European Commission

METIS 2

Study S1

Assessing the role and magnitude of different flexibility measures and assets in distribution and transmission grids

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Abbreviations

Abbreviation	Definition
BEV	Battery Electric Vehicle
CGMES	Common Grid Model Exchange Standard
DCLF	Direct current load flow
DCM	Distribution Core Model
DCOPF	Direct current optimal power flow
EU27+UK+6	EU27 + United Kingdom, Bosnia and Herzegovina, North Macedonia, Montenegro, Norway, Serbia, Switzerland
EV	Electric vehicle
HV	High voltage
HVDC	High voltage direct current
Hydro RoR	Hydro Run-of-River
LV	Low voltage
MV	Medium voltage
OCGT	Open cycle gas turbine
PHEV	Plug-in-Hybrid Electric Vehicle
PHS	Pumped hydro storage
PST	Phase shifting transformer
PV	Photovoltaic
RES	Renewable energy sources
TYNDP	Ten year network development plan
V2G	Vehicle-to-grid
vRES	Variable renewable energy sources

METIS configuration

The configuration of the METIS model used in the present study is summarised in Table 1.

Table 1 - METIS Configuration

METIS Configuration	
Version	METIS v2.0 Beta (non-published)
Modules	Power system and demand modules
Scenario	METIS EUCO3232.5
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Nodal

1. INTRODUCTION

1.1. CONTEXT

The decarbonisation of the European energy system is entailing a massive integration of Renewable Energy Sources (RES) in the power system, in particular of solar PV and wind energy. For instance, the targets that have been agreed in the Clean Energy Package aim at achieving an energy efficiency target of 32.5% and a renewable energy target of at least 32% by 2030. These objectives are being revised as more ambitious 2030 GHG emissions reduction objectives have been agreed to (-55% compared to 1990 levels from a previous target of –40%). This leads to a significant increase in renewable power generation which comes with several challenges, due to the specific characteristics of these sources. A first well-known challenge is the compensation of the variability of RES, which requires important flexibility means such as storage, demand response, flexible power plants, etc. A second challenge is linked to the fact that the transmission grid was initially designed to connect centralised generation systems based on thermal and hydro power plants with load centres and distribution grids dimensioned to ensure power supply meeting peak demand. Also, in many countries the grid was designed to ensure transmission to distribution power flows. RES are partly decentralised and often not located close to the historical power plants they are displacing. Current transmission and distribution systems are thus not fully adapted for a massive integration of RES: they can be subject to congestions, leading to curtailment of RES and requiring thermal generation (notably based on fossil fuels) combined with other flexibility solutions (batteries, demand-response, etc.) to maintain the load-generation balance, as it is already the case during windy days in Germany. Flexibility solutions and assets provide an opportunity to solve simultaneously these two challenges: if they are properly located, they can help to unlock grid congestions while compensating for the variability of renewable energy sources on all relevant timescales, from intra-hourly to seasonal time horizons. Additionally, an optimal management of grid-related flexibility solutions will ensure the extraction of maximum value from the investments made on the grid assets that are foreseen in the decarbonisation scenarios envisaged by the European Union (investments in power grids reach circa 100B€/y over the 2030-2050 period in the pathways of the Long-Term Strategy reaching net zero in 2050).

1.2. OBJECTIVES

The need for enhanced flexibility in power systems due to the variable production pattern of RES is not a new question, and several studies already tried to quantify how much and what kind of flexibility would be needed to optimally compensate this variability [1]. However, the consideration of congestions in the European power system is usually limited to cross-border congestions, i.e., to congestions between different countries (or between different bidding zones). The congestions appearing within national transmission grids or within distribution grids are analysed only to a limited extent. It is expected that the limitations imposed by grids will become more and more important with the increased penetration of RES. If not accompanied by an appropriate portfolio of flexibility solutions, an increase of RES could result in high integration costs and sub-optimal use of the existing infrastructure

In this situation, it becomes increasingly important for policymakers, and the European Commission in particular, to have the capability to assess the impacts of various policy options related to the investment in flexibility solutions and their operational management. Thanks to the developments carried out in the context of the METIS 2 project, METIS now has the capability to model transmission and distribution grids in more details, leading to better modelling of grid congestions. For more details on the modelling of the transmission and distribution grids, refer to the relevant METIS Technical Notes[1].

The general objective of this study is to identify and characterise flexibility solutions, and to assess their potential roles when considering power flowing through the transmission and distribution grids.

More precisely, the study has two major objectives: (i) to provide a holistic overview of the different flexibility options, including a description of their potentials in the EU MSs, their techno-economic characteristics and possible fields of deployment, and (ii) to provide a scenario-based assessment of the potential deployment of flexibility assets to avoid distribution and transmission grid congestions, enhance the utilisation of existing infrastructure and facilitate a cost-efficient integration of renewables. Overview of the methodology

The study is structured into six tasks. The flexibility solutions are identified and characterised in Task 1. This is followed by the identification of the KPIs for the assessment of congestions in the transmission and the distribution network. Task 2 is designed to define and analyse a reference situation in order to identify the congestions with limited flexibility solutions, if any. Task 3 identifies the flexibility solutions that can help alleviate congestions at the level of the transmission grid, whereas Task 4 identifies the flexibility solutions that can help in congestion alleviation at distribution level. Task 5 is a sensitivity analysis of the impact of higher RES penetration levels on the results of previous tasks. The final task, Task 6, is a synthesis of the results of tasks 3 and 4 to reach a holistic conclusion on the role and magnitude of different flexibility solutions in the alleviation of congestions at the transmission and the distribution network.

1.3. STRUCTURE OF THIS DOCUMENT

This document presents the methodology and the results of the assessment of the role of flexibility solutions in the integration of renewables in EU27 and neighbouring countries. In addition to the characterisation of the flexibility solutions, Section2 discusses the KPIs for the congestion assessment at the transmission and distribution levels. Section 3 describes the methodology developed under Task 2 for the definition and assessment of a reference situation. Sections 4 and 5 analyse the role of flexibility solutions in alleviating transmission and distribution grid issues, respectively. Section 6 analyses the impacts of flexibility solutions in accommodating an increased penetration of renewables compared to the reference situation. Section 7 synthesises the results that have been obtained in this study.

2. TASK 1: IDENTIFICATION AND CHARACTERISATION OF FLEXIBILITY SOLUTIONS AND DEFINITION OF KPIS

In Task 1, a literature review has been carried out to identify and characterise the different flexibility options with respect to their general functioning, their (MS-specific) potentials, technical constraints and related costs for investment and activation. This task provides a holistic overview of the different flexibility solutions and an assessment of the potential deployment of flexibility solutions to alleviate distribution and transmission grid congestions. The flexibility solutions analysed comprise of demand response in terms of load shifting and load shedding, that cuts or allocates demand at a later point in time to balance demand or local generation peaks; generation curtailment to reduce local RES peak generation; centralised or decentralised stationary storage like batteries; mobile storage from electric vehicles, considering vehicle-to-grid energy feed-back into the grid; flexibility provided by power-to-x (i.e. power-to-heat, power-to-gas, power-to-mobility, power-to-industry); flexible power generation (e.g. open cycle gas turbines or steam turbines); etc.

[1] https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en

The literature review is complemented by the introduction of a set of metrics that allow to characterise congestions (overload percentage on lines/transformers, number of hours per year, etc.) and thereby to measure the benefits of flexibility solutions.

2.1. CHARACTERISATION OF FLEXIBILITY SOLUTIONS

This section characterises the flexibility solutions in order to reach the objective of alleviating grid problems. In this document, "flexibility solutions" shall be understood as one or more of the following: a technology, asset or measure that offers flexibility services. The list of technologies that are considered in this study is given in Table 2.

In the context of this study, the considered scenario is the METIS-EUCO3232.5, which is based on the PRIMES EUCO3232.5 scenario[2] for the year 2030. It includes 34 zones corresponding to the EU27+UK (scope of PRIMES scenario) and is complemented with data for 6 additional countries[3] (referred to as EU27+UK+6), which enables a better representation of power exchanges within Europe. The derivation of the scenario is based on a standard methodology applied in numerous METIS studies [2]. The main parameters (installed capacities, availability, RES load factors, fuel prices, etc.) are adapted to be consistent with the original scenario from the European Commission [3]. The exchange capacities between zones are sourced from ENTSO-E's TYNDP 2018 reference grid for the year 2027[4].

The identification of the flexibility solutions includes the analysis of the various technologies that are included in the EUCO3232.5 scenario, followed by an assessment of their capability to offer flexibility on different timescales and their characteristics. Additional flexibility solutions are included below, based on a literature review and on previous METIS studies.

Table 2 consists of 10 columns which are described as follows:

- **Technology / Asset/ Measure type**: the assets or technologies or measures that are present in one or more countries in the EUCO3232.5 scenario are listed in this column. For example, solar fleet, wind offshore, nuclear, Open cycle gas turbines (OCGT), heat pump, stationary batteries, pumped hydro storage (PHS), Electric vehicles (EVs), etc. Note that the hydrogen fleet (electricity generation hydrogen turbines), electrolysis and methanation (production of electrolytic hydrogen and potential subsequent methanation) are not included in this list, as they are either absent or insignificant in the considered scenario [3].
- **Category**: each of the solutions listed in column 1 is mapped to a broader list of categories namely generation, demand, stationary storage and electric vehicles. This in turn is done for a better understanding of the characteristic of flexibility of that particular asset. For example, the asset mapped under generation has the flexibility of being shed whereas an asset mapped under stationary storage has have the flexibility of acting as a load (charging) at times and as generation at another time (discharging). The generation assets in turn are classified into generation based on variable renewable energy source (vRES), RES and non-RES generation. Yet another list of assets/solutions are grouped into demand category. The stationary storage category encompasses several assets for example, pumped hydro storage (PHS) and batteries. EVs are considered as separate category as depending on their charging strategies they can be treated as inflexible load, flexible load or as storage. Additionally, there are three more special assets/technologies that fall into the category of network assets namely interconnections, HVDC lines and phase shifting transformers. The last two types of flexibility solutions are not strictly speaking included in the EUCO3232.5 dataset itself

[2] https://ec.europa.eu/energy/sites/ener/files/technical_note_on_the_euco3232_final_14062019.pdf

[3] Bosnia (BA), Switzerland (CH), Montenegro (ME), FYROM (MK), Norway (NO) and Serbia (RS).

[4] Input Data for TYNDP 2018: https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/Scenarios%20Data%20Sets/Input%20Data.xlsx

as the modelling approach of underlying PRIMES model does not include grid-specific details on this level.

- **Presence of the flexibility asset is in T/D/T&D**: This column indicates whether the asset/flexibility measure is present in the transmission network only (T), distribution network only (D) or both in the transmission as well as the distribution network (T&D). It is worth noting that this is a general broad classification. The exact segregation of transmission level voltage and distribution level voltages varies from country to country.
- **Flexible**: This column indicates whether flexibility services can be delivered by the corresponding asset in order to participate in congestion alleviation ("x" indicates a the presence of this feature). For example, EVs that have smart charging functionality enabled can provide flexibility services whereas EVs with immediate charging enabled do not provide any kind of flexibility to the network. In addition to the immediate charging of EVs, the 'thermo sensitive remainder', the 'non-thermo sensitive' [4] and air conditioning do not provide any kind of flexibility to the network. The other columns in Table 1 give more details about the type of flexibility services that can be delivered by a given asset. This is described as follows:
- **Generation curtailment alone is the flexibility possible** and **Generation redispatch**: These columns are dedicated to the category of generation assets. It indicates whether the generation can provide flexibility by means of redispatch (that is, adapt its behaviour compared to the outcome of the market model) which includes generation shifting as well as curtailment (column 6) or whether generation curtailment is the only flexibility possible (column 5) out of the asset. For example, when it comes to vRES, curtailment is the only possible flexibility. However, for gas turbines (GT), generation redispatch is also possible. Similar to the previous column, "x" in the column indicates a "yes".
- **Redispatch of interconnections/HVDC/phase shifting transformers**: An "x" in the column indicates that a redispatch of the load for interconnections, HVDC and transformers, different from the one recommended by the market model, is possible for congestion alleviation.
- **Redispatch of load or storage with recovery at another point of time mandatory**: This column is dedicated to the redispatch of the load or storage asset where a shift in the dispatch is possible. However, a recovery at another point of time is to be ensured. This is true for heat pumps, sanitary hot water, EVs that are charging from home or office with smart charging possibility with or without vehicle-to-grid (V2G) functionality.
- **Redispatch of charging** & **Redispatch of discharging**: these columns are dedicated to those assets where charging and discharging takes place. Therefore, these columns are pertinent to the assets such as PHS, hydro reservoir, stationary batteries and EVs. Within these categories some of the assets can provide flexibility in the charging but not in the discharging. For example, EVs that are charging at home or office but with no V2G functionality enabled. Some other assets can provide flexibility in charging as well as discharging for congestion alleviation. For example, EVs that are equipped with V2G functionality.

Table 2:The list of technologies that are considered within the S1 study

Technology / Asset /Measure Type	Category	Presence Of The Flexibility Asset Is In T/D/T&D	Flexible?	Generation Curtailment Alone Is The Flexibility Possible	Generation Redispatch (Note: Implies Gen. Curtailment And / Or Redispatch Of Generation)	Redispatch Of Interconnections/ HVDC/ Phase Shifting Transformer	Redispatch Of Load Or Storage With Recovery At Another Point Of Time Mandatory	Redispatch Of Charging	Redispatch Of Discharging
Solar fleet	vRES	T&D	x	x					
Wind onshore	vRES	T&D	x	x					
Wind offshore	vRES	T	x	x					
Hydro RoR fleet	vRES	T&D	x	x					

Technology / Asset /Measure Type	Category	Presence Of The Flexibility Asset Is In T/D/T&D	Flexible?	Generation Curtailment Alone Is The Flexibility Possible	Generation Redispatch (Note: Implies Gen. Curtailment And / Or Redispatch Of Generation)	Redispatch Of Interconnections/ HVDC/ Phase Shifting Transformer	Redispatch Of Load Or Storage With Recovery At Another Point Of Time Mandatory	Redispatch Of Charging	Redispatch Of Discharging
Other RE fleet (Tidal)	vRES	T	x	x					
Waste fleet	RES	T&D	x		x				
Biomass fleet	RES	T&D	x		x				
Geothermal fleet	RES	T	x	x					
Nuclear fleet	Non-RES	T	x		x				
oil	Non-RES	T	x		x				
Lignite fleet	Non-RES	T	x		x				
Coal fleet young	Non-RES	T	x		x				
Coal fleet old	Non-RES	T	x		x				
OCGT young	Non-RES	T	x		x				
OCGT old	Non-RES	T	x		x				
Derived gases fleet	Non-RES	T	x		x				
CCGT fleet old	Non-RES	T	x		x				
CCGT fleet medium	Non-RES	T	x		x				
Interconnections	Network assets	T	x			x			
HVDC	Network assets	T	x			x			
Phase shifting transformer	Network assets	T	x			x			
Heat Pumps	Demand	D	x				x		
Sanitary hot water	Demand	D	x				x		
Airconditioning	Demand	D							
Thermo sensitive remainder	Demand	T&D							
Non thermo sensitive remainder	Demand	T&D							
PHS	Stationary Storage	T	x					x	x
Hydro Reservoir	Stationary Storage	T	x					x	x
Batteries 2-hour	Stationary Storage	T&D	x					x	x
Batteries 4-hour	Stationary Storage	T&D	x					x	x
EV at home with smart charging but non-V2G	EV	D	x				x	x	
EV at office with smart charging but non-V2G	EV	D	x				x	x	
EV at home with V2G	EV	D	x				x	x	x
EV at office with V2G	EV		x				x	x	x
EV at home with immediate charging	EV	D							
EV at office with immediate charging	EV	D							

2.2. CONGESTION METRICS

2.2.1. CONGESTION METRICS FOR TRANSMISSION NETWORKS

Including a transmission network representation in METIS allows to simulate the physics of the electricity flows on transmission networks within Member States. Technical indicators enable to assess the level of congestions in the transmission network for a given situation and to compare relevant snapshots (hours). The additional constraints induced by the flow modelling on the internal transmission grids increase the overall costs for the system compared to a situation where these constraints are absent. The comparison of different situations can provide economic insights on the costs of congestions and the impacts of the introduction of flexibility solutions. Below, is the list of the key performance indicators (KPIs) related to the congestion assessment metrics that are implemented in METIS:

- **Number of congested lines:** the number of congested lines in the network. In this study, a line is defined as being congested if its transmission usage is greater than 99.9%.
- **Transmission usage distribution (%):** distribution of the hourly flow on each line divided by the line rate
- **Curtailment (MWh):** total curtailed energy due to overloads (compared to the outcome of the market model)
- **Loss of load (MWh):** total unserved energy due to overloads (compared to the outcome of the market model)
- **Production mix (MW):** a change in production mix relates to the effects of congestions on the dispatch (difference from the outcome of the market model for a given hour).
- **Total production costs (€):** a change in production costs relates to the impact of alleviating congestions on the overall operational cost.

2.2.2. CONGESTION METRICS FOR DISTRIBUTION NETWORK

The following key performance indicators were considered for distribution networks:

- **Violation frequency (%):** measuring the percentage time of the network's operation (of typically one year), during which operational values are not within the nominal range (i.e., a technical violation is happening). Two types of metrics are distinguished:
  - **Overvoltage and undervoltage violation frequency**, which measures the share of time during which maximum and minimum nominal voltage values of the network are not respected, respectively.
  - **Cable and substations overload frequency**, measuring the share of time during which the electrical load exceeds the nominal capacities of cables and substations in the network, respectively.
- **Violation intensity (%):** it calculates the average value of the violations' magnitude (i.e., deviation between the actual value and the maximum/minimum technical limit), in percentage, with respect to the maximum/minimum nominal capacities, during the steps the violation is happening. Two types of metrics are distinguished:
  - **Overvoltage and undervoltage violation intensity,** which measures the intensity of the violation with respect to the maximum and minimum voltage values of the network, respectively.
  - **Cable and substations overload intensity**, measuring the intensity of the violation with respect to the nominal capacities of cables and substations of the network, respectively.

- **Total load (kWh):** yearly energy consumed by the network.
- **Total generation (kWh):** yearly energy produced by the network.
- **Total load shedding (kWh):** yearly energy shed by the network.
- **Relative load shedding (%):** percentage of the yearly energy shed by the network, with respect to its initial yearly demand.
- **Total generation curtailment (kWh):** yearly energy curtailed by the network.
- **Relative generation curtailment (%):** percentage of the yearly energy curtailed by the network, with respect to its initial yearly generation.

2.2.3. TASK 2: REFERENCE SITUATION

This task identifies issues of grid congestion at the distribution and transmission grid levels (implying RES curtailment or loss of load) based on a situation where the power dispatch was determined by a run of the METIS market module of the METIS EUCO3232.5 scenario, thereby demonstrating the need for flexibility and redispatch. That is, the optimal solution as suggested by the market model (considering a copper plate within countries) is imposed on the transmission and the distribution networks to check whether RES curtailment or loss of load would take place when not accounting for the physics of internal networks, or, in other words, without remedial measures being activated (e.g., redispatch).

For the transmission network that means that, in a first step, the optimised grid injections and withdrawals are simulated disregarding grid constraints, in order to determine the unrestrained power flow (based on the copper plate approach within countries). Subsequently, the analysis is repeated by considering grid constraints and observing the levels of loss of load as well as curtailment. The comparison of both simulations provides indications regarding the location and intensity of congestions (via the indicators introduced in Task 1) and the potential need for activation of flexibility measures such as redispatch or different settings of HVDCs or PSTs. A similar approach has been adopted for the distribution network.

