Smart TSO-DSO interaction schemes, market architectures and ICT Solutions for the integration of ancillary services from demand side management and distributed generation

D4.2 Scenario setup and simulation results

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Distribution Level	Public
Responsible Partner	RSE
Checked by WP leader **Marco Rossi**	Date: 28/06/2019
Approved by Project Coordinator **Gianluigi Migliavacca**	Date: 28/06/2019

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691405

Issue Record

Planned delivery date	31/12/2018
Actual date of delivery	28/06/2019
Status and version	FINAL

Version	Date	Author(s)	Notes
0.1	26/05/2017	Julia Merino Fernández	Section on the forecasting error
0.2	05/12/2017	Harald Svendsen	Preliminary version of the report, inclusive of the first scenario assumptions and datasets
0.1	18/01/2019	Harald Svendsen	Advanced version the scenario description part
0.8	20/06/2019	Marco Rossi	Revision of the received contributions
0.9	25/06/2019	Marco Rossi	Inclusion of the section on simulation results
1.0	28/06/2019	Marco Rossi	Finalization

About SmartNet

The project SmartNet (http://smartnet-project.eu) aims at providing architectures for optimized interaction between TSOs and DSOs in managing the exchange of information for monitoring, acquiring and operating ancillary services (frequency control, frequency restoration, congestion management and voltage regulation) both at local and national level, taking into account the European context. Local needs for ancillary services in distribution systems should be able to co-exist with system needs for balancing and congestion management. Resources located in distribution systems, like demand side management and distributed generation, are supposed to participate to the provision of ancillary services both locally and for the entire power system in the context of competitive ancillary services markets.

Within SmartNet, answers are sought for to the following questions:

- Which ancillary services could be provided from distribution grid level to the whole power system?
- How should the coordination between TSOs and DSOs be organized to optimize the processes of procurement and activation of flexibility by system operators?
- How should the architectures of the real time markets (in particular the markets for frequency restoration and congestion management) be consequently revised?
- What information has to be exchanged between system operators and how should the communication (ICT) be organized to guarantee observability and control of distributed generation, flexible demand and storage systems?

The objective is to develop an ad hoc simulation platform able to model physical network, market and ICT in order to analyse three national cases (Italy, Denmark, Spain). Different TSO-DSO coordination schemes are compared with reference to three selected national cases (Italian, Danish, Spanish).

The simulation platform is then scaled up to a full replica lab, where the performance of real controller devices is tested.

In addition, three physical pilots are developed for the same national cases testing specific technological solutions regarding:

- monitoring of generators in distribution networks while enabling them to participate to frequency and voltage regulation,
- capability of flexible demand to provide ancillary services for the system (thermal inertia of indoor swimming pools, distributed storage of base stations for telecommunication).

Partners

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List of Abbreviations and Acronyms

Acronym	Meaning
DSO	Distribution System Operator
AL	Atomic Loads
CGCL	Curtailable Generators and Curtailable Loads
CHP	Combined Heat and Power
CS	Coordination Scheme
CSV	Comma Separated Value
DK	Denmark
ES	Spain
EV	Electrical Vehicles
HDD	Heating Degree Days
HWP	HIRLAM/WAsP/PARK
ICT	Information and Communication Technology
IT	Italy
LTGF	Long-Term Generation Forecast
LTLF	Long-Term Load Forecast
MAE	Mean Absolute Error
MAPE	Mean Absolute Percentage Error
MOS	Model Output Statistic
MS	Multi Step
MSE	Mean Square Error
MTGF	Medium-Term Generation Forecast
MTLF	Medium-Term Load Forecast
MV	Medium Voltage
NWP	Numerical Weather Prediction
OPF	Optimal Power Flow
PHS	Pumped Hydro power Storage
PV	Photovoltaic
RES	Renewable Energy Resources
RMSE	Root Mean Square error
RSE	Ricerca sul Sistema Energetico
SS	Single Step
STATCOM	STAtic COMpensator
STGF	Short-Term Generation Forecast
STLF	Short-Term Load Forecast
TCL	Thermostatically Controlled Load
TSO	Transmission System Operator

US	United States
VSTGF	Very Short-Term Generation Forecast
VSTLF	Very Short-Term Forecast

Executive Summary

In order to simulate the electricity system and the related ancillary services provision on the basis of the proposed TSO-DSO coordination schemes, the scenario has a fundamental role. In previous reports, SmartNet investigated the possible high level electricity scenarios for Italy, Denmark and Spain, but they need to be translated to high-detail datasets in order to be processed by the simulation platform. In particular, assumptions and procedures have been defined in order to identify:

- The geographic position of the simulated resources
  High level scenarios mostly provided generic information at national/regional level. Their position on the national territory (as well as their physical characteristics) have to be defined on the basis of population statistics, pre-existing conditions, etc.
- The position of resources on the electricity system
  Assumptions on the electrical location of resources, voltage level connection, especially for distribution resources (since limited information are typically available for this system level) need to be defined in order to create a precise electrical model.
- The impact of profiles and related forecasting errors on the system
  In order to run the simulations, the profile of each considered resource needs to be defined, together with the impact of forecasting error on that (since prediction error is one of the conditions to have the necessity of ancillary services). Correlations among different kind of resources need to be considered in order to obtain realistic operating conditions of the network.

These are just some of the aspects that have been considered for the creation of a detailed dataset usable by the simulation platform. In particular, since the amount of information is significant, automatic procedures have been defined, aimed at guaranteeing that the returned data are in line with the high level scenario predictions and, at the same time, providing a feasible baseline condition for the simulator.

The document reports the main concepts adopted for the creation of the detailed datasets and all the necessary information for the simulation of the considered scenarios. Strategies for the reduction of the data and containment of the simulation timing have been also discussed. Finally, the main simulation results are presented and discussed, highlighting the impacts of the different scenarios and TSO-DSO coordination schemes on the different simulation layers.

1 Introduction

The increase of renewable generation in electricity mixes as well as new business potential for demand side management are expected to gradually move the centre of mass of flexibility reserve from pure transmission resources to distribution ones. This means that, the interaction between the operators of the two systems (transmission and distribution) will soon become crucial for the effective and efficient management of ancillary services.

In order to tests the TSO-DSO coordination schemes proposed by the project SmartNet and documented in [1], in addition to the simulation environment [2], electricity scenarios have been hypothesized for three reference countries on the 2030 time horizon [3][4]: Italy, Denmark and Spain.

Of course, the simulation software need numerous and detailed information in order to precisely address the implemented blocs. For this reason, the high level and generic scenarios (which contain mostly information with national/regional detail) need to be expanded for the creation of precise datasets, including transmission/distribution network details, information on each single power unit, numerical data related to the internal/initial state of all the system components.

The present document explain the main procedures and assumptions for the translation of the high level scenarios to the detailed datasets requested by the simulation platform: the definition of the electricity system, the creation of the distribution system scenario, the assignment of flexible resources to different geographical areas of the countries, etc. In addition, also the strategies for simplifying/reducing the dimension of the information (still preserving the functionality of the simulated system) have been discussed and adopted in order to contain the computational burden requested by the simulations.

Once the detailed datasets of the three scenarios have been created, they have been processed by means of the developed simulation platform. As explained in section 5, the complexity of the platform requested a significant amount of effort for a complete debugging, especially considering the amount of time requested for the simulation: 36 simulations (3 countries, 3 characteristics days, 4 coordination schemes) requested about one month of computational time. The same document section also reports the results of the main blocks and layers, and discusses their behaviour on the basis of the scenario characteristics and the effects of the different TSO-DSO coordination schemes on the effective provision of ancillary services.

2 Scenario creation approach

During the progress of the project SmartNet, high-level information have been provided concerning the three investigated countries (Italy, Denmark and Spain) in hypothetical 2030 electricity scenarios [3][4]. In order to translate them to a set of data usable by the developed simulator [2] the procedure described in this chapter is proposed.

2.1 Data requirements

The SmartNet simulator is a software enviroment that requires a large amount of input data that is in this report grouped into five categories:

- **Electrical network**
  The first group of data specifies the physical electrical network, including both transmission and distribution level. This data includes
  - the network topology (what is connected to what);
  - separation into zones or sub-networks (typically with one sub-network per distribution grid);
  - electrical parameters (voltage level, impedance, capacity, voltage ratio for transformers, and other parameters).
- **Scenario specifications**
  The second group of data is represented by parameters that describe various scenario settings, such as scenario identifier, simulation window, timestep length, certain market settings (latency, market horizon [5]) and choice of TSO-DSO coordination scheme [1].
- **Devices**
  The third group of data specifies parameters for flexible devices. There are ten different device types, with different sets of input parameters. Devices include generators, loads and storage devices (that act as both generators and loads). The flexible device types are:
  - Conventional generator (Con)
  - Wind power generator (Wind)
  - Photovoltaic generator (Pv)
  - Run-of-river hydropower generator (Hyd)
  - Combined heat and power generator (Chp)
  - Storage (Sto)
  - Sheddable (curtailable) load (Sel)
  - Thermostatically controlled load (Tcl)
  - Wet appliances / atomic loads (Wet)
  - STATCOM devices (Stat)

The required data for each device type is determined by the device model adopted by the simulator. Typically, data includes grid connection point, reference to time profiles for scheduled power injection/absorption or resource availability (e.g. for Wind and Pv) and various model parameters. Hydropower is special in that they may appear as either conventional generation (Con) for large plants with water reservoirs, as run-of-river hydro generators (Hyd), or as pumped hydro storage devices (Sto).

- **Previous market profiles**

  The fourth group of data specifies the results from the previous (day-ahead/intraday) markets. This gives the baseline before entering the SmartNet market.

  - scheduled power output for generators;
  - forecasted load/generation for other flexible devices;
  - energy prices.

- **Other profiles**

  Profiles are time-series data associated with:

  - available power for wind and PV and run-of-river hydro (this is different from scheduled power due to weather forecasting errors);
  - temperature (for Tcl and Chp devices);
  - availability (for electrical vehicles storage);
  - net load for non-flexible devices (forecasts and actual values);
  - node net injection forecasts, computed from other profiles.

2.2 National scenario specifications

The SmartNet scenarios on a national level are described in [4], where generation capacities per type are based on the selected ENTSO-E Vision scenarios for 2030 [3]. The three SmartNet scenarios assume different developments, and different degree of flexibility being available (see Table 1). Generation capacities per type for the three countries are given in Table 2, and flexible resources per type are quantified in Table 3.

Table 1: Scenario overview

Italy	• ENTSO-E Vision 3 • Demand response partly used (50%) • Poor cross-border capacity
Denmark	• Energinet.dk projections (ENTSO-E Vision 4) • Demand response fully used • Good cross-border capacity
Spain	• ENTSO-E Vision 1 • EU Reference scenario • No demand response • Poor interconnectors

Table 2: Expected installed generation capacity (MW) in 2030

(MW)	Biofuels	Gas	Hard coal	Hydro	Lignite	Nuclear	Oil	Others non-RES	Others RES	Solar	Wind
IT (Vision 3)	0	37993	7056	23535	0	0	1386	10160	10750	40400	18990
DK (Vision 4)	1460	3746	410	9	0	0	735	0	260	1405	12825
ES (Vision 1)	0	24948	5900	23450	0	7120	0	10480	2400	16800	35750

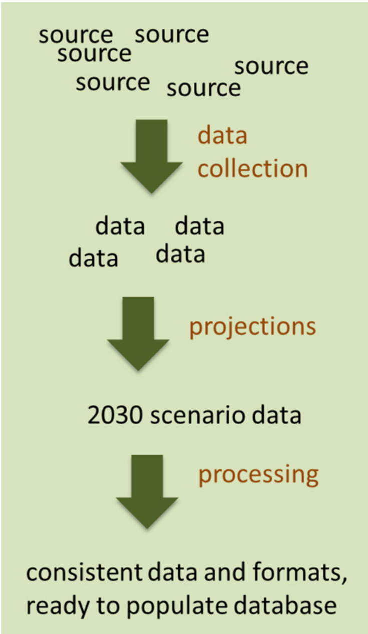
Table 3: Flexibility resources total availability data for 2030 [4]

		Distribution (MW)	Transmission (MW)	Total MW
Wind T.*	**Denmark (DK1)**	853	2 438	3 291
	Italy	1 261	3 041	4 303
	Spain	5 317	2 907	8 224
PV*	**Denmark (DK1)**	267	0	267
	Italy	6 945	89	7 034
	Spain	5 451	70	5 521
Stationary storage: Battery	**Denmark (DK1)**	*NA*	*NA*	*NA*
	Italy	19	123	142
	Spain	4	0	4
Stationary storage: Hydro	**Denmark (DK1)**	0	0	0
	Italy	817	6 470	7 287
	Spain	11	6 968	6 979
Stationary storage: Flywheel	**Denmark (DK1)**	0	0	0
	Italy	0	0	0
	Spain	1	0	1
Mobile storage	**Denmark (DK1)**	6 000	0	6 000
	Italy	285	0	285
	Spain	2	0	2
CHP	**Denmark (DK1)**	990	825	1 815
	Italy	4 841	13 020	17 861
	Spain	3 719	3 100	6 819
TCL*	**Denmark (DK1)**	306	72	378
	Italy	652	0	652
	Spain	772	0	772
Load shifting*	**Denmark (DK1)**	228	0	228
	Italy	49	0	49
	Spain	37	0	37
Load curtailment*	**Denmark (DK1)**	0	0	0
	Italy	394	0	394
	Spain	NA	NA	NA
Industrial processes*	**Denmark (DK1)**	119	0	119
	Italy	548	137	685
	Spain	72	287	358

* GWh/year values (yearly generated or consumed energy) is converted to MW by dividing it to 8760

2.3 From nation to node

As anticipated above, high-level scenarios give information on national level, and in some cases on a regional level. The SmartNet simulator, however, need information down to individual devices, including which node they are connected to in the network. The general approach for how detailed per-node data has been generated from national/regional projections is indicated in Figure 2.1.



1. Start from national 2030 scenario – high level scenario
2. Provide realistic model parameters for each device
3. Generate list of devices per type (number of devices, total power/energy)
4. Determine regional distribution of devices, using statistical information
5. Determine devices locations on transmission grid
6. Convert power profiles from various sources
7. Run a day-ahead simulation to get reasonable generator schedules and prices (optionally, include intraday adjustments)
8. Determine detailed location of devices within distribution grids
9. Export dataset with CSV input files

Figure 2.1: Detailed scenario specification – general approach

In some cases, source data already provide transmission grid connection points. This is mostly the case for large generators in the transmission grid. In these cases, available data has been used, with capacities scaled to match the national 2030 projections. In other cases, grid connection points are not available, but geographical locations are. In these cases, transmission grid connection points have generally been determined based on shortest distance. This is typically the case for existing Pv and Wind generators.

For flexible loads and storage devices, generally located in distribution grids, such information is typically not available. In these cases, the list of devices and their parameter values have been determined such as to get reasonable statistical spread. Geographical distribution of devices is first done per region, using regional data or relevant statistical information, such as population and population density per region. Next, devices were distributed amongst transmission grid nodes per region, considering primary substations in the cases of distribution grid devices. Finally, locations within distribution grids were determined such as to give realistic amounts of congestion, see Section 3.1.2. More details regarding device data creation is provided in Section 0.

2.3.1 Use of statistical data from Eurostat

Population per region for 2030 was estimated based on statistics from Eurostat [6], using regional population and growth rate in 2017 (*demo_r_gind3* – population change, demographic balance and crude rates at regional level), and national population projection for 2030 (*proj_15npms* – population on 1st January by age, sex and type of projection), assuming that the growth rate for 2017-2030 is proportional to the 2015 growth rate. For population densities, the same values as for 2015 were used, again obtained from Eurostat (*demo_r_d3dens* – population density by NUTS 3 region).

Number of households per region was estimated based on 2030 population per region, as described above, and average household size per country, obtained from Eurostat (*ilc_lvph01* – average household size - EU-SILC survey)

Other statistical information, such as gross domestic product per capita and characteristics of economic activity (for example types of industries) were also considered, but were eventually not used.

2.3.2 From region to transmission grid nodes

For some resources such as large power plants, there is enough information link the devices directly to a transmission grid node. In other cases, this is not possible, but latitude/longitude information may be used to find the nearest transmission grid node. This is the case e.g. for Pv capacity specified per municipality or postcode. In many other cases, however, no geographical information is available and other information is used instead. This is the case for most loads, e.g. wet appliances, electric cars, etc. The process of assigning such flexible resources to transmission grid locations is illustrated in Figure 2.2. The starting point is the overall number of devices or power rating for the entire country or region. Regional statistics such as population as explained above is then used to split this per region and per province. Finally, resources are split evenly between grid nodes (of the appropriate type) inside each province

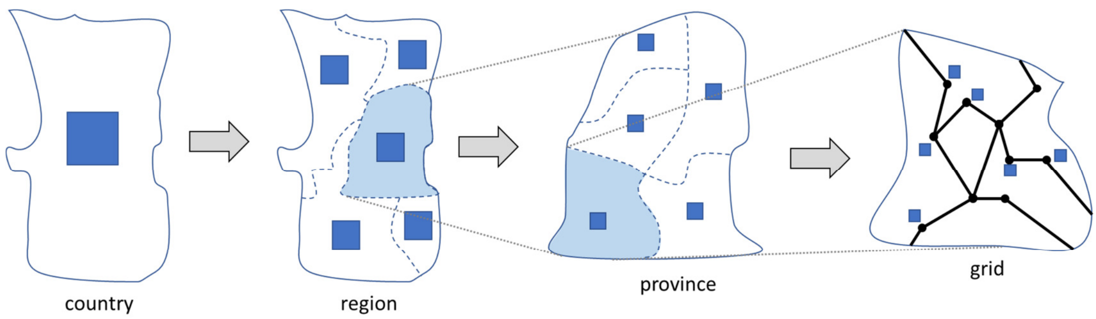


Figure 2.2: Distribution of flexible resources from national scenario to transmission grid. Blue squares represent the number or capacity of a given type of flexible resource

3 Scenario dataset generation

Once the general procedure for the creation of the scenario to be simulated has been clarified on the basis of the available information, the detailed methodologies for the creation of the actual dataset can be defined as described in the following sub-sections.

