of privacy constraints. The model therefore provides a practical way to account for ADN behavior in studies where the TSO-DSO interface is relevant.

Selection of active and reactive power values for the different assets of the EDM is not trivial. An even distribution of those values doesn't warranty that the behaviour seen during the fault and after its clearance will correspond to that behaviour observed in the benchmark simple. This is because the collective dynamic behaviour depends on the installed capacity of the individual assets. The parameter estimation process is useful as it determines a relation between the pre-fault values of active and reactive power plus the dynamic variables that also need to be tuned in order to reach a similar pre-fault, transient and stabilization as in the benchmark system.

Overall, the developed methodology produces a representative system that mimics both, steady state and transient behaviour, of a given ADN at the TSO-DSO interface. The presented methodology

can be used by TSOs during their rutinary operational and extraordinary analysis including power flows, short-circuit analysis, stability and dynamic studies.

Future work that will contribute to the improvement of the methodology and results consists of using larger ADNs with higher levels of IBRs as benchmark systems.

The work here developed was included in a scientific paper that was submitted and accepted in the 2026 IEEE 9th Energy Conference (ENERGYCON) [40].

7 Conclusion

The reported work demonstrates the value of Digital Twins for the operational planning and operation of electricity grids by connecting network models, forecasts, operational data and simulation tools within decision-support workflows. It addressed dynamic security, probabilistic cross-border capacity, flexibility prequalification, short-circuit assessment and the dynamic representation of active distribution networks.

Collectively, the results demonstrate that Digital Twins can transform system data and simulation models into decision-relevant indicators of security, capacity and flexibility. Operational adoption requires further work on i) validation of models, ii) interoperable data exchange, and iii) sustained coordination among system operators, service providers and market entities.

The implementation of UC-Ib03 “DT-enabled multi-area system dynamic behaviour assessment” demonstrated the capability of assessing Iberian frequency robustness and sizing new ancillary services under progressively lower inertia. The results indicate deteriorating frequency Nadir and RoCoF towards 2040, especially during high-renewable spring conditions. A hybrid SC-GFM strategy is recommended, although detailed operator models and additional disturbance data are required before operational deployment.

The UC-Ib10 “Probabilistic cross-border capacity allocation”, developed a probabilistic ATC methodology integrating forecast uncertainty, asset availability, N-1 security and already allocated capacity for the Portugal-Spain border. The approach quantified minimum, expected, maximum and confidence-based secure capacities, revealing the trade-off between usable capacity and security confidence. All planned connector-based exchanges succeeded, but additional operating days and further validation using TSO models remain necessary before operational adoption of the methodology.

The UC-Ib11 “Cross-border assessment of flexibility and pre-qualification”, validated a reduced dynamic model and demonstrated the technical prequalification and cross-border activation of BESS-based FFR. The 235.08 MW portfolio produced technically compliant responses, although the Nadir improvement was modest relative to the 22.55 GW disturbance.

The UC-Ib13 “Enhancement of short-circuit models and TSO/DSO information exchange for operational planning”, confirmed that technology-specific wind-generator models can materially change short-circuit planning conclusions. The results support technology-specific modelling and day-ahead assessment. Dynamic fault behaviour, unbalanced faults and measured-event validation remain important follow-up requirements.

The “Equivalent dynamic model of distribution networks”, developed an automatically calibrated model that reproduces active-distribution-network behaviour at the TSO-DSO interface using limited network information. A parameter set estimated from an 80% voltage sag generalized successfully to less severe disturbances and steady-state conditions. The model provides a practical option where observability, confidentiality or data availability prevents the exchange of full network models.

Across the use cases, Digital Twins enabled the anticipation of dynamic-security risks, probabilistic assessment of cross-border capacity, technical qualification of flexibility resources, day-ahead identification of short-circuit constraints and representation of distribution-network dynamics at TSO-DSO interfaces. These capabilities can support earlier, more transparent and risk-informed decisions,

from procuring ancillary services and allocating cross-border capacity to verifying equipment margins and coordinating flexibility.

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Annex A UC-Ib03. DT-enabled multi-area system dynamic behaviour assessment

This section details the TwinEU Iberian Pilot use case 03 (UC – IB03) “DT-enabled multi-area system dynamic behaviour assessment”

A.1 Scope and objectives of the use case

The use case UC-Ib03 focuses on addressing the challenges posed by the progressive integration of converter-interfaced Renewable Energy Sources (RES), which will reduce system synchronous inertia that can endanger the system frequency stability behaviour. This trend is particularly critical in weakly interconnected systems such as the Iberian Peninsula, where frequency stability is more vulnerable to large disturbances, such as sudden generation losses.

To tackle this issue, a Digital Twin (DT) is developed to represent the dynamic behavior of the Iberian Peninsula (IP) system, considering its interconnection with the Central European (CE) system. The DT enables system operators and planning engineers to evaluate the system’s dynamic robustness following a possible large disturbance and to identify appropriate volumes of new ancillary services tailored to the evolving system needs. Within this context, the main objectives of this use case are:

1. To represent the dynamic behavior of the Iberian system and evaluate its robustness in response to large disturbances;
2. To support identifying and quantifying frequency ancillary services—both existing and innovative, such as Fast Frequency Response (FFR) —that are necessary to maintain system stability under reduced inertia conditions.

A.2 Complete description

The UC-Ib03 DT is designed to be implemented within the Transmission System Operator (TSO) dispatch center, where it receives real-time data related to system operation. Specifically, information on:

- Generation levels for both conventional and RES power plants;
- Volume and type of ancillary services available from generation and flexible demand;
- And, the magnitude of sudden generation loss to be simulated and evaluated by the DT defined by the dispatch operator.

The DT processes this data and provides to the dispatch center dynamic stability performance indicators, such as the Rate of Change of Frequency (RoCof), the Frequency Nadir and Frequency Zenith, and the Area Control Error (ACE). These indicators allow system operators to assess the stability of the system following the defined disturbance and determine whether additional frequency ancillary services are required to guarantee the safe operation of the system.

The DT is based on an electromechanical model, presented in Figure 3, that represents the IP and CE systems as two distinct but interconnected control areas. Each control area is modeled by a swing equation where the frequency control loops of the four main synchronous generation technologies in the European generation mix (Coal fired power plants, Combine Cycle Power Plants, Nuclear power

plants, and Hydro power plants) are connected. The existing interconnection between the two control areas, which for the purpose of this study corresponds to the active power flow between both areas, is modeled as the synchronizing torque coefficient.

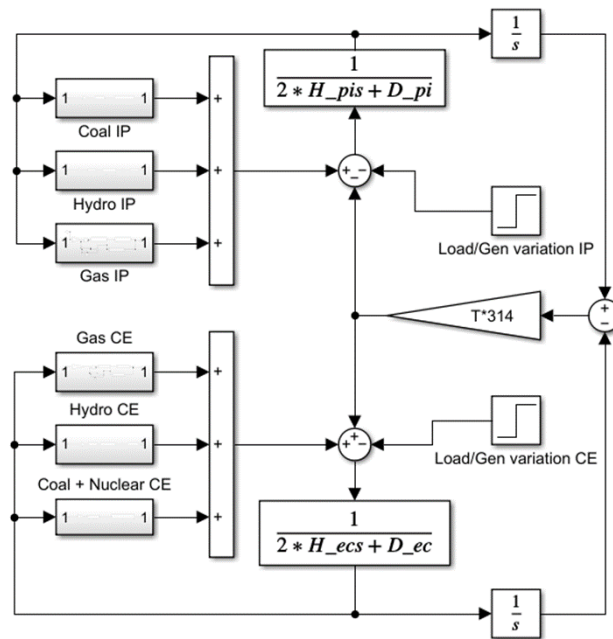


Figure 52. DT electromechanical basis-model.

The DT model needs to be calibrated using a parameter estimation methodology that tunes the model frequency response to the real system frequency response when facing large disturbances. A parameter identification, that involves the identification of the values for system inertia, system damping, generator droops and synchronization coefficients, is performed by solving an optimization problem, which corresponds to the minimization of the quadratic error summation between the model frequency response and the real system frequency response using in this case a metaheuristic approach based on a particle swarm algorithm. An initial parameters estimation was performed exploiting the real data of the frequency behaviour during a disturbance related with the sudden loss of 1 GW of Active Power, due to the Almaraz II Nuclear plant unit disconnection in October 2011. Further calibration is expected during the project using data from frequency behaviours following large disturbances obtained from system operators records for other disturbances. Accessing this data is an important requirement for the quality of the results obtained when using this DT. The DT model also includes the Automatic Generation Control operation and corresponding control loops, as well as the modelling of different generation technologies, including the ones using electronic power converters related to RES. The DT model includes blocks representing the dynamic response from demand, like thermal loads, electric mobility and electrolyzers when responding to frequency excursions, for Frequency Containment Reserve (FCR), or response to set points from an AGC platform, in the case of automatic Frequency Restoration Reserve (aFRR). Figure 53 shows how these control loops are integrated in the DT model. Each control area includes a supplementary control where the frequency deviation is multiplied by a polarizing (bias) factor which will then allow to calculate the ACE, by adding the active power interchange between the control areas. The ACE is then sent to a transfer function block, where it is multiplied by an integral gain K_i and integrated that leads the ACE to zero in steady-state. The output signal of this control block yields the necessary change in active power to restore the system frequency to its nominal value and therefore represents the control signal

that is generated in control centres when performing secondary control. This signal is then distributed among the different technologies according to weighting factors.