From that reference situation, flexibility solutions at both transmission and distribution levels are integrated one by one in Task 3 (transmission) and Task 4 (distribution), in order to evaluate their potential role and to quantify the magnitude of the resulting impacts, and also their limitations (for example, a saturation effect of interconnections' benefits is expected beyond a specific interconnection capacity).

The following subsections discuss the methodologies and assumptions that are pre-requisites for the launch of the simulations of the reference situation in the METIS platform. Starting from the input and results of the market model simulation, the section discusses how the generation and load data are disaggregated to build the input data required for the transmission and the distribution network models. This is presented as methodologies and assumptions at the transmission network level followed by those at the distribution network level.

2.3. METHODOLOGIES & ASSUMPTION FOR TRANSMISSION

2.3.1. MARKET MODEL DISAGGREGATION FOR TRANSMISSION MODULE

The zonal market model included in METIS simulates the country-level optimal dispatch of power generation in each zone (usually a country) and the exchanges between zones using an hourly time resolution, on a one-year horizon (8760 consecutive time-steps). For each zone, a description of the production capacities, including flexibility solutions, the commodity prices, and the non-flexible and flexible demands is given with a high technological granularity. Every technology is characterised by a set of techno-economic parameters and operational constraints. The market module computes the optimal hourly dispatch of each asset to meet the balance between electricity demand and production, while minimising the overall cost of the system. The zonal market situation is used as an input to create the transmission reference situation, based on a methodology that is described in the following paragraphs.

Disaggregation process

Transmission grid modelling in METIS has the purpose to extend the scope of power system modelling from a pure market-based approach to a more holistic assessment. The newly developed transmission module aims at explaining how the results of the pure market-based approach (which is also called "zonal market model" in the following sections) differ from a simulation at nodal level that takes into account internal transmission network constraints. These constraints are not considered in the initial zonal market model that only models the commercial exchange capacity between zones (NTC), where each bidding zone is considered as a "copper plate". The overall framework relies on the assumption that the market drives the process of dispatch for each bidding zone of the system. However, since the markets do not take into account the physical constraints of internal networks, the outcome of the market clearing can include unfeasible dispatches. To overcome this issue, TSOs have mechanisms to avoid congestions on transmission networks through a set of measure, including re-dispatching part of the production and/or demand, which comes at a certain cost. The transmission module aims at better capturing the techno-economic stakes of this process.

The METIS transmission module simulates a projection of the "zonal market model" on a nodal model of the transmission network for each European country. The nodal model includes internal transmission lines, interconnections, transformers, aggregated generation capacity per technology per node and aggregated demand per node. The "nodes" of the network are aggregated per voltage level and represent the network substations. They are linked either to an asset (generation, demand) or to another node via a transmission or a transformer. The process of projecting a market model scenario onto the transmission grid is called "disaggregation". The disaggregation allows the user to switch from a zonal approach to a nodal approach based on the same scenario. The information related to the dispatch of the zonal market model is also inherited by the nodal model so as to enable the simulation of the outcome of the market clearing (without any redispatch or remedial action). Once the disaggregation is performed, a Direct Current Optimal Power Flow (DCOPF) model is run on the nodal transmission model, which computes the optimal re-dispatch to minimise the overall costs of the system, while considering the dynamics of the flows of electricity on the transmission network.

A commonly used network model is the AC Optimal Power Flow but its computational complexity (the problem is non-linear and non-convex) makes it difficult to solve at the scale of the European network. The approach that has been chosen in the METIS transmission module is therefore a DC Optimal Power Flow, which is a linearisation of the AC Optimal Power Flow. This established industry approach offers a trade-off between the complexity of the computation and the accuracy of the results. DC power flow only considers active power flows, assumes perfect voltage support and reactive power management, and neglects transmission losses.

Additional optimisation constraints can be added to simulate specific re-dispatch processes, for example a re-dispatch by zone that respects the net-positions (exports – imports) for each zone given by the zonal market model simulation.

How does the transmission disaggregation work?

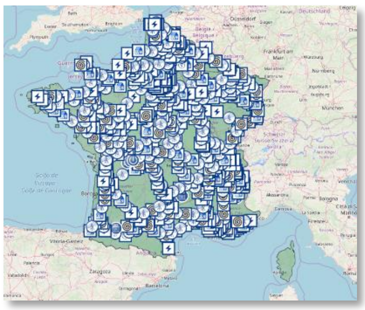

Figure 1: Zonal market model (left) - nodal transmission model (right) for France

The disaggregation from the zonal market model to the nodal transmission model is done in 4 steps:

a) Mapping from zonal technologies to nodal technologies

b) Disaggregation of installed capacities of generation technologies for each node

c) Disaggregation of demand for each node

d) Disaggregation of commodity prices and production costs.

The disaggregation principle relies on a projection of the zonal market model to a nodal transmission model. This nodal representation of the grid is further described in the following section (2.3.2). The nodal description of the grid is composed of the following elements:

- Transmission lines (internal and interconnections):
  - Maximum capacity in MW
  - Reactance in Ω
- Transformers:
  - Maximum capacity in MW
  - Reactance in Ω
  - For Phase Shifting Transformers: minimum and maximum phase shift angles in degrees
- Generation assets per node and per technology:
  - Disaggregation capacity in MW
  - Minimum load in % of available capacity – if applicable
- Demand assets per node:
  - Disaggregation demand in MW

The outputs of the disaggregation process are the results of the projection of the characteristics of the zonal scenario on the nodal transmission model. More precisely, the disaggregation process outputs are:

- Installed capacity in MW per generation asset per node, disaggregated from zonal modelling (based on an initial "Disaggregation capacity" assumption in the nodal representation that serves as a disaggregation key, enabling the user to e.g. change assumptions in the market model, for example by adding solar PV in a country, and re-running the disaggregation process, resulting in a consistent update of the transmission-level assumptions)
- Commodity prices from zonal modelling (CO2 emissions costs, fuel costs)
- The availability timeseries that set the available capacity for each timestep of the simulation per asset, derived from zonal modelling
- Production costs for each nodal technology derived from the results of the zonal market model.
- Net-positions (exports – imports) for each zone given by the zonal market model simulation, as inputs in some constraints
- Power production by asset and by zone, resulting from the zonal market model simulation

Description of the disaggregation steps

a) Mapping zonal and nodal technology

This first step is important because the description of the technologies might vary from one zone or from one dataset to the other. Thus, the mapping process enables to link the zonal market model conventions (in our case, the METIS list of technologies), with the nodal transmission model description. In this study, the nodal datasets are partly based on ENTSO-E's TYNDP 2018 CGMES dataset [5] (see section 2.3.2).

Example of a technology mapping for the disaggregation process:

Table 3: Illustration of the assets mapping in the disaggregation process

Zonal Technology	Nodal Technology
Coal fleet Decentralised thermal fleet Derived gasses fleet Geothermal fleet Lignite fleet OCGT fleet Oil fleet Other renewable fleet Other thermal fleet Regulated Coal fleet Regulated Oil fleet Waste fleet	Other fleet
Wind offshore fleet	Wind offshore fleet
Wind onshore fleet	Wind onshore fleet
CCGT fleet	CCGT fleet
Hydro fleet	Hydro fleet
Pumped storage fleet	Pumped storage fleet
Hydro RoR fleet	Hydro RoR fleet
Nuclear fleet	Nuclear fleet

In this example, 12 different zonal technologies are mapped to a generic technology "Other fleet", because of the difference of accuracy of the available nodal description of the European grid. As mentioned above, this mapping can differ from one dataset to the next, allowing the user to refine the disaggregation process when updates of e.g. the nodal dataset is made available.

The mapping must be provided for each zone, as the accuracy of the system's description can vary from one zone to the next (e.g. in case different TSOs adopt different conventions when reporting installed capacities in their respective grid models).

b) Disaggregation of installed capacities of generation technologies for each node

The second step of the disaggregation process is the adjustment of installed capacities at the nodal level, for each nodal technology. The mapping realised in the first step enables to compute the total capacity per nodal technology that has to be disaggregated between the nodes of each zone.

Then, a nodal coefficient for disaggregation is computed for each technology, based on the "disaggregation installed capacity" that is given in the default nodal description of the grid (built from the CGMES dataset of the TYNDP 2018 2025 Best

[5] https://www.entsoe.eu/digital/cim/cim-for-grid-models-exchange/

Estimate scenario). This value is used as a "weight" to compute the share of a given nodal asset over the total capacity of its zone to be consistent with the zonal scenario. The example below is a simplified version for the "Wind onshore fleet" technology in the case of a 3-nodes representation of France's transmission network and a total zonal installed capacity of 30 GW. The left-hand side shows the to-be-disaggregated zonal model, with 30 GW of installed capacity. On the right-hand side, one can see in green the "disaggregation installed capacity" allocation key, that is based on the TYNDP CGMES dataset. In order to obtain the nodal installed capacities, the disaggregation process automatically distributes the zonal installed capacity (30 GW) onto nodes, in proportion of the allocation key. The results are shown in orange

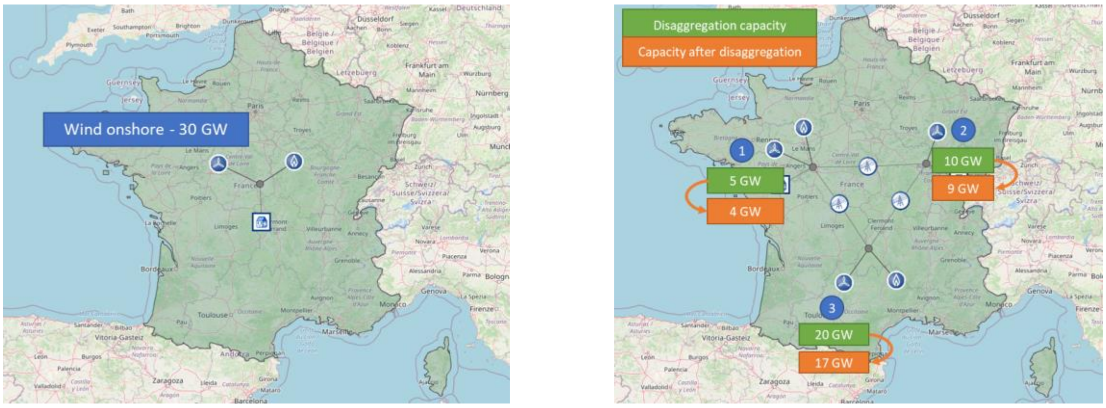

Figure 2: Illustration of capacity disaggregation (simplified model)

	Disaggregation capacity	Disaggregation coefficient	Nodal capacity
Wind onshore 1	5	14% = 5 / (5 + 10 + 20)	4
Wind onshore 2	10	29% = 10 / (5 + 10 + 20)	9
Wind onshore 3	20	57% = 20 / (5 + 10 + 20)	17

The availability (which represents the maximal "load factor") for generation assets in the nodal description are taken from the corresponding zonal market model asset.

c) Disaggregation of demand for each node

The disaggregation of the demand is based on the same principle as the disaggregation of the installed capacities of power generation. Each node has a determined coefficient for the share of the demand of the zonal model, which comes from the CGMES dataset. The demand is split between the nodes based on this coefficient, which is provided in the nodal description of the grid for each zone.

d) Disaggregation of commodity prices and production costs

The last step is the disaggregation of the costs from the zonal model to the nodal model. For CO2 emissions, and fuel costs (gas, oil, coal, lignite, biomass etc.), they are retrieved from the zonal model and implemented in the nodal model depending on the zone (costs might vary from one zone to another).

Methodology for nodal simulations

The previous section has described how the disaggregation process is performed, to project zonal market model output onto a nodal transmission model. This section's purpose is to present how simulations are performed. The following figure presents an overview of the three models that are available: the zonal market model, and two nodal ones that are run depending on the type of questions being explored.

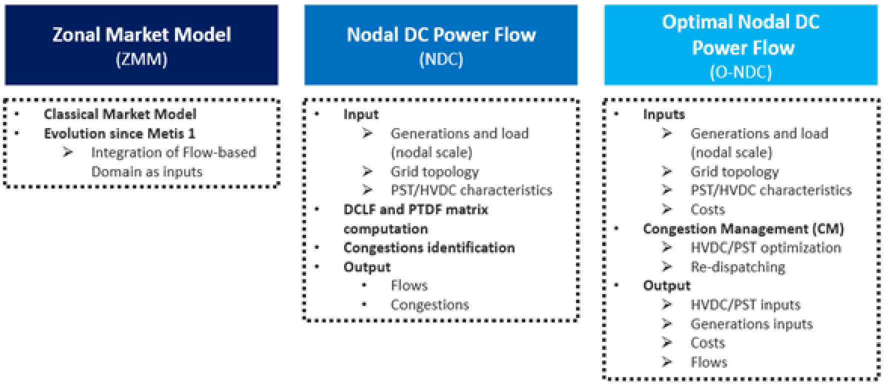

Figure 3 - Workflow for METIS transmission modules

The reference situation is the result of a "Nodal DC Power Flow", taking injections and withdrawals at each node as assumptions built from the outputs of the market model. A Direct Current Load Flow (DCLF) problem takes the net power injection at each node of a network and determines how the power flows through the lines of this network. It is mainly used to identify congestions as indicated above. The "Optimal Nodal DC Power Flow" optimises the injections and withdrawals of each technology on the nodal network. It is therefore used to adapt the dispatch in case congestions are identified. Both Direct Current Load Flow (DCLF) and Direct Current Optimal Power Flow (DCOPF) are based on network physical laws alongside three major hypotheses (the DC simplification of the AC model):

- The voltage magnitude is fixed for each node to its nominal value
- The voltage angle difference is small for each pair of adjacent nodes
- The resistance of transmission lines is negligible compared to their reactance
- To perform a pure DCLF, the injection at each network node per generation asset is required. To do this, an accurate dispatch of each production unit has to be performed. Two methods are possible to perform the DCLF:
    1. Provide as inputs of the disaggregation process **technical data of each production unit**, to know for example which power plant is the most likely to produce. This way the dispatch over individual power plants at each node can be done following a merit order.
    2. Provide as inputs of the disaggregation process a **distribution key** for the nodes of each zone and for each technology.

In this study, instead of relying on a DCLF approach to identify congestions, a **congestion detection methodology** that uses a **DC optimal power flow** (DCOPF) problem has been designed. This choice has been made to avoid introducing complexity related to the disaggregation of the production plan into this study. Future studies may use the DCLF approach to detect congestions, based on its random dispatch generator which allows to generate market-compatible nodal dispatches, based on a probabilistic allocation of production levels of a given zonal fleet to nodal assets belonging to that technology fleet.

Reference situation specificities

- Dispatch of the production

The goal of the reference situation is to analyse how the zonal market model can be projected on the nodal transmission network to simulate the power flows on the grid. To ensure the consistency with the zonal market simulation, the **total production of a zone in the nodal context is constrained to be equal, for each technology, to the resulting value of the zonal market model for this zone and this technology**. The required information is extracted from the market model via the disaggregation process.

This constraint allows to maintain the key market outputs in the zonal model: **the net positions** and the **production by technology type of each zone** remain equal to the market model results.

$$\sum_{i \in nodes\_in\_zone(z)} P_i^j = P_z^j \,, \qquad \forall j \in technologies, \forall z \in zones$$

In the equation above, P_i^j is the variable representing the power injected at node i by the technology j. Therefore, adding the above set of constraints to the nodal DCOPF model ensures that for each zone and for each technology, the production is optimally dispatched between the nodes belonging to the same zone. Practically, it implies that the total production of on technology type is optimally dispatched between the nodes (subjected to production capacity constraints) within each zone, and is compatible with the outcome of the zonal market dispatch.

- High Voltage Direct Current transmission lines:

As high-voltage direct current (HVDC) lines uses direct current, the equations governing the flows have to be adapted. The flow through the HVDC is considered as being entirely controllable, that is why they can be seen as an optimisation leverage. As the HVDC lines represent a significant proportion of the interconnection lines in our 2030 scenario, it is necessary to consider their flows in the reference situation. The amount of power flowing through each HVDC line is an optimisation variable of the DCOPF run in this study. It can take any value compatible with the power limit of the line.

- Phase Shifting Transformer:

A phase shifting transformer (PST) is a specialised form of transformer used to control the flow of real power on three-phase electric transmission networks. The phase shift angle of each PST is set to zero in the reference situation. PSTs are considered as one of the flexibility solutions that are investigated in the following.

Time-step selection

The METIS transmission module allows to assess the power flows on a transmission grid description on **snapshots** (hours). A selection of relevant snapshots is made using criteria based on variable renewable energy production and power demand. They aim at representing both extreme and average situations for the grid. The key indicator used to select time-steps of these snapshots is the residual demand of the entire system. It is obtained as the difference between the market module optimised demand (consumption after optimisation of flexible assets such as heat pumps or electric vehicles) and the non-dispatchable production in the model, mainly variable renewable energies (Hydro RoR, Solar, Wind onshore/offshore). Below are the definitions of selected snapshots:

- T1: Minimum of residual demand
- T2: Maximum of residual demand
- T3: Minimum of residual demand in winter (October 15th – April 14th)
- T4: Maximum of residual demand in summer (April 15th – October 14th)
- T5: Average wintertime time-step
- T6: Average summertime time-step

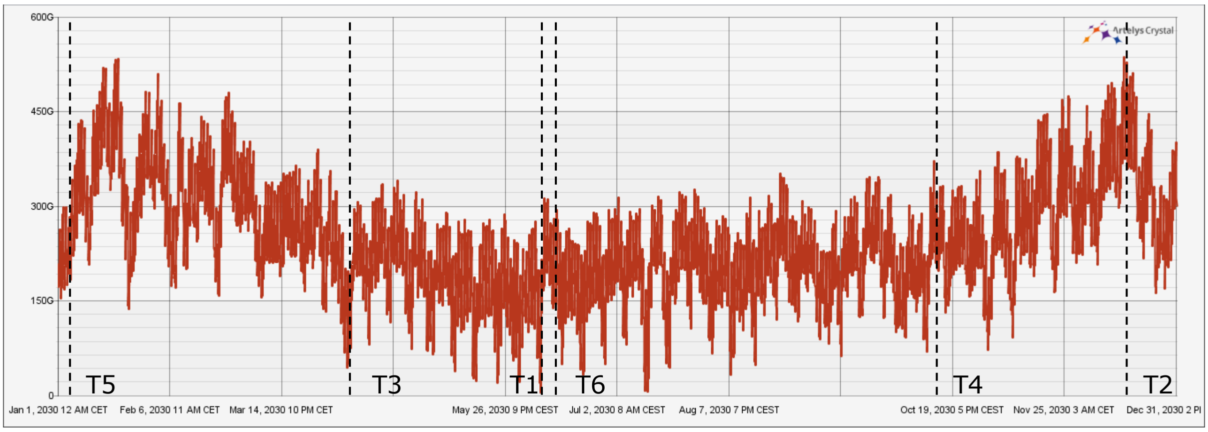

Figure 4: Snapshot selection based on the residual demand time-series

2.3.2. Transmission network description

The main transmission network dataset has been obtained via the ENTSO-E On-Line Application Portal for Network Datasets[6]. This dataset is based on the data collection from each European transmission system operator (TSO) and uses the Common Grid Model Exchange Standard (CGMES) format. It includes the input grid datasets for the preparation of the TYNDP 2018 and describes the situation of the TYNDP Best Estimate 2025 scenario. As the data is collected from various TSOs, some heterogeneity in the accuracy of the provided data have been found and processed. In a following step, the CGMES dataset has been analysed and converted to a format readable by the METIS transmission module.

The dataset includes a description of the network topology (lines, nodes, transformers), a list of generating units and the results of a simulation on one time-step corresponding to a winter hour. The current dataset describes the transmission systems of 28 countries (including Albania) corresponding to two synchronous regions: Continental Europe and Baltics (see Figure 5). The data of 5 remaining countries (Great-Britain, Ireland, and Nordic countries) are not included, notably due to legal constraints in the case of the Nordic countries.