3.1 Network data

3.1.1 Transmission grid

The transmission grid contains the highest voltage levels of the electricity network. The largest generators and loads are typically connected to the transmission grid. Data for the relevant electrical properties of the transmission grid were obtained for each country as described below.

IT: Transmission grid data for Northern Italy was deduced from the network information available in [7]. The transmission grid data includes information about generators (location, power capacity, and type), and information about which nodes are primary substations for distribution grids. The data includes 3648 nodes and 638 primary substations and it is limited to the Northern part of Italy (North and North-Centre market areas), having maintained the connections with the remaining part of Italy and neighbouring countries.

DK: The Danish TSO Energinet maintains a public dataset [8] for the transmission grid. This data was provided by Energinet (project partner) and used for the simulations. The information was provided in an Excel spreadsheet containing static data for the western and eastern Danish transmission system on 132/150/400 kV level: bus data, line data, transformer data, generation data, load data. Only Western Denmark was included in the simulation model, but with connections to Eastern Denmark as well as neighbouring countries maintained.

ES: A transmission grid model for all of Spain was deduced by publicly available maps of the Spanish transmission system, also used in order to reconstruct the geographical position of the network buses.

3.1.2 Distribution grid

Detailed and useable distribution grid data was not so easy to obtain within the SmartNet project. For Denmark, this was partly possible, but for Italy and Spain it was decided to use reference distribution network models developed within the ATLANTIDE project [9].

IT: For Italy, distribution grid models were provided by EDYNA (project partner – Italian DSO). However, the collected networks refer to a specific area of Italy (South Tyrol) characterized by a mountainous terrain. These networks can be assumed to be typical of the alpine regions, but their characteristics do not match the ones operating on plain areas. For this reason, in addition to the data provided by EDYNA, the ATLANTIDE project collects few (Italian) reference networks that can be

assumed to be the typical urban, rural and industrial distribution networks. According to this, these distribution grids have been assigned to each transmission network node (classified as primary substation), looking also at the potential typology of area (urban, rural, industrial or mountainous).

ES: Since no distribution system were available/found for Spain and, having checked that the voltage levels and gird characteristics are very similar to the Italian standard, the same reference networks adopted for Italy were used and connected to the primary substations identified on the transmission network model.

DK: SE Energi provided the distribution network model of their controlled area, which includes both HV (meshed) and MV (radial) sections, together with the geographical coordinates of the nodes. In spite the amount of information is relevant, simplifications have been added in order to create scenarios that can be easily simulated. In particular:

- The HV portion of the grid has been removed from the model (this corresponds to the assumption that this part of the network is not subjected to congestions). The reasons for this simplification are mainly represented by the fact that the SmartNet simulator has not been designed in order to manage meshed distribution grids, condition for which also some TSO-DSO coordination schemes cannot be easily implemented.
- The MV radial networks have been assumed to be connected to the closest transmission grid node (the ones classified as primary substation) and distribution power units connected directly to their buses.

Once the distribution network models were defined and linked to the transmission one, the resources needed to be located on them. Since most of the power units to be simulated are part of a future scenario, their position over the distribution network is unknown. In addition, since the assumed networks are not the actual ones, it is not possible to establish *a priori* to which node the hypothesized resources are connected. For this reason, the position of the simulated units has been defined according to the following procedure (Figure 3.1):

1. All the non-controllable resources assigned to a specific network are randomly located in different positions of the distribution grid.
2. A simulation of the network (to which only the non-controllable resources are connected) is carried out. Since the simulated units cannot be controller, the resulting network situation has to be not affected by congestions. In case it is, a new random position of non-controllable resources is defined. Depending on the severity of experienced congestions, power units can be distributed on more distribution networks/feeders.
3. As soon as a feasible network situation is found, controllable units are connected to the resulting distribution grid (still using a random allocation procedure).

4. In this case, distribution network congestions are acceptable since system operators can activate power flexibility to solve them. However, some limitations to the severity of congestions have been assumed (i.e. maximum +50% of loading/voltage above the limits and for few hours per day) in order to maintain a realistic scenario.

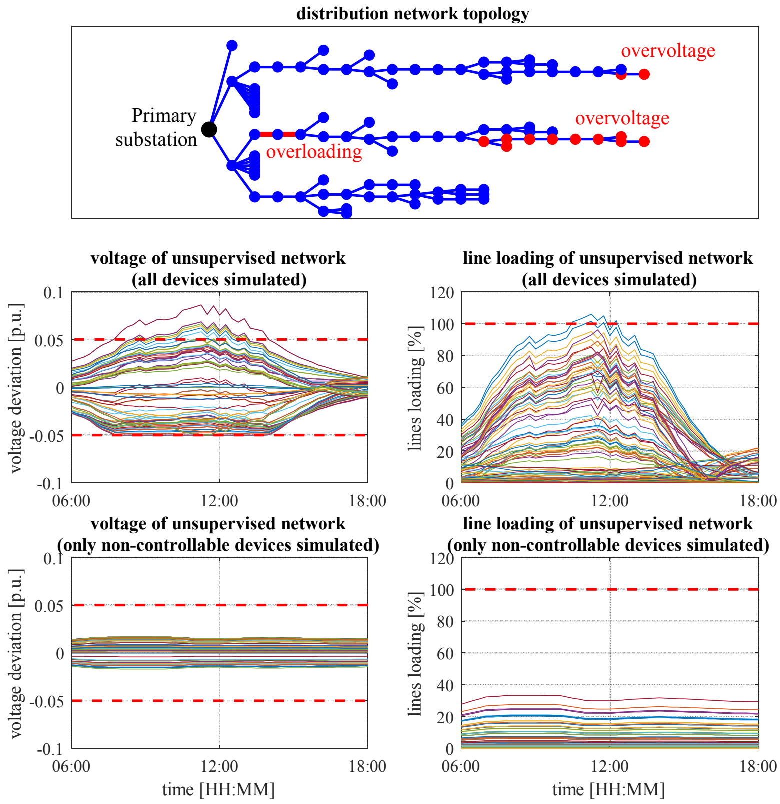


Figure 3.1: Profiles of voltage and loading for an illustrative distribution grid. Results of both the case with only non-controllable devices and the case in which all the resources are included are presented.

Thanks to this procedure, distribution network scenarios can be easily obtained. In areas where several controllable resources are connected, congestions will be likely occurring and being solved thanks to the exploitation of the available flexibility. On the contrary, situations in which fixed load/generation is prevailing, the distribution network can be still safely operated.

3.2 Device data

Fundamental data to be generated/collected for the definition of the scenario are the ones related to the flexible devices. The following sub-sections report, for each technology, the main adopted assumptions for the definition of the scenario dataset. For generators connected at transmission level, this data is often found with the transmission grid model (described above). In all scenarios, generator capacities are scaled to match the 2030 projection for the country/region, see Table 2.

3.2.1 Conventional generators (Con)

Conventional generators are devices where the output is readily controllable and the source energy (fuel) is storable. This includes conventional fossil fuel power plants, biofuel plants, hydroelectric power plants with water reservoirs. However, run-of-river hydropower is treated differently (as there is no storable fuel), and pumped hydro plants are treated as storage devices.

IT: Data including both transmission level and distribution level (conventional) have been extracted from both public and private databases. Transmission level generators were taken from generator information bundled together with the transmission grid data, matching also the data reported in [10][11], whereas distribution grid generators were extracted from lists of generators per type obtained from public datasets [12]. Distribution grid generators were linked to distribution grid nodes (or primary station in the transmission grid) by selecting the nearest node according to latitude/longitude information. Non-conventional generators, i.e. CHP and pumped hydro units were extracted from this list and included together with CHP and storage devices respectively.

DK: Generators were provided with the grid model, and for conventional generators this list was considered complete.

ES: Lists of generators connected to the transmission grid and distribution grid were extracted from [13][14]. Large generators were already associated with a transmission grid node, whereas distribution grid generators were placed using latitude/longitude information. Capacities were scaled to get the correct total according to the 2030 scenario for Spain.

3.2.2 Wind power generators (Wind)

Wind power generators are different from conventional generators in this context mainly because the source energy is not storable. Availability of energy is determined by the weather, and wind not captured is lost energy. This also means there is a variable maximum power output.

IT: Wind turbine / wind farm data from the database [15] has been used as a starting point. It was assumed that new wind power capacity will be concentrated in the south of Italy (which is not included in the simulation dataset), so no capacity increase was considered. Grid connection point of wind turbines were determined from latitude/longitude assuming shortest distance. Generators larger than 10 MW

were assumed connected to the transmission grid whilst smaller generators were assumed connected to the distribution grid. Wind power profiles were determined based on historical data [10] and weather measurements, and forecasts were generated by adding random errors (in line to the statistics reported in section 3.3).

DK: A list of existing Wind turbine installations in all of Denmark was provided by Energinet and used as a starting point. The capacities of the currently operating 6131 Wind devices was scaled up to give the correct total capacity for Denmark expected for 2030, and then devices were linked to grid nodes using latitude/longitude information. Finally, only devices in western Demark were kept. Wind power profiles were obtained from [16], and forecasts were generated by adding random errors according to the data reported in section 3.3.

ES: Wind generators were determined using the same input data as described for conventional generators (see above). As for DK, wind power profiles were obtained from [17], and forecasts were generated by adding random errors (in line to the statistics reported in section 3.3). Different profiles were used for different regions of Spain on the basis of historical profiles of existing wind power plants and collected weather measurements.

3.2.3 Photovoltaic generation (Pv)

Photovoltaic power systems are very similar to Wind when it comes to data requirements and model representation in the SmartNet simulator.

IT: A list of Pv devices as of 2016 was used as a starting point [12]. To get the overall correct capacity for the 2030 scenario, this list was first duplicated and then scaled up, with the assumption that present distribution of Pv units is a good indication of future additions. Pv power profiles were determined in the same way as Wind profiles as described above.

DK: A list of existing Pv installations in all of Denmark was provided by Energinet and used as a starting point. The capacities of these 95504 Pv devices was scaled up to give the expected 2030 total capacity for Denmark, and then devices were linked to grid nodes using latitude/longitude information. Finally, only devices in western Demark were kept. PV power profiles were obtained from [17].

ES: PV data was generated in the same way as Wind data (see above).

Also for this technology (being one of the most relevant source of imbalance – see section 4), forecasting error is added according to the statistics reported in section 3.3.

3.2.4 Hydro power run-of-the-river generation (Hyd)

Run-of-river hydro generators differ from conventional hydropower generators since they have no storage, and available power is determined solely by water flow in the river, which in turn depends on rainfall/snow melting in the catchment area of the river.

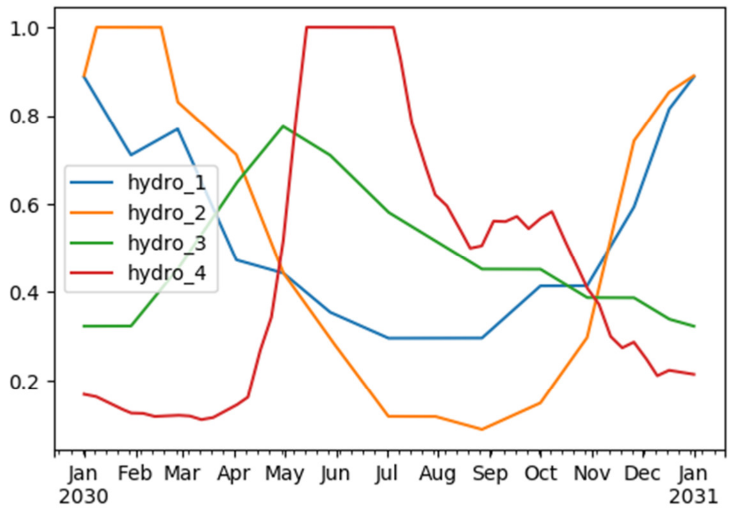


Figure 3.2: Normalised water inflow profiles from the TradeWind project

IT: The starting point for run-of-the-river hydro in Italy was a list of distribution grid hydro generators (in the same format as Con and Pv generators) [12]. Power profiles were obtained by using measurements form actual power plants located in the South Tyrol area..

DK: No run-of-river hydropower was included in the Danish dataset.

ES: The list of run-of-the-river hydro generators was obtained in the same way as other generators (from [13][14]). Reasonable seasonal variation in water inflow was based on profiles used by the TradeWind project [15] (see Figure 3.2). Power profiles were generated from the normalised profile "hydro_2" assuming that run-of-the-river generators have a capacity factor of 0.5, i.e. on average, generators produce at 50% of full capacity.

3.2.5 Combined heat and power generation (Chp)

In all cases, the heat demand profiles and power profile for CHP devices were taken as identical, with the assumption that all power demand is driven by the heat demand. Thermal parameters for CHP devices were derived in accordance with this assumption. It has also been assumed that the thermal storage of CHP units corresponds to 5 hours of maximum output.

IT: CHP generators were extracted from the list of generators (see Con) both for transmission level and distribution level devices. Four different power profiles were obtained from electricity market transparency data [10], and each CHP device was associated with one of these profiles randomly.

DK: Three large existing transmission-level CHPs were included in the dataset for western Denmark. The large number of smaller CHP units in the distribution today were assumed to have been replaced by

heat pumps by 2030 and are therefore represented as Tcl devices instead. CHP power (and heat demand) profiles for each of the CPH units were extracted from historical data from [10].

ES: CHP devices were extracted from the same source data as other generators. Thermal energy storage was assumed to be 5 hours at full load in all cases. Power and heat demand profiles were generated from data extracted from [10].

3.2.6 Storage devices (Sto)

Storage devices that are considered are pumped hydro power storage (PHS) plants and electrical vehicles (EV). Projections for stationary batteries in the 2030 are very small and is only included for Denmark.

Pumped hydro and batteries: Information about pumped hydro storage and electro-chemical batteries has been taken from the US Department of Energy (DOE) database of worldwide energy storage [18]. For Italy, this information is in quite good agreement with information from the transmission grid map (which also has pumped hydro power plants identified). All baseline profiles for pumped hydro have been assumed to be zero, i.e. idle operation, with storage filling level of 60%.

Electric vehicles: Three classes of EVs have been considered, with different typical parameters and driving patterns: Family cars, commuter cars, and taxis. For each EV class, 10 different profiles for availability (i.e. when it is connected to the charger) and driving pattern were generated, such as to get some variation in when EVs are connected to the grid, without needing a separate profile for each single EV, see Figure 3.3. It is assumed that as a baseline (before SmartNet market changes) EVs are charged with constant power over the whole period when they are connected.

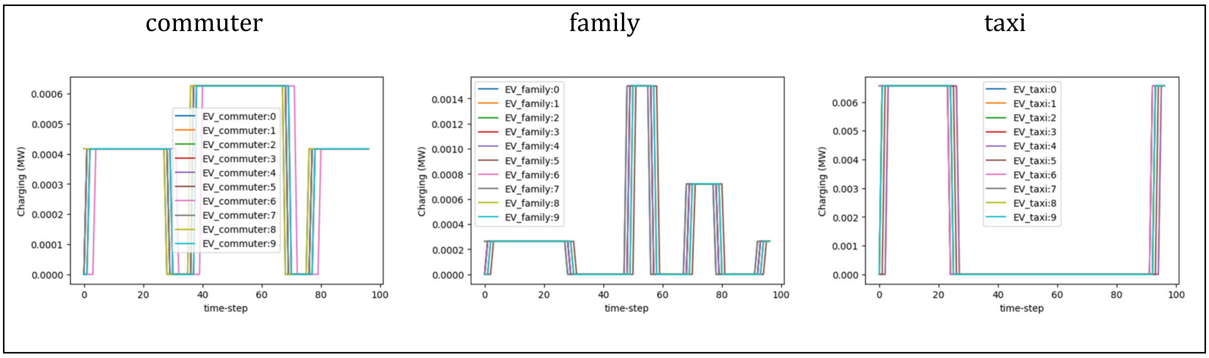


Figure 3.3: Charging profiles for EVs (one day, 15 min time-steps)

IT: 2030 projections for the number of EVs in Italy per region have been provided by RSE. This has been used together with population and population density per province ([6] NUTS3 level) to estimate the distribution of EVs. The number essentially scales with the population, but with an urban bias, such that there are relatively more EVs in places with high population density. PHS plants were associated to the nearest transmission node marked as hydro power plant.

DK: Energinet's 2030 projections were used as a starting point for generating the list of EVs. The total number of EVs were distributed in districts in the same way as for IT, using population and population density data. One PHS plant and two small battery storages are included in the dataset based on information from the DOE database [18]. No capacity scaling was performed, and they were assumed connected to the nearest transmission grid node and, eventually, redistributed over the correspondent distribution network.

ES: The total number of EVs in Spain in 2030 was assumed to be 200,000. This equals the 2020 target according to the 2016 IEA Global EV outlook [20], and as a low estimate for 2030. Type and geographical distribution were determined in the same way as for IT and DK, using population data. PHS and batteries data was generated as for DK. In total 41 PHS/battery devices have been assumed.