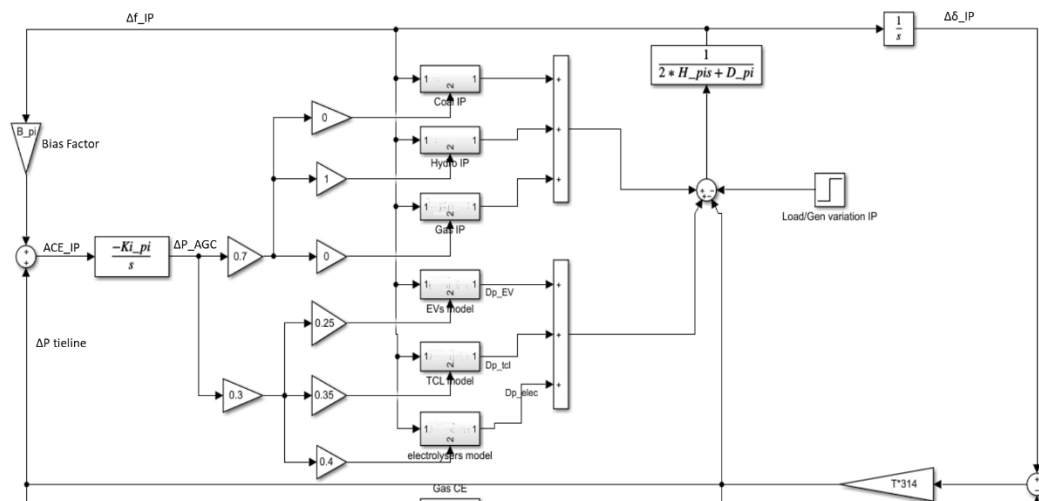


Figure 53. Dynamic model of the DT extended to consider the AGC control loops and demand side response

With this DT, and when properly calibrated, it will be possible to evaluate the dynamic behaviour of the Iberian system when facing active power disturbances, identifying the type, volume and characterization of frequency ancillary services - including innovative ones, like Fast-Frequency Response (FFR) - needed by the system and provided by both generation power converters (synchronous and non-synchronous), storage units (hydro pumps or batteries) and responsive demand (EV charging, thermal loads and electrolyzers).

A.3 Key performance indicators

To effectively evaluate the robustness and accuracy of DT in representing the frequency stability of the Iberian grid, a set of Key Performance Indicators (KPIs) has been established. These KPIs serve as quantitative metrics that allow both system dispatch operators and planning engineers to assess the system's dynamic response to large disturbances. Each KPI is aligned with specific use case objectives, ensuring that the DT provides meaningful insights into system behavior.

- Frequency Nadir (KPI_Ib03_1)

The Frequency Nadir corresponds to the minimum value of frequency excursion, and it is an indicator of the dynamic robustness of the system. The system is considered in a dynamic safe region if the frequency nadir does not cross the boundary defined for dynamic safe operation (49.2 Hz);

- Frequency Zenith (KPI_Ib03_2)

The Frequency Zenith corresponds to the maximum value of frequency excursion, and it is an indicator of the dynamic robustness of the system. The system is considered in a dynamic safe region if the frequency nadir does not cross the boundary defined for dynamic safe operation (50.8 Hz);

- Rate of Change of Frequency (KPI_Ib03_3)

The RoCoF corresponds to the maximum value of the time derivative of frequency excursion regarding time (for a time window to be defined), and it is an indicator of the dynamic robustness of the system. The system is considered in a dynamic safe region if the RoCoF does not cross the boundary defined for dynamic safe operation (1 Hz/s);

- Area Control Error (KPI_Ib03_4)

The Area Control Error (ACE) measures the imbalance between scheduled and actual power exchanges in the system. It is expected that after a disturbance, the ACE should return to zero within 300 seconds, indicating that the system has successfully restored balance through secondary frequency control mechanisms. This KPI is crucial for assessing the effectiveness of Automatic Generation Control (AGC).

A.4 Use conditions

The application of the Digital Twin (DT) for frequency stability assessment is based on specific assumptions and prerequisites that define the scope of its operation and calibration. These conditions ensure that the DT provides accurate and relevant insights into the dynamic behavior of the Iberian system under realistic scenarios.

Assumptions:

1. The disturbances considered in the DT simulations correspond to sudden losses of large amounts of generation or significant step increases in load demand. These events represent critical challenges for system stability and serve as primary test cases for evaluating frequency response mechanisms.
2. The initial DT configuration does not include virtual inertia contributions.

Prerequisites:

1. The DT requires continuous updates of real disturbance data, particularly frequency time behavior records from both the Iberian and Central European systems. System Operators' datasets must be leveraged to ensure the DT remains accurately calibrated. This data is essential for re-tuning key parameters such as equivalent system inertia, damping coefficients, and generator droops within each control area.

A.5 Use case diagrams

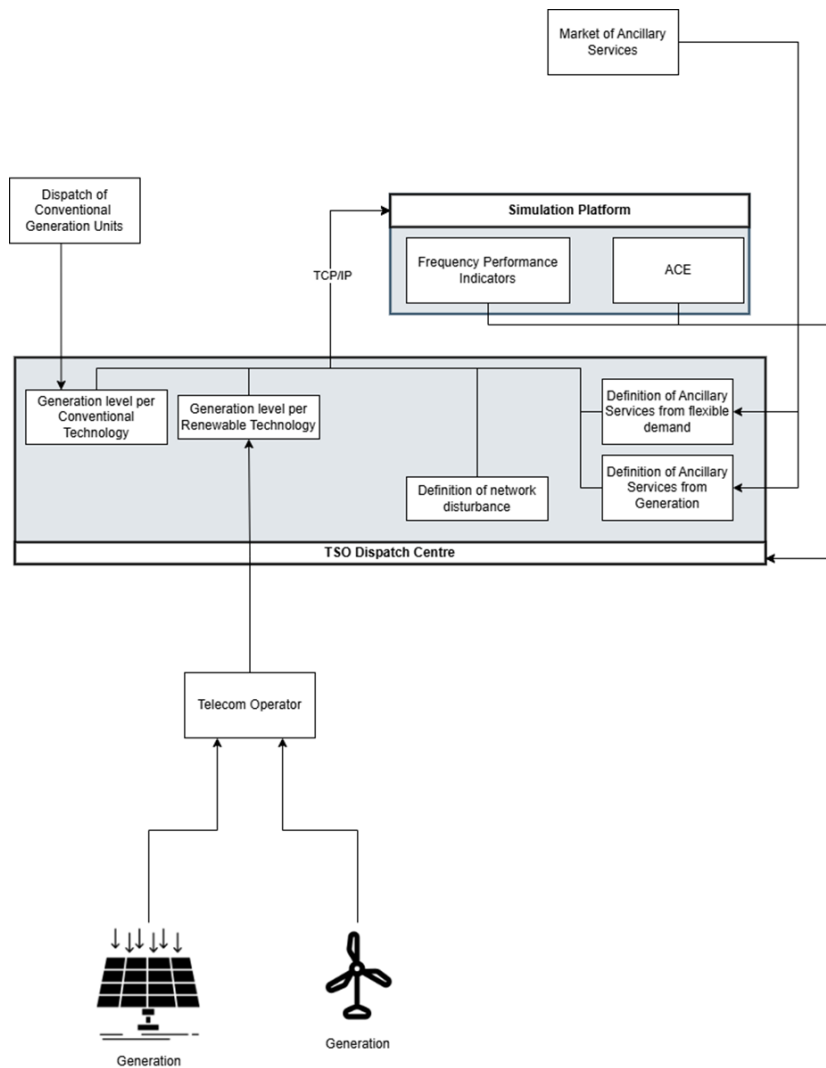


Figure 54. UC Ib03 Diagram

A.6 Actors/Systems

The primary actor in this use case is TSO, which according to Article 2.4 of the Electricity Directive 2009/72/EC is defined as "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". Moreover, the TSO is responsible for the connection of all grid users at the transmission level and the connection of the DSOs within the TSO control area.

Within this context, the DT serves as a valuable simulation platform for the TSO, enabling the evaluation of the dynamic robustness of the power system and supporting decision-making for frequency stability and ancillary services.

In terms of systems, the TSO SCADA System plays a crucial role in providing real-time grid measurements that are essential for both operational planning and the activation of ancillary services. This system continuously monitors the grid's status and supplies the Digital Twin with the operational data necessary to replicate real-world conditions. By leveraging SCADA measurements, the DT can

accurately simulate disturbances and assess the system's response, ensuring that its outputs align with actual system behavior.

A.7 Overview of the use case scenarios

The use case considers a set of representative operating conditions to assess the dynamic robustness of the Iberian power system using a Digital Twin (DT) framework. These scenarios are selected to reflect critical system states where the risk of frequency instability is heightened due to high penetration of renewable energy sources and reduced system inertia.

Two scenarios are currently defined: the *Winter Valley Scenario*, characterized by low demand periods with high wind power generation, and the *Peak PV Generation Scenario*, representing high solar production during peak irradiation hours. Both scenarios involve the simulation of large disturbances, such as sudden generation losses, and are used to identify the need for ancillary services to ensure system stability.

A.8 Step analysis of the use case scenarios

Each scenario follows a systematic process to evaluate the dynamic response of the power system using the DT. The analysis begins with the definition of the system's operational point based on actual or forecasted generation and demand levels. A disturbance is then introduced, typically representing a significant loss of generation or a large load increase.

The DT simulates the system response, enabling the TSO to monitor key performance indicators such as frequency nadir, rate of change of frequency (RoCoF), and Area Control Error (ACE). Based on these outputs, the TSO can assess the system's dynamic frequency robustness and determine the volume and type of ancillary services needed, including Fast Frequency Response (FFR), to maintain frequency stability under such stressed conditions.