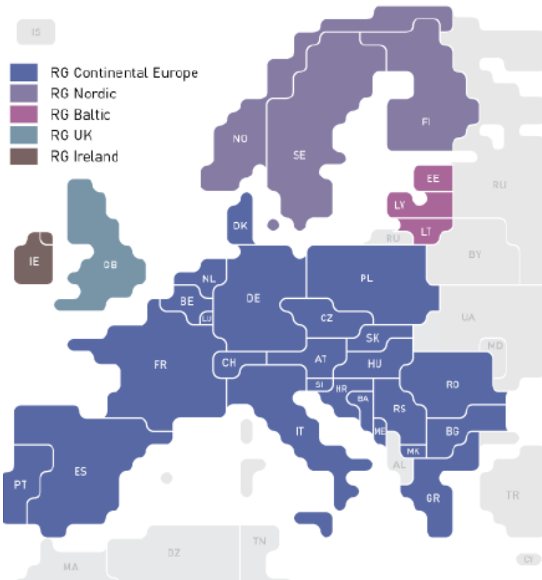

Figure 5: ENTSO-E network regions. Source: TYNDP 2018 ENTSO-E dataset specification.

[6] entsoe.eu/publications/statistics-and-data/#entso-e-on-line-application-portal-for-network-datasets

Network topology description

The nodal network dataset contains 14972 nodes divided into the different zones according to the following table.

Zone	Nb nodes		Zone	Nb nodes		Zone	Nb nodes
AL	281		HU	89		DK	246
AT	94		IT	1869		EE	259
BA	274		LT	455		ES	1012
BE	461		LU	31		FR	1655
BG	695		LV	300		GR	974
CH	153		ME	134		HR	216
CZ	65		MK	125		PL	286
DE	2315		NL	1067		PT	587
RS	1005		SK	28		RO	111
SI	175						

Table 4: Number of network nodes per zone based on the CGMES dataset

The following chart (Figure 6) shows the breakdown of the voltage nodes of the whole dataset of the transmission network:

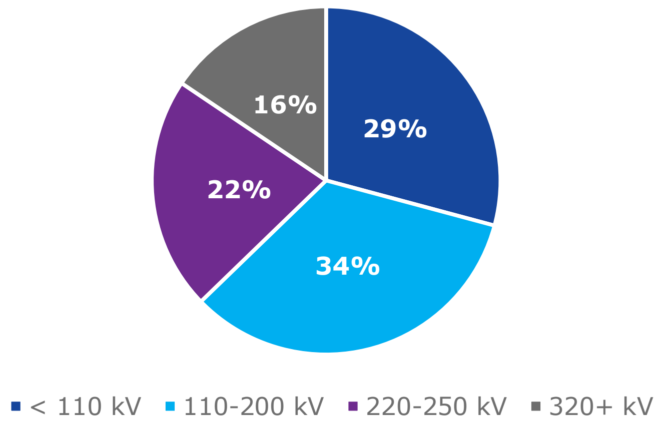

Figure 6: Distribution of voltage levels

There are 14594 AC-transmission lines in the transmission network dataset, 259 of them are identified as interconnections between different zones. The rest of them are internal lines divided into zones according to the following table:

Zone	Nb of internal lines		Zone	Nb of internal lines		Zone	Nb of internal lines
AL	202		HU	85		DK	291
AT	128		IT	966		EE	317
BA	294		LT	565		ES	1192
BE	690		LU	22		FR	2172
BG	850		LV	325		GR	1170
CH	226		ME	90		HR	303
CZ	101		MK	147		PT	599
DE	1393		NL	930		RO	159
SI	267		PL	366		RS	699
SK	45						

Table 5: Internal AC-line number per zone based on the CGMES dataset

There are 69 HVDC lines in the network, 68 of them are identified as interconnections between different zones.

The transmission network contains 7781 transformers plus 107 Phase Shifting Transformers (PST).

Generation and demand description:

The nodal transmission description of the European transmission network is based on the CGMES dataset for the scenario "Best Estimate 2025" for the synchronous zones of continental Europe and Baltics. In the disaggregation process of the transmission module, the zonal market model is projected on this representation. The original installed capacity of the generation plants located on the different nodes are based on the scenario "Best estimate 2025" of TYNDP 2018. As detailed in the disaggregation process, they are used as weights to disaggregate zonal installed capacities, based on METIS EUCO3232.5, onto the nodal system.
The initial dataset provides the following generating unit types:

- Generating Unit
- Thermal Generating Unit
- Hydro Generating Unit
- Wind Generating Unit
- Solar Generating Unit
- Nuclear Generating Unit

After processing, the nodal description of the transmission network is composed of 9 different technologies: Nuclear fleet, Thermal fleet (gathering Coal, Lignite, Oil and Gas-powered generation plants), Solar fleet, Hydro RoR, Pumped storage fleet, Hydro reservoir, Wind onshore, Wind offshore and a generic type "Other fleet". This last type is used to gather the generation units that are not labelled in the CGMES dataset[7].
The breakdown per country is as follows:

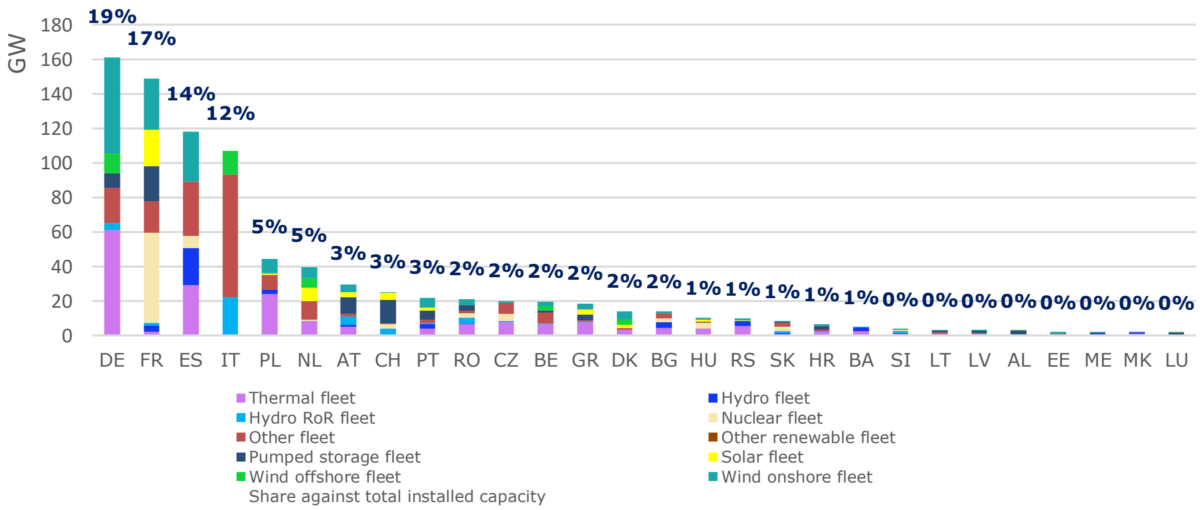

Figure 7: Installed capacities per country based on the TYNDP18 2025 BE scenario, extracted and processed from the CGMES dataset

These installed capacities per technologies, per zone are used in the disaggregation process to weight the downscaling from the zonal model installed capacities to the nodal description. As it can be seen in the graph below, the share of "Other fleet" is still quite important (22% of total nodal capacity). The challenge is to reduce this share to a minimum, with a more accurate description of the nodal grid. Future updates of the nodal dataset may increase the technological granularity of the default representation of the transmission model.
The demand is shared between zones based on the data extracted from the CGMES data set that represents a simulation of a wintertime time-step over Europe:

[7] An additional data request is under discussion between the European Commission, the contractors and the ENTSO-E.

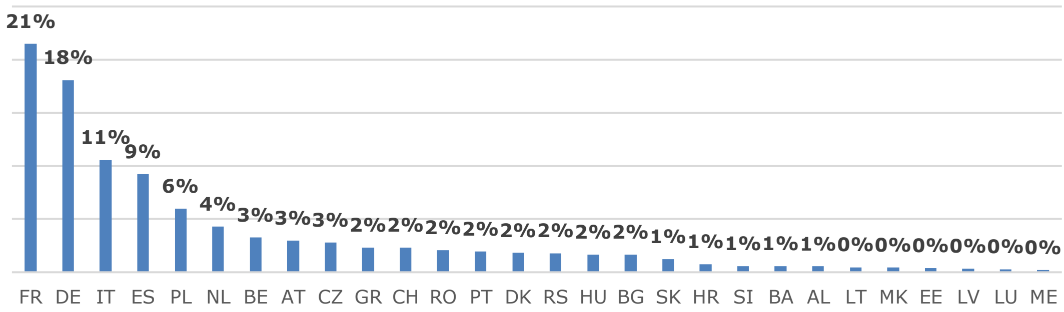

Figure 8: Share of total demand over European countries

Thanks to this default transmission configuration, one can easily disaggregate the METIS EUCO3232.5 scenario onto the transmission grid via the METIS transmission module.

2.4. Methodologies & Assumption for Distribution

This section discusses the methodologies and assumptions for the distribution network. This section is divided into two major parts:

- Part 1: deals with the methodologies and assumptions applied for building the representative distribution networks by means of archetypes and climatic zones that is elaborated in Section 2.4.1.
- Part 2: deals with the methodologies and assumptions for running the distribution core model (Section 2.4) This section in turn has subsections as follows:
    - The methodology for disaggregation of operational parameters of market assets
    - Mapping of assets to match the distribution assets as defined in the DCM
    - Flexibility considerations and their impact on the DCM's objective function
    - Assumption on the current task scenarios

2.4.1. Archetypes and Climatic Zones Building

"Archetypes" are synthetic networks whose aim is to be representative of the distribution networks of a country. Three types are distinguished: urban, semi-urban and rural, depending on the degree of urbanisation of the represented zone. Each of these three categories are characterised by a certain number of parameters typically seen in this type of networks as shown below:

- Topology: density of consumers and producers, density of substations, length of feeders, number of feeders per substation, etc.
- Electrical equipment: nominal capacities and resistance of transformers, nominal capacities and resistance of cables, substations capacity, etc.

One of archetypes' main assumptions is on their uniformity. This means that, disregarding the actual size of the network, whenever looking at any unitary surface within it, its topology and operation becomes the same. This comes from the fact that, at macro scale, networks tend to become homogeneous. Based upon this, whenever assessing the operation of a given archetype, the tool simulates its operation within a unitary surface and extends subsequently the results based upon the absolute area of the network.

2.4.1.1. Disaggregation of network parameters

The way archetypes are constructed follows a top-down approach. Firstly, the country-level data is collected for the 34 countries considered in the zonal market model. Information such as the total number of consumption nodes, type of voltage levels and the total length of distribution lines are collected and classified by country. Secondly, following the work done in [5], representative urban, semi-urban and rural networks are generated for the whole Europe. These three networks are then projected over the country's urban, semi-urban and rural zones and adjusted to match the real values collected in the first step.

The above process is called "disaggregation" of network parameters and aims at shifting from the zonal market representation to a distribution network representation. It follows a proxy-based approach, meaning that the way values are projected from country to archetypes follows a proportionality rule with respect to (macro) proxies that can be estimated for the network. For instance, the density of consumption nodes becomes proportional to the population density of the zone of interest; similarly, the length of lines is considered as being proportional to the number of substations and the population of the zone. An example of mapping from zonal to distribution representation is shown in Figure 9.

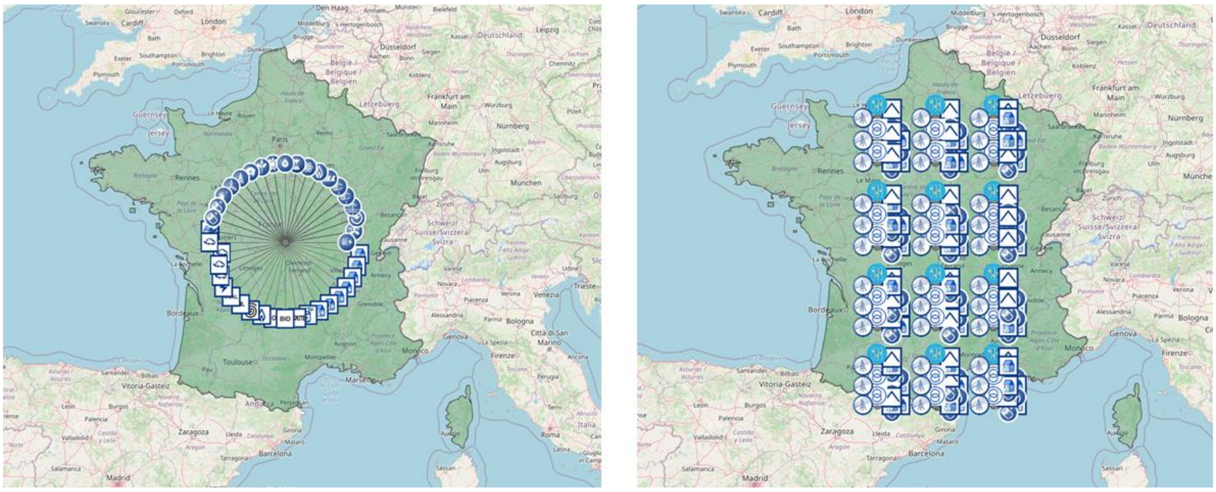

Figure 9: Zonal market model (left) - distribution model (right) for France

2.4.1.2. Climatic zones

A second concept needed for the understanding of the present modelling are "climatic zones". This notion tries to capture how different weather conditions impact the operation of the electrical network. This is of great importance when assessing the impact that distributed energy resources on the electrical mix of a country. In order to accomplish this, a climatic zone is constructed by clustering the temperature, solar irradiation and wind speed profiles of the urban centres of each country. All locations belonging to the same cluster are represented by the same profile, and archetypes mapping the networks within those locations are all exposed to them. In this way, the same type of network (for example, urban) is subjected to different operational conditions, reflecting different situations that can be encountered along the geography of the country. It is observed as well that a climatic zone, following the zonal market model's approach, captures the climatic variability with on an hourly time-step resolution in a one-year time horizon. In this way, daily, weekly, and seasonal effects that are climatic-zone specific can be captured. An example of the clustered climatic zones for France is shown in Figure 10.

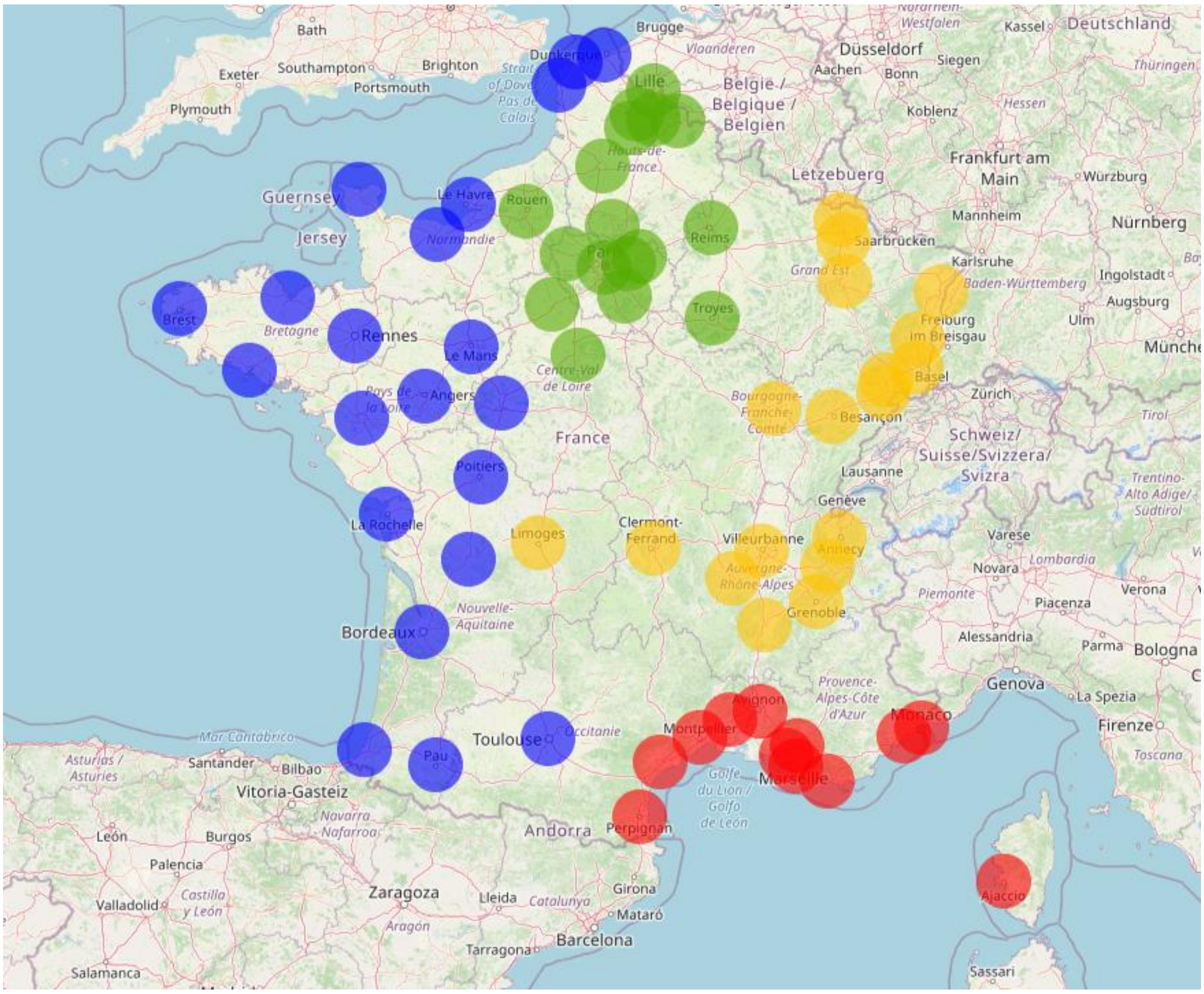

Figure 10: Illustration of the climatic zones clustering for France

It is important to understand that a country's networks are defined by pairing an archetype with a climatic zone: while the first (i.e., the archetype) characterises the electrical topology of the network, the second (i.e., the climatic zone) describes its geography-related parameters such as position, size, and climatic conditions. This is done by mapping the location of the network and linking it with the respective climatic zone. The details with the number of networks constructed by country are presented in Table 6. The number of archetypes being constant (i.e., urban, rural, semi-urban =3) per country, their number of climatic zones were defined considering their total surface and degree of climatic variation. For 34 countries considered, a total of 288 networks were designed.

Table 6: Summary of the number of archetypes and climatic zones per country

Country	Number of Climatic Zone	Number of Archetypes	Distribution Networks
Austria	2	3	6
Belgium	2	3	6
Bulgaria	3	3	9
Croatia	2	3	6
Cyprus	2	3	6
Czech Republic	2	3	6
Denmark	2	3	6
Estonia	2	3	6
Finland	3	3	9
France	4	3	12
Germany	5	3	15

Country	Number of Climatic Zone	Number of Archetypes	Distribution Networks
Greece	4	3	12
Hungary	3	3	9
Ireland	3	3	9
Italy	4	3	12
Latvia	2	3	6
Lithuania	2	3	6
Luxembourg	1	3	3
Malta	1	3	3
Netherlands	3	3	9
Poland	5	3	15
Portugal	3	3	9
Romania	5	3	15
Slovakia	2	3	6
Slovenia	2	3	6
Spain	6	3	18
Sweden	2	3	6
United Kingdom	4	3	12
Bosnia and Herzegovina	2	3	6
Macedonia	2	3	6
Montenegro	1	3	3
Norway	3	3	9
Serbia	2	3	6
Kosovo	2	3	6
Switzerland	3	3	9
34 countries / total:	**96**	**105**	**288**

Note that a network's installed capacities (e.g., solar PV) is defined via interaction with the zonal market model, in a disaggregation process that will project demand and generation over the distribution networks. This is discussed in the next section.