3.2.7 Sheddable load (Sel)

Street-lights are the only sheddable (curtailable) loads included in the datasets. It is assumed that each light is 50 W and that there are 100 lights per controllable device, such that each device in the SmartNet simulator has total load of 5 kW. It is further assumed that there is one streetlight per 10 persons. The total number of controllable devices therefore scales with the population and this has been assumed equally for all scenario datasets. All street-lights are on between 7 pm and 7 am.

3.2.8 Thermostatically controlled loads (Tcl)

The overall TCL device energy consumption has been taken from [4], also repeated in Table 3 except for DK, where detailed 2030 projections by Energinet have been used.

The number of controllable devices has been estimated as the total electrical consumption for controllable TCLs divided by the consumption per unit, assuming heat pump efficiency (COP) of 3.0. The geographical distribution of TCL devices has been determined based on population distribution per province. Within each province, devices have been assigned to the closest transmission grid node and then to the correspondent distribution network.

Some parameters individual heat pumps are generated using random sampling within a range of typical values, whilst others are the same for all devices. For example, it is assumed that user comfort temperature for all devices is set to 22°C with a max-min range 18-24°C.

IT: For Italy, the annual consumption has been estimated as 652 MW × 8760h = 5,711 GWh, and it has been assumed that 52% of TCL demand is controllable, and that 20% is due to space heating. The consumption per TCL unit has been estimated assuming it covers a dwelling's heating requirement. Heating requirement per dwelling has in turn been estimated as average values for *heating degree days (HDD)* × *heat loss*. Heating degree days depends on the climate and desired indoor temperature. Heat loss depends on the ventilation and insulation of the dwelling. A typical heat loss value of 332 W/K has been

assumed, and HDD = 1,829 K*24h, which is the average for Italy (according to [6]). This gives heat demand 14.6 GWh/year (heat).

DK: TCL devices are split between small domestic heat pumps, district heating heat pumps, and swimming pools. Total consumption projections have been taken from Energinet rather than the numbers in Table 3. For small-scale TCLs this is 1,385 MWh/year for district heating and 818 MWh/year for all of Denmark. For small-scale TCLs it has been assumed that all devices are domestic space heating devices., and that 52% are controllable. Heating demand per dwelling has been assumed as 15.677 MWh/year (heat), translating to an electricity demand of 5.22 MWh/year (electric). The number of district heating units have been estimated based on the assumption that there are 1,000 dwellings per district heating heat pump.

ES: Same procedure as for IT, except annual consumption of 6,763 GWh, and heating per dwelling 5.22 MWh/year (electric).

3.2.9 Wet appliances (Wet)

Wet appliances are atomic loads whose load profile is fixed once started, but with flexibility regarding *when* the load can start. In the dataset, only domestic wet appliances are included, i.e. dishwashers, washing machines and tumble dryers.

The number of controllable wet appliances per type (dishwasher, washing machine, tumble dryer) is determined per region from household numbers, ownership levels, and the fraction of devices that are flexible. Household numbers per province is estimated from Eurostat population projections [6] and average household size. 2030 ownership levels are assumed to be independent of country. Numbers are based on 2007/2008 information from the REMODECE project [20]. Flexibility fraction has been estimated based on the overall scenario assumptions for the different countries: For DK, 25% of devices are flexible whereas for IT and ES, 5% of devices are flexible and can participate in the SmartNet market (see Table 4). Probability distribution for when devices are booted by the users are taken from the Smart-A project [21] (see Figure 3.4). It is assumed that each device is booted once per day, so the probability density sums to 1 for a 24-hour period. Power profiles once started are based on measured data from [22] (see Figure 3.5). For each device, the booting time is determined from the boot time probability distribution.

Table 4: Wet devices ownership levels and fraction of devices which are flexible

	IT	DK	ES
Ownership dishwasher	0.94	0.94	0.94
Ownership washing machine	0.61	0.61	0.61
Ownership tumble dryer*	0.56	0.56	0.56
Flexible fraction	0.05	0.25	0.05

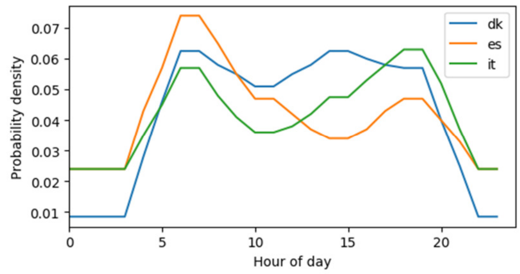


Figure 3.4: Probability distribution for wet appliance booting.

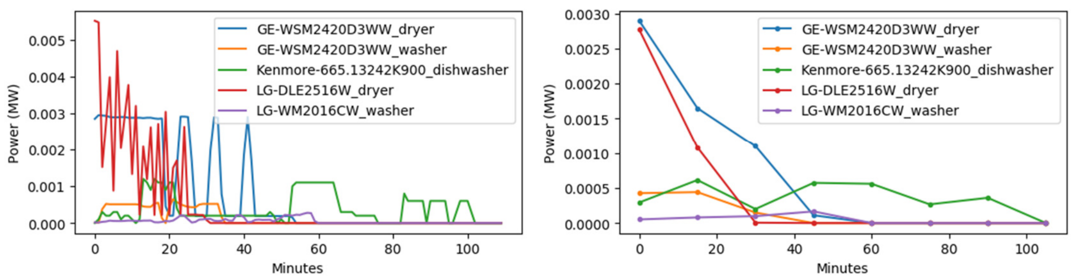


Figure 3.5: Wet appliance power profile with 1 min time-steps (left) and re-sampled to 15 min time-step (right).

3.3 Uncertainty in forecasting

This section reviews on the main forecasting techniques, comparing their accuracy but with a special focus on the SmartNet interest. The effectiveness of a forecasting technique is usually measured and compared by the evaluation of the Mean Absolute Error (MAE), the Mean Square Error (MSE), the Root Mean Square error (RMSE) or of the Mean Absolute Percentage Error (MAPE). These indexes will be then used along this document in order to quantify the differences between the forecasted load/generation and the real load/generation values and thus, the performance of the algorithms. It has to be noticed that the performance of a certain forecasting method is dependent on the error type. That means that some methods can be good in the prediction of some variables, but bad for others.

3.3.1 Load forecasting

Load forecasting is the estimation of the future value of the load, which has a great impact in the energy management system and in a better planning of the power system operation. The accuracy of load forecast is basic for the market clearing process in order to get the minimum price when purchasing energy. The load forecasting algorithms can be clustered into several categories, considering the time ahead where they are valid to predict the load. The more commonly agreed time horizons are:

- Long-term load forecast (LTLF), 1 year to 10 year ahead
- Medium-term load forecast (MTLF), 1 month to 1 year ahead
- Short-term load forecast (STLF), 1h to 1 day or one week ahead
- Very short-term forecast (VSTLF), 15 min to 1h ahead.

In a deregulated market, utilities tend to maintain their generation reserve as close as possible to the minimum required by the system operator in order to save operational costs for the system. This forces the need to have accurate load forecasts in very short periods ahead of the dispatching (in very short-term prediction horizons). This is the focus in the case of SmartNet, where the market is cleared every 15 minutes for the next hour. This implies the forecast is updated and corrected with a sampling period of 15 minutes. Very short-term load forecasting requires a different solution if compared with the approaches considered for longer horizons. Instead of modelling relationships between load, time, weather conditions and other load affecting factors the VSTLF methods are rather focused on extrapolating the recently observed load pattern to the nearest future [23]. Regardless the importance of the very short-term predictions, the applicable methods are still limited and they can be clustered into three main groups:

- Parametric or statistical methods
- Non-parametric methods
- Artificial intelligent-based techniques

Parametric or statistical methods include time series models or exponential smoothing (among others). Non-parametric methods root on the historical data available. Artificial intelligence techniques include a wide variety of techniques such as neural networks, fuzzy logic methods, adaptive neuro-fuzzy inference system methods, Kalman filtering or support vector regression. Usually, weather conditions in very short-term load forecasting are ignored because of the large time constant of load as a function of weather. Most of the load forecasting methods currently employed in the very short-time are based on statistics because the effectiveness of artificial intelligent methods in such as the very short term is still unclear. In [24] the implementation of an adaptive exponential smoothing method with a MAPE of 0.6% is shown.

In [23] one application of the neural networks techniques to the VSLF is detailed. The method shifts the neural networks' task from forecasting actual loads to only forecast the relative increments, leading to a better accuracy of the method, which has a MAPE between 0.4% and 1.1%.

In [25] an application of different very short-term (statistical) forecast techniques is tested with data from the British system, where the measurements for every minute are available. All of them are based on statistical methods. The methods are applied and compared on an increasing complexity basis. The comparison of the MAPE errors for the different methods (considered by [25]) for different time horizons is shown in Figure 3.6.

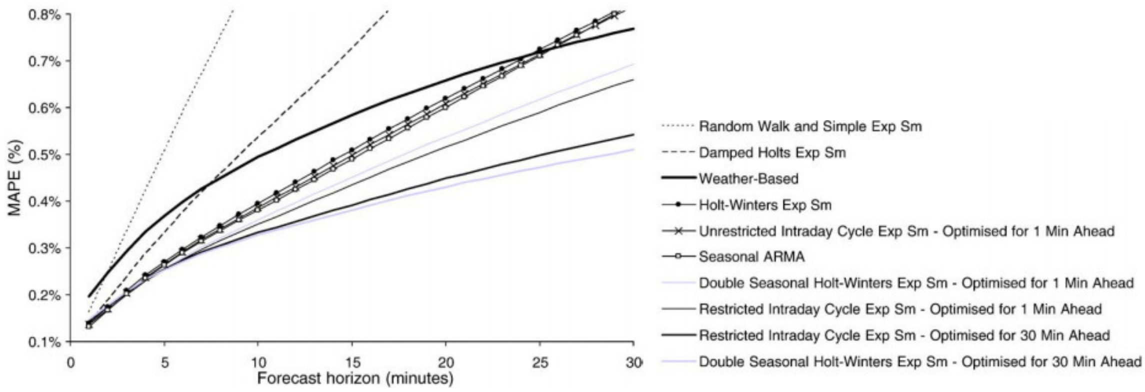


Figure 3.6: Comparison of MAPE for different methods according to the forecast horizon.

3.3.2 Generation forecasting

Due to the massive implementation of renewable power into the power systems, the generation forecasting advances have been traditionally linked to the better estimation of the power produced and it is possible to find multiple research work done on this topic, especially for Wind. Solar forecasting is still quite new and not so widely used. However, the methodologies for Pv estimation are evolving very fast.

The consideration of different time frames where the methods are able to predict the generation forecast is also applicable to the generation forecasting even the timeframes, according to the literature references, differ over the ones for load forecasting [26]. In generation forecasting, these time frames are shorter with exception of the very short-term that covers the same period ahead.

- Very short-term generation forecast (VSTGF) – Intra-hour: 5-60 min ahead
- Short-term generation forecast (STGF) – 1h-6h ahead
- Medium-term generation forecast (MTGF) – Days ahead
- Long-term generation forecast (LTGF) – Weeks, 1 year or more ahead

The long term planning is basic for the resource planning or the contingency analysis, the medium-term forecasts are mainly applied for the definition of the reserves' requirements or the market trading while the short-term is required for scheduling, load-following or congestion management. Again the focus of SmartNet is on the very-short term, where the forecast is essential for the market clearing and the real-time dispatch.

The methods to be used according to the window timeframe are also different. Three groups of methods can be highlighted [27]:

- Physical models: they consist of a combination of several sub-models (with all the physical correlations modelled) that directly translate the forecast estimation done by the Numerical Weather Prediction methods into power at the wind turbine hub.
- Statistical models: they emulate the relationship between the weather predictions, the historical measurements and the generation data using statistical models whose parameters are calculated from the data but not considering the physical links between the variables.
- Hybrid: they combine both physical and statistical models.

The project Anemos Plus [28] worked about the wind power forecast methodologies, evaluating the impact of their uncertainty in power system key management functions. Figure 3.7 shows an exemplary comparison of several methods (in terms of their RSME) for a 5,175 kW wind farm, as a function of the forecast length (in hours). The Persistence method is the simplest one and, due to this, is usually used as basis to compare the new algorithms developed. In the persistence model, the forecast for all times ahead is set to the value it has now. NewRef is a method that is based on a combination of the persistence model with an added trend towards the mean of the time series. The HWP is the known Prediktor coupled with a Model Output Statistic (MOS) model [29].

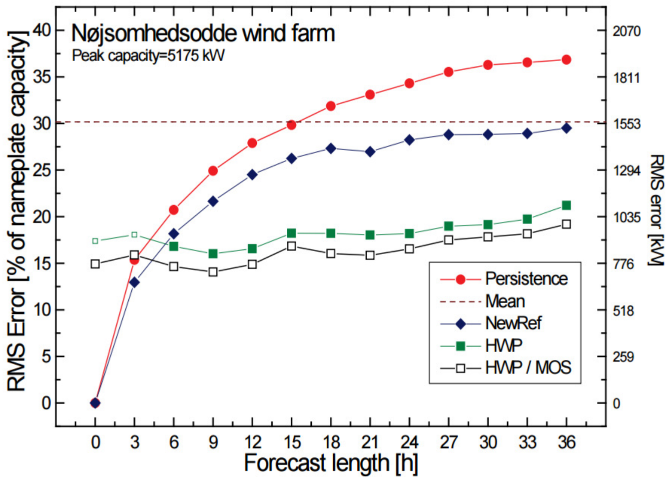


Figure 3.7: RMSE for different forecast length and different prediction methods.

It is clear that as closer is the prediction to the real time operation, the better is the accuracy. For example, SIPREÓLICO [30], the forecasting tool employed by the Spanish TSO, which is able to predict the wind power for the next 48 hour (with resolution of 1 hour) by combining different methods running in parallel is able to reach an accuracy of less than 5% (MAPE). The decrease of the error of SIPREÓLICO due to the prediction horizon is shown in Figure 3.8.

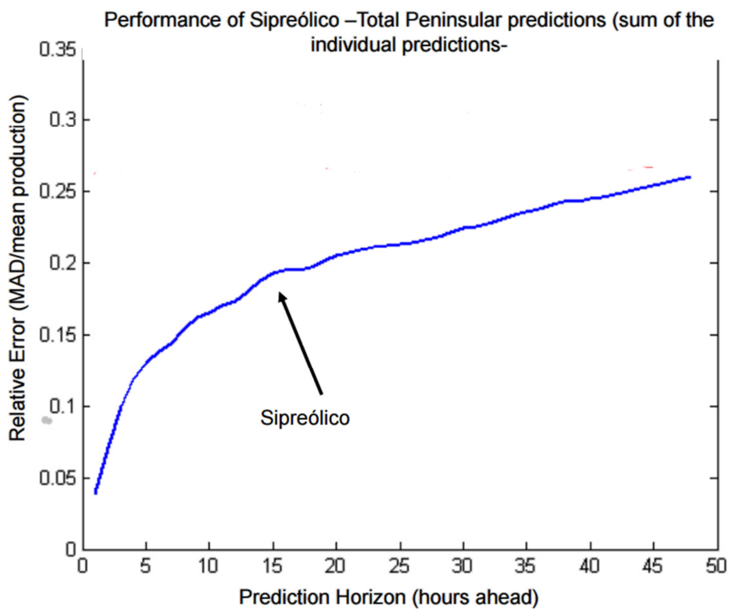


Figure 3.8: Relative error of SIPREÓLICO as a function of the prediction horizon.

In [31] a very short-term algorithm based on recurrent neural networks for predicting the PV production is presented. The method uses real measurements of power production, solar radiation,

temperature, humidity, atmospheric pressure, wind speed and direction. It also uses the hourly weather forecast data provided by NWP models and, as an output, the method is able to calculate the Pv production and the temperature of the panel. The comparison for the application of the method in a single step (SS) or with a multi-step (MS) approach (direct prediction – DR or iterative prediction – IT) as a function of its Mean Square Error (MSE) is shown in Figure 3.9. The MSE gives to errors over 15% in the worst cases simulated. However, it should be noticed that the "very short-term" timeframe considered here is much longer than the one considered along this document (2÷8 hours versus less than 1 hour), so much better accuracy for the 1 hour ahead horizon can be expected from the application of this algorithm.

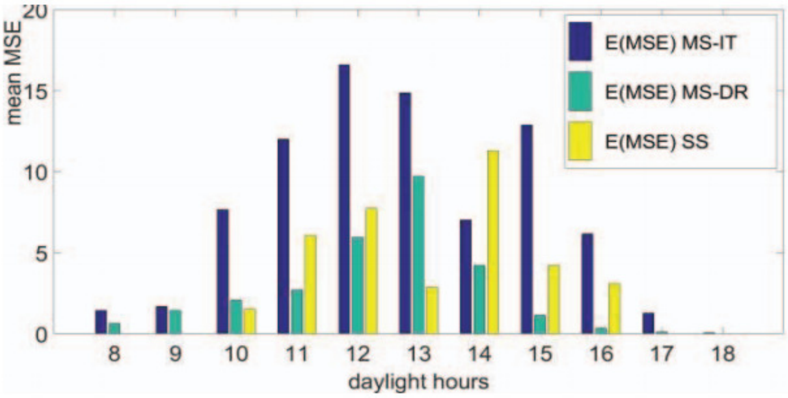


Figure 3.9: Comparison of MSE for SS and MS methods.