A.9 Information exchange

The Digital Twin (DT) interacts with the TSO dispatch center through a continuous exchange of critical system data. This information flow includes:

Data Exchanged from the TSO Dispatch Center to the Digital Twin:

- **Generation Level (ID1):** Real-time generation levels for both conventional and RES technologies.
- **Network Disturbance (ID2):** Magnitude of the sudden generation loss or load increase to be simulated.
- **Ancillary Services (ID3):** Volume and type of available ancillary services from generation and flexible demand.

Data Exchanged from the Digital Twin to the TSO Dispatch Center:

- **Frequency Nadir (ID4):** Minimum frequency value recorded during a disturbance event.
- **Frequency Zenith (ID5):** Maximum frequency value recorded during a disturbance event.
- **RoCoF (ID6):** Maximum rate of change of frequency over a defined time window.
- **ACE (ID7):** Area Control Error (ACE) measured 300 seconds after the disturbance.

This structured data exchange ensures the accurate simulation and evaluation of system frequency stability, supporting decision-making on system robustness and ancillary service requirement.

Annex B UC-Ib10. Probabilistic cross-border capacity allocation

This section details the TwinEU Iberian Pilot use case 10 (UC – IB10) “Probabilistic cross-border capacity allocation”

B.1 Scope and objectives of the use case

The use case delves with the probabilistic cross-border capacity computation based on Available Transfer Capacity (ATC) methodology, allowing the assessment and definition ex-ante of the expected maximum capacity between adjacent bidding zones. The specific case addresses the border between Portugal and Spain.

The objectives are the following:

1. Provide an approach that naturally incorporates uncertainty to calculating the amount of electricity that can be safely traded across borders.
2. Congestion Management to prevent overload on the transmission system. It acts as a safeguard to ensure security of supply.
3. To contribute to the coordinated transmission capacity allocation with tools better adapted to weather-dependent generation uncertainty to manage risks associated with cross-border trading.

B.2 Complete description

In relation to the day-ahead and intraday markets, the congestion management mechanism plays a crucial role in preventing congestion in the interconnections. This mechanism is primarily supported by the capacity allocation methodologies, which ensure efficient utilization of the available transmission capacity.

A Capacity Calculation Methodology is a systematic approach used to determine the available capacity between different bidding zones. The calculation methodologies specified by the regulation provide guidelines for this process. It's important to highlight that while regulation outlines requirements for flow-based and coordinated net transmission capacity (ATC – available transfer capacity) approaches, they do not prescribe the exact process or algorithm to be used. Instead, it's the responsibility of the Transmission System Operators (TSOs) within each common calculation region to propose a unified capacity calculation methodology based on these regulations.

The ATC, or sometimes also referred to NTC, methodology is used in Southwest Europe System Operation Region (SWE SOR). In the ATC methodology, TSOs determine a net transfer capacity (NTC) for each direction at the border of their control area. This determination is based on historical data from a reference day and considers factors such as potential loop flows, seasonal variations, and a justified security margin. The NTC values represent the maximum allowed commercial exchanges that can be accommodated without exceeding the maximum physical flow of critical network elements. These values are established through agreement among the relevant TSOs. By subtracting the already allocated capacity (AAC) from the NTC, the ATC values are derived.

The goal of this UC is to add probabilistic scenarios on top of the typical ATC and propose an optimization method that maximizes the ATC considering the uncertainty arising from forecasting errors. In probabilistic ATC calculation, historical data, such as load profiles, generation patterns, and weather conditions, are analyzed to develop probabilistic scenarios of system behavior. These capture

the inherent uncertainty associated with factors like demand fluctuations, renewable energy generation variability, and equipment outages. By considering multiple scenarios and their associated probabilities, it is deemed that probabilistic ATC calculation provides a more comprehensive and realistic assessment of cross-border transfer capacity, aligned with the probabilistic risk assessment of the system security.

This approach allows TSOs to better understand the reliability and robustness of the grid under varying conditions, helping to identify the probability of potential constraints and vulnerabilities. Additionally, probabilistic ATC calculation enables TSOs to trade-off the risk of overload critical network elements with the ATC, making more informed decisions in the system operational planning, ultimately allowing the use of the grid according to risk.

B.3 Key performance indicators

To assess the effectiveness of the probabilistic approach for the calculation of the ATC and impact on the system security, a series of Key Performance Indicators (KPIs) have been defined in this use case.

Table 30: KPIs for UC Ib-10

KPI	Purpose	Assessment approach
KPI_Ib10_1: % of total cross-border capacity utilization	Measures the percentage of the calculated cross-border capacity that is actually used by the physical flow in the corresponding market time unit.	For each MTU and direction: utilization = physical cross-border flow / pATC x 100. The physical flow is compared with the pATC calculated for the same timestamp and direction, to determine if the physical flow lies between the estimated probability.
KPI_Ib10_2: % of cross-border capacity adequacy probability	Measures the probability that the calculated cross-border capacity is adequate under the probabilistic scenario set.	Calculated as the share, or probability-weighted share, of scenarios in which the calculated capacity is sufficient and the monitored security constraints are not violated.
KPI_Ib10_3: Grid Security Improvement Index (%)	Measures the effect of the probabilistic ATC calculation on the secure operation of the grid by integrating security indicators for CNE loss probabilities.	Calculated by comparing a baseline security score with the security score obtained when applying the probabilistic capacity assessment. CNEs are based on the available transmission-grid unavailability records, generation-unit unavailability records and selected loss-of-line cases.

B.4 Use case conditions

The use case relies on several key conditions:

- It assumes that all input data related to generation, demand, and network status is accurate, timestamped, and synchronized between the Portuguese (PT) and Spanish (ES) control areas. Additionally.
- It requires a well-defined regulatory framework for cross-border capacity allocation and market operation.
- The prerequisites include system operators having access to historical data, a current Common Grid Model (CGM) being shared among all parties, and each control area employing an Individual Grid Digital Twin (IGDT) system to support coordinated transmission capacity calculations.

B.5 Use case diagrams

The following diagrams show the interactions between actors/systems and the process flows. The actor/systems and the information used in the process are detailed in the next sections.

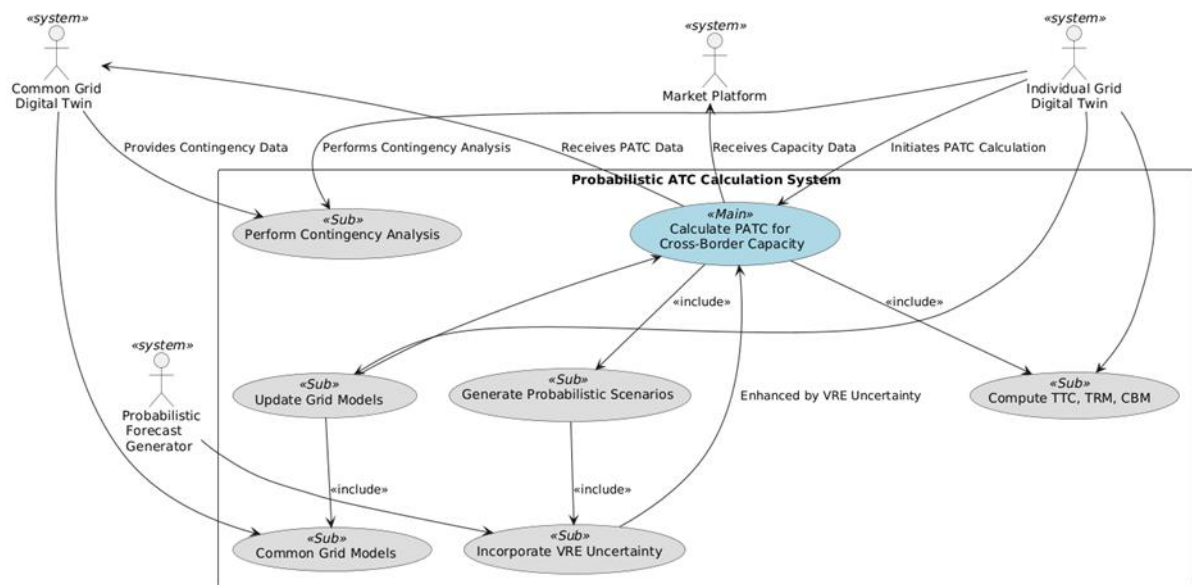


Figure 55. UC-Ib10: UML use-case diagram for Probabilistic cross-border capacity allocation