2.4.2. *DISTRIBUTION CORE MODEL AND ZONAL MARKET MODEL INTERACTION*

Once the archetypes are built, a simplified optimal power flow simulation model is used to calculate the flow of power going through their different elements. This is done by means of the Distribution Core Model (DCM), an optimisation tool developed for the analysis of large-scale distribution systems.

The main principle defining the interaction between the zonal market model and the DCM is that the former is the main decision-maker on the platform. In principle, the DCM follows what is suggested by the market, provided that the physical constraints captured by the archetypes are respected. For doing so, the output of the zonal market model is disaggregated and projected on the archetypes, and in case infeasibilities are encountered, the market's instructions are redispatched by the DCM to deviate in the less possible way from the initial dispatch produced by the METIS market model.

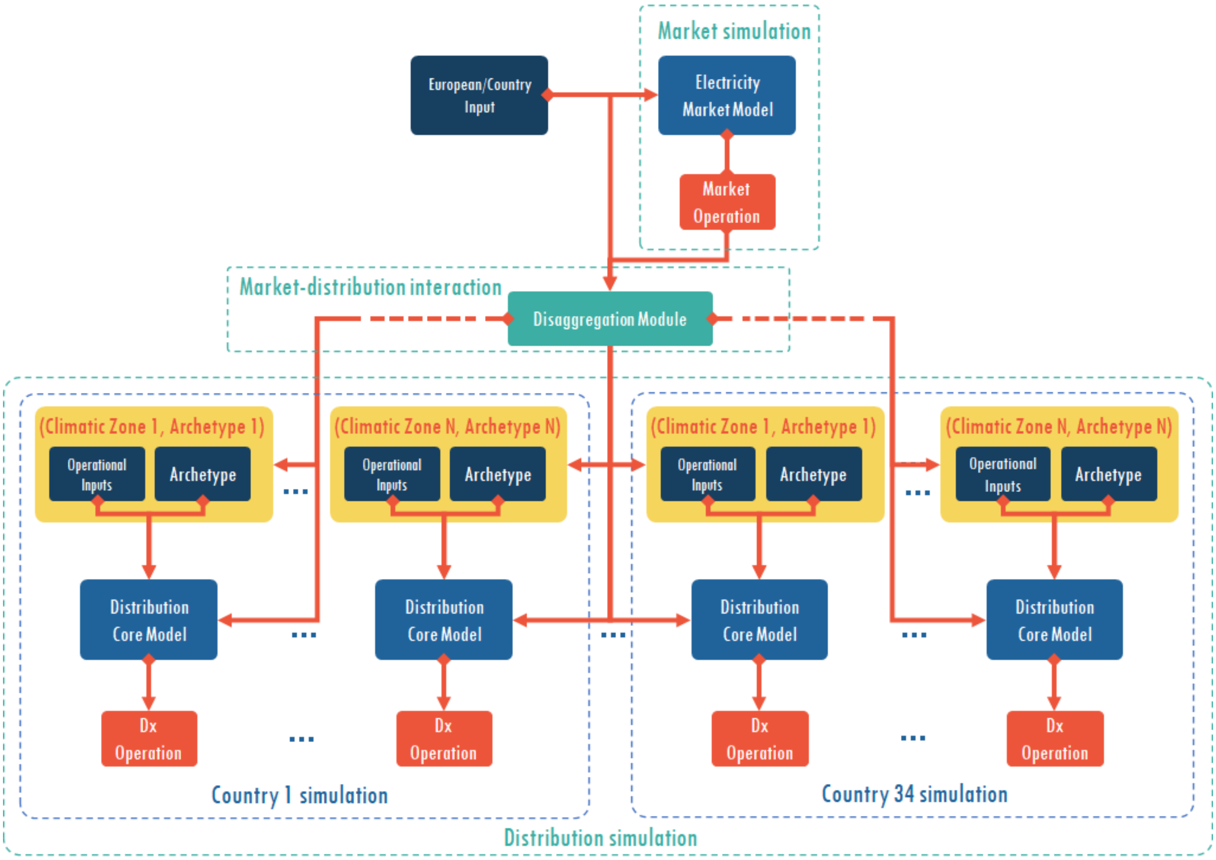

Figure 11: Market - DCM interaction diagram

A diagram describing the interaction between market and distribution is presented in Figure 11. The process can be divided in three main steps:

a) Market simulation: The process starts by solving the zonal market model. This provides the optimised dispatch of each country according with their own operational restrictions and techno-economic parameters.

b) Market-distribution interaction: Market dispatch is projected over the archetypes of each country. This process determines the operational information needed for an archetype to be launched under the DCM. Example of this type of information are generation and consumption profiles.

c) Distribution simulation: It corresponds to the process archetype optimisation process by means of DCM simulations. A single DCM must be launched for each network. A total of 288 DCM runs is therefore needed to simulate the ensemble of countries.

The market module being part of the first version of the tool, the following subsections elaborates only on the two last steps of the process which includes a disaggregation methodology for projecting the market's operation output, and the modelling of the DCM's objective function.

2.4.2.1. Disaggregation of market assets operational parameters

In this process, information regarding the market operation at country (zone) level, as decided by the zonal market, is projected over all the archetypes within the country. The data is classified mainly in three types, demand, generation, EVs, corresponding mainly to the hourly dispatch profiles of the respective assets present in the market. Other types of information are considered as well by the disaggregation process, such as the technical constraints restricting the operation of the assets.

Following a similar approach as of the network topology disaggregation methodology, a certain number of proxies are used to estimate how much of electricity, in terms of generation and demand, is allocated to each archetype. This is summarised in Table 7. For example, the number of heat pumps is considered as being proportional to the archetype's and climatic zone's population. Additionally, the intensity of the demand is considered as well to be proportional to a given temperature coefficient, which reflects how the temperature of the climatic zone varies along the year and its impact on the demand itself. This is captured by the specific climatic zone into which the asset is disaggregated. It is important to note that factors are normalised across all the archetypes and climatic zones of the country. The absolute values of the coefficients are therefore not relevant, but their relative weight compared with the rest of the distribution networks of the country.

Table 7: Disaggregation proxies per type of market asset

Market Asset	Archetype proxy	Climatic Zone proxy	Distribution voltage level
Heat pumps	Population	Population and Temperature	LV
Sanitary hot water	Population	Population	LV
Air conditioning	Population	Population and Temperature	LV, MV
Thermosensitive remainder	Population	Population and Temperature	LV, MV
Non-thermosensitive remainder	Population	Industrialisation	LV, MV, HV
Wind onshore fleet	Surface[8]	Wind speed and Size[9]	LV, MV, HV
Solar fleet	Surface[8]	Irradiation and Size[9]	LV, MV, HV
Hydro ROR fleet	Surface[8]	Size[9]	LV, MV, HV
Biomass fleet	Surface[8]	Size[9]	LV, MV, HV
waste fleet	Surface[8]	Size[9]	LV, MV, HV
PHEV home charge	Population	Population	LV
PHEV work charge	Population	Population	LV
BEV home charge	Population	Population	LV
BEV work charge	Population	Population	LV

We note that the previous methodology considers an allocation of assets between the transmission and distribution levels, i.e., it estimates which part of the capacity/production belongs to transmission level and which part does belong to the distribution level. Only the distribution part is therefore considered by the distribution-level disaggregation process discussed here.

Once an asset's profile is projected over a network, the next step is to disaggregate it into the different voltage levels of the distribution network. For doing so, repartition coefficients are defined in terms of the asset itself. For instance, electrical vehicles are always connected at the lowest voltage level of the distribution network, whereas the industrial demand is connected to the low, medium, and high voltage levels in different proportions. Coefficients for this disaggregation have an hourly resolution and depends on the country. Mapping of assets to match the distribution assets as defined in the DCM

[8] Surface estimates the actual surface of the zone within the country.

[9] Size measures the number of urban zones contained in the climatic zone.

The DCM can mainly distinguish four types of generic assets: demand, generation, EVs[10] and Batteries. Profiles belonging to the same category are grouped by direct addition, giving a single input profile per type. The specific way they are threated is described as follows:

- Demand: one single demand assets profile, divided in two subcategories:
    - Flexible demand, which considers both Heat-pumps and Sanitary Hot Water assets. This demand can be dispatched via load shifting actions.
    - Non-flexible demand, considering the following market assets: Air Conditioning, Thermosensitive Remainder, Non-thermosensitive Remainder, and Hybrid and Battery immediate-charging EVs. This part of the demand is considered as a fixed load which can be modified neither by the market nor the DCM.
- Generation: one single generation asset profile, considering Wind Onshore, Solar, Hydro RoR, Biomass and Waste market assets. This type of asset is considered as curtailable.
- Electrical Vehicles: Electrical vehicles that can be charged either in vehicle-to-grid or smart charging mode is considered in this section.[11] Four types are distinguished, based on their technical characteristics and driving patterns: hybrid and batteries EVs both at home and at work.
- Batteries: distribution-level electrical storage, representing batteries that are connected directly at the consumer's site. The reference situation as described by the EUCO3232.5 scenario only considers a small capacity of storage in Portugal. This asset was therefore not considered in the disaggregation process of any of the studied countries.

The above definition of generic assets within DCM calls for a reaggregation of the zonal market technologies. This mapping is done according to Table 8.

Table 8: Assets mapping, from market to distribution

Market Disaggregated asset	Distribution asset
Heat pumps	Flexible demand
Sanitary hot water	
Air conditioning	Non-flexible demand
Thermosensitive remainder	
Non-thermosensitive remainder	
PHEV and BEV immediate charging	
Wind onshore fleet	Generation
Solar fleet	
Hydro ROR fleet	
Biomass fleet	
waste fleet	
PHEV home charge	EV Hybrid home
PHEV work charge	EV Hybrid work
BEV home charge	EV Battery home
BEV work charge	EV Battery work

[10] Following the market's approach, the number of generic EVs handled by the DCM to model the four types of vehicles modelled by the market has been extended.

[11] Vehicle-to-grid and Smart charging modes are mechanisms inherited from the zonal market model. The DCM can consider these charging modes in an equivalent way.

2.4.3. FLEXIBILITY CONSIDERATIONS IN THE DCM

The DCM being an optimisation tool by itself, it can make decision based on its cost minimisation criteria to optimise the operational costs of network that is being assessed. In the context of the current project, however, its dispatching strategy is subordinated to the decisions coming from the market model. The DCM is specifically used to, in the first place, check whether the market's dispatch, after disaggregation, respects the archetype's physical constraints and, in the second, propose a redispatch if conditions are not met. The way this is achieved is by making use of the cost associated to the decision variables of the demand, generation and EV assets. This is done in a way that, if the model wants to activate flexibility, it has to pay the associated costs and shall therefore do it only to prevent constraint violations. Details on these concepts are given in the following paragraphs.

The way the model make uses of the network's flexibility is by the introduction of decision variables that modifies the initial profiles of the load, generation and EV assets. First, let ${load^{initial}}_{inflex}[v,t]$ and ${load^{initial}}_{flex}[v,t]$ be the initial inflexible and flexible components, respectively, of the load profile at voltage level v at time t, for a given distribution network. These components represent the initial demand as dispatched by the market after processing of the disaggregation module. The dispatched load $load[v,t]$ follows the following equation within the DCM formulation

$$load[v,t] = {load^{initial}}_{inflex}[v,t] + {load^{initial}}_{flex}[v,t] - \mathrm{shedding}[v,t] + \mathrm{shifting}^{+}[v,t] + \mathrm{shifting}^{-}[v,t]$$

$$0 \leq \mathrm{shedding}[v,t] \leq {load^{initial}}_{inflex}[v,t] + {load^{initial}}_{flex}[v,t]$$

$$0 \leq \mathrm{shifting}^{+}[v,t]$$

$$-{load^{initial}}_{flex}[v,t] \leq \mathrm{shifting}^{-}[v,t] \leq 0$$

$$\sum_{t=i+0}^{i+23} \mathrm{shifting}^{+}[v,t] + \mathrm{shifting}^{-}[v,t] = 0, \forall i \in (0,24,48,\dots,364)$$

We note first that the shedding term, $\mathrm{shedding}[v,t]$, can potentially reduce the total load of the network to zero. This variable is introduced to assure convergence of the model, as it can reduce the consumption profile to prevent an excess of load that would eventually surpass limits on the thermal capacities of the equipment and/or on the voltage drop on lines. In addition to this, the positive and negative shifting terms, $\mathrm{shifting}^{+}[v,t]$ and $\mathrm{shifting}^{-}[v,t]$ respectively, which act only on the flexible part of the load, can shift the load profile in time by assuring conservation of the energy. This is assured by the last constraint, which states that the total shifted energy must be zero at the end of the day.

A similar approach holds for the electric vehicles' dispatch, except that for this asset the entire profile is considered as fully flexible. If $EV^{initial}[v,t]$ corresponds to its initial charging profile, the dispatched profile $EV[v,t]$ follows,

$$EV[v,t] = EV^{initial}[v,t] + \mathrm{EV}^{+}[v,t] + \mathrm{EV}^{-}[v,t]$$

$$0 \leq \mathrm{EV}^{+}[v,t]$$

$$-EV^{initial}[v,t] \leq \mathrm{EV}^{-}[v,t] \leq 0$$

$$\sum_{t=i+0}^{i+23} \mathrm{EV}^{+}[v,t] + \mathrm{EV}^{-}[v,t] = 0, \forall i \in (0,24,48,\dots,364)$$

This formulation allows the activation of shifting, with mandatory recovery of the displaced energy during the same day. It can be observed that this strategy treats EVs as simple shiftable loads and do not necessarily respect the driving patterns and battery energy needs upon which the initial $EV^{initial}[v,t]$ profile is constructed at the market level. This approximation, however, is needed to ensure that the DCM respects as much as possible the initial profile provided by the market.

Finally, a curtailment term that can reduce the initial generation profile $generation^{initial}[v,t]$

$$generation[v,t] = \ generation^{initial}[v,t] - \mathrm{curtailment}[v,t]$$

$$0 \leq \mathrm{curtailment}[v,t] \leq generation^{initial}[v,t]$$

is used to reduce the excess of generation that would eventually violate the maximum equipment's thermal capacities and/or voltage rise on the lines.

The associated costs of the previously defined decision variables are calculated according to the following equations

$$Cost\ Load\ Shifting = C_{shifting} \sum_{t,v} \mathrm{shifting}^{+}[v,t]$$

$$Cost\ EV\ Shifting = C_{EV\ shifting} \sum_{t,v} \mathrm{EV}^{+}[v,t]$$

$$Cost\ Shedding = C_{shedding} \sum_{t,v} \mathrm{shedding}[v,t]$$

$$Cost\ Curtailment = C_{curtailment} \sum_{t,v} \mathrm{curtailment}[v,t]$$

where $C_{shifting}$, $C_{EV\ shifting}$, $C_{shedding}$ and $C_{curtailment}$ are linear costs factors representing unitary costs (€/MWh) of flexibility activation.

The way previous factors are used for the current study is to establish priorities among the decision variables of the model, rather than to represent real operational costs. For instance, if $C_{shedding} > C_{shifting}$, the model dispatches in priority the load shifting mechanisms instead of shedding, as the first one has a lower impact on the model's objective function. Given this consideration, these priorities are defined in the following way

$$C_{shedding} \geq C_{curtailment} \geq C_{shifting} \geq C_{EV\ shifting}$$

Inequalities that have the following implication: whenever the model sees there is a need of flexibility activation, it prioritises EV shifting and load shifting actions above shedding and curtailment. Also, their actual numerical values are calibrated so the model does not see any economic benefit from activating any of their associated decision variables, and therefore, will do it only to prevent violations of constraints from occurring. In this way, the model respects the initial profiles received from the market as much as possible, as any extra deviation introduced by means of decision variables activation has a negative impact on the model's objective function.

2.4.4. TECHNICAL SCENARIOS

In the reference situation, two different scenarios, featuring different levels of technical constraints on the grid, were simulated: an unconstrained and a constrained scenario.

- **No flexibility unconstrained scenario**: voltage limits and thermal capacities of cables and substations are relaxed; also, any flexibility mechanisms on the distribution systems are deactivated. Thank to this relaxation, the model performs a standard power flow on the network, based on the demand and generation profiles disaggregated from the market. This allows to compute the rate of overload on the system (in terms of voltage variation and cables and/or transformers overload), as the model allows as much power as needed to flow through the different elements of the network.

- **No flexibility constrained scenario**: voltage limits, and thermal capacities of lines and substations are enabled. Load and EV shifting remains deactivated, whereas shedding and curtailment are enabled to assure convergence. The model activates either one of the last two whenever one or several physical constraints are met by the system. As an outcome, the level of shedding and curtailment needed to maintain the grid within its nominal limits can be quantified.

The voltage variation limits considered in the constrained scenario are the same for all countries, in accordance with [6]. Those limits depend on the level of voltage of the distribution network as well as on whether the variation is positive (upstream flow) or negative (downstream flow).

Table 9: Voltage variation limits for the three distribution voltage levels.

Voltage level	Variation limits
HV	[-2.0%, +2.0%]
MV	[-5.0%, +1.5%]
LV	[-6.0%, +1.5%]

On the other hand, for the thermal capacities of cables and substations, their limits are defined as to be 100% of the nominal capacity of the respective equipment. Those limits depend on different factors such as the country, the type of archetype, and the voltage level itself.

2.5. RESULTS FOR MARKET

In terms of capacity, the EUCO3232.5 scenario features a total of 1400 GW of installed power production capacity (Figure 12), with Germany, France, Great Britain, Spain and Italy as the top countries in terms of installed capacities. The scenario features a high degree of RES penetration. The main technologies installed are Solar (GW) and Wind onshore (270 GW), accounting for 41 % of the European mix, followed by CCGT (160 GW), Hydro (140 GW) and Nuclear (110 GW).

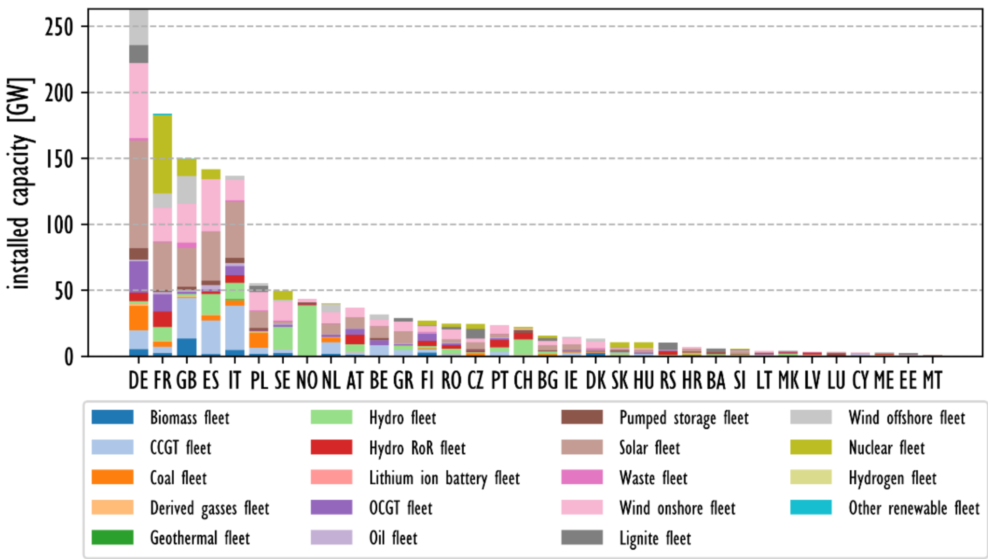

Figure 12: Installed capacities per country in the EUCO32325 scenario

The market's dispatched production and generation is shown in Figure 13, where values correspond to the yearly energy for each of the EU27+UK+6 countries. A total demand

and generation of 3667 TWh and 3731 TWh, respectively, is optimised for Europe, with Germany, France, Great Britain, and Italy accounting for more than 50% of both quantities. In terms of RES production, Solar and Wind onshore accounts for 58% of the yearly European power production.