3.4 Previous market data

3.4.1 Previous market clearing

The SmartNet simulator only simulates the real-time market for the activation of balancing and congestion-management services, and needs the results from previous market trading as input data. Since the simulation scenarios represent future 2030 situations with different mix of generators, historical market results cannot readily be used. Instead, to obtain previous market results that are in line with generator costs, power demand profiles and profiles for wind and solar radiation as used in the SmartNet market simulation, this input data has been generated by running a linearized Optimal Power Flow (OPF) calculation for each timestep. This has been done using the PowerGAMA tool [32]. Day-ahead forecasts for power demand, wind and solar production have been used (see section 3.3). At this stage, flexible loads (Sto, Wet, Sel, Tcl) are assumed to follow a baseline profile that is computed from available information and added to the non-flexible net load per node. Power losses are included, but only as added load. CHP fuel cost is temporarily set very low to ensure that CHP production follows heat demand.

The output from the OPF is generators output and nodal prices for each time-step. Nodal prices are subsequently averaged (with weights equal to the demand in the node) to give a common price for the entire country. The result from PowerGAMA simulations provides scheduled output for generators (but not for loads). Marginal costs for generators are given by the type, and includes non-fuel costs, fuel costs and CO2 costs. These costs are provided using figures from the 2030 scenario hypothesized by the OffshoreGrid project [33]. Having assumed that CO_2 price is 44.39 €/tonne, and considered that both fuel costs and CO_2 costs depend on the fuel efficiency of the generator type (the marginal cost breakdown is shown in Table 6) the resulting key outputs are shown in Figure 3.10.

Table 5 Breakdown of generator marginal costs per type

Type	Non-fuel cost [€/MWh]	Fuel price [€/Mwh^{fuel}]	Fuel efficiency	CO2 content [ton/MWh^{fuel}]	CO2 cost [€/MWh]	Marginal cost [€/MWh]
Hydro	3	0	1	0.00	0.00	3.00
Wind	0.5	0	1	0.00	0.00	0.50
Other renewable	3	16	0.34	0.00	0.00	50.06
Nuclear	6	5	1	0.00	0.00	11.00
Lignite coal	2	4.2	0.41	0.43	46.01	58.26
Hard coal	2	10.13	0.41	0.33	35.34	62.04
Gas	1.7	24.63	0.5	0.20	18.09	69.05
Oil	5	53.79	0.42	0.28	29.52	162.59

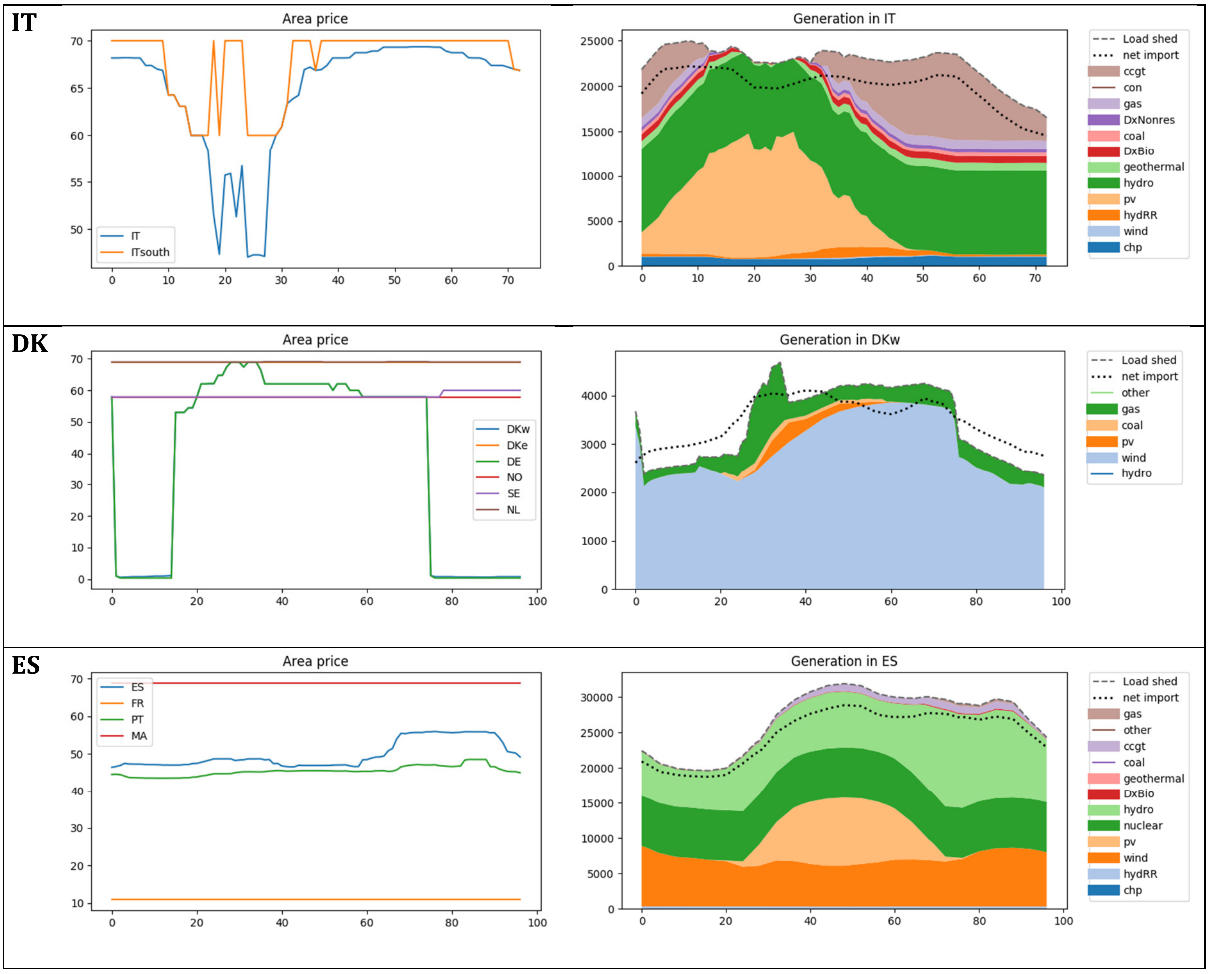


Figure 3.10: Previous market results

3.4.2 Intraday market trading

The impact that intraday markets might have on the SmartNet simulation (in particular on the bidding process) can be represented by means of an intraday trading discomfort cost parameter defined for each device, and intraday price deltas [34]. If included, intraday price deltas need to be computed offline on the basis of:

- intraday market imbalance, estimated from the difference between day-ahead and intraday forecast profiles for Wind, Pv and demand;
- day-ahead prices, computed using PowerGAMA, as described above.

However, for simplicity, and since the previous market may be interpreted as already representing the intraday market, this interaction with the intraday market has not been included in the scenario simulation datasets.

3.5 Profiles

For each of the three main simulation scenarios (IT, DK, ES) different days of the year have been selected to represent different operating conditions. What makes days different is mainly power demand and Pv and Wind power availability. Figure 3.11 shows histograms of daily average wind and solar power output over a year. Values are normalised such that 1 represents maximum output. The coloured vertical lines correspond to the selected scenario days and shows that they give a good representation of typical combinations of wind and solar power output. Normalised time-series for Pv and Wind power availability on the selected dates are shown in Figure 3.12. In general, three profiles are given for each variable:

- the previous market forecast (day-ahead/intraday);
- the updated forecast for the SmartNet market (immediately before the real-time market, i.e. 1 hour before activation of flexibility);
- actual values.

3.5.1 Non-flexible net load

IT: For Italy, day-ahead forecast and actual demand data per hour per major region (north, centre north) have been obtained from market transparency data [10]. Historical values from 2016 have been used but, since data are stored with the time resolution of 1 hour, higher resolution time-series have been made by linear interpolation. Previous market forecast profiles are computed as the weighted average of the day-ahead and actual demand profiles with 50% weight on each. Updated forecasts are the same except weights are 20% on day-ahead and 80% on actual values.

DK: For Denmark, demand profile from the ENTSO-E 2030 Vision 4 dataset is used [36]. The profile is normalised to have a mean value of 1.0. Forecast errors are added to this using 2015 data for (day-ahead) forecasted and actual demand from [37]. Relative forecast errors are then computed as the weighted average of day-ahead and actual values as for IT. These forecasts errors are finally added to the 2030 profile to give 2030 forecasts with realistic forecast errors.

ES: For Spain, demand profile from the ENTSO-E 2030 Vision 1 dataset is used [36]. In this case, forecast errors are added as random noise as with Pv and Wind. Based on historical data from ENTSO-E for 2016, standard deviation between actual and day-ahead values were estimated according to the numbers reported in section 3.3.1.

It should be noted that this approach of using the same demand profiles and forecast profiles for all loads in a large area under-estimates local forecast errors. For individual nodes, the actual forecast error is likely much larger than the average for e.g. all Northern Italy.

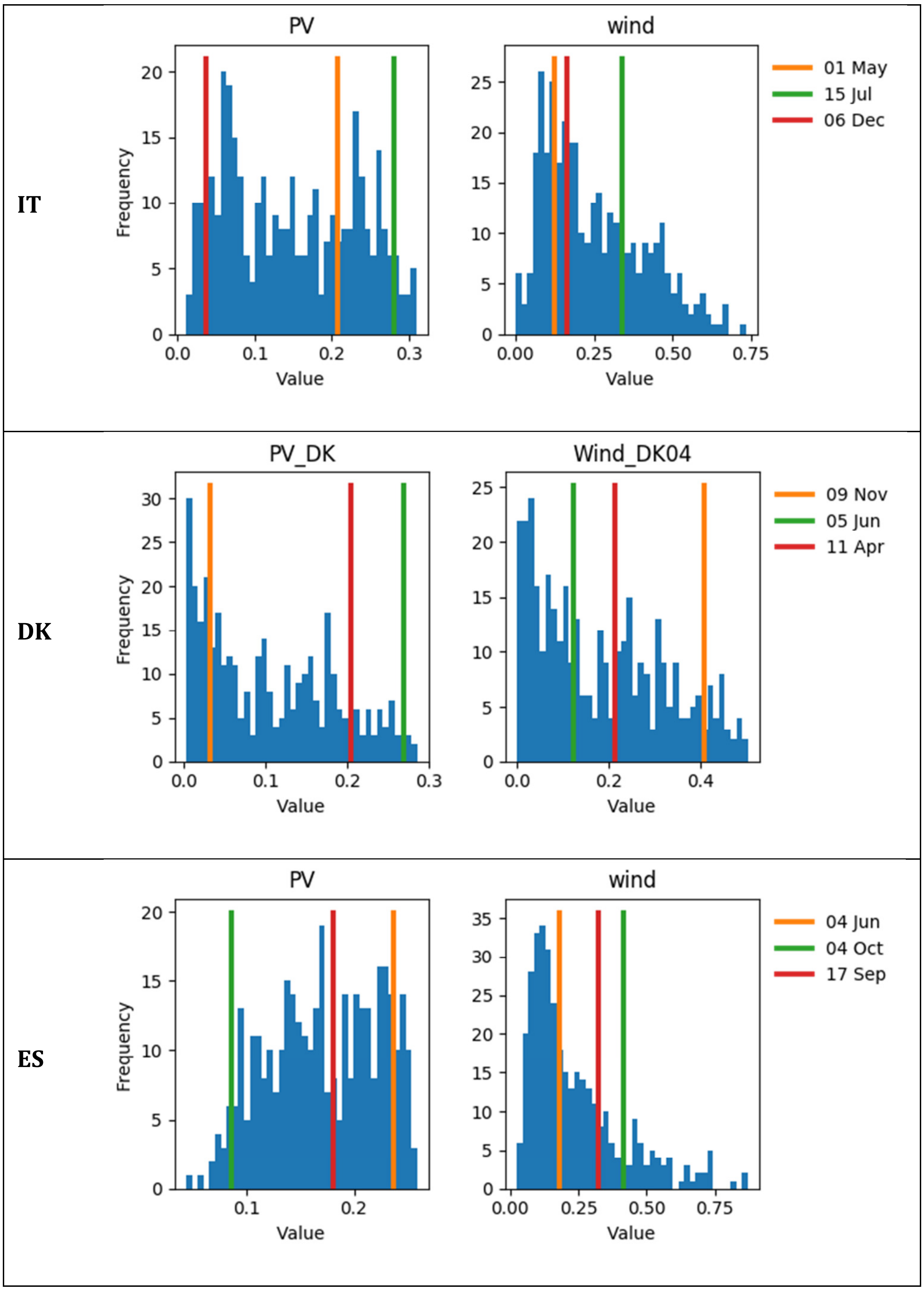


Figure 3.11 Histograms for daily average values of normalised wind and PV output. Coloured bar shows the values for the dates used for scenario datasets.

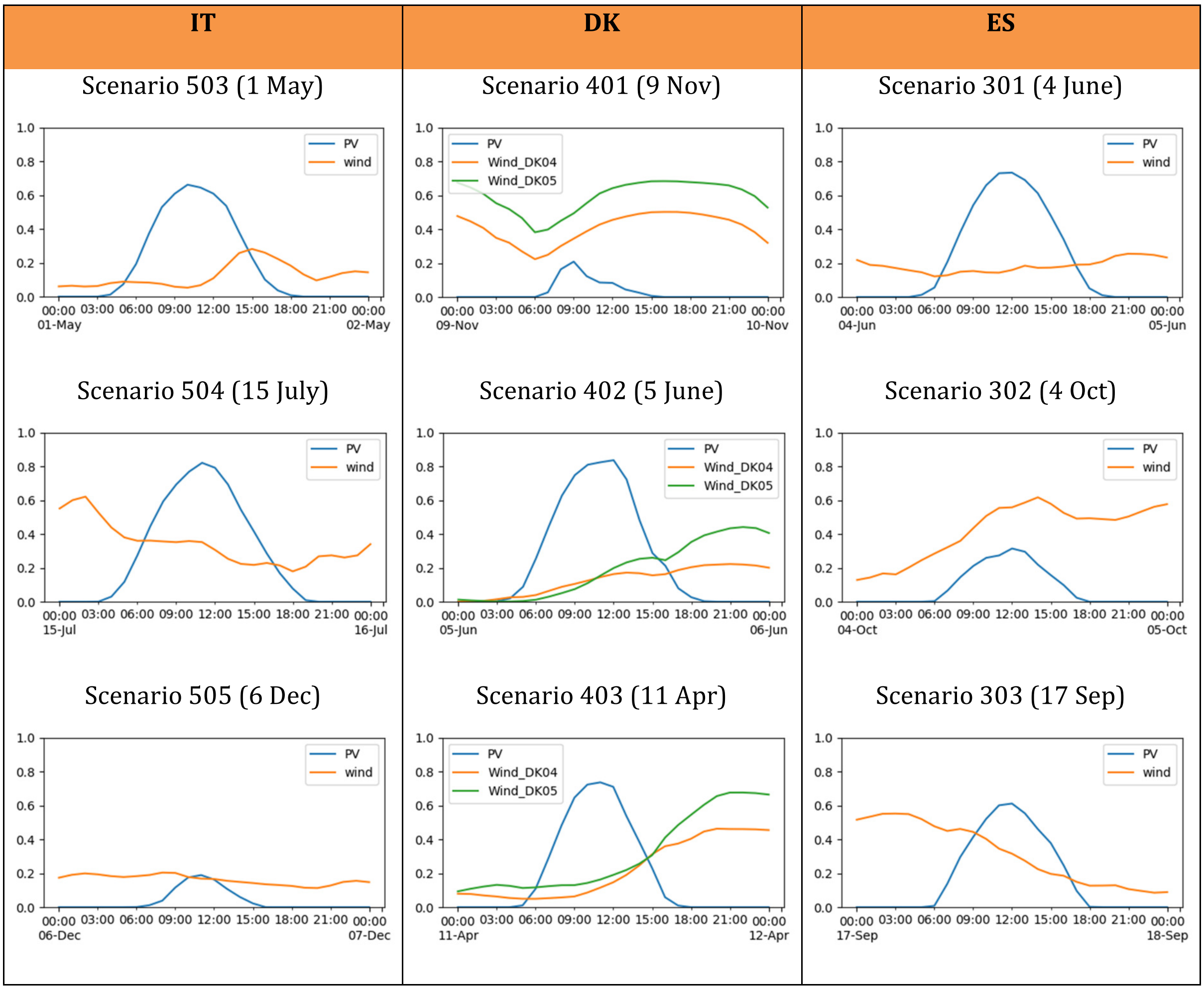


Figure 3.12 Normalised wind and pv power profiles for selected scenario dates

3.5.2 Renewable energy

The generation of renewable power profiles was already outlined in the relevant device sections 0. However, one issue is worth pointing out: What is the most reasonable way to give the updated forecast for Wind and PV production (due to the availability of wind and solar power deviating from what was assumed in the previous market)? This forecast is used to estimate the nodal imbalances in the SmartNet market. Three different options have been considered (see Figure 3.13):

1. P_forecast = P_previousmarket
2. P_forecast = P_available
3. P_forecast = min(P_previousmarket, P_available)

The chosen option is the third. If renewable power availability increases, it is assumed that renewable generators will limit their production and still generate according to previous market (production may already have been limited in the previous market). If, however, the forecasted power availability

decreases and is less than the previous market commitment, renewable power output will have to reduce as well, never exceeding available power.