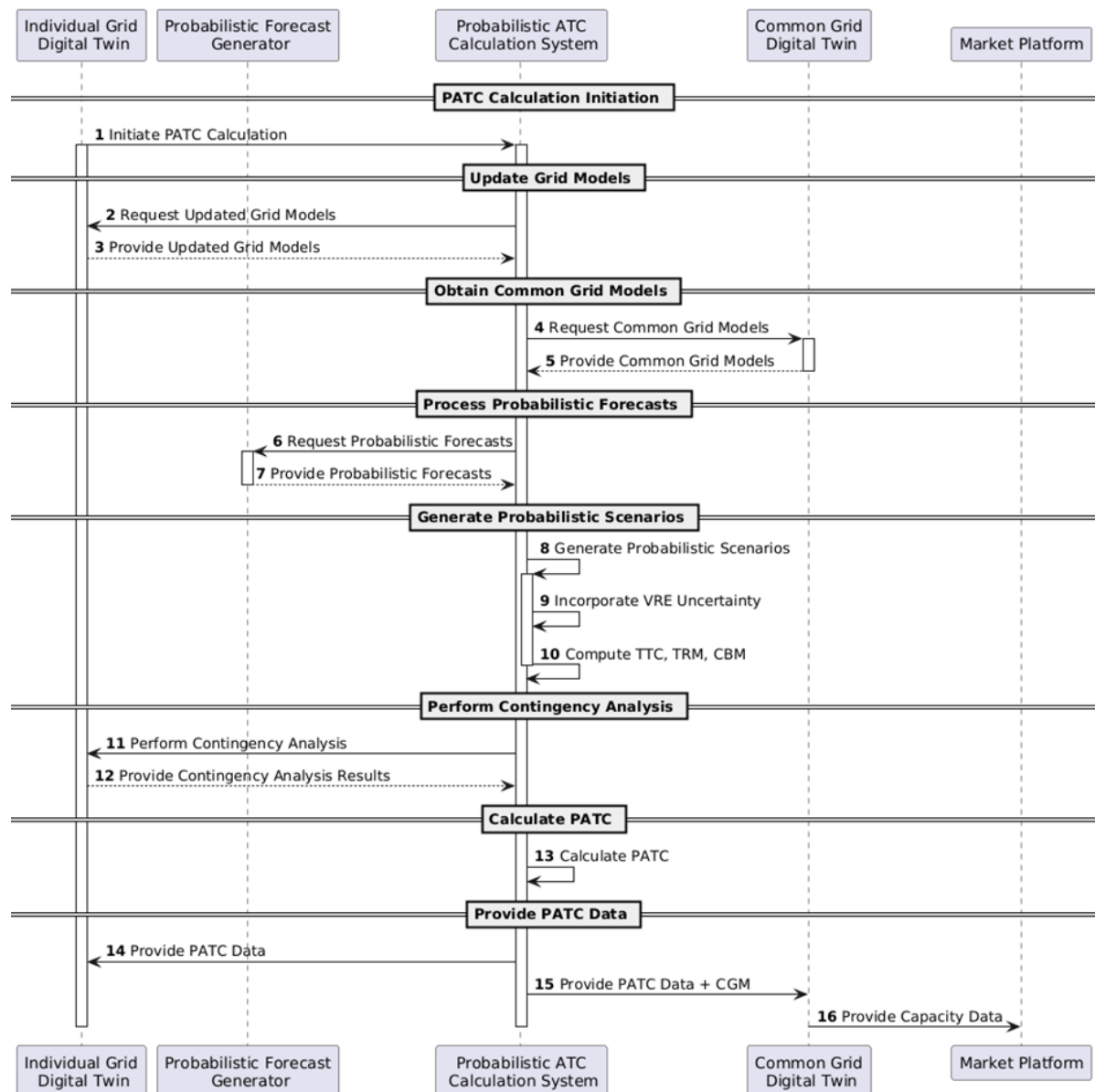


Figure 56. UC-Ib10: UML Sequence Diagram for Probabilistic cross-border capacity allocation

B.6 Actors/Systems

The actors involved in the use case are listed and described below:

- Individual Grid Digital Twin (IGDT)

This digital twin operates at the control area level, supporting coordinated transmission capacity calculations. It initiates the ATC (Available Transfer Capacity) calculation process, performs contingency analysis, selects remedial actions, coordinates with other actors, and provides probabilistic scenarios to the Common Grid Digital Twin (CGDT).

- Probabilistic Forecast Generator of VRE Generation and Demand (PFG)

As a data provider, this actor generates probabilistic forecasts for Variable Renewable Energy (VRE) generation and demand. It supplies these forecasts to the Probabilistic ATC Calculation System (PCCS) to account for uncertainties in VRE and demand within the scenario analyses.

- **Market Platform**

This digital twin manages electricity market operations, including capacity allocation and market clearing. It receives ATC data to support both day-ahead and intraday market processes.

- **Common Grid Digital Twin (CGDT)**

The CGDT acts as a regional security coordinator, enabling coordination between TSOs. It aggregates coordinated grid models and contingency data, implements the regional digital twin framework, and provides this information to the PCCS to support secure and reliable grid operation.

- **Probabilistic ATC Calculation System (PCCS)**

As a calculation module, the PCCS computes the ATC using a probabilistic approach that incorporates VRE uncertainty and grid contingencies. It calculates probabilistic TTC (Total Transfer Capacity) and communicates the results to other relevant actors.

B.7 Overview of the use case scenarios

The “PATC Calculation in Operational Planning” scenario describes the process of calculating the Probabilistic Available Transfer Capacity (PATC) during the operational planning phase. The process includes updating grid models, integrating probabilistic forecasts, and performing contingency analysis.

- **Primary actor:** The Individual Grid Digital Twin (IGDT) leads this process.
- **Triggering event:** The process begins when the IGDT sends a PATC calculation request to the Probabilistic ATC Calculation System (PCCS).
- **Pre-conditions:** To proceed, grid models and probabilistic forecasts must be available, all systems must be operational, and communication channels should be functioning.
- **Post-conditions:** Once completed, the PATC is calculated and shared with the Common Grid Digital Twin (CGDT) and Market Platform (MP). Updated grid models are also distributed, and the systems revert to standby mode in preparation for the next planning cycle.

B.8 Step analysis of the use case scenarios

Considering the actors and systems in Section B.6, the following structured scenario ensures a robust, coordinated, and reliable calculation and dissemination of Probabilistic Available Transfer Capacity, effectively supporting cross-border operational planning and market processes.

Step 1: PATC request to PCCS

The Individual Grid Digital Twin (IGDT) initiates the Probabilistic Available Transfer Capacity (PATC) calculation by sending a calculation request to the Probabilistic ATC Calculation System (PCCS).

Step 2: PCCS request to IGDT

PCCS responds by requesting updated grid models from IGDT to ensure it uses the latest network data for the calculation.

Step 3: IGDT response to PCCS

IGDT provides the requested updated grid models to PCCS, ensuring the calculation is based on accurate and timely network data.

Step 4: PCCS request to CGDT

PCCS then requests the Common Grid Digital Twin (CGDT) to provide the Common Grid Models, ensuring regional coordination.

Step 5: CGDT response to PCCS

CGDT responds by providing the Common Grid Models to PCCS, incorporating regional coordination data.

Step 6: PCCS request to PFG

PCCS requests probabilistic forecasts from the Probabilistic Forecast Generator (PFG) to integrate uncertainties associated with Variable Renewable Energy (VRE) generation and demand.

Step 7: PFG response to PCCS

PFG provides the requested probabilistic forecasts to PCCS, helping it account for VRE and demand uncertainties.

Step 8: VRE Probabilistic scenarios generation

PCCS generates probabilistic scenarios internally, incorporating the uncertainties from VRE forecasts to support accurate capacity margin calculation.

Step 9: Joint VRE and Demand probabilistic scenarios generation

PCCS explicitly integrates the uncertainties related to VRE generation and demand into the probabilistic scenarios, further refining the calculations and scenario analysis.

Step 10: TTC, TRM and CBM calculation

Using these scenarios, PCCS computes Total Transfer Capacity (TTC), Transmission Reliability Margin (TRM), and Capacity Benefit Margin (CBM), ensuring a comprehensive assessment of network capability.

Step 11: Contingency analysis request

PCCS requests IGDT to conduct a contingency analysis, identifying potential impacts and risks associated with transmission disturbances.

Step 12: Contingency analysis response

IGDT performs the contingency analysis and sends the results back to PCCS, ensuring robustness and reliability in the capacity calculations.

Step 13: PATC calculation

PCCS calculates the final Probabilistic ATC (PATC) by combining grid models, forecasts, probabilistic scenarios, and contingency analysis results.

Step 14: Operational planning input

PCCS sends the calculated PATC data back to IGDT, allowing IGDT to utilize this information for operational planning.

Step 15: Regional coordination input

PCCS also sends the calculated PATC data, along with the updated Individual Grid Model (IGM), to CGDT for broader regional coordination and reliability management.

Step 16: Capacity data to Market

Finally, CGDT forwards the validated capacity data to the Market Platform, supporting capacity allocation decisions in day-ahead and intraday markets.

B.9 Information exchange

Below is an overview of the key information exchanges that occur among the various systems and actors involved in the probabilistic ATC (PATC) calculation process. Each information exchange (IE) represents a distinct data flow or request that ensures up-to-date models, forecasts, and contingency assessments, enabling coordinated operational planning and reliable capacity calculations across the interconnected transmission system.

- IE1: PATC Calculation Request. IGDT requests the Probabilistic ATC Calculation System (PCCS) to initiate the calculation of Available Transfer Capacity (ATC) using a probabilistic approach.
- IE2: Grid Model Update. PCCS requests updated grid models from IGDT to ensure that the latest network configurations and planned outages are included in the calculation. This includes network topology, equipment statuses, and planned maintenance schedules relevant to the planning horizon.
- IE3: Common Grid Models (CGMs). CGDT provides aggregated grid models that combine Individual Grid Models (IGMs) from various IGDTs, ensuring a consistent regional network model.
- IE4: Probabilistic Forecast. PCCS requests probabilistic forecasts from the Probabilistic Forecast Generator (PFG) to account for uncertainties in Variable Renewable Energy (VRE) generation and associated factors, based on weather predictions and historical data for the planning period.
- IE5: Probabilistic Scenarios and Capacity Margins. PCCS internally generates probabilistic scenarios and computes capacity margins—Total Transfer Capacity (TTC), Transmission Reliability Margin (TRM), and Capacity Benefit Margin (CBM)—by incorporating VRE uncertainties and grid models.
- IE6: Contingency Analysis. PCCS requests IGDT to perform a contingency analysis to assess the grid's ability to handle potential component failures or outages during the planning period.
- IE7: Contingency Notification. IGDT provides contingency analysis results to PCCS, highlighting potential vulnerabilities and network limitations under various failure scenarios (e.g., N-1 conditions).
- IE8: PATC Calculation. PCCS estimates the Probabilistic ATC (PATC) based on the collected data, probabilistic scenarios, and contingency analysis results, serving as an internal output of PCCS.
- IE9: Grid Model and Probabilistic ATC Data. PCCS provides the calculated PATC data to the Common Grid Digital Twin (CGDT).
- IE10: PATC Communication to IGDT. PCCS communicates the calculated PATC to IGDT, ensuring they have the accepted available transfer capacities for operational planning and coordination.
- IE11: Capacity Data to Market Platform. Based on the probabilistic ATC assessment, CGDT communicates a single ATC value for each MTU and direction to the Market Operator (OMIE) to facilitate capacity allocation in the electricity market. The transmitted value corresponds to the secure PATC associated with the selected confidence criterion, after application of the relevant capacity limits.