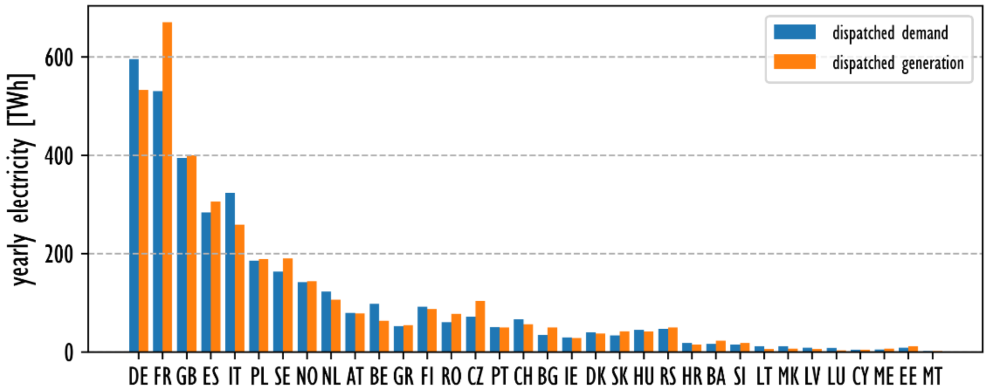

Figure 13: Yearly demand and generation per country as dispatched by the market, for EUCO3232.5 scenario

2.6. Results for transmission

2.6.1. Production and consumption

Figure 14 and Figure 15 show the overview of the production and the consumption obtained from the nodal simulations, for each of the selected snapshots

The difference between production and consumption over a time-step is explained by:

- The curtailed energy,
- The volume of energy not served,
- The imports and exports towards other zones (Baltics, Nordic countries and the British Isles).

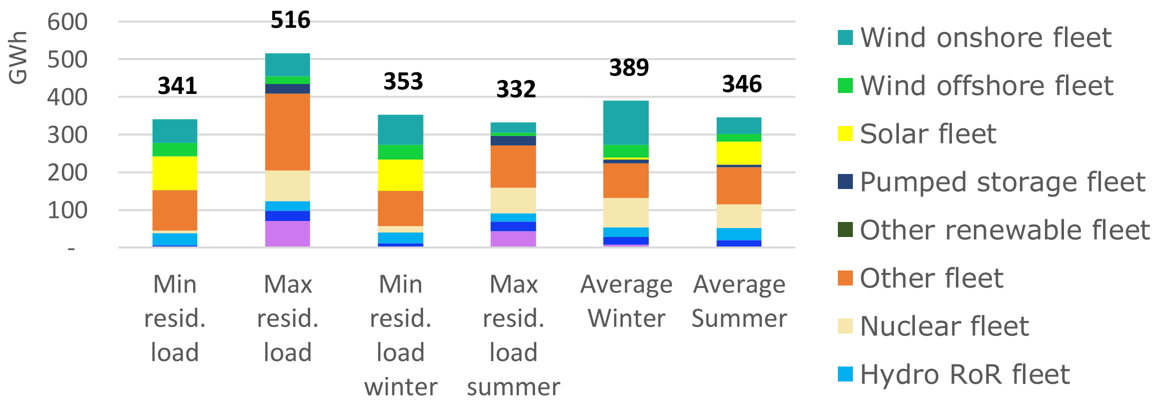

Figure 14: Hourly production over Europe for 6 time-steps

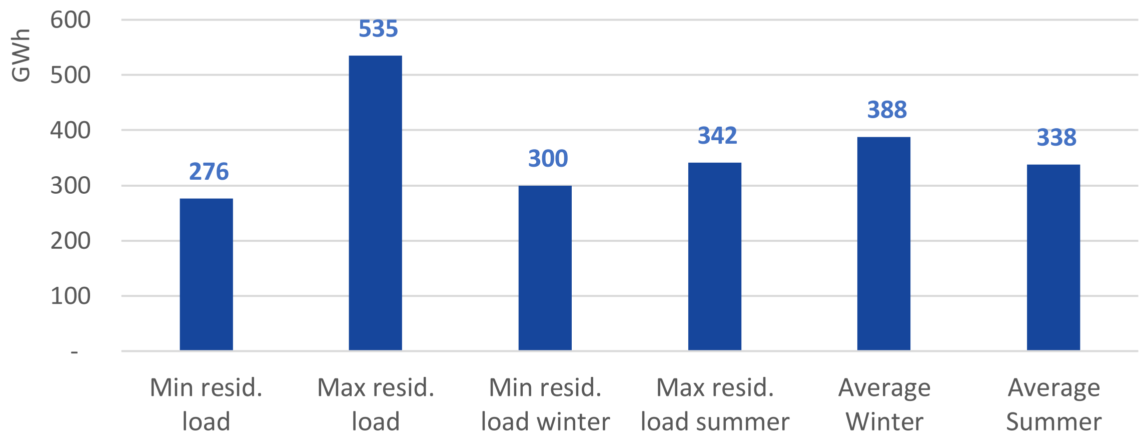

Figure 15: Hourly consumption for 6 time-steps

2.6.2. Transmission usage of internal transmission lines

Figure 16 shows the cumulative number of lines for a given utilisation rate range for 6 different time-steps, while Figure 17 shows the distribution over utilisation rate range.

Those graphs show that « average winter » and « max residual load » snapshots generate more congestions on the transmission network. The « min residual load» snapshot seems to be the less congested snapshot of our selection. There is also a shift of the utilisation rate of internal transmissions from lower to higher values between most-congested time-step and less-congested ones.

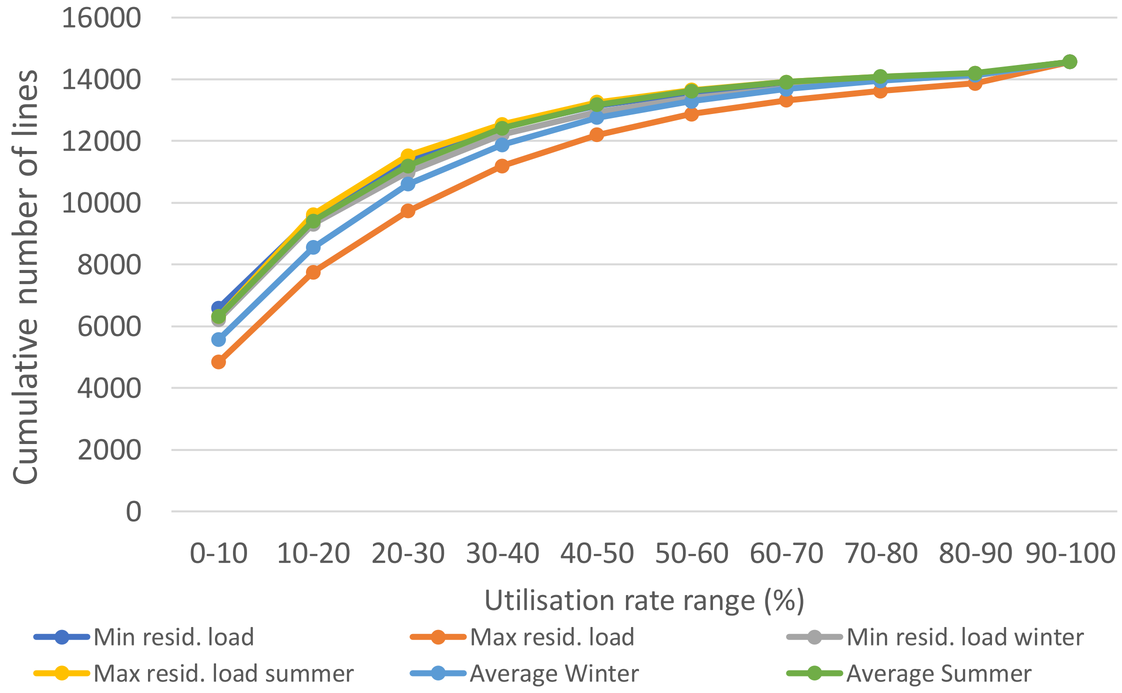

Figure 16: Cumulative number of lines versus utilisation rate range

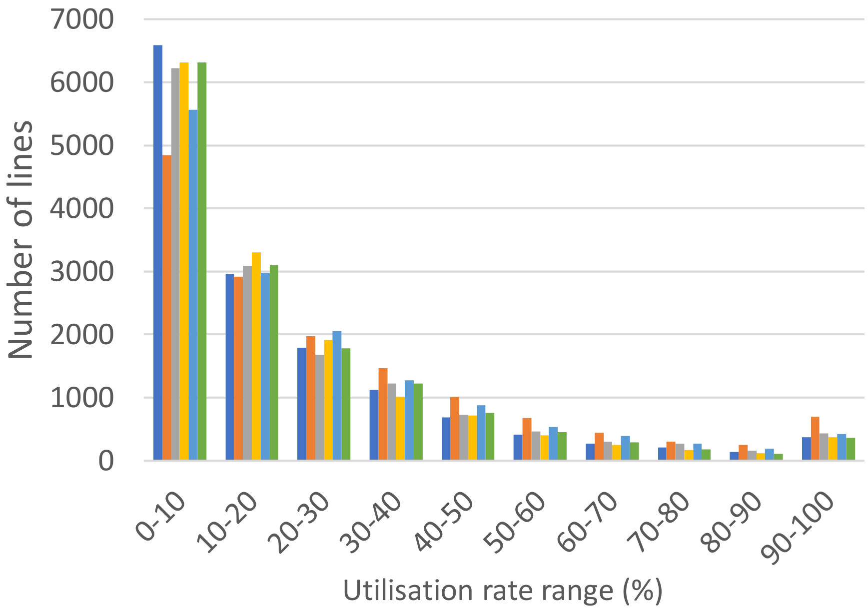

Figure 17: Number of lines versus utilisation rate range for 6 time-steps

2.6.3. Loss of load and curtailment

Figure 18 shows both the relative curtailment and energy not served due to the presence congestions on the transmission network. Loss of load (energy not served) is relative to consumption while curtailment is relative to production.

The « extremum » situations (both minimum and maximum residual load) show the highest volume of curtailed energy. The « max residual load » situation shows the highest volume of loss of load. « Average » situations show less tension emerging from accounting for the physics of electricity flows on the transmission network.

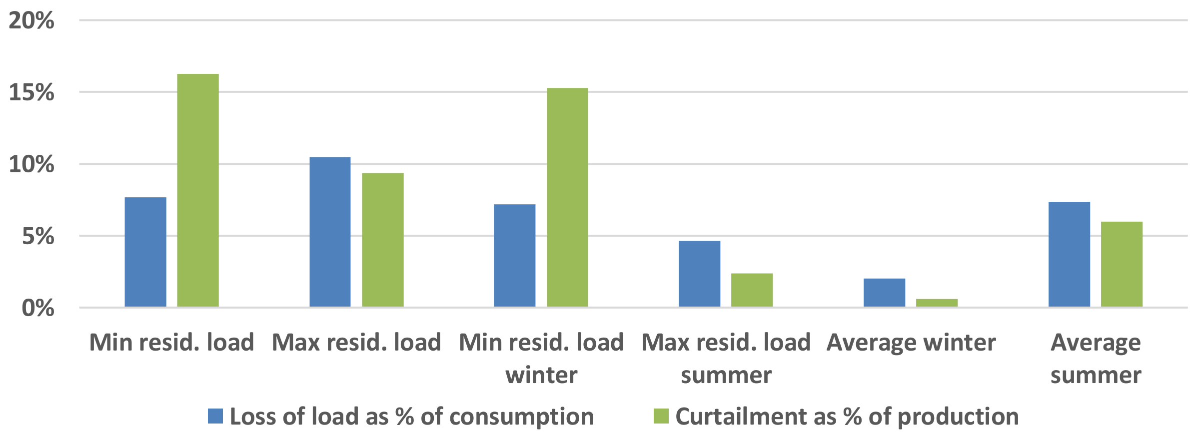

Figure 18: Relative curtailment and energy not served due to congestions

2.7. Results for distribution

2.7.1. Market disaggregation

The disaggregation module projects the information contained in the market over the distribution networks of a country. It defines which part of the demand and generation at the national level belong to the distribution system by using a certain number of disaggregation proxies (cf. Table 7). This process allocates both a demand, and a generation profile to each of the distribution systems (archetypes) that were constructed.

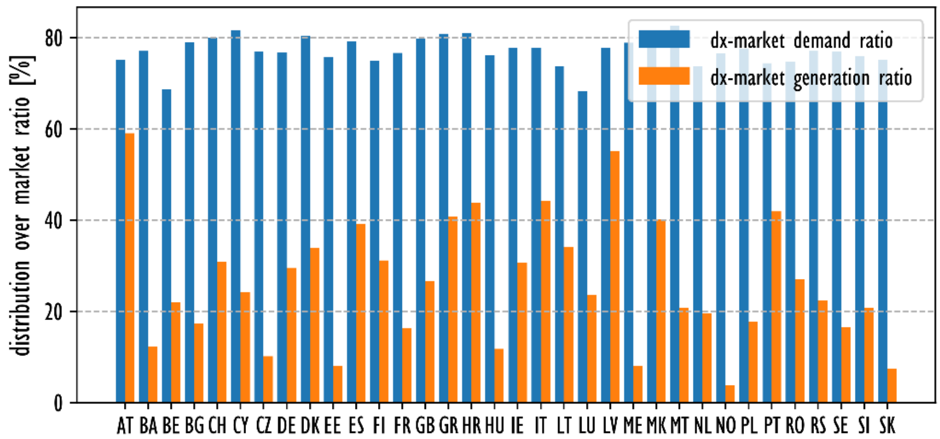

Figure 19: Ratio of the demand/generation between distribution and market

In Figure 19, the distribution-over-market ratio of the yearly load and generation per country is shown. This metric measures which part of the yearly demand and generation of a country belongs to the distribution system, and it was obtained by comparing the market's output over the EUCO3232.5 scenario (cf. section 2.5) with the demand and generation profiles obtained through the disaggregation process (cf. section 2.4.2.1). With respect to the load, the ratio varies between 70% and 82% among the countries, while the average is about 77%. For the generation, the value varies between 5% and 58%, with an average of 26%.

Absolutes values of the yearly demand and generation per country is presented in Figure 20. It is observed that the top producing and consuming countries are Germany, France, Great Britain and Spain. These countries are also top producers and consumers at the market level. It can be observed as well that for each one of them the yearly demand is bigger than the generation, which means that net imports of their distribution systems is positive when summed up during the year.

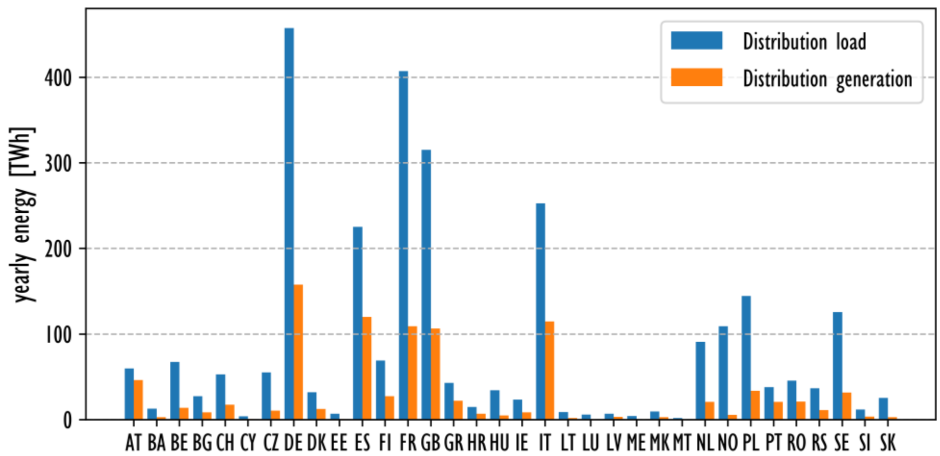

Figure 20: Initial yearly demand and generation at the distribution level

2.7.2. UNCONSTRAINED SCENARIO

As it was previously mentioned, the unconstrained scenario features no technical limits on the operation of the networks. This means that the DCM applies no restrictions to the flow of power to follow the market's suggested demand and generation profiles, after disaggregation by archetype. This operation, even if unrealistic, allows to calculate the following metrics of constraints violations: frequency and intensity of overvoltage, undervoltage, cables overload and substations overload violations. Their specific definition given in Section 2.2.2, they can be interpreted as follows: a substation experiencing an overload frequency of 6%, means that during the 6% of the operation period, at least one type of substation was loaded with more than 100% of its nominal capacity. In parallel with this, a substation overload of 40% means that during that 6% of the time, substations where loaded, in average, 140% of their nominal capacity.

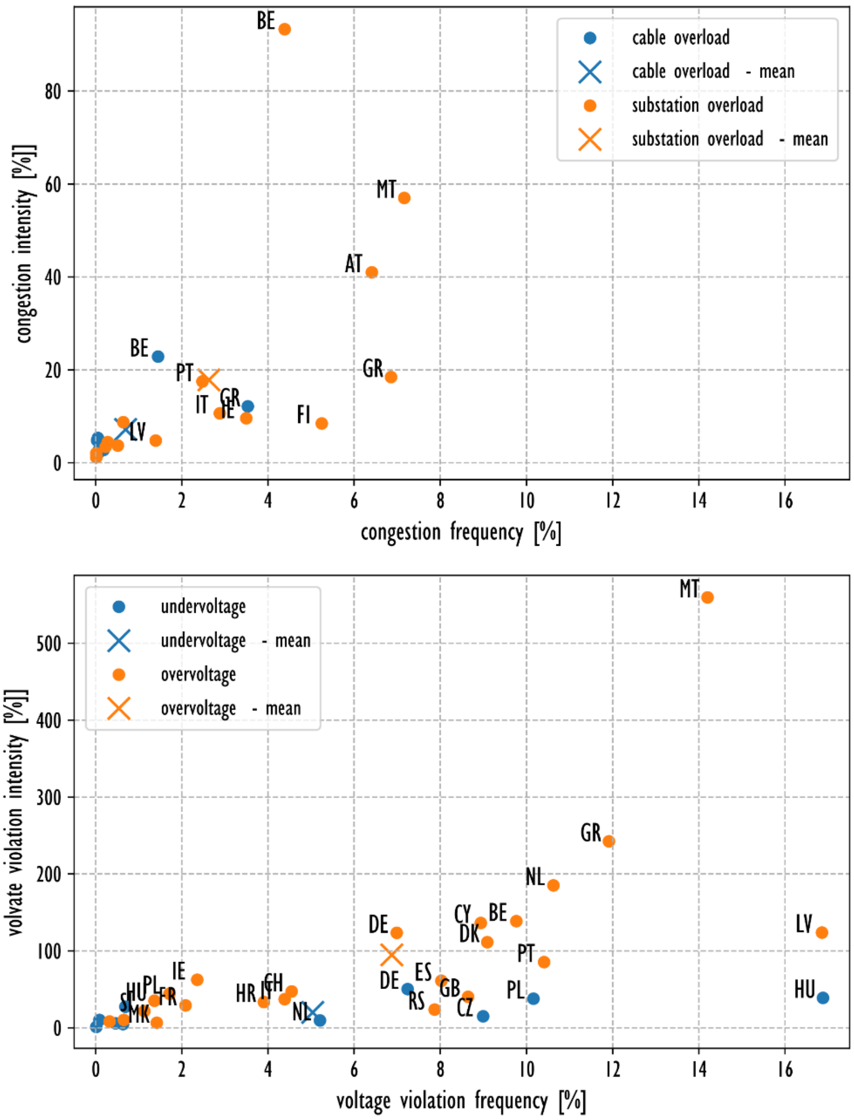

Figure 21: Average frequency and intensity for overvoltage, undervoltage, cables overload and substations overload violations

Figure 21 shows congestion metrics' average[12] values per country. It is observed first that congestions in substations are more relevant than in cables, in terms of intensity, frequency and number of congested countries. The same applies for overvoltage with respect to undervoltage violations. The formers are more frequent, happen in more countries and are particularly more intense (a mean among countries of 95% and 20% for overvoltage and undervoltage, respectively). As it will be seen, this last effect will translate into a big role for generation curtailment, as the main factor inducing overvoltage are local injections from distributed generation.