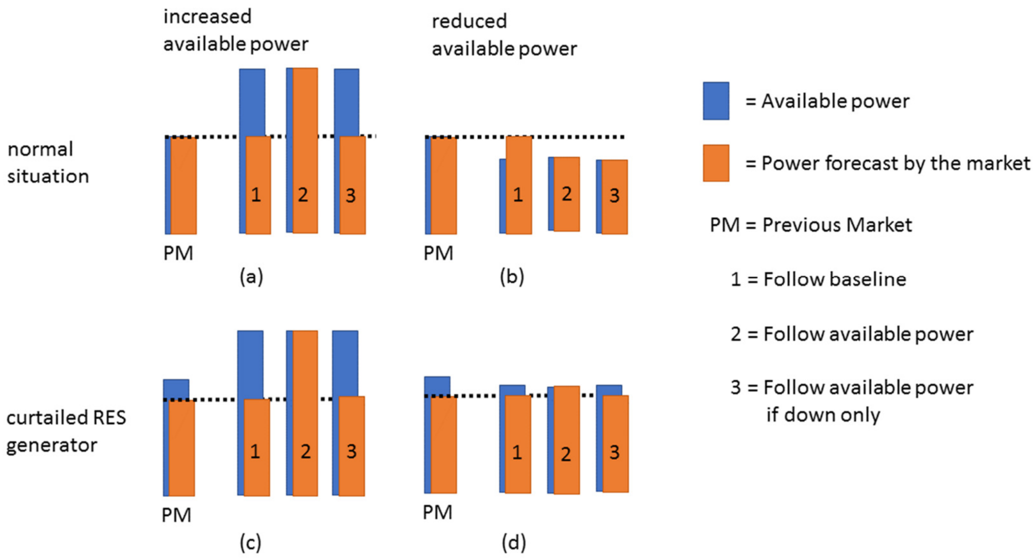


Figure 3.13 Illustration of the the impact of three alternatives (1,2,3) for forecasting Wind and Pv generation in the SmartNet market. Top: Normal situation with previous market output (baseline) equal to available power. Bottom: Curtailed situation where baseline is less than available power.

3.5.3 Imbalances

The market part of the SmartNet simulator requires as input forecasted values for the node net injection in each node. The sum of all node net injections (including power transmission losses) is zero in a balanced system, as produced in the previous market clearing (see Figure 3.14). The imbalance that occurs due to deviations from forecasts between the clearing of the previous market and the SmartNet market is what the SmartNet market must re-balance (see Figure 3.15). Real-time imbalances due to differences in the forecasts used in the SmartNet market and the actual values will be balanced by the TSO via reserve activations.

Node net injection is the sum of all power injections minus all power extraction at a given node and is computed based on forecasts for net demand and flexible devices. For most flexible loads, there are no updated forecasts since the previous market, and therefore no contribution to forecasted imbalance. The most important contributors to the imbalance are non-controllable net demand and wind and solar power.

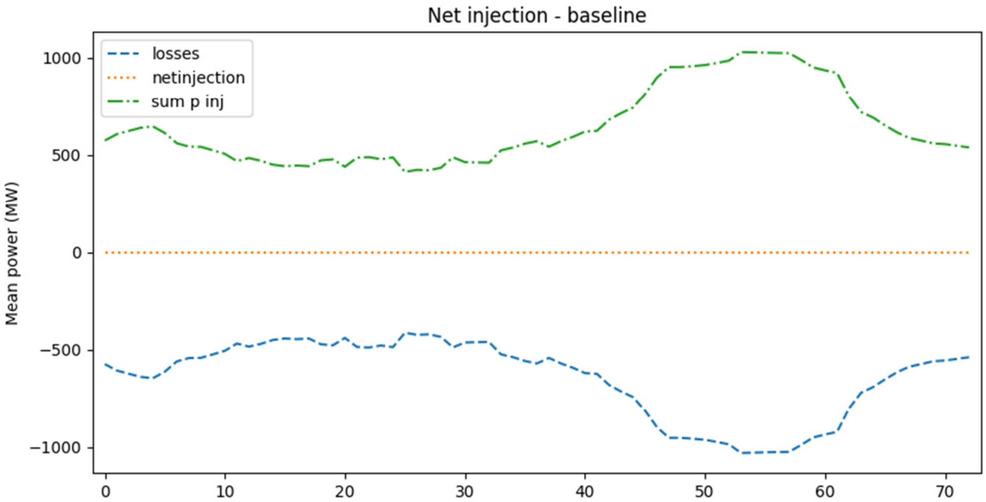


Figure 3.14 Previous-market generates a balanced system: Sum of power injections are equal to transmission losses, such that the computed node net injections sum to zero. (Italy dataset)

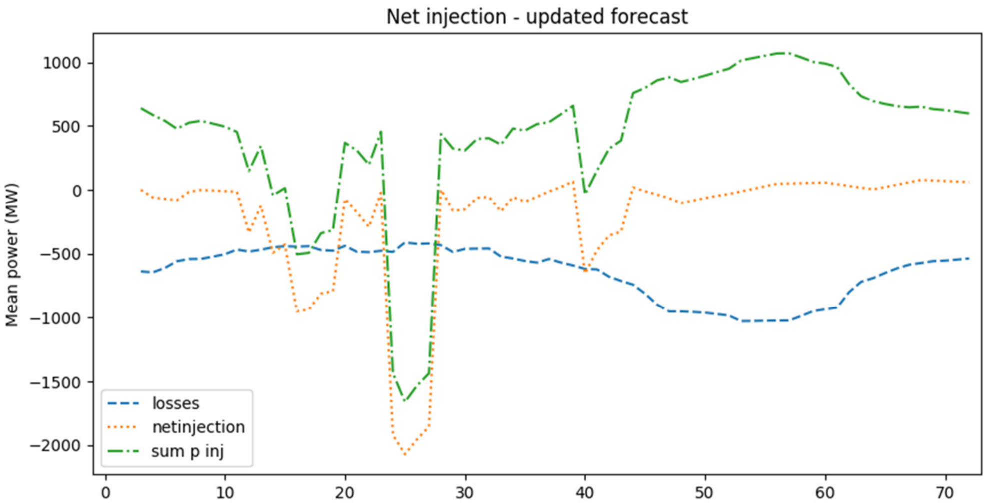


Figure 3.15 Imbalance assumed by SmartNet market: Updated forecasts give a modified view of power injections and non-zero net injections that needs to be balanced in the SmartNet market.

3.6 Final steps to minimise dataset size

To limit the number of devices in the simulation, Pv, Wind and Sto devices connected to the same node have been lumped together. This lumping has been made such that it should not make any difference for the simulation results.

4 Characteristics of scenario datasets

At this point of the process, the entire scenario is defined for the three considered countries. A summary of each final datasets generated is given in Table 6. The table shows the number of considered flexible devices as well as the number of network elements.

Table 6: Key characteristics of scenarios datasets. Numbers in brackets are numbers after similar devices on the same node have been lumped together in order to decrease scenario complexity and reduce computational burden within the simulations.

Category	IT	DK	SP	Comment
Photovoltaic	655 323 (5 746)	203 502 (2 568)	59 943 (1 951)	
Wind	31	3 472 (375)	1 053 (192)	
CHP	1 531	3	922	Large CHP
Hydro	1 833	0	555	Run-of-the-river hydro
Conventional	1 774	67	596	
Storage	212 717 (69 909)	139 355 (43 716)	200 033 (60 134)	EV and pumped hydro
Wet	1 236 325	3 206 570	1 847 500	Domestic appliances
TCL	68 481	74 688	124 539	Domestic heat pumps
Sheddable load	33 783	3 383	43 501	Street lights
Nodes (transmission)	3 648	144	1 493	Transmission network
Nodes (distribution)	2 410	3 388	2 799	Distribution network
Edges (transmission)	4 230	199	2 231	Transmission network
Edges (distribution)	2 410	3 387	2 755	Distribution network
Distribution grids	638	66	397	Primary substations

4.1 Italian scenario dataset

The Italian scenario dataset includes Northern and Central-Northern parts of Italy. Figure 4.1 shows the included transmission grid while Figure 4.2 reports the sum of power injection per type for each timestep, including both previous market baseline profiles and updated forecasts as assumed by the SmartNet market. The *netinjection* curve in red is the sum of all the power units. In the baseline, this sum is zero (as the netload includes losses). Figure 4.3 shows the difference between the updated forecast and the baseline. As is clear, the main contribution to the imbalance comes from solar power (Pv), with some contribution also from net demand, and minor ones from wind and run-of-the-river hydro.

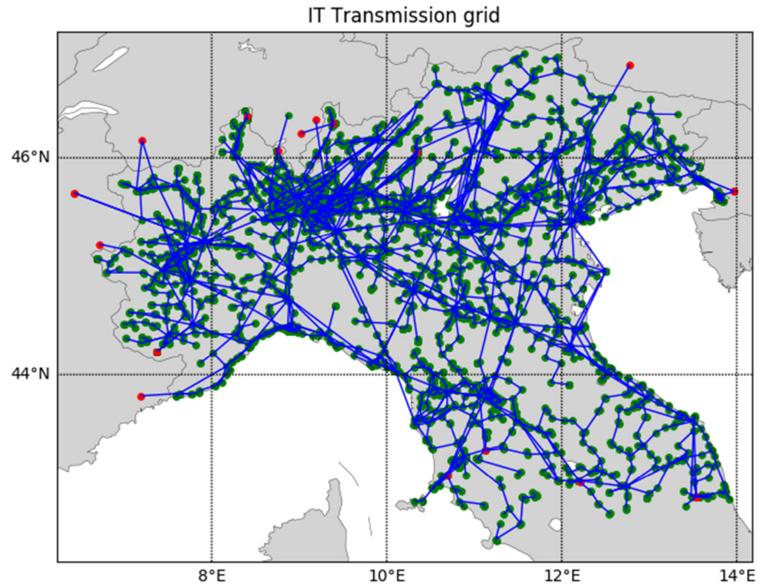


Figure 4.1: Italian transmission grid (North and North-centre). Red dots are boundary nodes.

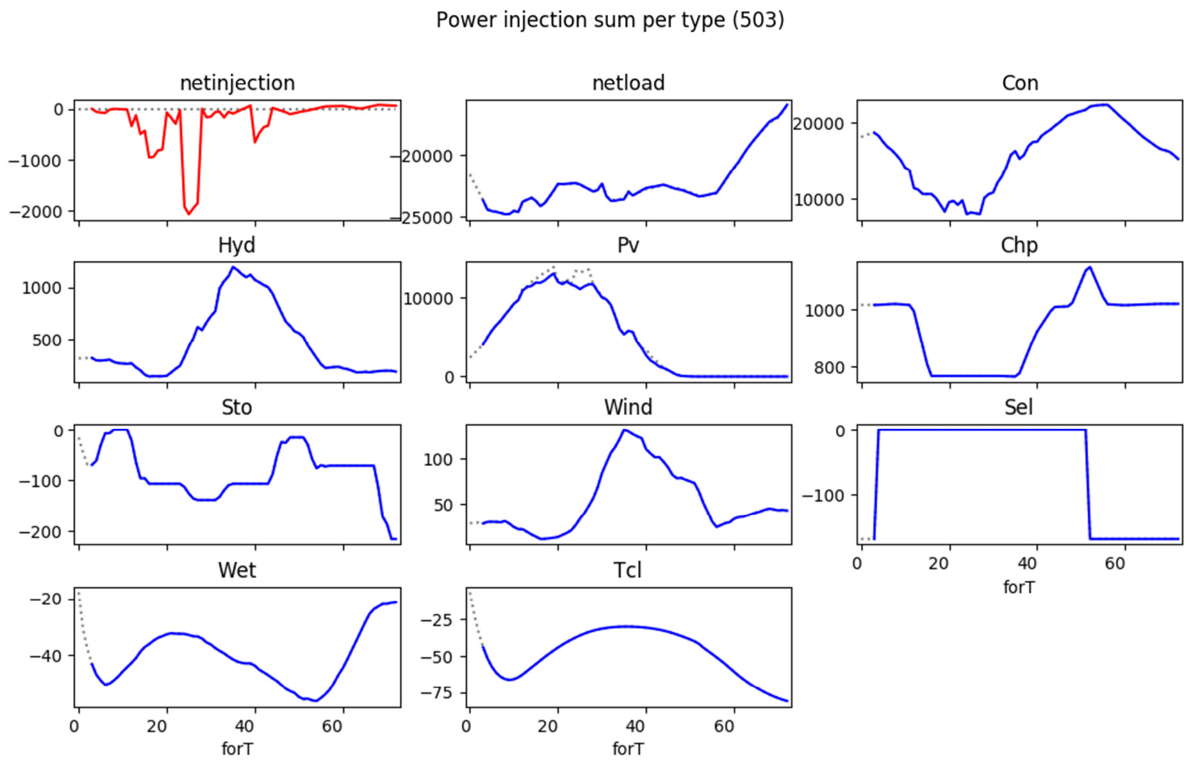


Figure 4.2: Italian scenario: sum of power injections in MW per type, baseline (dotted line) and forecasted (solid line).

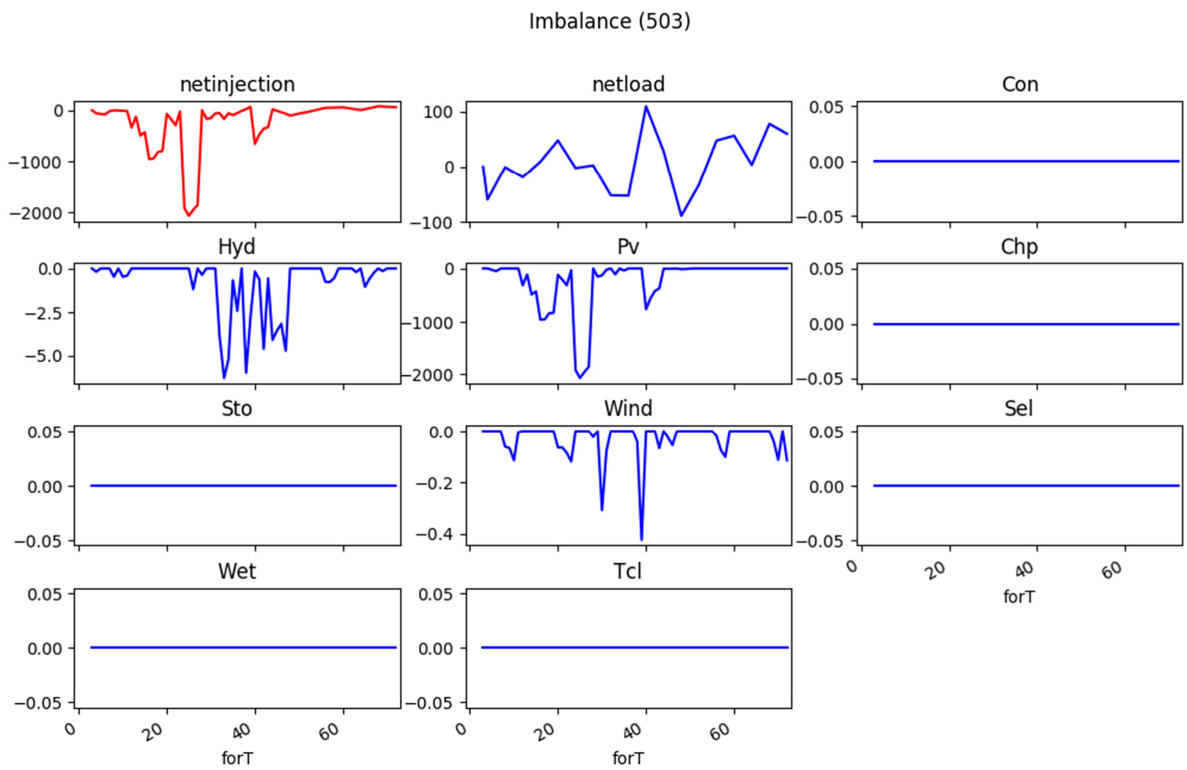


Figure 4.3: Italian scenario: difference between forecasted vs baseline power injection in MW.

4.2 Danish scenario dataset

The Danish dataset includes Western Denmark as shown in Figure 4.4. This is the part that is synchronously connected to Continental Europe. Power injection profiles and imbalances are shown in Figure 4.5 and Figure 4.6 respectively. In this case, Wind power is hugely important and the dominant contributor to the imbalance.

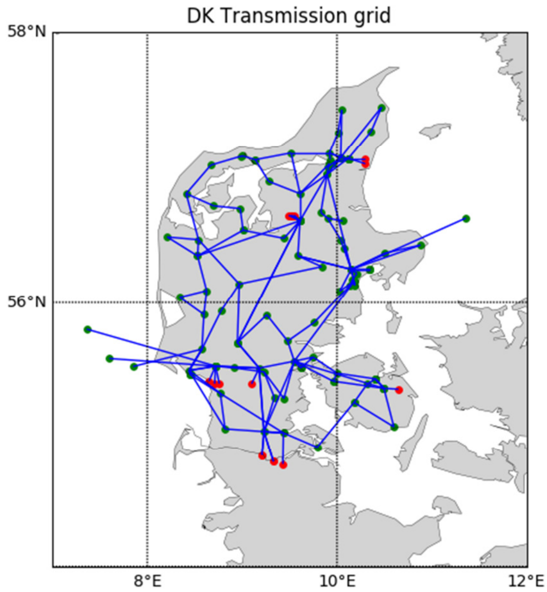


Figure 4.4: Danish (West) transmission grid.