Annex C UC-Ib11. Cross-border assessment of flexibility and pre-qualification

This section details the TwinEU Iberian Pilot use case 11 (UC – IB11) “Cross-border assessment of flexibility and pre-qualification”

C.1 Scope and objectives of the use case

The scope of this use case is to enable the coordination between System Operators (SOs) and Flexibility Service Providers (FSPs) for cross-border flexibility product integration particularly fast frequency reserves (FFR) in the Iberian Peninsula with the following objectives:

1. Design and test the prequalification process phase between neighbour SOs, namely for a new Fast Frequency Reserve (FFR) service.
2. Exchange (cross-border) grid and product prequalification information using digital twins (DTs).
3. Facilitate the entry of FSPs into the various flexibility markets cross-border, namely for a new Fast Frequency Reserve (FFR) market.

C.2 Complete description

The prequalification and forecasting phases are critical for ensuring the effective and secure operation of flexibility markets, especially for Fast Frequency Reserves (FFR) services. Prequalification guarantees that FSPs meet both product-specific and grid-related requirements, minimizing risks to system stability. These processes are dynamic and must be regularly updated to reflect changes in FSP capabilities or grid conditions.

The Iberian Pilot demonstrates how FFR can be effectively deployed in low-inertia scenarios, an increasingly common challenge due to the growth of renewable energy. It explores the creation of a dedicated Iberian FFR market, inspired by Nordic practices, where service providers (here generically referred as FSPs) undergo rigorous technical validation and respond autonomously to frequency disturbances.

Through periodic forecasting and national hourly markets, the pilot promotes advanced coordination and informed bidding. It supports cross-border integration, enhances the use of Digital Twins for operational planning, and provides key recommendations for scaling FFR markets in low-inertia systems.

In this context, this use case will streamline procedures to minimize complexity and effort for both FSPs and SOs, regarding FFR, and tuned the Digital Twins regarding grid models and communication framework, in order to facilitate the coordination between the involved parties (SOs and FSP, if applicable), such as propose standardize processes to facilitate smoother cross-border participation, allowing FSPs to operate seamlessly in FFR market, with the ultimate aim of increase participation by lowering entry barriers that encourages broader participation, leading to a more robust and competitive flexibility market (FFR mainly).

C.3 Key performance indicators

Table 31: KPIs for UC-Ib11

KPI	Purpose	Assessment Approach
IB11_KPI1: Dynamic Equivalent Model Validity	How accurately the reduced dynamic equivalent model reproduces the frequency response characteristics of the original system following a major generation loss event.	The original and reduced dynamic models are subjected to identical generation-loss events. Frequency and voltage responses at common retained buses are compared using RMSE, frequency nadir and nadir error, RoCoF, time-to-nadir error, minimum-voltage error, equivalent system inertia, and steady-state consistency checks.
IB11_KPI2: BESS FFR Controller Prequalification Compliance	Whether the representative BESS FFR controller satisfies the selected FFR prequalification requirements.	A synthetic FFR frequency test signal is applied to a representative BESS controller. Compliance is assessed against the 49.70 Hz activation threshold, ≤ 1.30 s full activation time, 12 MW reserve delivery, minimum full-power support period, deactivation-rate limitation, and SoC requirements.
IB11_KPI3: Total system Inertia	It is calculated as the sum of the kinetic energy contributions of all online synchronous generators.	The total inertia-weighted capacity, $\Sigma(H_{iS_i})$, total synchronous-machine MBASE, ΣS_i , and equivalent system inertia, H_{eq} , are calculated for all online synchronous machines represented by GENROU and GENSAL models and compared between the original and reduced models.
IB11_KPI4: Volume of Flexibility by Prequalified Units	The total volume of flexibility that is available from units that have completed the prequalification process.	The rated FFR capacity of all successfully prequalified BESS units is summed and reported by country and for the combined Iberian system.
IB11_KPI5: Frequency Nadir Improvement	Improvement in frequency nadir achieved through FFR activation.	Identical FFR-disabled and FFR-enabled simulations are performed using the same defined system disturbance. The frequency nadir improvement is calculated from the difference between the corresponding minimum-frequency values during the BESS operating period, supported by the frequency and BESS active-power response trajectories.

C.4 Use conditions

The implementation of the cross-border prequalification and flexibility market use case relies on several assumptions and prerequisites that ensure technical feasibility and operational coherence:

- It is assumed that prequalification can occur at the unit level, aggregated, or portfolio level if technically viable.
- Furthermore, disturbances and flexibility needs are expected to span multiple national grids, necessitating cross-border coordination.
- Information-sharing agreements between SOs and FSPs must be established to enable secure data exchange.

- For demonstration purposes, the grids of the two participating SOs are assumed to be directly connected, forming adjacent control areas facilitating the harmonization and testing of prequalification processes via Digital Twin connectors.
- On the prerequisite side, System Operators must have full access to relevant FSP information, and grid prequalification is conditional upon prior successful product prequalification. Lastly, FSPs are required to maintain active communication with their resources to ensure proper coordination, monitoring, and compliance throughout the demonstration process.

C.5 Use case diagrams

The following diagrams show the interactions between actors/systems and the process flows. The actor/systems and the information used in the process are detailed in the next sections.