[12] Values are calculated by taking the average of the respective congestion metric among the distribution networks of the country. Then, a mean is calculated by taking the simple mathematical average over the previously calculated metrics over EU24+UK+6

2.7.3. CONSTRAINED SCENARIO

Figure 22 shows a summary of the scenario's outcome in terms of the relative load shedding and generation curtailment applied by each country. Values are calculated as the total amount of load shedding (generation curtailment) over the yearly amount of load (generation) aggregated among the distribution networks of the country. The average generation curtailment for all the countries is 7% whereas that of load shedding stays relatively low at 0.4%.

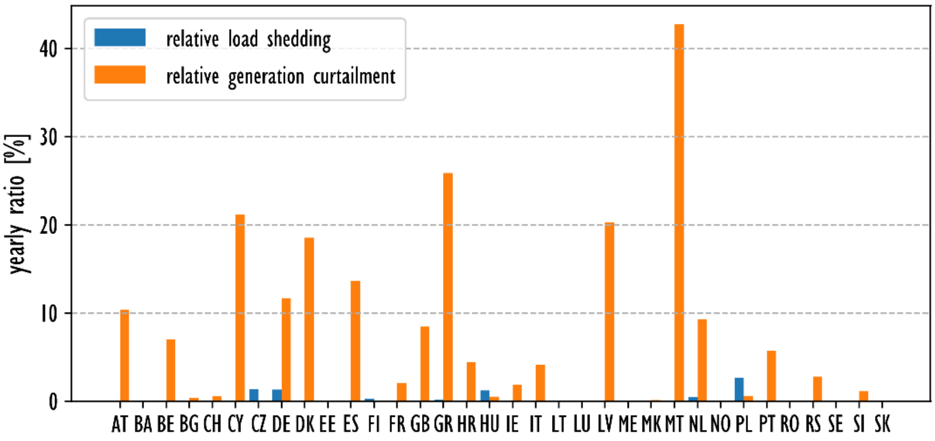

Figure 22: Relative load shedding and generation curtailment per country

It might be noted that Malta, Greece, Cyprus, Latvia, Denmark, Spain, Germany and Austria show significant generation curtailment of more than 10%.

Figure 23 shows a decomposition of the main causes of curtailment activation[13]. From the total actions of generation curtailment observed on the networks of a country, the percentage that are applied due to overvoltage, undervoltage, substations (transformers) maximum load rate and cables maximum load rate are represented in the graph. For most of the countries the curtailment is happening due to overvoltage problems, whereas a minority experience a mix of several types of constraints limitations. It can be seen how overvoltage violations appear to be the main technical limitations on the networks.

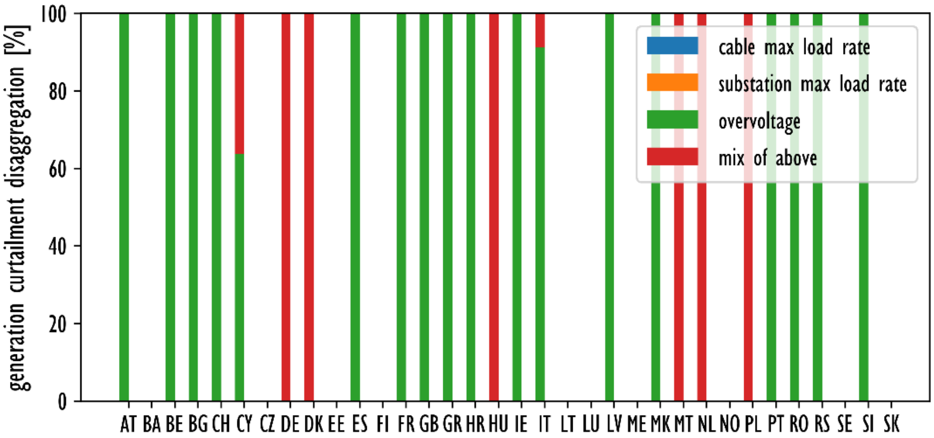

Figure 23: Decomposition of the causes leading to generation curtailment activation

[13] Load shedding activation was disregarded as relatively low for EU24+UK+6

Figure 24 shows the relative contribution of each country to the total values of load, load shedding, generation, and generation curtailment of the distribution systems in EU27+UK+6.

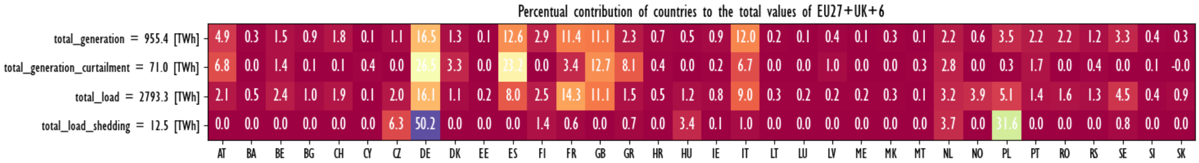

Figure 24: Heat map with each country's relative contribution to the total values of EU27+UK+6

Based on the previous figure, the following observations can be made:

- The total load as recommended by the market, and after disaggregation, is 2793.3 TWh, out of which 12.5 TWh (0.4%) are shed.
- The total generation as recommended by the market, and after disaggregation, is 955.4 TWh, out of which 71.0 TWh (7.4%) are curtailed.
- Germany, Spain and Great Britain contribute, each of them, with more than 10% to the total curtailed generation in Europe.

2.7.4. SUMMARY OF OBSERVATIONS

The main observations of the current section can be summarised as follows:

- Among the four types of constraints studied
  - Overvoltage due to injections is the main driver of constraint violations, followed by overload on substations.
  - Cables overload and undervoltage were encountered for some countries but remains negligible compared with the precedent constraints.
- More than 7% of the European distribution generation is being curtailed to avoid violation of constraints.
- Load shedding activation remains small (0.4%) compared with generation curtailment.
- Countries presenting more than 10% of curtailment with respect to their own total distribution network generation: Malta, Greece, Cyprus, Latvia, Denmark, Spain, Germany and Austria

3. TASK-3: FLEXIBILITY MEASURES FOR NETWORK PROBLEMS ALLEVIATION AT TRANSMISSION LEVEL

3.1. METHODOLOGY

The methodology (Figure 25) that has been designed to assess the magnitude of different flexibilities is named "all-but-one flexibility approach". It means that, to assess the role of a given flexibility solution, two scenarios are compared. In the first scenario all flexibility solutions are enabled. The second scenario disables the flexibility solution being investigated. Hence, comparing both scenarios' results allow to assess the role and magnitude of the investigated flexibility solution by measuring the impacts of that solution being absent.

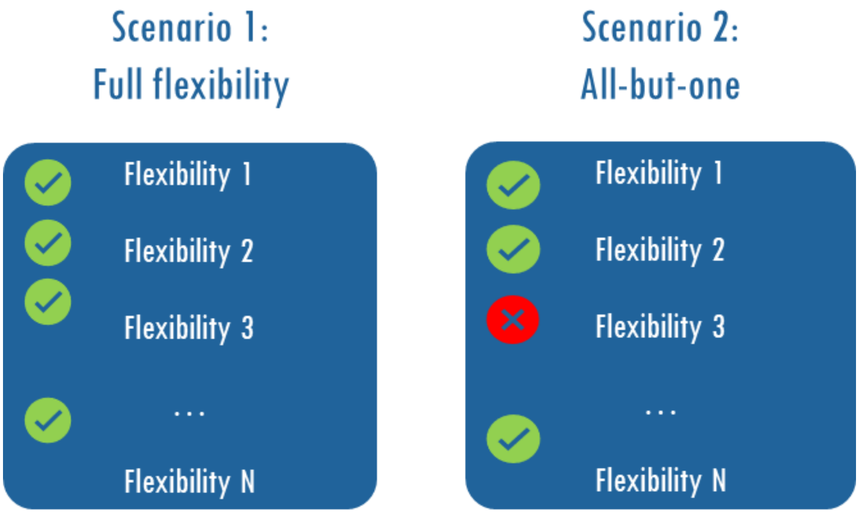

Figure 25: Comparison between the full flexibility and all-but-one flexibility scenarios

3.1.1. Description of scenario 1: full flexibility

This scenario consists in launching the transmission model with all flexibility solutions being activated. Table 10.

Table 10: Summary of flexibility solutions and their relation with zonal technologies

Flexibility type	Related zonal technologies	Modelling approach
Generation redispatch	Biomass, CCGT, Coal, Derived gases, Lignite, Nuclear, OCGT, Oil, Waste	• The production of each technology can be curtailed • Thermal dispatchable production levels are optimised • The net position of each zone must be equal to the one of the market model
Flexible storage	Hydro reservoir, Pump storage, 2-hours batteries, 4-hours batteries	• The total storage level in each zone is flexible around the zonal value • Each nodal asset is only restricted by its technical characteristics
Network flexibility	Phase shifting transformer	• The phase shift angle is optimised between two limits, impacting the flows on the lines

The transmission model tries to follow the market recommendations but can deviate from them using three different kinds of flexibility solutions. The activation of flexibility solutions is dispatched to avoid constraints violations that could materialise when accounting from the physical limitations imposed by national transmission grids.

3.1.2. Description of scenario 2: all-but-one

This second scenario consists in activating all flexibility but the solution being investigated. To assess all the available flexibilities, one flexibility mechanism is disabled at a time.

Figure 26 summarises the three different kinds of "all but one" scenarios that are studied, one for each family of flexibility solutions. It also gives the key model characteristics for each case.

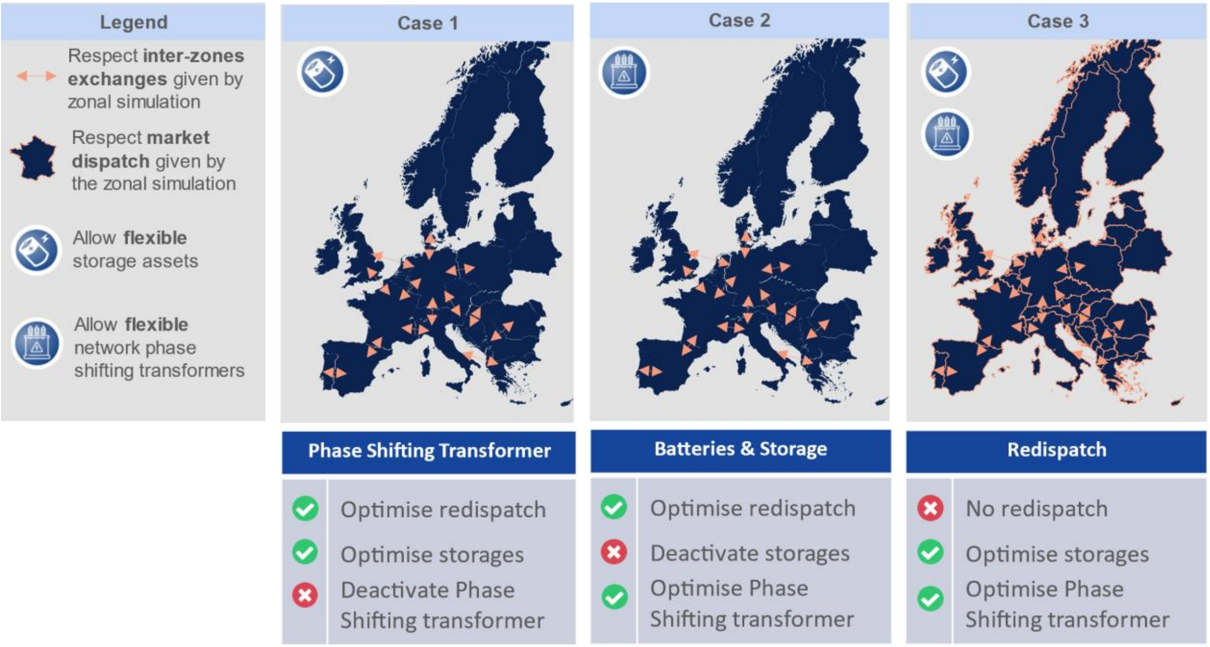

Figure 26: Summary of the three different cases of "all but one" scenarios

3.2. RESULTS

3.2.1. GENERAL REDISPATCH

This section presents the results obtained for the general redispatch flexibility, comparing scenario 1 to scenario 2 case 3 where general redispatch flexibility (of generation from Biomass, CCGT, Coal, Derived gases, Lignite, Nuclear, OCGT, Oil, Waste) is deactivated. The thermal dispatchable productions of these technologies are optimised, allowing one technology to displace another one, but the net position of each zone must remain equal to the one obtained by the market model.

3.2.1.1. Congestion management

Figure 27 and Figure 28 show respectively congested lines for the Minimal residual load winter snapshot in Northern Italy and Austria for scenario 1 and scenario 2 respectively. Orange lines are transmission lines with transmission usage between 80% and 99%. Red lines are transmission lines with transmission usage over 99%. It illustrates how generation redispatch allows to solve many congestions in this particular situation of a highly congested grid.

Figure 27: Congestion issues for scenario 1 (redispatch enabled)

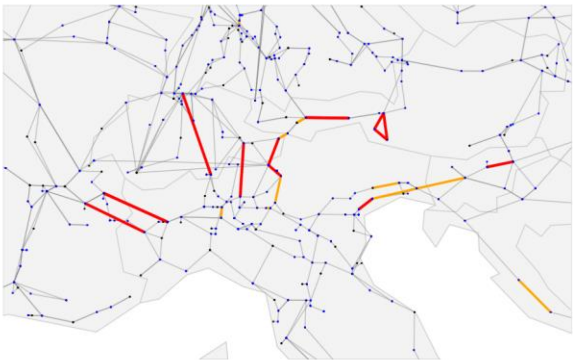

Figure 28: Congestion issues for scenario 2 (redispatch disabled)

3.2.1.2. Additional production

Figure 29 gives the additional production when generation redispatch is enabled for each technology and for the 6 different snapshots. Loss of load decrease is also represented. The amount of power produced in excess compared to the loss of load reduction is power substituted to another power source.

One can see how dispatchable production substitutes vRES production to reduce Loss of Load in the minimal residual load snapshot. For the minimal residual load winter snapshot, the additional wind power produced is partially compensated by solar curtailment. Here generation redispatch enables to select the best source of power in function of the overall grid configuration and to solve congestion issues.

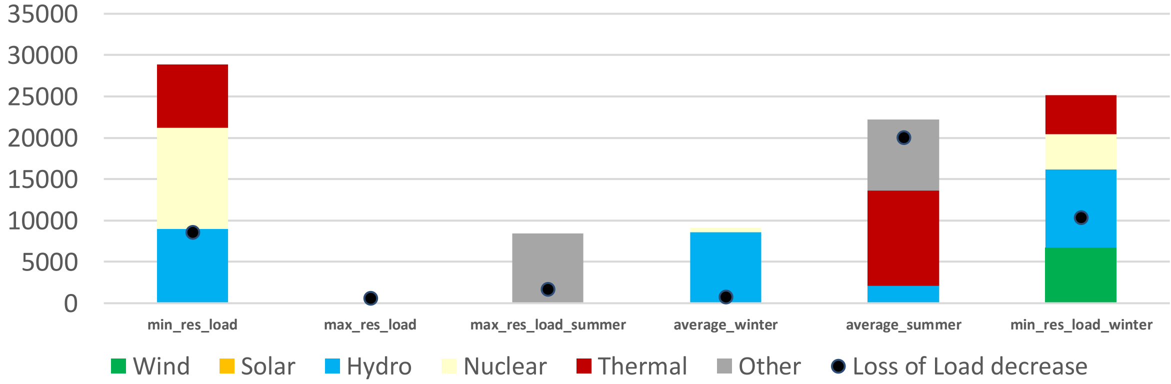

Figure 29: Additional production with generation redispatch enabled (MWh)

3.2.2. PST

This section gives results obtained for the phase shifter transformer (PST) flexibility, comparing scenario 1 to scenario 2 case 1 where PST flexibility is deactivated.

We recall that PST flexibility consists in optimising the phase shifting angle between the two limits of each PST, impacting the flows on the network lines.

3.2.2.1. Congestion management

Figure 30 and Figure 31 show respectively congested lines for the Average winter snapshot in Poland and North East Germany for scenario 1 and scenario 2 respectively. Orange lines are transmission lines with transmission usage between 80% and 99%. Red lines are transmission lines with transmission usage over 99%. It illustrates how PST flexibility allows to solve congestions in this particular situation.

As illustrated in this example, PST flexibility enables to alleviate congestions mostly near their location.

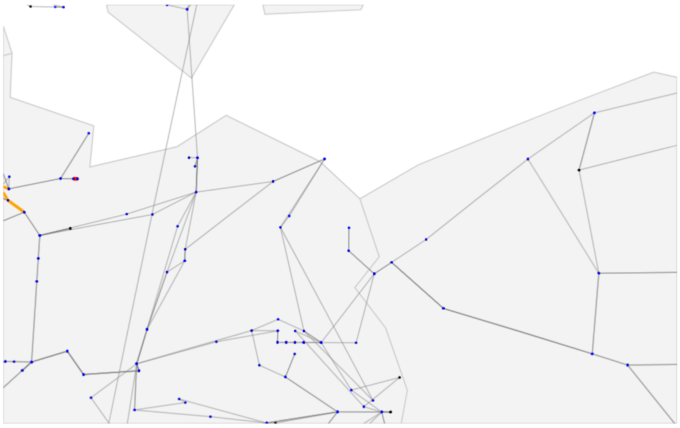

Figure 30: Congestion issues for scenario 1 (PST enabled)

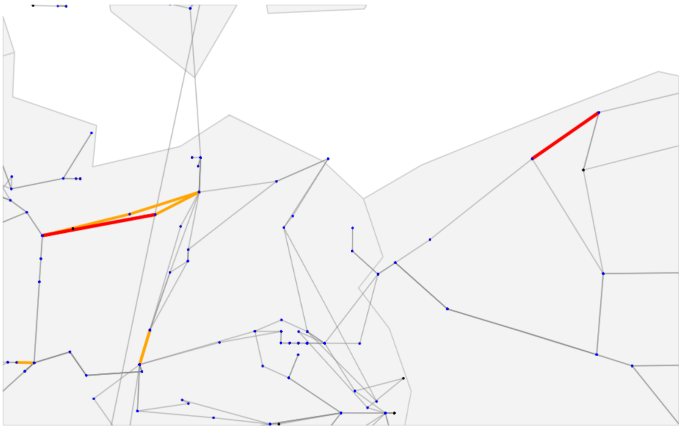

Figure 31: Congestion issues for scenario 2 (PST disabled)

3.2.2.2. Additional production

Figure 32 gives the additional production with PST flexibility being enabled for each technology and for the 6 different snapshots. Loss of load decrease is also represented. The amount of power produced in excess compared to the loss of load reduction is power substituted to another power source.