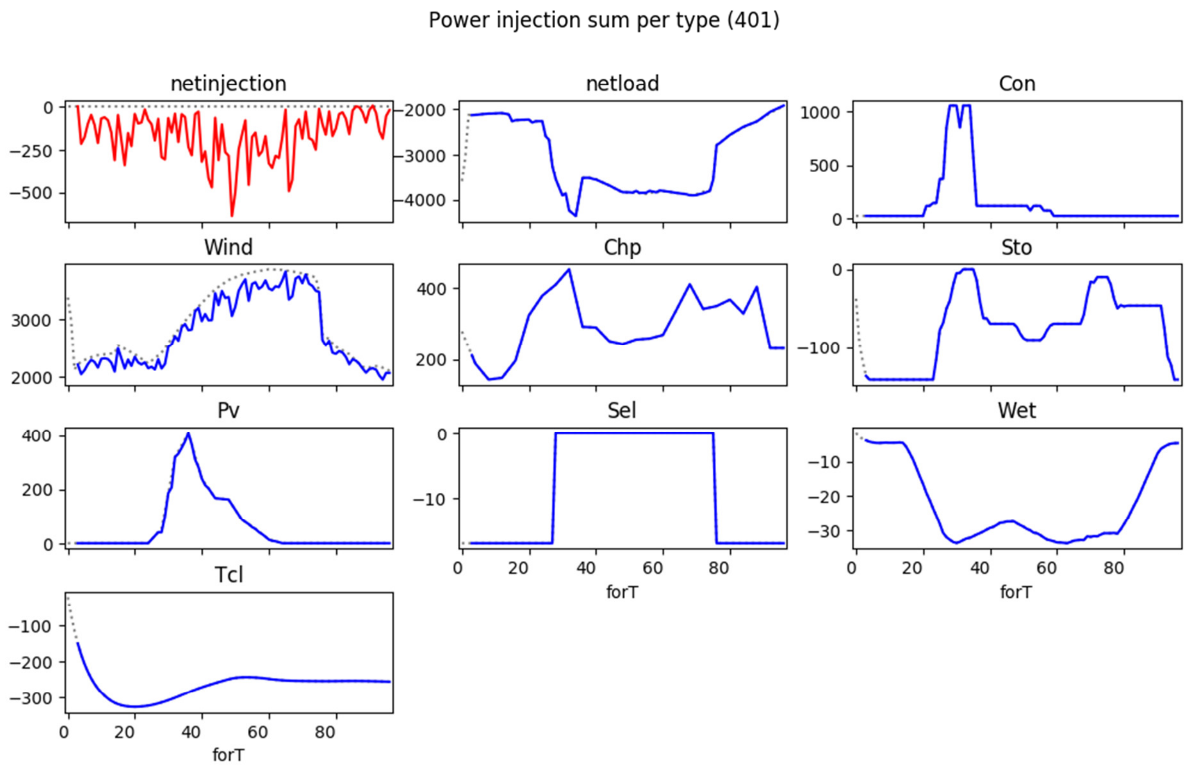


Figure 4.5: Danish scenario: sum of power injections in MW per type, baseline (dotted line) and forecasted (solid line).

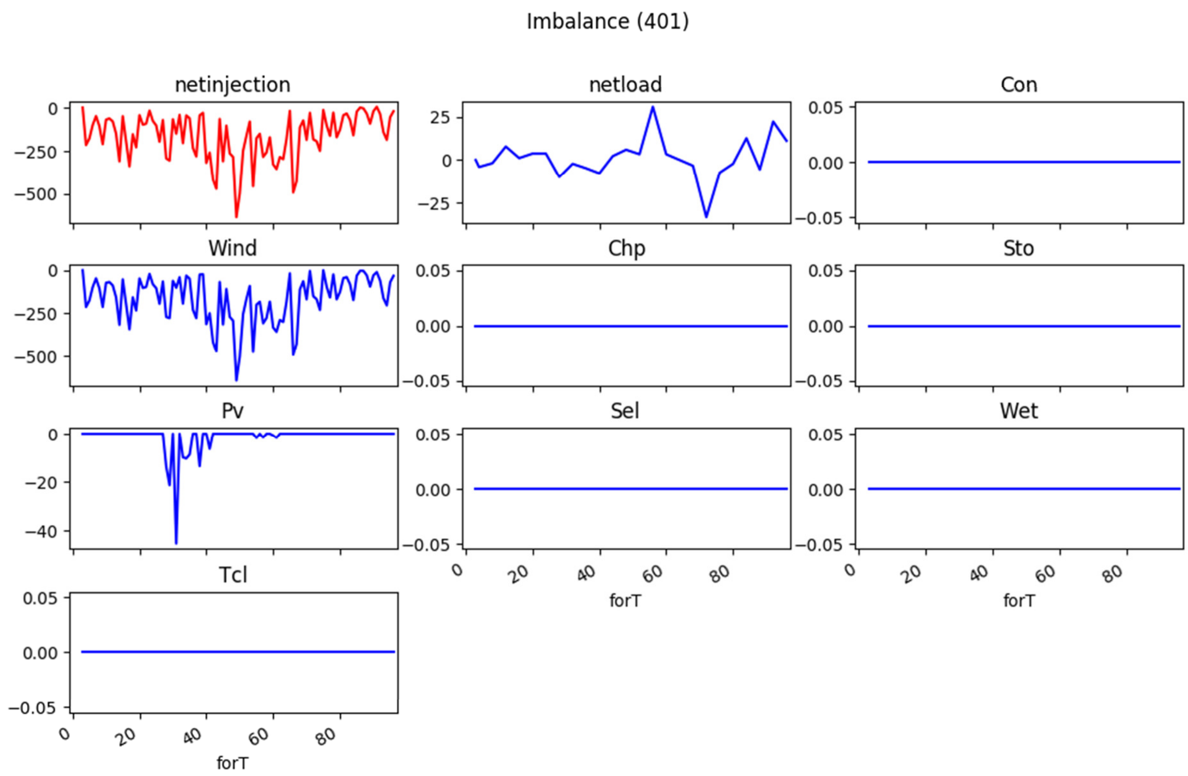


Figure 4.6: Danish scenario: difference between forecasted vs baseline power injection in MW.

4.3 Spain dataset

The transmission grid of the Spanish dataset is mapped in Figure 4.7. Power injection summed per type is shown in Figure 4.8 and differences between updated forecasts and previous market baselines are reported in Figure 4.9. In this case net load, Wind and Pv have similar contributions to the imbalance, while run-of-the-river hydro contributions are an order magnitude lower.

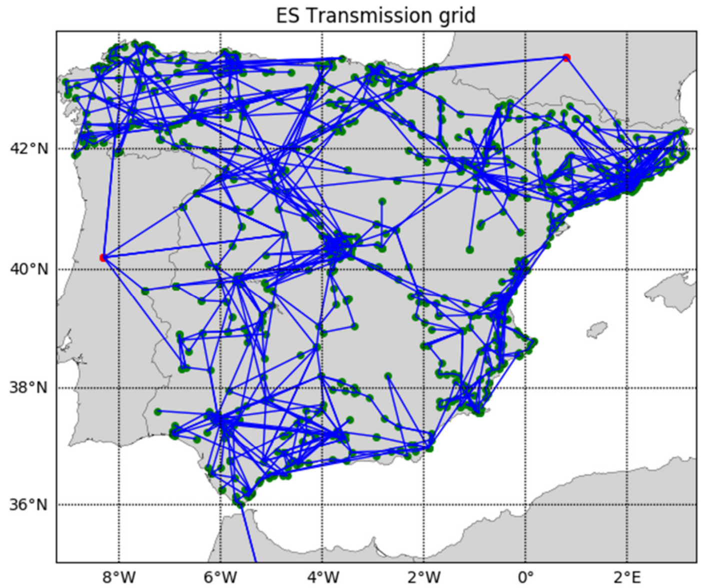


Figure 4.7: Spanish transmission grid.

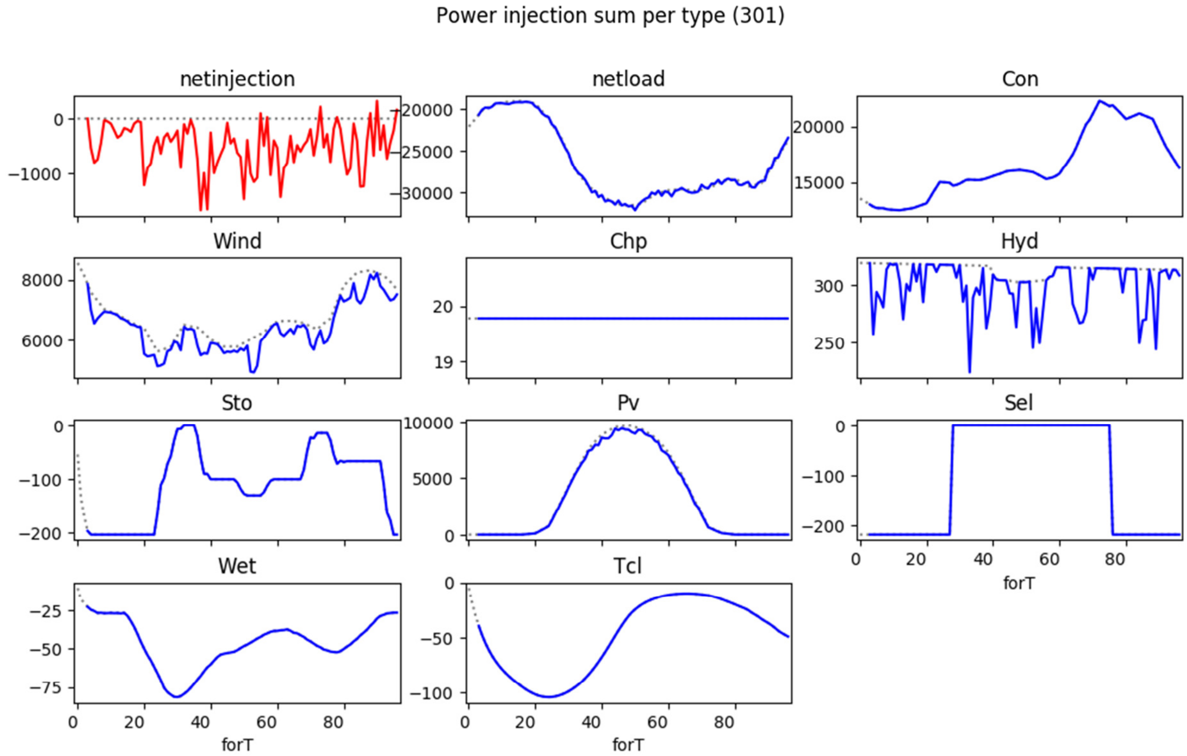


Figure 4.8: Spanish scenario: sum of power injections in MW per type, baseline (dotted line) and forecasted (solid line).

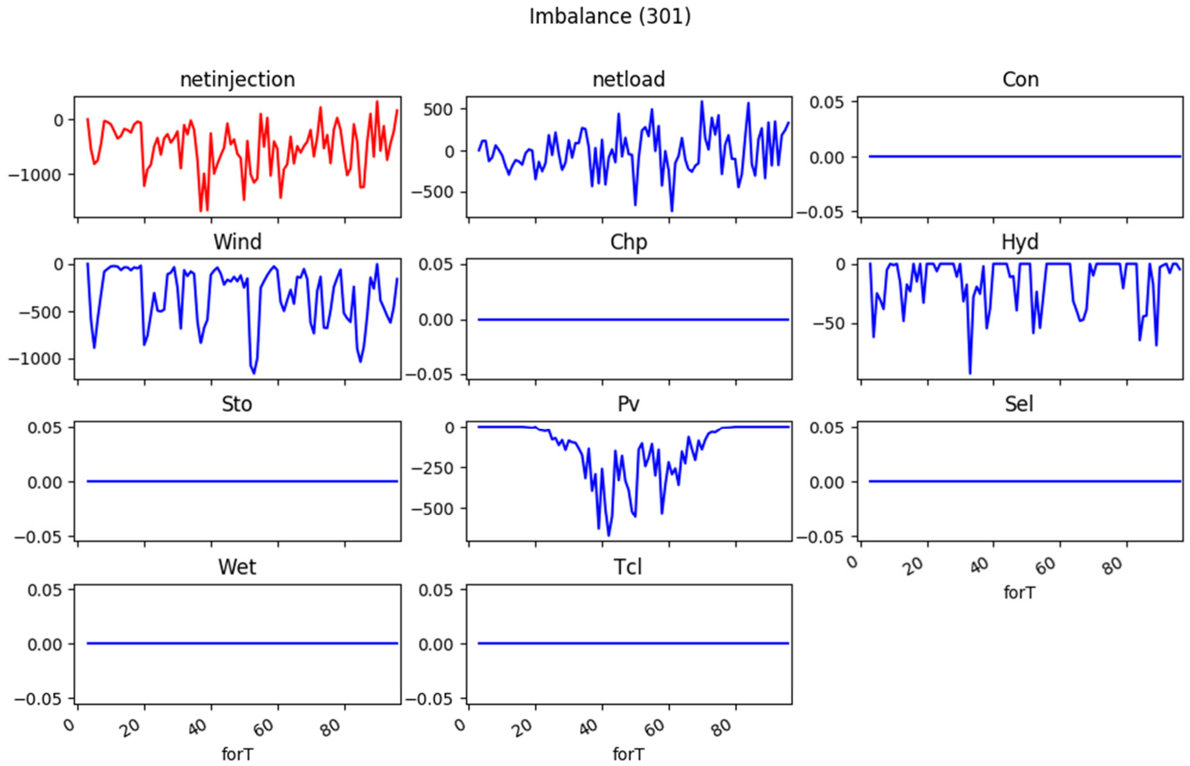


Figure 4.9: Spanish scenario: difference between forecasted vs baseline power injection in MW.

5 Simulation results

The defined scenarios datasets have been converted into a specific database format in order to be processed by the SmartNet simulator [D4.1]. The three selected days (see section 3.5) of each considered country have been simulated independently by running in sequence:

- day-ahead/intraday market simulation (see section 3.4);
- initialization of the SmartNet simulation database with scenario data;
- running of the SmartNet simulation.

For each day, four TSO-DSO coordination schemes [1] have been tested:

- Centralized ancillary services market model (CS A)
  The DSO is not allowed to buy flexibility and market products can be acquired only by the TSO in order to perform balancing and congestion management at transmission level (with the use of distribution resources too).
- Local ancillary services market model (CS B)
  The DSO has priority in selecting distribution resources flexibility for the management of local grid services (congestion management). The remaining flexibility can be acquired by the TSO to activate balancing and congestion management services.
- Shared balancing responsibility model (CS C)
  DSO and TSO manage their system separately, both performing balancing and congestion management with the resources available within their system.
- Common TSO-DSO ancillary services market model (CS D)
  DSO and TSO access to the same market to buy flexibility aimed at solving congestions and balancing. As for CS B, the DSO is responsible of the only congestion management at distribution level, but flexibility is acquired on the same market used by the TSO for the other (transmission) services.

SmartNet has foreseen also a fifth TSO-DSO coordination scheme (i.e. integrated flexibility market model) which is an extension of CS D where also non-regulated market parties can have access to the ancillary services market under the same conditions of network operators. However, this TSO-DSO interaction resulted particularly difficult to be simulate, especially for the difficult management of priorities that some services (e.g. congestion management) have among others (e.g. balancing).

According to this, 3 countries × 3 days × 4 coordination schemes = 36 simulations have been launched. Depending on the complexity of the scenario (the amount of resources, their typology, the extension of the grid, etc.) the simulations had different durations. The most complex country to be simulated resulted

to be Italy, for which one day of scenario took about 30 days of simulations. Figure 5.1 reports a pie chart with the time spent (in hours) in each software block during the simulation of one Italian day (and one coordination scheme). It can be noticed that all the three layers took about the same simulation time (~10 days).

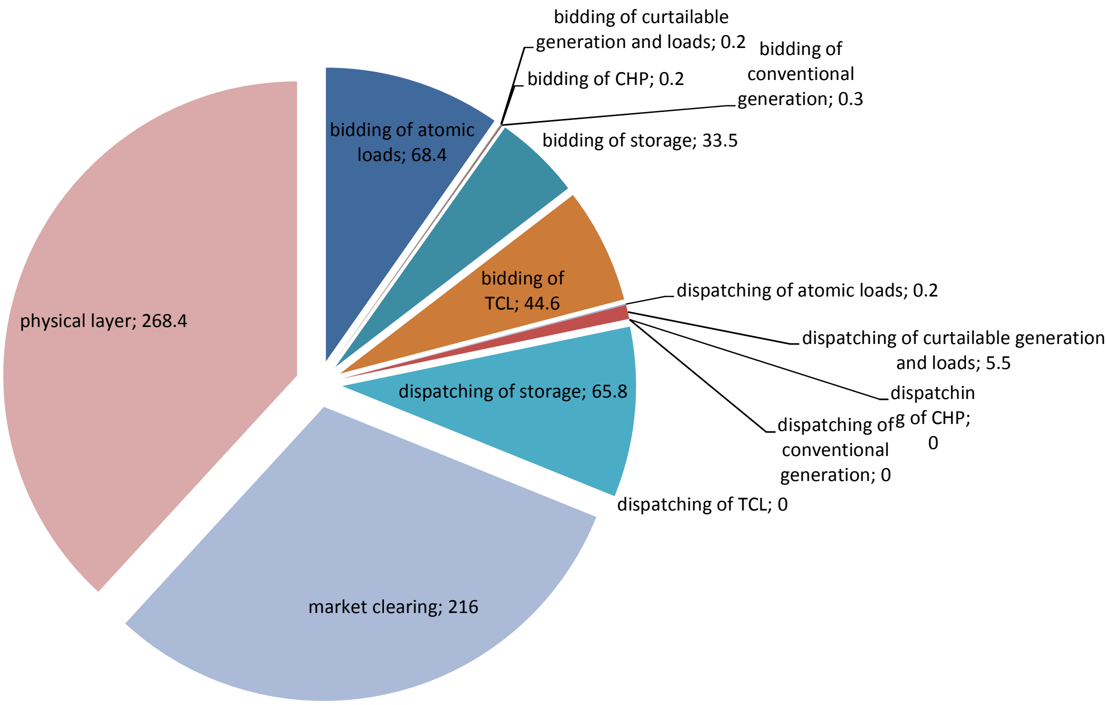


Figure 5.1: Duration of the simulation for one day of scenario. For each simulation block, the number of hours spent within the algorithm are reported.