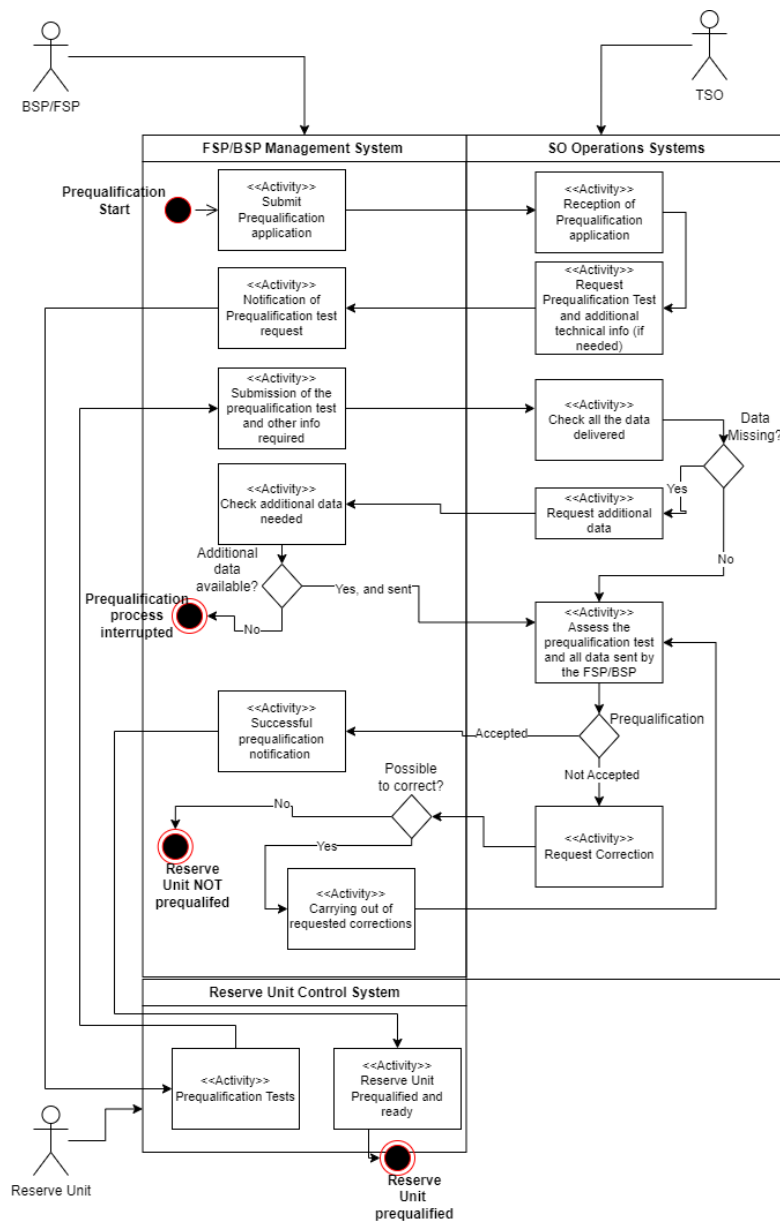


Figure 57. UC-Ib11: Scenario 1- Prequalification phase

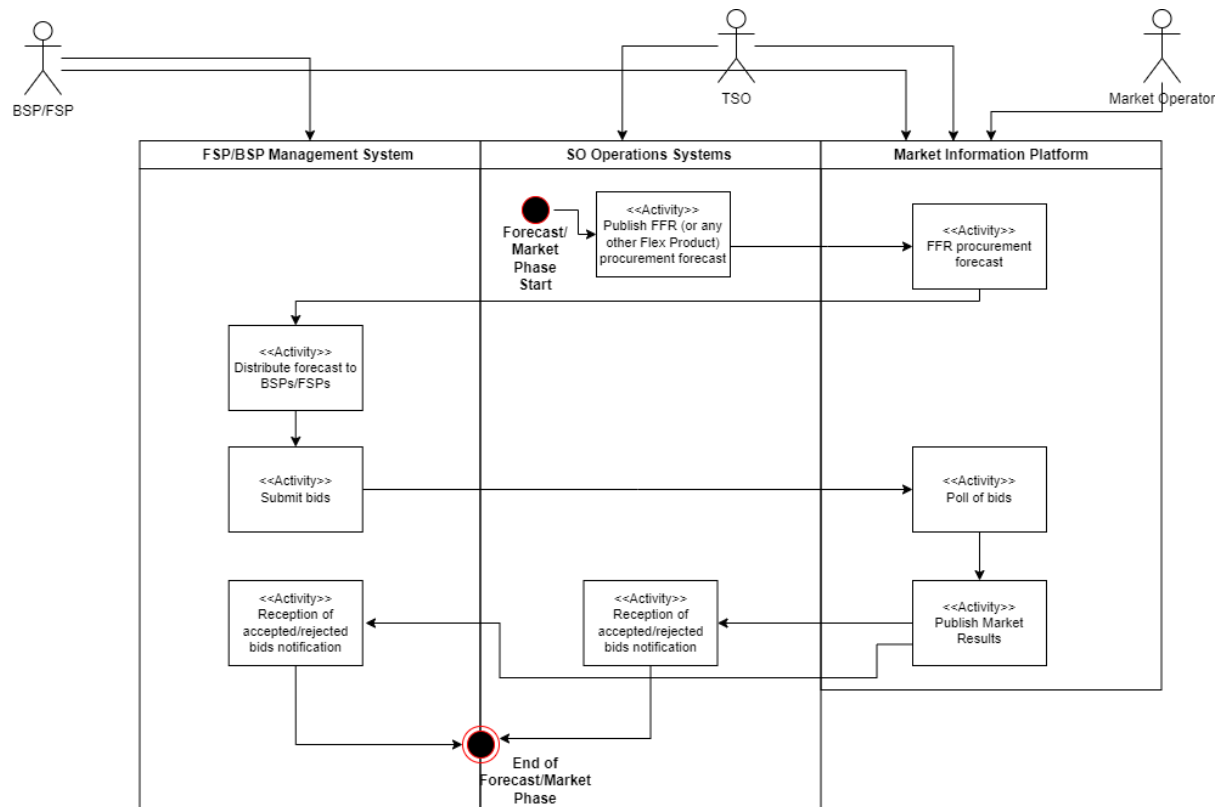


Figure 58. UC-Ib11: Scenario 2 – Forecasting/Market Phase

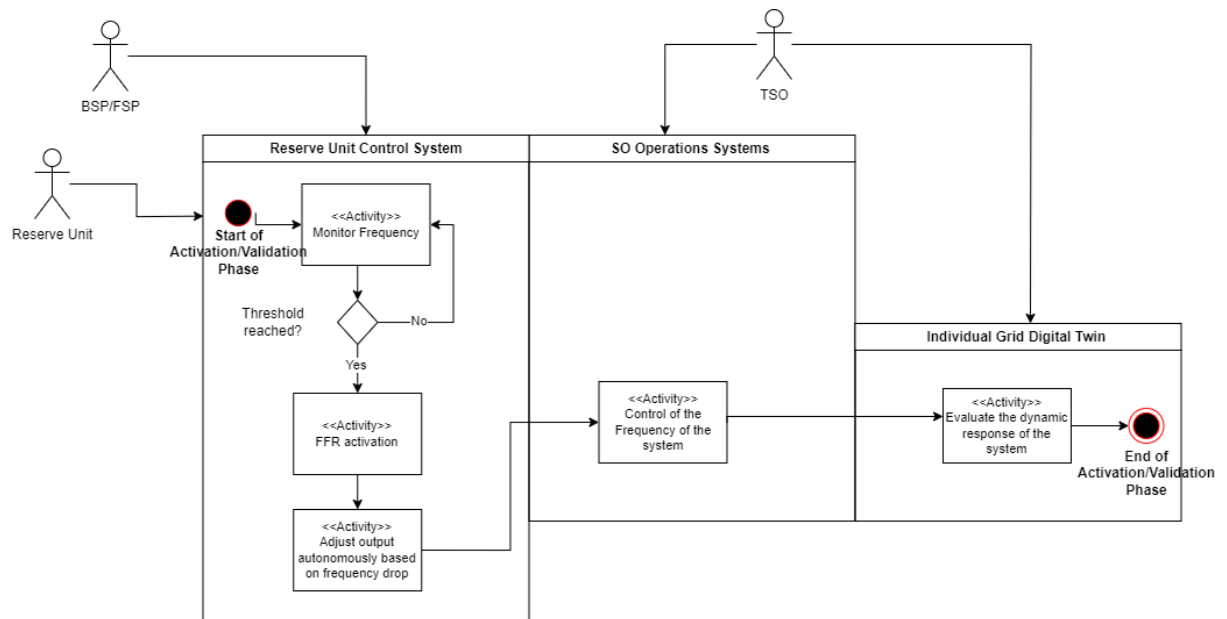


Figure 59. UC-Ib11: Scenario 3 – Activation/Validation Phase

C.6 Actors/Systems

The execution of this use case involves several key actors and supporting systems, each playing a vital role in enabling the delivery, monitoring, and validation of cross-border Fast Frequency Reserve (FFR) services. The interactions between these actors and systems ensure a coordinated, transparent, and technically sound prequalification and market activation process. The following are the actors and their associated systems:

- Transmission System Operator (TSO)

TSO is responsible for managing the transmission grid and ensuring system stability. In this use case, the TSO oversees prequalification, market operations, and activation monitoring. The systems associated with the TSO include the Grid Digital Twin (DT)- a real-time simulation tool for analysing grid conditions and supporting operational decisions and the System Operator (SO) Operations System which oversees prequalification, forecasting, market clearing, and post-activation performance assessment.

- Balancing/Flexibility Service Provider (BSP/FSP)

It is responsible to provide balancing or flexibility services by adjusting power production or consumption. These entities must complete prequalification and ensure their reserve units can respond autonomously. They are supported by the BSP/FSP Management System, which is used to manage prequalification processes, submit bids, and facilitate communication with SOs.

- Reserve Unit

It is a physical asset (e.g., generator, battery, or controllable load) controlled by the BSP/FSP, capable of delivering a rapid frequency response when activated. It is associated with the Reserve Unit Control System, which monitors local frequency and autonomously activating and adjusting reserve power output when a frequency threshold is crossed, reporting its actions to the TSO for post event assessment.

- Market Operator:

Oversees the FFR market platform, including bid matching, market clearing, and result dissemination. This role is supported by the Market Information Platform, a centralized system for publishing forecasts, collecting bids, and sharing market results with participants.

C.7 Overview of the use case scenarios

The use case is structured around three main scenarios that reflect the lifecycle of cross-border Fast Frequency Reserve (FFR) integration, from prequalification to activation and validation. Each scenario involves specific actors, information flows, and system interactions, ensuring a comprehensive assessment of the flexibility service deployment process.

- **Prequalification Phase:** This scenario ensures that Reserve Units meet technical and operational standards before participating in the flexibility market. BSPs/FSPs submit prequalification applications, may undergo technical tests, and receive feedback and final approval from the TSO. The process is supported by coordination systems, including the SO operations system and BSP/FSP management platforms.
- **Forecast and Market Phase:** In this scenario, the TSO publishes FFR procurement forecasts via the Market Information Platform. BSPs/FSPs review these forecasts and submit bids accordingly. The market operator manages bid collection and selection, and notifies participants of awarded contracts, aligning market participation with system needs.
- **Activation and Validation Phase:** This phase is triggered by frequency disturbances. Reserve Units autonomously respond based on local frequency measurements. Their performance is monitored by the TSO using the Grid Digital Twin and validated through real-time and post-event data. This ensures reliable service delivery and compliance with prequalified standards.

C.8 Step analysis of the use case scenarios

The use case is structured into three operational scenarios that collectively represent the lifecycle of cross-border flexibility service implementation, from prequalification to market execution and post-activation evaluation.

C.8.1 Prequalification Phase

The prequalification phase ensures that Flexibility Service Providers (FSPs) and their Reserve Units meet the technical and operational requirements to participate in the FFR market.

Step 1.1. Submit Prequalification Application:

The BSP/FSP submits a formal request to the TSO indicating its intention to participate in the flexibility market. This is the initial step of the prequalification process. Information exchanged: Info1 – Prequalification application.

Step 1.2. Reception of Prequalification Application:

The TSO receives and registers the application submitted by the BSP/FSP.

Step 1.3. Request Prequalification Test and Additional Technical Information (if needed):

The TSO may request additional technical data or testing requirements from the BSP/FSP to proceed with the evaluation. Information exchanged: IE2 – Infos/Tests request form.

Step 1.4. Notification of Prequalification Test Request:

The BSP/FSP is notified of the request for tests and any additional technical documentation required by the TSO.

Step 1.5. Prequalification Tests:

The BSP/FSP performs the necessary technical tests on the Reserve Unit to validate its compliance with product requirements. Information exchanged: IE3 – Technical tests.