In both the minimal residual load and minimal residual load winter snapshots, one can see how PST flexibility allows additional vRES production to be transmitted across the grid.

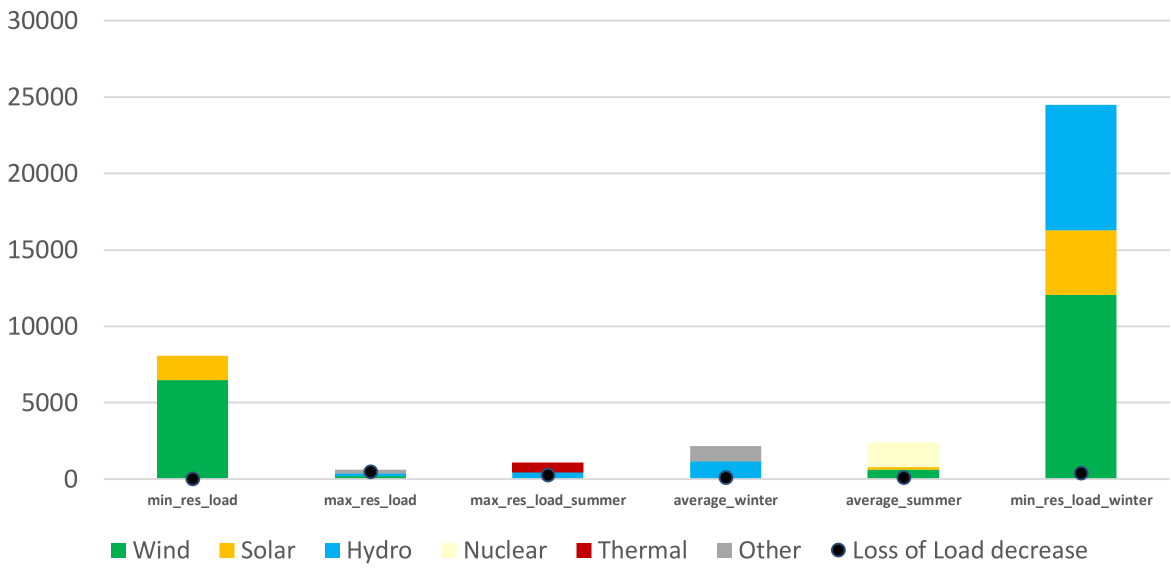

Figure 32: Additional production and consumption transmitted across the grid with PST flexibility enabled (MWh)

3.2.3. Storage

This section presents the results obtained for the storage flexibility, comparing scenario 1 to scenario 2 case 2 where storage flexibility is deactivated.

We recall that storage flexibility consists in the possibility to store or withdraw energy around its zonal value in each node for each technology. The impacted technologies in this approach are the following: hydro reservoir, Pumped-hydro storage, 2-hour batteries, and 4-hour batteries.

3.2.3.1. Congestion management

Figure 33 and Figure 34 show respectively congested lines for the Minimal residual load winter snapshot in Germany for scenario 1 and scenario 2 respectively. Orange lines are transmission lines with transmission usage between 80% and 99%. Red lines are transmission lines with transmission usage over 99%.

In general, flexibility provided by storage technologies enables to solve some congestions across the European grid. In the examples below, we show impacts in several regions in Germany.

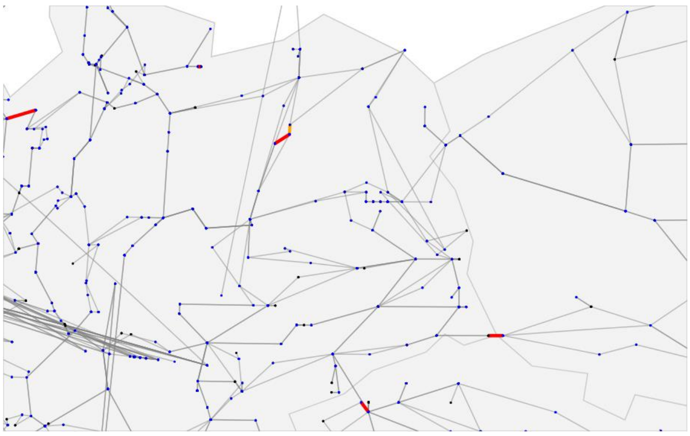

Figure 33: Congestion issues for scenario 1 (nodal storage dispatch enabled)

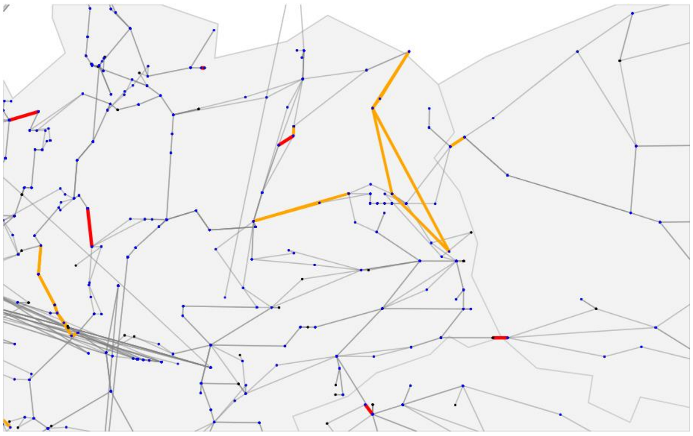

Figure 34: Congestion issues for scenario 2 (nodal storage dispatch disabled)

3.2.3.2. Additional production

Figure 35 gives the additional production with flexible storage being enabled for each technology and for the 6 different snapshots. Loss of load decrease is also represented. The amount of power produced in excess compared to the loss of load reduction is power substituted to another power source.

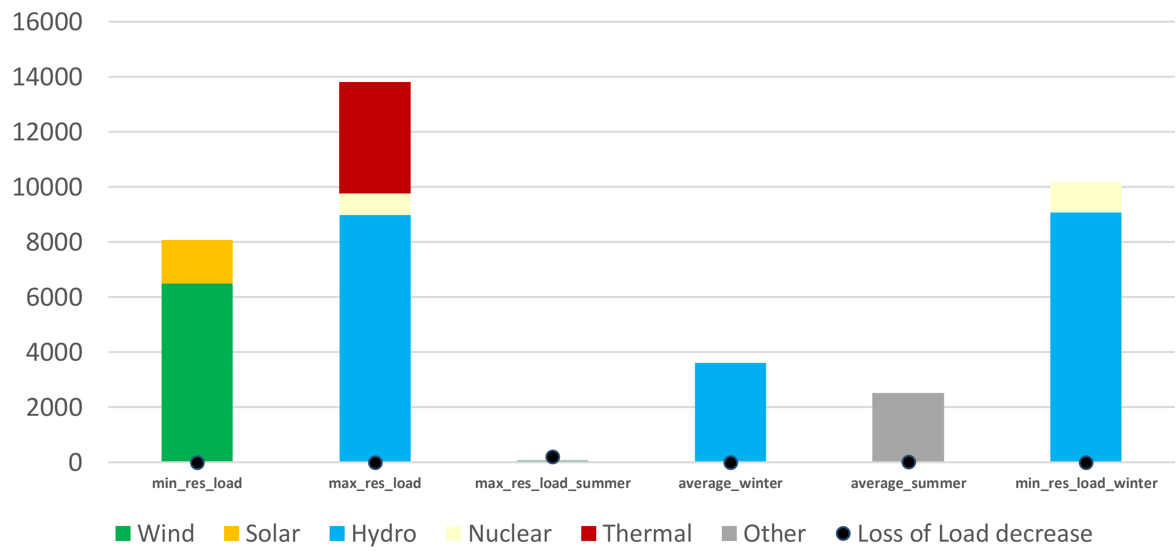

Figure 35: Additional production and consumption transmitted across the grid with flexible storage enabled (MWh)

3.3. Conclusions

By examining the results of the simulations launched for the 6 snapshots for each family of flexibility solutions and for the full flexibility scenario, we can assess the order of magnitude of the impacts of each of the three different families.

Redispatch flexibility seems to have an impact that is circa twice times higher than the other flexibilities in terms of loss of load and curtailment reduction. PST and storage flexibilities have a much lower effect and are having impacts of the same order of magnitude.

4. TASK-4: FLEXIBILITY MEASURES FOR NETWORK PROBLEMS ALLEVIATION AT DISTRIBUTION LEVEL

4.1. METHODOLOGY

The current part of the study relies on the previous task as the starting point of the assessment. From the constrained scenario of Task 2 (Section 2.4.4), different combinations of flexibility solutions are activated to help reducing the level of constraint saturation detected by the model. This process of network problems alleviation is reflected by a reduction of the generation and load shedding levels observed, together with an increase of the load and EV shifting rates. The way these two flexibility mechanisms are considered in the DCM already described in Section 2.4.3, we briefly summarise them as follows:

- Load shifting mechanisms: Redispatch of the flexible load profile with mandatory recovery of the displaced energy during the day. No limitations in terms maximum/minimum power or energy are considered.
- EV shifting: EVs charging profiles whose redispatch follows the same rules as of load shifting. Note that vehicle-to-grid injections at the zonal market level are not considered in the PRIMES EUCO3232.5 scenario and therefore this feature was also not considered in our modelling. However, METIS users can activate this feature should they be interested in assessing its impacts.

Table 11: Summary of flexibility mechanisms and their related assets

	Task-4			Task-2
Flexibility mechanism	Load Shifting flexibility	EV Shifting flexibility	Full flexibility	No flexibility constrained scenario
Load shifting	✔	✘	✔	✘
EV shifting	✘	✔	✔	✘
Load shedding	✔	✔	✔	✔
Generation curtailment	✔	✔	✔	✔

We distinguish three possible combinations (see Table 11) depending on which type of flexibility is enabled: load shifting flexibility, EV shifting flexibility and Full flexibility. The last row also provides the flexibility configuration used in Task −2's constrained scenario. Finally, it is noted that both generation curtailment and load shedding are enabled across all the configurations to ensure convergence of the model.

Table 12 shows a summary of the flexibility solutions in relation with the zonal market model assets. It should be noted that since at the distribution level several market assets are aggregated into a single asset (e.g., heat pumps and sanitary hot water aggregated into a single load profile), the flexibility mechanisms activated upon them cannot distinguish which specific asset is redispatched.

Table 12: Summary of flexibility mechanisms and their associated market assets

Market Disaggregated asset	Distribution asset	Flexibility approach

Heat pumps	Flexible demand	Redispatch of the load with mandatory recovery by the end of the day
Sanitary hot water		
Wind onshore fleet	Generation	Generation curtailment
Solar fleet		
Hydro ROR fleet		
Biomass fleet		
waste fleet		
PHEV home charge	EV Hybrid home	Redispatch of charging and discharging with recovery by the end of the day
PHEV work charge	EV Hybrid work	
BEV home charge	EV Battery home	
BEV work charge	EV Battery work	

4.2. RESULTS

The current section is divided into two parts. In the first, different study cases illustrating how flexibility can be activated by the tool to help solving network problems are discussed. For that purpose, different types of distribution networks of representative countries under the EUCOE3232.5 scenario are taken as an example. In the second, a summary of the outcome for EU27+UK+6 is presented, in terms of the level of load shedding and generation curtailment reduction, for the three flexibility configurations (Table 11).

4.2.1. STUDY CASES

4.2.1.1. Load shedding alleviation via load shifting

The present analysis shows the outcome of the DCM optimisation on a rural archetype in Denmark in the Task 2 constrained scenario. Upper graphs of Figure 36, shows both the initial (before DCM dispatch) and final (after DCM dispatch) generation profiles all over the year. A selection over a specific period is shown in the right-hand side figure, where no generation curtailment is applied. Following the same logic, middle graphs show the load profile of the network together with its dispatched flexibility mechanisms, both during the year (left-hand side figure) and during a specific period (right-hand side figure). It can be seen how the final load profile is the result of the initial load (which in turn is the sum of the initial flexible and inflexible loads) subtracted by the shedding mechanism. According to the DCM formulation, this activation happens to prevent violations of physical constraints, specifically due to the intensity of the demand profile in those specific moments. Finally, Figure 37 shows the alternative profile when the shifting flexibility mechanism is activated. It can be seen how shedding is replaced partially by shifting, which in turn is recovered in other periods of the day[14]. It can be observed that not all the shedding can be compensated in this way, as the available flexible load is not high enough compared with the shedding needs. This alleviation procedure reduces an initial load shedding (Task-2 constrained scenario) of 1.94 TWh by 0.23 TWh (i.e., 12% of relative reduction).

[14] It is observed as well how the shifting addition is done in a way that it synchronises with the peaks of generation, maximizing the self-consumption of the generation (e.g., solar PV)

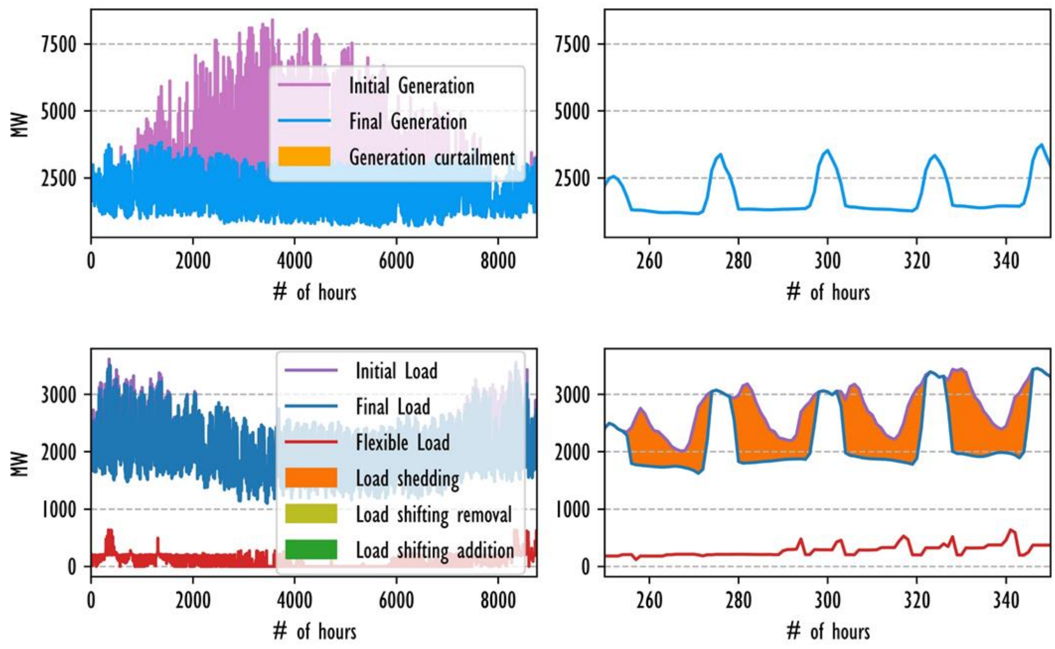

Figure 36: DCM dispatch during the year (left) and a specific period (right) – Task-2 constrained scenario – Denmark rural archetype

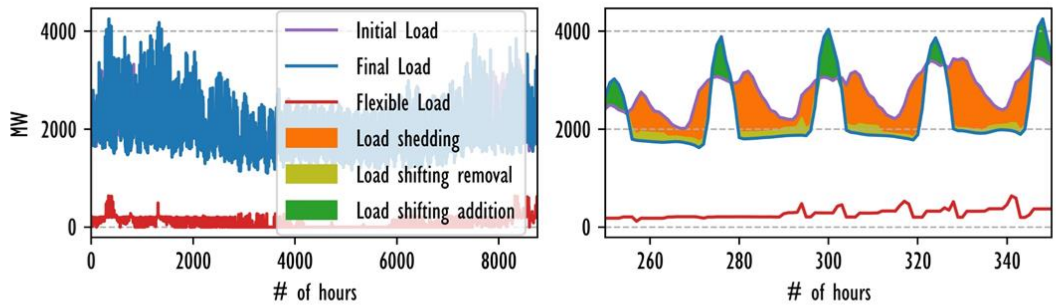

Figure 37: DCM dispatch when the load shifting mechanisms is enabled - Denmark rural archetype

4.2.1.2. Generation curtailment alleviation via load shifting

This case exemplifies how load shifting can help to reduce curtailment by synchronising demand and generation. For this, a congested grid due to intense local generation, which in turn exhibits a significant degree of generation curtailment is showcased. This can be seen in the upper graphs of Figure 38, for a rural archetype in Spain, where differences between the initial and final generation due to curtailment can be observed. The lower graph exhibits how the load is shifted towards the moments where curtailment is taking place. This process, which produces peaks of demand, is carried out by the DCM to reduce the net injection profile into the grid, which in turn reduces the flow of electricity through it and therefore its generation curtailment rate.

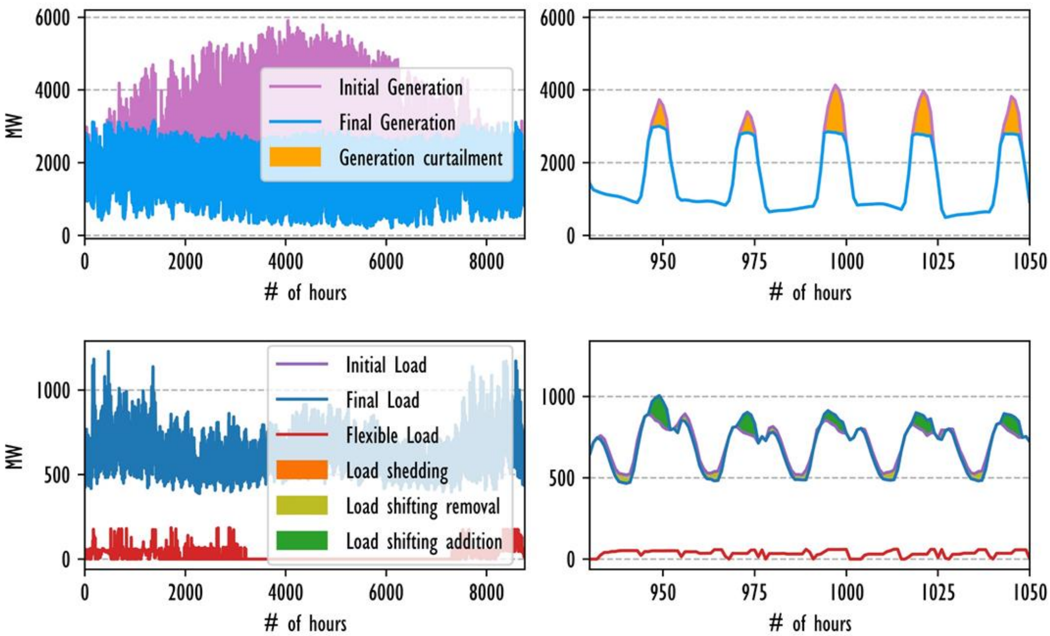

Figure 38: DCM dispatch during the year (left) and a specific period (right) – load shifting mechanism enabled – Spain rural archetype

A different situation happens for the same network but during a different period (see Figure 39), where no load shifting is activated due to the absence of flexible demand during that time. In this case, more intense peaks of generation are observed, which are correlated with a more important curtailment activation. This unavailability of flexible demand has important consequences on the rate of curtailment reduction, as it happens all along during the warmer periods of the year (around hours 3200 to 7200) where most of the generation curtailment is taking place. The outcome of the alleviation process allows to reduce an initial generation curtailment of 3.14 TWh by 0.05 TWh (i.e., 1.7% of relative reduction). Most of the countries of the current study present a null flexible load during the warmer seasons of the year, the reason being that Heat Pumps (main asset providing flexibility) are not used during those periods[15]. Load shifting capabilities for network problems alleviation are in consequence highly impacted for those countries. It will be seen though in the upcoming cases that EVs can then potentially play an important complementary role as they are available independently of the season.