In addition to the scenario complexity, also the simulation timing represented a significant obstacle for the debugging of the simulation platform and of the scenario. Many simulation attempts have been carried out, also monitoring partial results during the processes.

Finally, once the simulator code have been completely debugged, the 36 full simulations have been carried out. Some of the most significant results are reported within the following sections, which are aimed at highlighting the peculiarities of simulation blocks and scenarios.

5.1 Bidding and dispatching layer

One of the main simulation platform layers is represented by the set of blocks aimed at simulating the bidding and dispatching processes carried out by aggregators. The flexible resources assumed by the scenarios are aggregated and their flexibility (which availability depend on their status) is forwarded to the market. One particular case is represented by the Curtailable Generators and Curtailable Loads (CGCL) which offer only downward flexibility (decrease generation/increase load) according to:

- the actual availability of primary energy to be curtailed in case of renewable generators;
- the possibility of making loads consuming power when they are not currently operating (switching on public illumination).

Figure 5.2 reports the results of CGCL aggregation. From the analysis of the data it can be noticed that the actual availability corresponds to the profiles of renewable generation assumed by the Spanish scenario (see Figure 3.12).

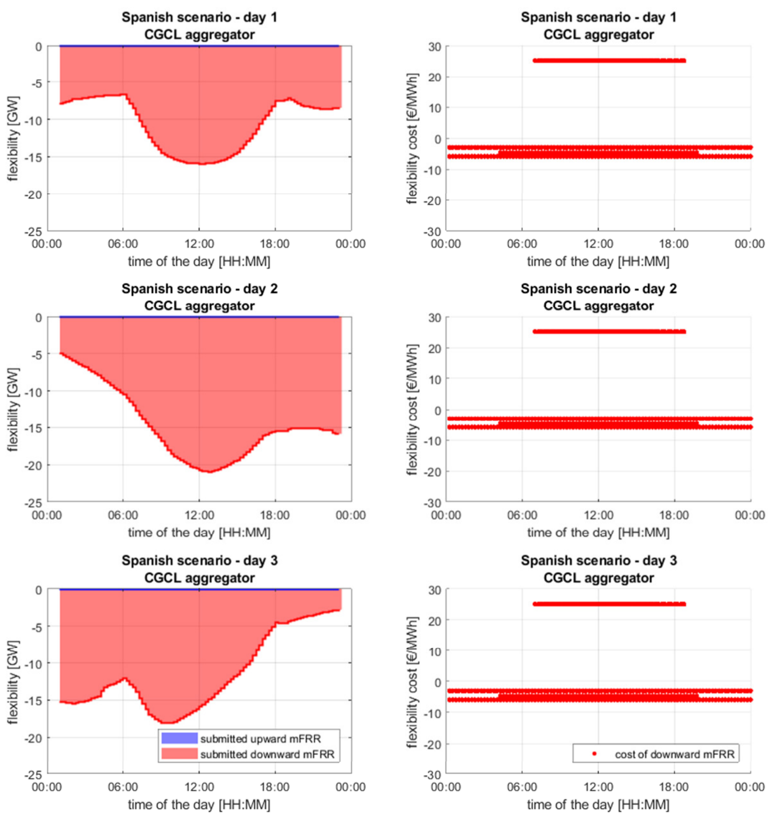


Figure 5.2: Bidding of curtailable generation and curtailable loads. Actual flexibility and related price.

Since curtailed generation is lost energy, the bidding price is high (~5 €/MWh). In case this flexibility is accepted, the power plant owner is only paying back for the avoided power plant maintenance costs. During the day (from 7:00 am to 7:00 pm), public illumination is switched off, by can be re-activated anytime in order to provide flexibility. In this case the bidding price is much higher (~25 €/MWh).

Another interesting bidding process is represented by the aggregation of storage-based units (Figure 5.3). In particular, it can be noticed that also in this case the flexibility is time dependent: in the early morning and late afternoon, most of the electric vehicles (the majority of storage-based technology in Denmark) are on the road and cannot provide ancillary services to the system. In this case the flexibility price depends on the price of the energy (in addition to the costs of storage management – i.e. losses) and this can be seen by comparing the costs of upward/downward bids with the data reported in Figure 3.10.

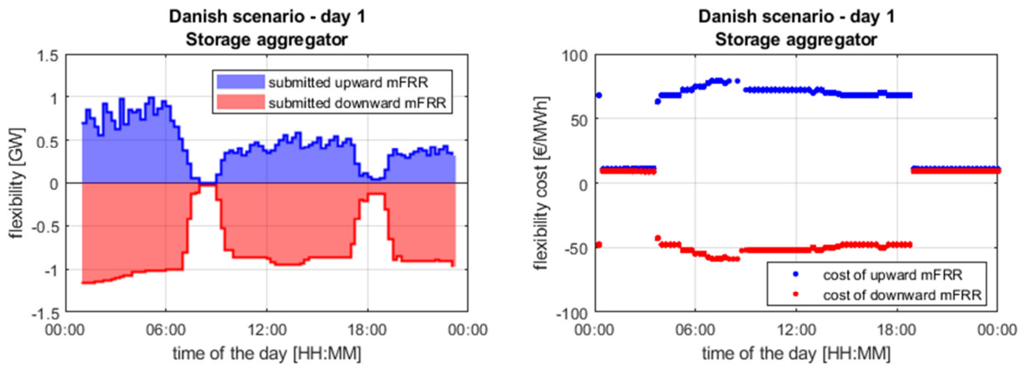


Figure 5.3: Bidding of storage-based technology. Actual flexibility and related price.

In addition to these two technologies (CGCL and storage), also the other flexible devices are accessing to the market by means of dedicated aggregation routines. According to the requested services and the network conditions, the proposed bids are processed and accepted/rejected depending on the competitiveness and/or strategic position of resources. Figure 5.4 reports the percentage of accepted bids for each simulated country and bidding technology. It can be noticed that:

- The technology with the highest level of acceptance is represented by Atomic Loads (AL). In fact, the actual costs of this flexibility is pretty marginal since it consists of a pure time shifting of fixed loads, with no discomforts for the final users.
- The second most activated flexibility is represented by CHP. Also in this case, according to the assumption made in section 3.4.1, it is one of the cheapest technologies.
- As discussed above, one of the most expensive technology is represented by curtailable generation and, consequently, the percentage of activation is pretty marginal. In this case, the activated bids are selected because of the strategic position of specific power plants in congested areas of the network.

- In all the scenarios and TSO-DSO coordination schemes, the level of acceptance of resources is more or less the same, except for CS C. In this case, the introduction of balancing as a DSO oriented service, dramatically change the flexibility demanded by network operators.

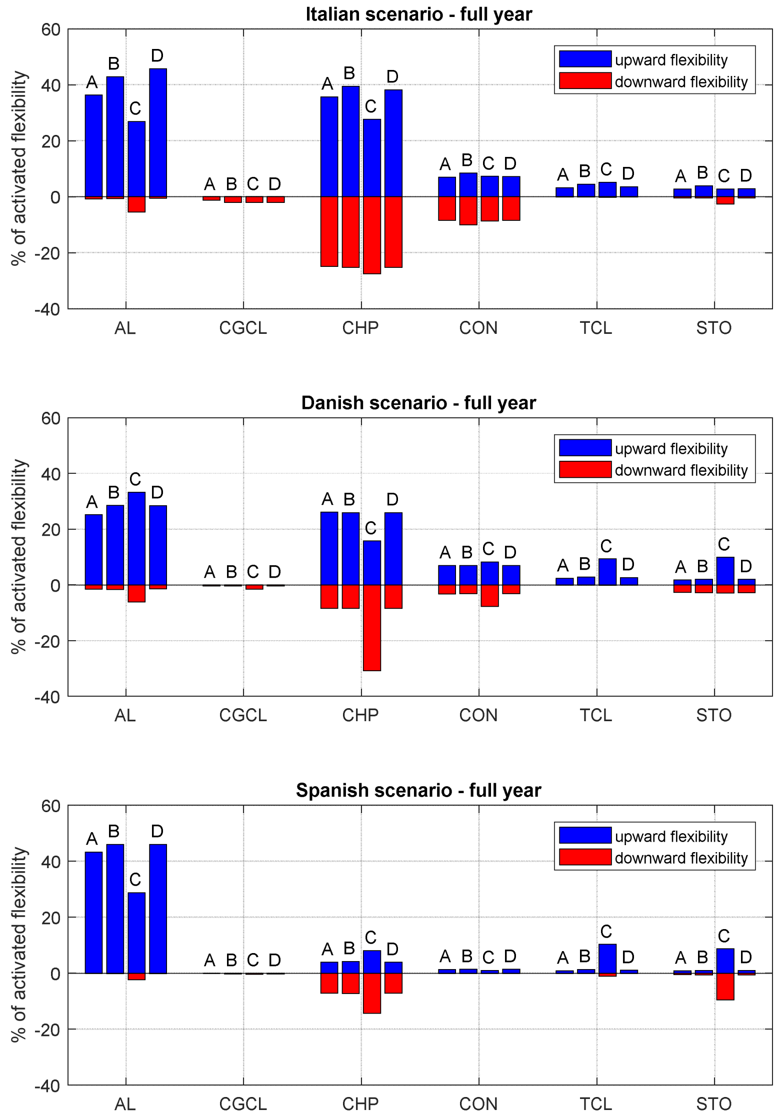


Figure 5.4: Statistics of bidding acceptance for each simulated scenario and flexible technology.

5.2 Market layer

The bids submitted by the bidding and dispatching layer are processed by the market layer in order to manage the predicted imbalance (15÷60 minutes ahead forecast) and the expected congestions. The activations depend on the services requested by network operators, thus on the simulated TSO-DSO coordination scheme.

The market clearing algorithm implemented for CS A is dealing with only TSO ancillary services (balancing and congestion management at transmission level). Figure 5.5 reports the activated flexibility reserve (manual Frequency Restoration Reserve – mFRR) for the management of these services. Looking at the requested balancing actions and splitting the mFRR located at distribution and transmission level, it can be noticed that:

- Upward and downward mFRR is often activated simultaneously. This identifies the presence of congestions to be solved.
- Even if CS A is not dealing with DSO services, (upward) resources located at distribution level result to be competitive with respect to transmission ones.

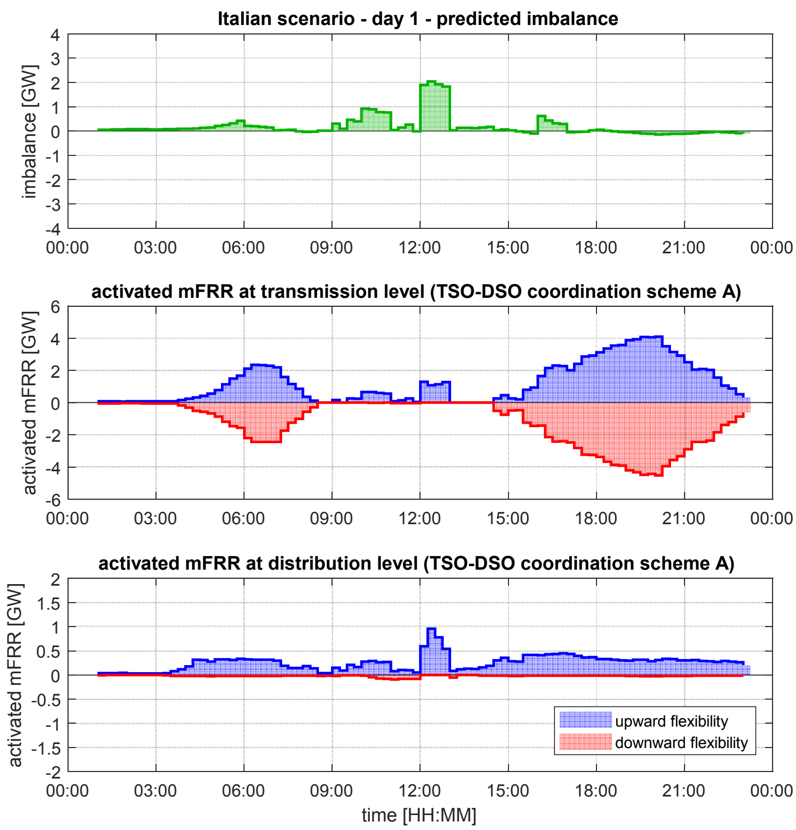


Figure 5.5: Activated transmission and distribution mFRR for the solution of predicted imbalance and congestions (TSO-DSO coordination scheme A).

Different results are returned by the market when more complex TSO-DSO coordination schemes are implemented. For instance, when DSO is allowed to buy flexibility for congestion management at distribution level (CS B and CS D), some noticeable different activations are experienced. Figure 5.6 reports the activations of CS D for an illustrative scenario (at this level of detail, CS B returns very similar results). By comparing them with the ones of CS A, significant differences are present, particularly at distribution level:

- The presence of distribution system bottlenecks limit the activation of upward mFRR. In CS A some of the mFRR activations are blocked manually by the network operator (see section 0).
- In the illustrative scenario (Italy day 1), distribution network congestions are mainly caused by Pv generation, and the solar production pattern can be recognized within the profile of downward activations.

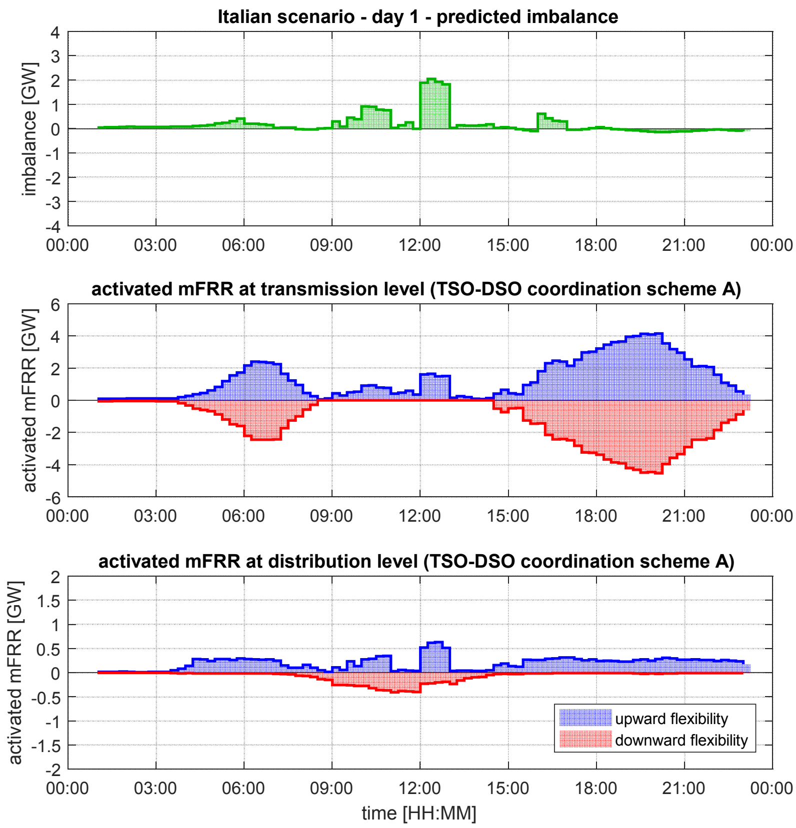


Figure 5.6: Activated transmission and distribution mFRR for the solution of predicted imbalance and congestions (TSO-DSO coordination scheme D).

Finally, the results of TSO-DSO coordination scheme C are presented in Figure 5.7. As anticipated within the previous section, the balancing role assigned to the DSO as well as the complete split of distribution and transmission market, dramatically change the activations profiles. In addition, the scarcity of resources often does not allow the fulfilment of the requested services (such as balancing), even if more reserve is used.