Step 1.6. Submission of the Prequalification Test and Other Required Information:

The BSP/FSP submits test reports, performance data, and any other supporting information to the TSO. Information exchanged: IE4 – Report and records.

Step 1.7 – Check All the Data Delivered:

The TSO verifies that all required documentation and test results have been received.

Step 1.8 – Request Additional Data:

If the submitted documentation is incomplete or insufficient, the TSO requests further data or clarification from the BSP/FSP. Information exchanged: IE2 – Infos/Tests request form.

Step 1.9 – Check Additional Data Needed:

The TSO reviews whether the additional data fulfills the requirements for final evaluation.

Step 1.10 – Assess the Prequalification Test and All Data Sent by the FSP/BSP:

The TSO conducts a detailed review of the technical data and test results to confirm that the Reserve Unit complies with operational and market participation standards.

Step 1.11 – Request Correction:

If any deficiencies are found, the TSO issues a correction request to the BSP/FSP. Information exchanged: IE2 – Infos/Tests request form.

Step 1.12 – Carrying Out of Requested Corrections:

The BSP/FSP implements the necessary changes and resubmits the updated data.

Step 1.13 – Successful Prequalification Notification:

Once all conditions are satisfied, the TSO notifies the BSP/FSP that the Reserve Unit has successfully completed the prequalification process. Information exchanged: IE5 – Prequalification result.

Step 1.14 – Reserve Unit Prequalified and Ready:

At this step, the Reserve Unit is officially considered prequalified and is authorized to participate in the flexibility market.

C.8.2 Forecast and Market Phase

This phase focuses on market preparation and execution based on forecasted FFR requirements.

Step 2.1 – Publish FFR Procurement Forecast:

The TSO publishes an FFR procurement forecast on the Market Information Platform, accessible by all BSPs. Information exchanged: IE6 – Product procurement needs forecast.

Step 2.2 – FFR Procurement Forecast:

The TSO projects the volume of FFR required based on expected grid conditions and publishes this forecast to inform market participants.

Step 2.3 – Distribute Forecast to BSPs/FSPs:

The Market Information Platform distributes the forecast data to BSPs and FSPs. Information exchanged: IE6 – Product procurement needs forecast.

Step 2.4 – Submit Bids:

Based on the forecast, BSPs/FSPs submit their bids specifying reserve capacity and pricing for the upcoming market period. Information exchanged: IE7 – Bids.

Step 2.5 – Poll of Bids:

All submitted bids are collected, ranked by merit and technical assessment, and evaluated to select those that meet the required FFR capacity.

Step 2.6 – Publish Market Results:

The Market Operator announces the selected bids and clearing prices to all participants.

Step 2.7 – Reception of Accepted/Rejected Bids Notification:

BSPs/FSPs and the TSO receive notifications confirming which bids have been accepted. Information exchanged: IE8 – Awarded bid contracts/notification.

C.8.3 Activation and Validation Phase:

Triggered by a system event, this phase focuses on reserve activation, system response, and validation.

Step 3.1. Monitor Frequency:

The Reserve Unit Control System continuously monitors the local grid frequency to detect potential disturbances.

Step 3.2. FFR Activation:

If a significant frequency drop is detected, the Reserve Unit autonomously initiates reserve activation.

Step 3.3. Adjust Output Autonomously Based on Frequency Drop:

The Reserve Unit responds by adjusting its power output accordingly and reports the measurements to the TSO. Information exchanged: IE9 – Electrical measurements.

Step 3.4. Control of the Frequency of the System:

The TSO monitors grid frequency in real time, using the Individual Grid Digital Twin to maintain system stability and take necessary corrective actions. Information exchanged: IE9 – Electrical measurements.

Step 3.5. Evaluate the Dynamic Response of the System:

The TSO uses the Digital Twin to simulate, analyse, and assess the effectiveness of the grid's dynamic response to the activation.

C.9 Information exchange

In this use case nine types of information are exchanged namely

- IE1: Prequalification application. A formal submission from the BSP/FSP containing technical details, documentation, and certifications required for Reserve Unit prequalification.
- IE2: Infos/Tests/Request form. A request issued by the SO, detailing any additional information or specific tests needed from the BSP/FSP to complete the prequalification assessment.
- IE3: Technical tests. A set of performance tests conducted on the Reserve Unit to demonstrate compliance with activation and response standards required for market participation.
- IE4: Report and Records. Documentation of test results, performance data, and compliance status, submitted by the BSP/FSP to verify technical standards and track prequalification history.
- IE5: Prequalification Result. An outcome notification from the SO to the BSP/FSP, indicating whether the Reserve Unit has passed, failed, or requires further adjustments.
- IE6: Product procurement needs forecast. A forecast published by the SO showing expected Fast Frequency Reserve (FFR) demand (or any other product, guiding BSPs/FSPs in preparing bids for the upcoming period.
- IE7: Bids. Capacity and price offers submitted by BSPs/FSPs in response to the SO's forecast, detailing the volume of FFR (or any other product) they can provide and their proposed rates.
- IE8: Awarded bid contracts/notification. A notification sent by the SO to the BSPs/FSPs confirming accepted bids, including contract details and activation terms.

- IE9: Electrical measurements. Frequency, power output and other data collected from Reserve Units and grid sensors, sent to the SO for monitoring and validation.

Annex D UC-Ib13. Enhancement of short-circuit models and TSO/DSO information exchange for operational planning

This section details the TwinEU Iberian Pilot use case 13 (UC – IB13) “Enhancement of short-circuit models and TSO/DSO information exchange for operational planning”

D.1 Scope and objectives of the use case

The scope of this use case includes technical validation of short-circuit currents and improvements in data exchange mechanisms between TSOs and DSOs. It ultimately aims to increase the security of operation and quality of service across interconnected grid areas. The core objectives are the following:

1. Enhance TSO short-circuit models—especially with regard to RES generators
2. Ensure that estimations of short-circuit currents are more closely aligned with reality.
3. Improve mutual awareness between TSOs and DSOs regarding their respective fault current contributions, leading to a more synchronized operational planning process.

D.2 Complete description

Short-circuit currents are critical parameters for power system stability and protection. With the growing presence of Distributed Energy Resources (DERs), both TSOs and DSOs must improve real-time awareness and modeling of fault contributions. In Portugal, for instance, TSO/DSO interaction at 63kV bays exemplifies the need for better observability. The short-circuit current at these interfaces arises from both transmission-side and distribution-side contributions, requiring coordinated analysis.

Hence, the use case focuses on improving the estimation and coordination of short-circuit currents at the interface between Transmission System Operators (TSOs) and Distribution System Operators (DSOs). The purpose of the use case is to enhance operational planning through more accurate modeling and structured information exchange, especially given the increased penetration of Renewable Energy Sources (RES). This improved planning capability is necessary for day-ahead assessments of three-phase symmetrical short-circuit faults in Extra High Voltage (EHV) and High Voltage (HV) substations. A major aim is to address the lack of observability and model inaccuracies that currently hinder effective security assessments and protective equipment calibration.

This use case proposes a process where both TSO and DSO independently calculate and exchange their respective short-circuit forecasts for the upcoming operational day. The TSO first computes the short-circuit currents considering its own infrastructure and connected producers. This data is shared with the DSO, who integrates the impact of DER connected to the distribution grid to generate an updated, aggregated short-circuit profile. This exchange ensures that both system operators operate with full visibility of the combined short-circuit potential at their interface, supporting more robust operational planning and contingency management.

Only the three-phase symmetrical fault type is considered in this use case, as it is the most severe and critical for protection systems. Despite different national topologies, the methodology is proposed to be harmonized across TSOs and DSOs.

D.3 Key performance indicators

Table 32: KPIs for UC-Ib13

	Description	Assessment
KPI 1	This KPI evaluates the difference between the maximum short-circuit current foreseen by the model and the reference short-circuit current value used by the TSO for planning purposes at a given EHV/HV substation. It supports the assessment of the consistency between the model-based forecast and the values considered in existing planning studies.	Deviation from planning reference
KPI 2	This KPI compares the maximum short-circuit current forecasted by the model with the rated short-circuit breaking capacity of the circuit breaker installed at the corresponding EHV/HV substation. It supports the identification of potential operational or planning risks by indicating how close the expected short-circuit current is to the equipment technical limit.	Margin vs. TSO CB (31.5 kA)
KPI 3	This KPI evaluates the variation in KPI 1 and KPI 2 before and after the enhancement of wind-based generation models in the short-circuit model used within the DT. It quantifies the impact of improving the representation of wind generation units on the estimated short-circuit currents and on their relation to planning reference values and circuit breaker technical limits.	Shift in max Short-Circuit current

D.4 Use conditions

The use case assumes that

- only three-phase symmetrical short-circuit events will be analyzed.
- The technical validation of short-circuit currents is to be performed after the wholesale day-ahead market results are available.
- Two prerequisites are required: access to a steady-state model of the network and access to machine reactance values to ensure accurate calculations.

D.5 Use case diagrams

The following diagrams show the interactions between actors/systems and the process flows. The actor/systems and the information used in the process are detailed in the next sections.