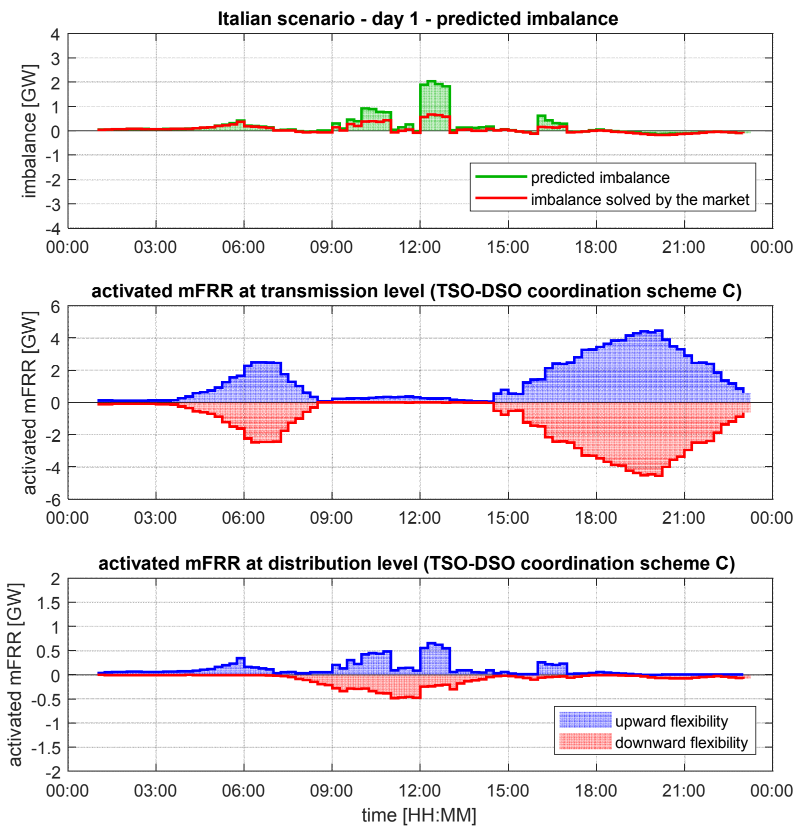


Figure 5.7: Activated transmission and distribution mFRR for the solution of predicted imbalance and congestions (TSO-DSO coordination scheme C).

The described aspects of each TSO-DSO coordination schemes are also visible on the total activations experienced in the full simulated scenarios (Figure 5.8):

- Lower amounts of distribution mFRR (or higher amounts of distribution downward mFRR) are activated in coordination schemes considering also DSO services (except CS C).
- CS C systematically requires totally different reserve activation at both transmission and distribution level.

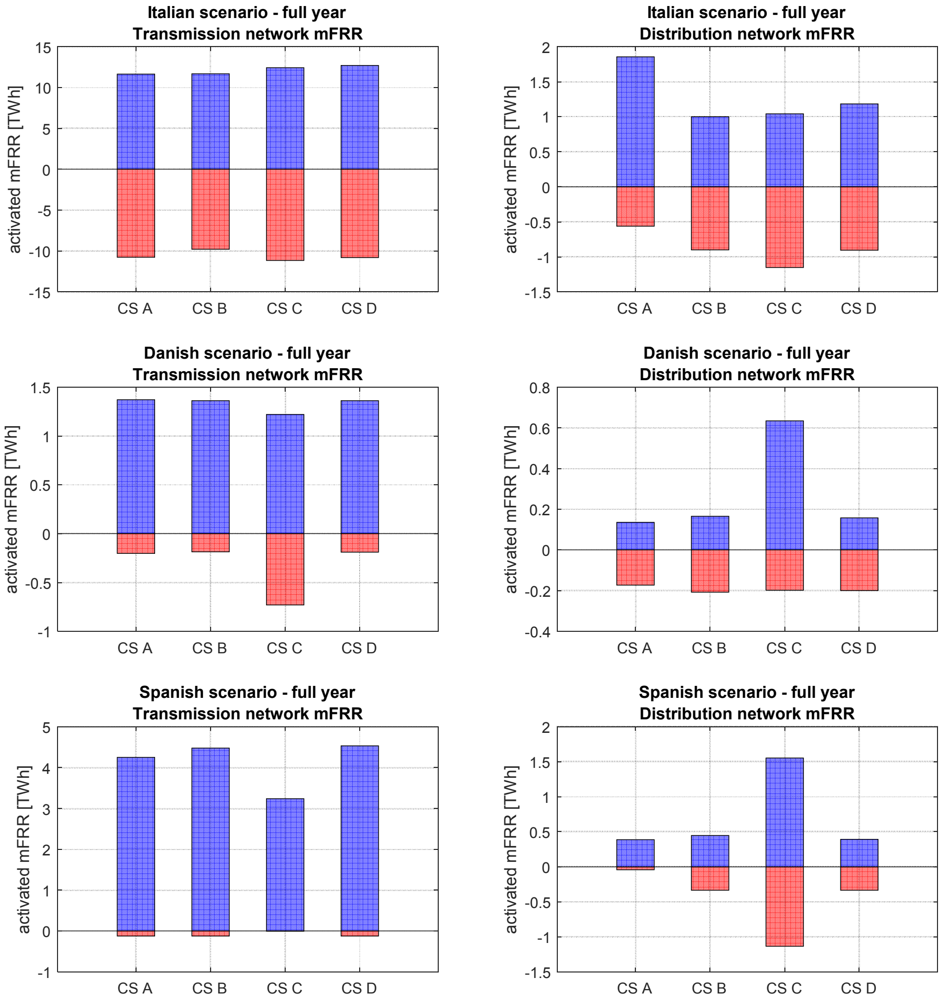


Figure 5.8: Activated transmission and distribution mFRR for the full year of the simulated countries.

5.3 Physical layer

Once bidding and market clearing routines have been carried out, the requested activations are processed into individual set-points and transmitted to the controlled resources. At this point, the physical layer simulates the actual behaviour of the resources, which might be different with respect to their expected behaviour (the one anticipated by the aggregators) because of two main reasons:

- Forecasting errors make set-points inapplicable, since the predicted flexibility has been overestimated in the bidding process.
- Unpredicted network issues (loading/voltage congestions) might require the re-dispatch of some resources located in strategic position of the network.

Figure 5.9, Figure 5.10 and Figure 5.11 reports the energy impacts of these deviations for the Italian, Danish and Spanish scenarios respectively.

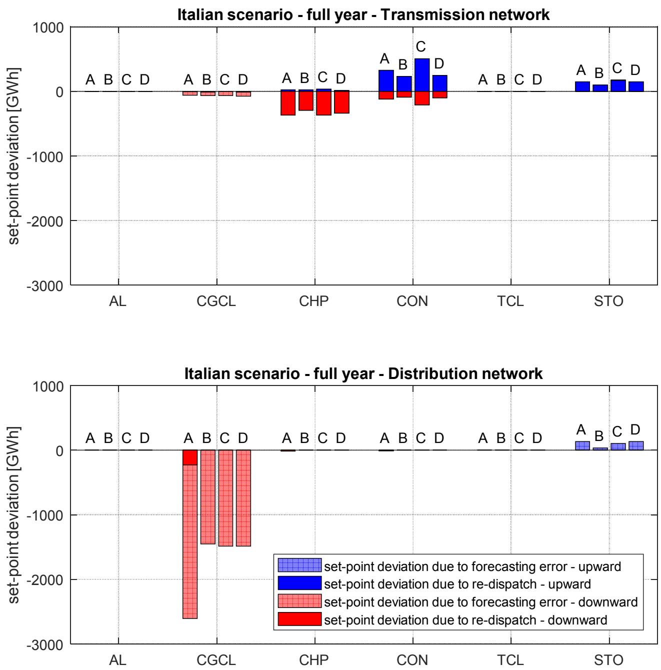


Figure 5.9: Energy impact of deviation of resource from the set-points requested by disaggreator/market (Italian scenario).

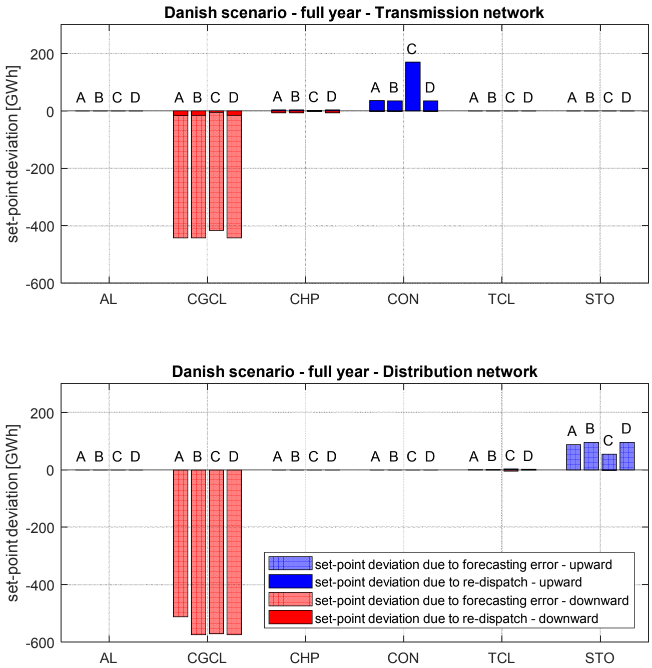


Figure 5.10: Energy impact of deviation of resource from the set-points requested by disaggreator/market (Danish scenario).

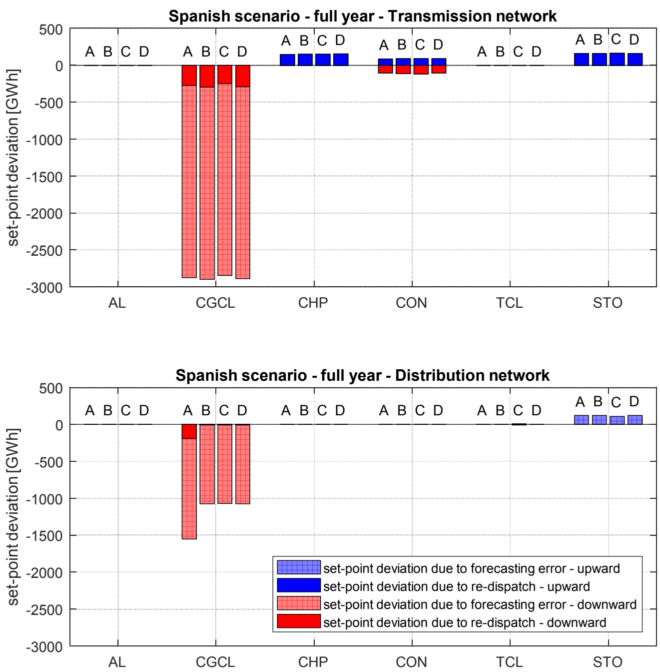


Figure 5.11: Energy impact of deviation of resource from the set-points requested by disaggreator/market (Spanish scenario).

According to the reported results, few interesting aspects can be noticed:

- As expected, forecasting errors are significant for renewable energy. In particular, it can be noticed that the energy impact of renewables in CS A is slightly higher than other coordination schemes in Italy and Spain. This is can be explained the fact that DSO services are curtailing more distributed generation, preventing the deviation of renewables production due to forecasting error.
- In the same countries, the DSO operated re-dispatch of curtailable generation is evident in CS A. According to the assumptions done for the simulation of this TSO-DSO coordination scheme, this happens since the ancillary services market is returning activations regardless of distribution network constraints.
- In other circumstances, forecasting errors are practically the same in all the remaining coordination schemes. In Denmark, since distribution congestions are assumed to be not significant, the deviation from set-point is the same in every CS.
- Transmission (non-renewable generation) resources are mostly affected by TSO re-dispatching.

The re-dispatching performed by network operators is only the last resource for the congestion management of distribution networks. In fact, two main kind of network bottlenecks can be experienced at these voltage levels: overloading and voltage limits violations. In addition to active power (a remunerated market product) the DSO can also activate its own asset as well as reactive power of flexible resources (which is assumed to be available at no extra costs). Figure 5.12 report a summary of the actions taken by the DSO in a distribution network of the Italian scenario in a day with high Pv production. It can be noticed that the control of reactive power and tap-changing transformer already solve a large portion of the congestions (the ones related to voltage issues). However, the only solution to overloading consists of active power regulation, which is performed:

- Directly by the DSO, when the market is not dealing with distribution services (CS A).
- Through the market, when the DSO is accessing to it in order to buy flexibility aimed at performing congestion management (all coordination schemes except CS A).

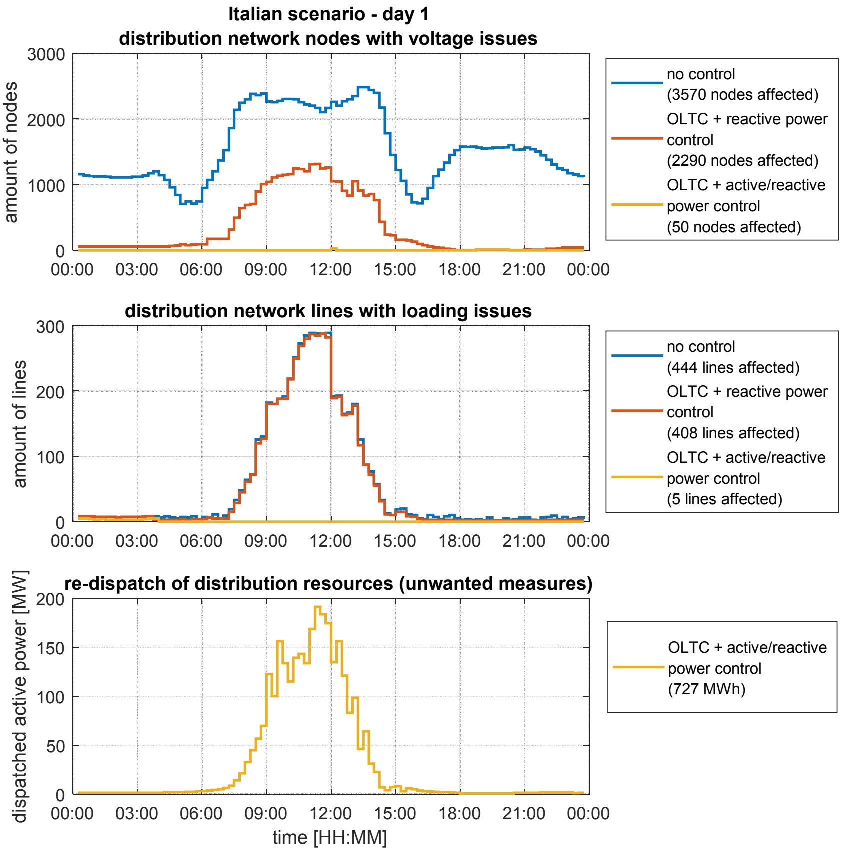


Figure 5.12: Control of local asset, reactive power and active power re-dispatch for the management of distribution network congestions.

Re-dispatching of resources, forecasting error are causing imbalance which, according to the presented results, is expected to be different depending on the implemented TSO-DSO coordination scheme. In fact, according to the data reported in Figure 5.13:

- CS B and CS D are the ones with the lower values of residual imbalance (thanks to the optimal management of both TSO and DSO services).
- Larger volumes of residual imbalance are experienced in CS A mainly because of the DSO re-dispatching actions. This is less visible in Denmark since lower congestions are assumed at distribution level.
- As anticipated in section 5.2, CS C is often failing in managing the balancing service. For this reason, it is the coordination scheme with the lowest performance.

This residual imbalance is managed by a dedicated reserve: the automatic Frequency Reserve Restoration, which is normally more expensive than mFRR [38].

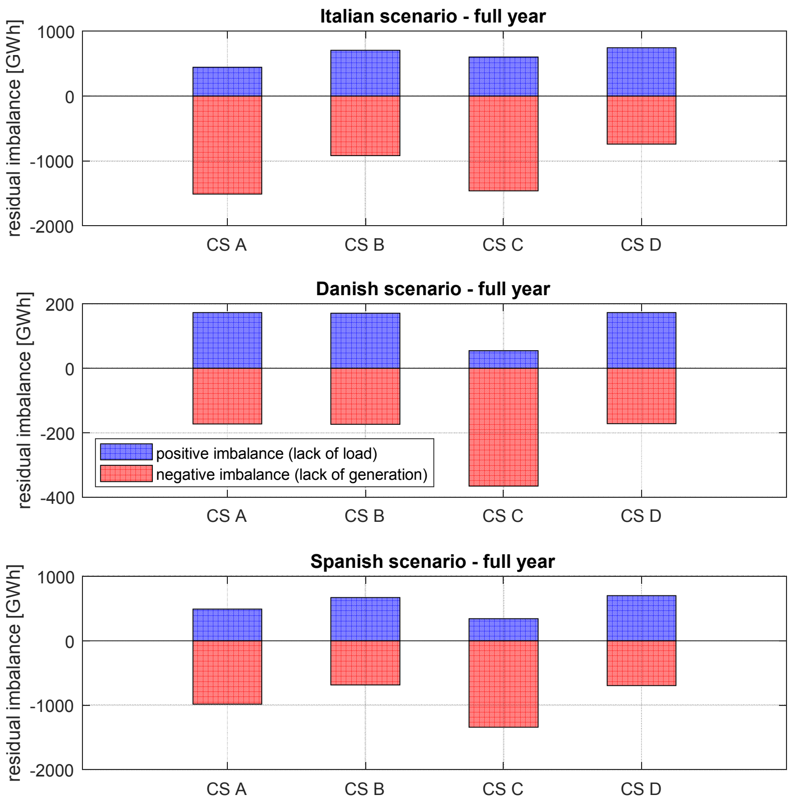


Figure 5.13: Total residual imbalance experienced within the simulated scenarios

6 Conclusions

This document has outlined the simulation datasets used in the simulation platform, describing in detail the procedure adopted for their creation on the basis of high level scenarios. Geographical position of electricity resources, electrical/physical characteristics of flexible power units, their location on transmission and distribution network, hypothesis on the level of congestions expected at distribution level have been described and implemented.

Thanks to these datasets and additional simplifications, one scenario for each reference country (Italy, Denmark and Spain) has been defined, representing one year of ancillary services operation both at transmission and distribution level.

The document reported also some of the most significant simulation results, which are pointing out the peculiarities of each electricity scenario and the impact of the different TSO-DSO coordination schemes on it. In particular, the presented data highlighted the importance of the services addressed to the DSO for the optimal management of the distribution network (especially when small resources are participating to TSO services as well) and the potential of central/local market for the activation of the related flexibility.

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