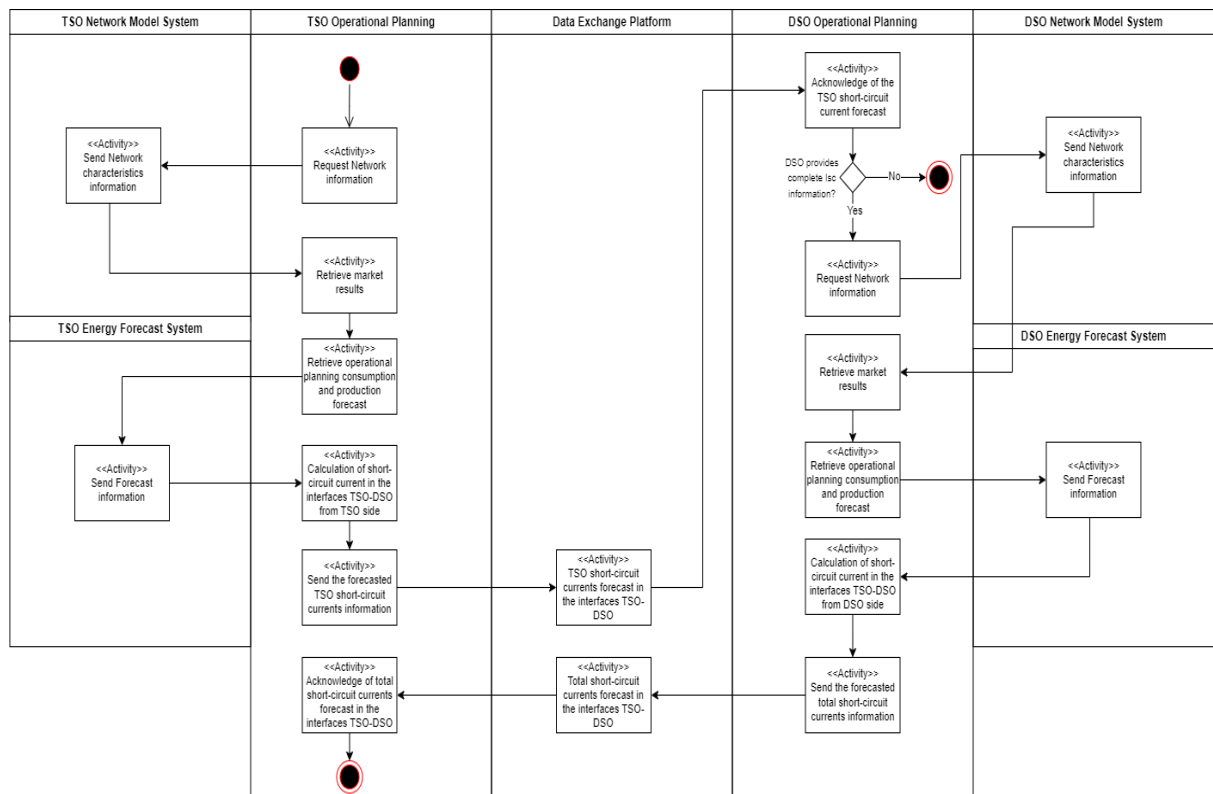


Figure 60. UC-Ib13 use case diagram

D.6 Actors/Systems

The use case involves several key systems, each playing a critical role in data acquisition, modeling, planning, or information exchange.

- The Network Model System

This is an internal system managed by each System Operator. It is responsible for maintaining mathematical representations of the grid, including current as-built configurations, future planned infrastructures, and hypothetical scenarios. It supports various analytical functions such as steady-state power flow, contingency analysis, and stability studies. This system ensures consistent data for all network-related computations and operates across both horizontal (TSO-TSO) and vertical (TSO-DSO) boundaries.

- The Energy Forecast System

It handles predictions related to consumption and generation, especially from intermittent or price-inelastic sources. It includes forecasts for DERs and provides technology-specific data that feed into the operational planning and short-circuit calculation processes.

- The Data Exchange Platform

It serves as a generic, data-agnostic infrastructure for scheduled and structural data exchange. It does not handle real-time operational or control data but supports secure and reliable transmission of forecasts and planning information between TSOs and DSOs. When data is sent, the receiving party is automatically notified, ensuring synchronized communication.

- The Operational Planning System

It models future grid conditions using “what-if” analyses, adequacy assessments, and risk-based forecasting. It integrates network topologies, forecasts, and market results to plan the grid’s operation under foreseeable conditions. It is responsible for calculating the short-circuit contributions and integrating the outputs from forecasting and modeling systems into actionable operational scenarios.

Each of these systems collaborates within the process flow to enable precise, bidirectional sharing of short-circuit forecast data, ensuring that both TSOs and DSOs have a complete and shared situational awareness.

D.7 Overview of the use case scenarios

The TSO provides the forecasted short-circuit current values derived from the EHV and HV transmission network, including the contributions from producers connected at these voltage levels. Based on this information, the DSO performs its own calculation of short-circuit currents, incorporating the additional fault contributions from DER connected to the distribution network. This coordinated approach ensures that both system operators obtain a comprehensive estimation of the total short-circuit currents expected for the following day at the TSO-DSO interface substations.

D.8 Step analysis of the use case scenarios

This section describes the complete sequence of activities, data flows, and responsibilities shared between the TSO and the DSO in forecasting short-circuit currents at the TSO-DSO interface. The process is executed once per day after the gate closure time of the day-ahead electricity market and focuses on the operational planning horizon for the following day.

Step 1.1 – Request Network Information

The operational planning system initiates the process by requesting structural and topological data from the internal Network Model System. This includes electrical characteristics necessary for short-circuit calculation, such as impedances, reactances, and network configurations.

Step 1.2 – Send Network Characteristics

The Network Model System provides the requested data to the operational planning system. These data represent the as-built status of the grid, including transmission elements and connected generating units relevant for the computation of short-circuit currents.

Step 1.3 – Retrieve Market Results

Once the Day-Ahead Market (DAM) results have been cleared, the operational planning system retrieves the corresponding dispatch schedules. These results are essential to determine which generation units are expected to be online and contribute to the fault levels during the next operational day.

Step 1.4 – Retrieve Forecast Data

The operational planning system collects the latest forecasts for consumption and production, including intermittent and distributed generation. These forecasts are typically disaggregated by technology type and may include probabilistic metrics (e.g., quantiles) if stochastic methods are applied.

Step 1.5 – Send Forecast Information

The Energy Forecasting System sends the relevant production and consumption forecasts to the operational planning system. These forecasts are internally used for simulating credible operating scenarios and estimating expected short-circuit levels.

Step 1.6 – TSO Computes Short-Circuit Currents

Using the network model, market results, and forecast data, the TSO calculates the short-circuit currents at the interface substations. This includes the fault contribution from all EHV/HV network components and generation units connected to the transmission grid.

Step 1.7 – TSO Sends Short-Circuit Forecasts

The TSO sends the 24-hour forecast of short-circuit current values at the TSO-DSO interface nodes through the data exchange platform. These forecasts represent the contribution from the TSO side only.

Step 1.8 – Data Exchange Platform Notification

Upon successful transmission, the data exchange platform notifies the DSO operational planning system that new forecast data is available from the TSO.

Step 1.9 – DSO Acknowledges Receipt

The DSO acknowledges receipt of the TSO short-circuit forecast. This serves as the input for its own fault current computation, now enriched by upstream system conditions.

Step 1.10 – Request Network Information (DSO)

The DSO's operational planning system repeats the request to its internal Network Model System to obtain the structural characteristics of the distribution network, including DER interconnections and local impedances.

Step 1.11 – Send Network Characteristics (DSO)

The Network Model System responds with the required data for accurate fault current estimation within the distribution grid.

Step 1.12 – Retrieve Market Results (DSO)

In parallel, the DSO accesses the Day-Ahead Market results to determine which distribution-level generators will be in operation during the next day.

Step 1.13 – Retrieve Forecast Data (DSO)

The DSO retrieves its own set of load and generation forecasts, reflecting local conditions and expected DER behavior over the next 24-hour horizon.

Step 1.14 – Send Forecast Information (DSO)

The DSO's forecasting system transmits the forecasted values for local generation and demand to its operational planning system. These values will be used to simulate active contributions to short-circuit currents from the distribution network.

Step 1.15 – DSO Computes Total Short-Circuit Currents

The DSO performs its short-circuit analysis using the full system model, combining the TSO's upstream fault contributions with those calculated from DER and distribution-level infrastructure.

Step 1.16 – DSO Sends Total Forecast to TSO

The DSO sends the aggregated short-circuit current forecast—representing the total expected fault level at each TSO-DSO interface for every hour of the next day—back to the TSO via the data exchange platform.

Step 1.17 – Data Exchange Platform Notification

Upon receipt, the data exchange platform notifies the TSO operational planning system that the total short-circuit current forecast from the DSO is available.

Step 1.18 – TSO Acknowledges Receipt

Finally, the TSO acknowledges the full short-circuit forecast from the DSO. The forecasted values, now reflecting the complete fault contribution from both sides of the interface, are integrated into operational security assessments and protection system validations.

D.9 Information exchange

Five main types of information are exchanged between systems. These include requests and responses for network characteristics, consumption and generation forecasts, and short-circuit current forecasts. The short-circuit forecasts cover each observability node at the interface for the 24 hours of the following operational day:

- IE1: Request (internal) the Network characteristics information. Request the structural information of the network characteristics are required to the computation process. This information is exchange between the SO systems. The focus of the UC will be in the improvement of these models
- IE2: Network characteristics (internal) information. Submit The structural information of the network characteristics are required to the computation process. This information is exchange between the SO systems. The focus of the UC will be in the improvement of these models
- IE3: Request (internal) the Consumption and production forecast. Request the submission of the day-ahead consumption and generation foreseen.
- IE4: Consumption and production forecast (internal) information. Submit the consumption and generation forecast.
- IE5: Short-Circuit currents forecast. Exchange of short-circuit currents in each node in the observability area.