[15] This situation however does not happen for France and UK whose flexible load considers in addition the Sanitary Hot Water asset, which is present all along during the year. For them, the flexible component is different from zero during the warmer seasons and can therefore contribute to network problems alleviation.

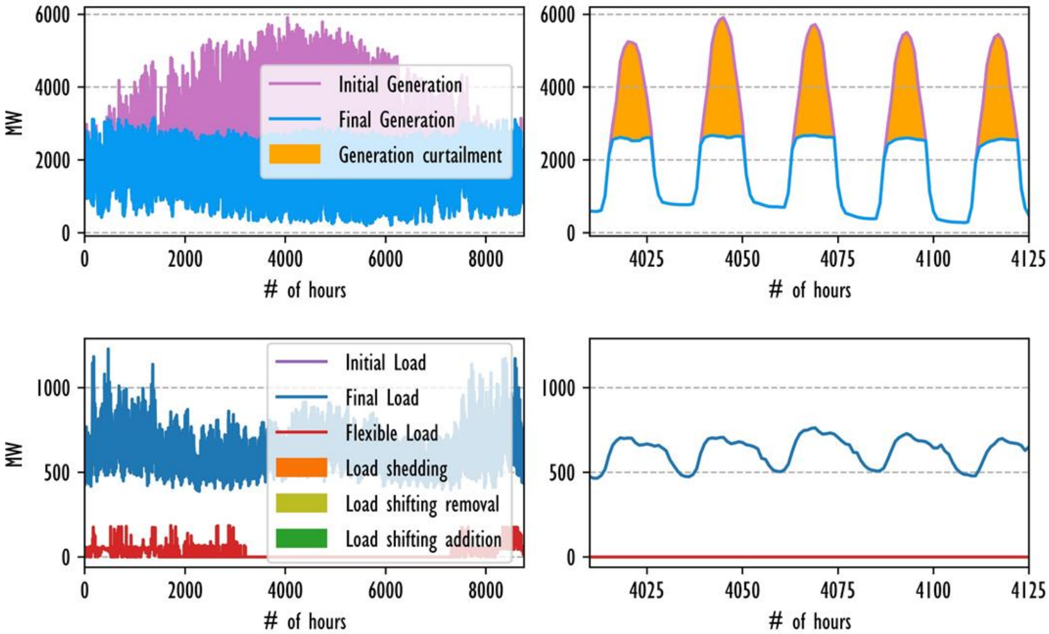

Figure 39: DCM dispatch during the year (left) and a specific period (right) with no flexible load available – load shifting mechanism enabled – Spain rural archetype

The last case of interest shows a highly congested rural network in Austria, in which generation curtailment happens constantly all along the year (Figure 40). A zoom in on the specified period, shows that even if the flexible load is available, no load shifting is activated. Indeed, the recovery process of the load shifting states that whatever is increased in some moment must be decreased within a 24-hours window, and since the generation curtailment is applied all along the day, the net reduction of the curtailment, if shifting were activated, would also be zero. As an outcome, there is no reduction of the initial generation curtailment rate (of 4.3 TWh), and no load shifting activation is observed.

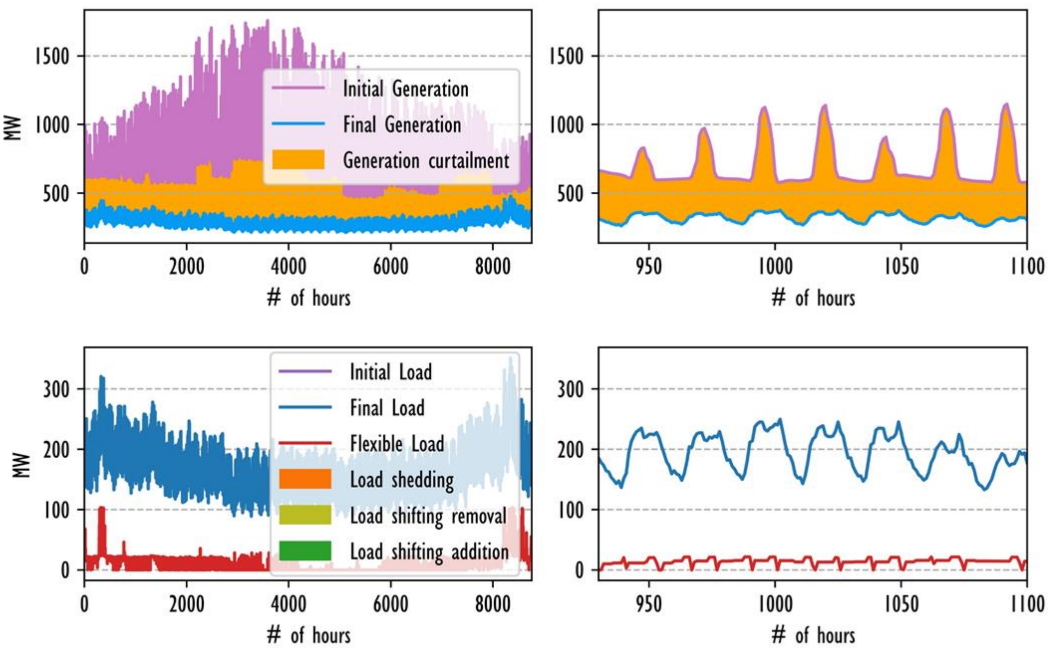

Figure 40: DCM dispatch during the year (left) and a specific period (right) – load shifting mechanism enabled – Austria rural archetype

4.2.1.3. Generation curtailment reduction via load and EV shifting

The following case shows how load and EV shifting can both support generation curtailment reduction in a rural network in the Netherlands (Figure 41). The right-hand side of the figure illustrates how both load and EV are shifted to match generation curtailment activation. One may note that, based on section 2.4.3's discussion, a higher priority is assigned to load shifting. The model therefore uses as much load shifting as possible before activating the EV mechanism. In this example one observes however how the EV demand is fully reduced to zero outside the periods where curtailment is taking place, to maximise its increase when generation curtailment happens. Load shifting alone is not enough to fully reduce the initial curtailment rate.

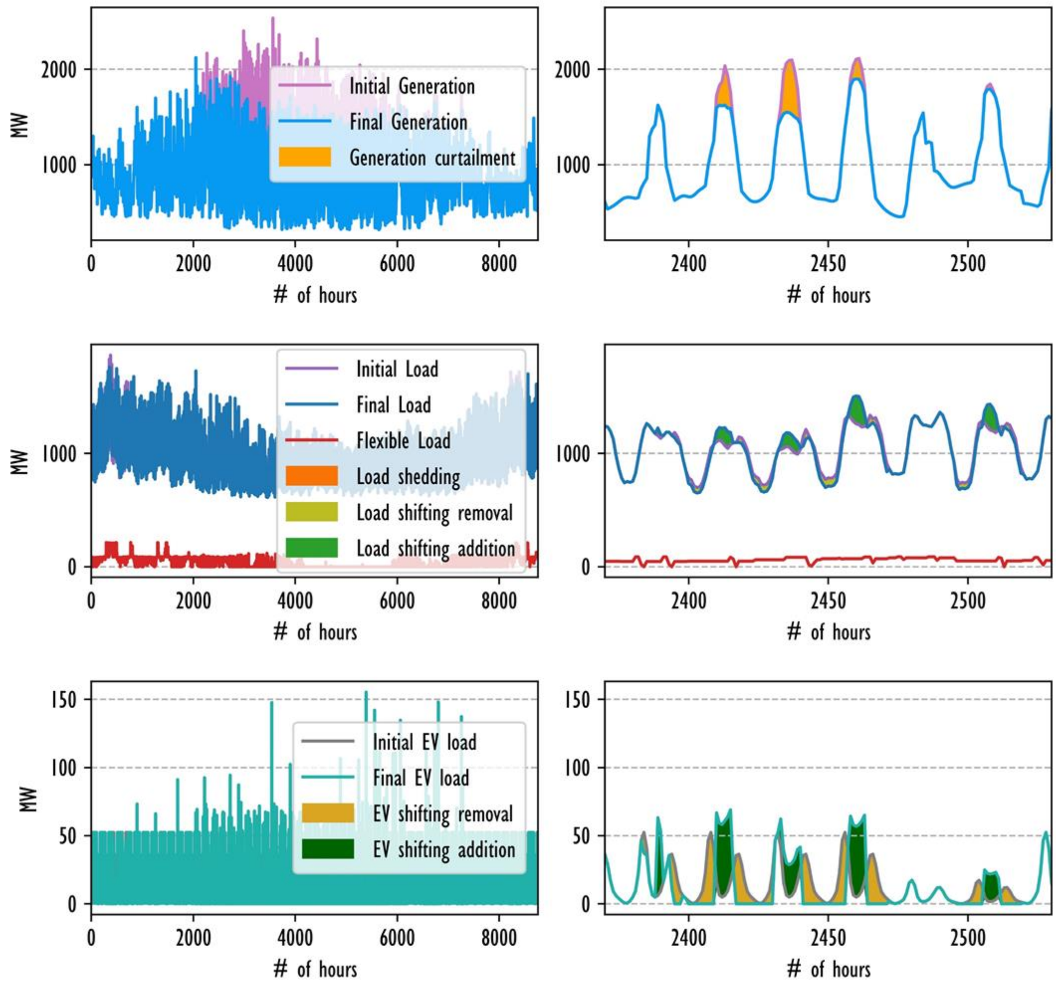

Figure 41: DCM dispatch during the year (left) and a specific period (right) – load shifting mechanism enabled – The Netherlands rural archetype

A different simulation period (during summer) for the same network (Figure 42) shows how the only mechanism activated for curtailment reduction is that of EV shifting. The flexible load profile, which is given by heat pumps, is zero as there is no demand for heating during the warmer periods of the year, and therefore cannot contribute to the reduction. Even if the yearly potential for flexible consumption (0.34 TWh) is almost three times bigger that the one of EVs (0.12 TWh), both assets contribute in the same order of magnitude to the alleviation process, with 0.034 TWh and 0.033 TWh of flexibility activation for load and EV shifting, respectively. The main reason being that contrary to the flexible load, EVs are fully available when curtailment happens, which makes that the model can make use of them more often to alleviate network problems. Finally, the outcome of the alleviation procedure exhibits a generation curtailment reduction of 0.061 TWh, from an initial curtailment rate of about 0.36 TWh (i.e., 17% of relative reduction).

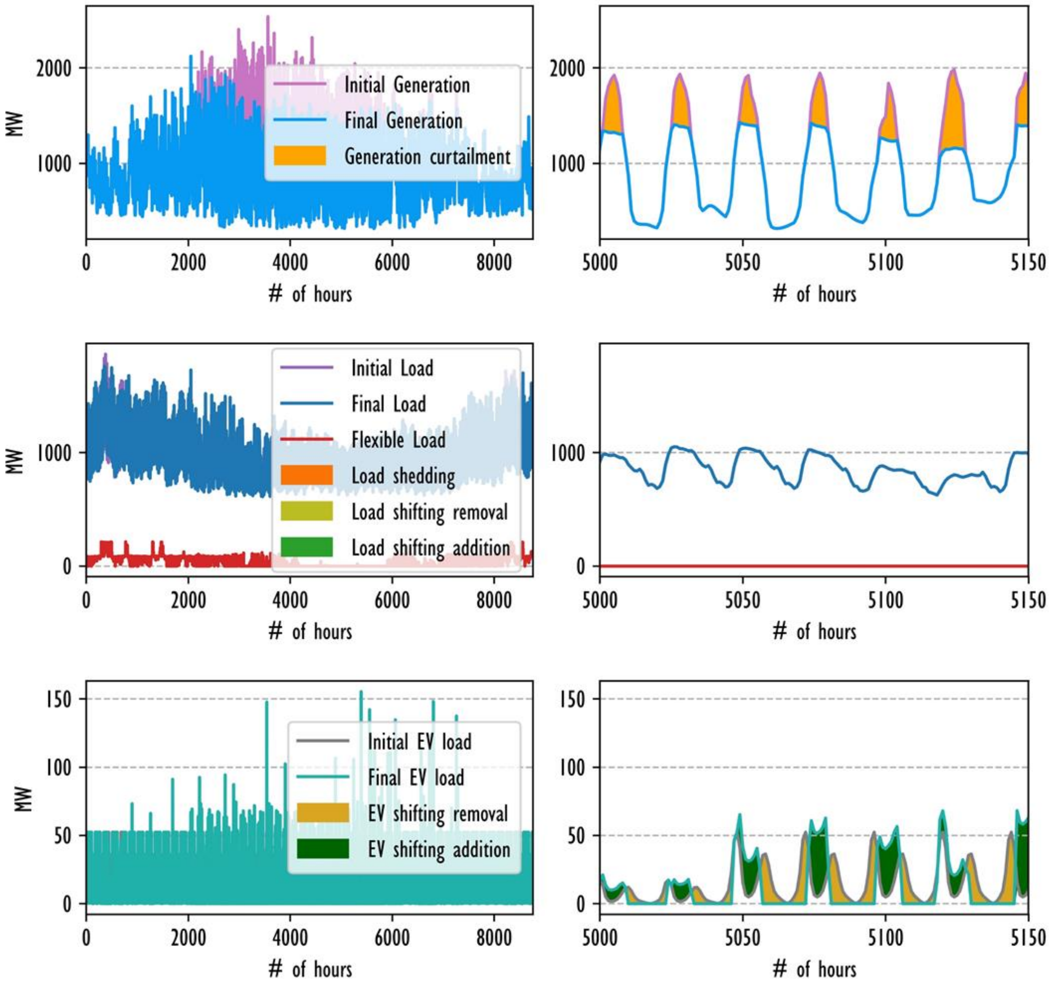

Figure 42: DCM dispatch during the year (left) and a specific period (right) where no flexible load is available – load shifting mechanism enabled – The Netherlands rural archetype

Finally, a French rural network is shown in Figure 43, for which the flexible load profile is available during the entire year. A zoom in during the specific period shows however that EV shifting is activated whereas load shifting remains null. This happens as the flexible load (middle graph of the figure) is already synchronised with the generation curtailment as a result of the market-based dispatch and therefore no alleviation actions can be taken by the distribution model. The alleviation procedure allowed to reduce by 0.15 TWh an initial generation curtailment of 0.72 TWh (i.e., 21% of relative reduction). As in the previous example, even if the flexible load potential (1.76 TWh) is significantly bigger than that of EV (0.34 TWh), both assets contribute by a similar rate, with 0.09 TWh and 0.06 TWh for load and EV shifting, respectively.

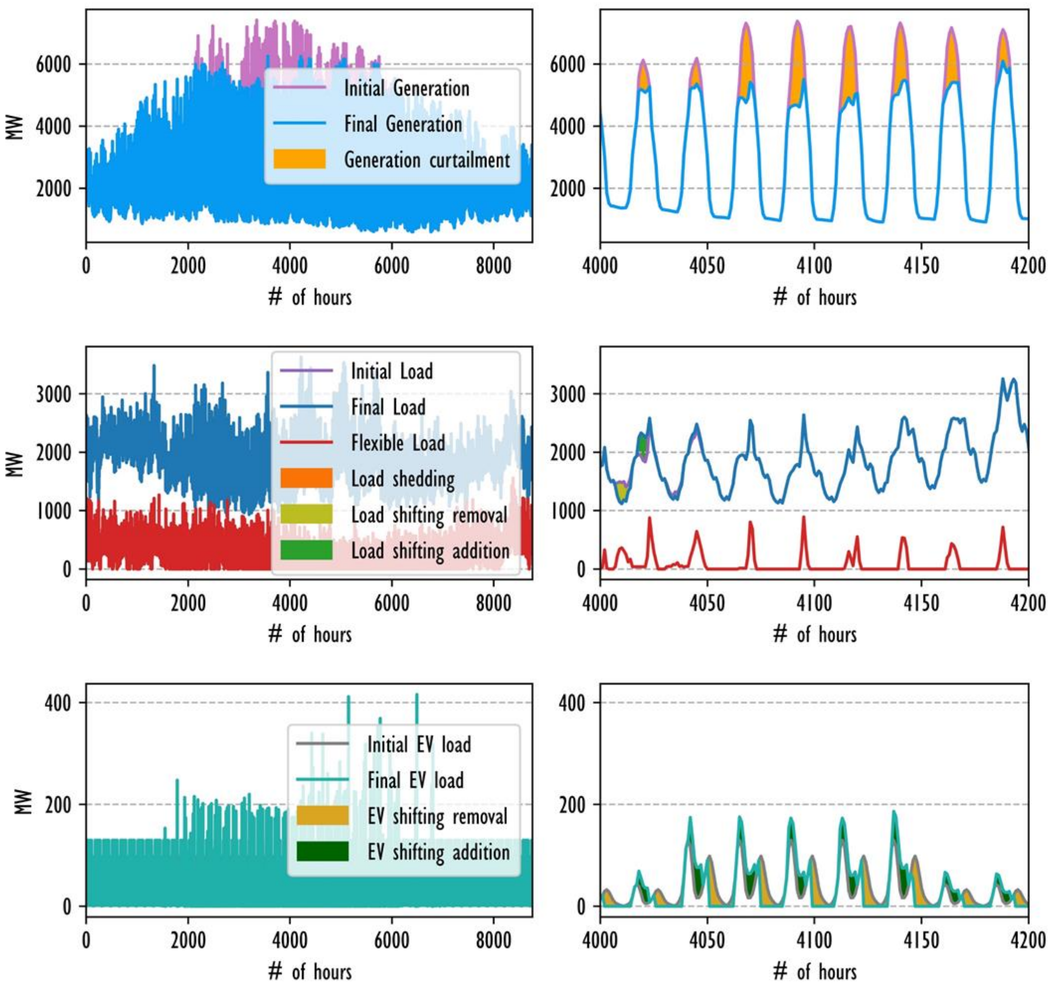

Figure 43: DCM dispatch during the year (left) and a specific period (right)– full flexibility mechanism enabled – France rural archetype

4.2.2. SUMMARY

A network-wise view of the load shedding and generation curtailment reduction for the full flexibility configuration is presented in Table 13. From an initial number 103 networks reaching constraints limits, a total of 71 observed a decrease on their rate of generation curtailment and/or load shedding. In terms of generation curtailment, among those networks the average relative reduction (with respect to their initial generation curtailment rate) was 37%. For load shedding reduction, this average value went up to 51%.

Table 13: Load shedding and generation curtailment reduction per network, in the full flexibility configuration

Networks reducing generation curtailment and/or load shedding	Curtailment reduction across the networks	Shedding reduction across the networks
71/103	mean: 11% max: 37% min: 1%	mean: 51% max: 100% min: 5%

When considering the effectiveness of the flexibility mechanisms at country level, the relative size of the network with respect to the country's electricity mix plays a fundamental role. The average relative reduction per country, which is calculated by aggregating the effects of shedding and curtailment reduction among all the networks of it, becomes 8% and 44% respectively. A summary is presented in Table 15.

Table 14: Load shedding and generation curtailment reduction per country, in the full flexibility configuration

Countries reducing generation curtailment and/or load shedding	Curtailment reduction across countries	Shedding reduction across countries
21/34	mean: 8% max: 20% min: 1%	mean: 44% max: 100% min: 6%

Finally, an overview of the alleviation outcome for EU27+UK+6 is shown in Table 15, where values are aggregated across all the 288 networks. The non-flexible configuration shows a total generation curtailment and load shedding of 71.0 TWh and 12.5 TWh, respectively (cf. Section 2.6). In terms of alleviation, the load shifting mechanism alone was able to reduce both the generation curtailment and load shedding rates by around 3% (i.e., from 71.0 TWh to 69.1 TWh) and 15% (i.e., from 12.5 TWh to 10.5 TWh), respectively. The EV load shifting mechanisms contributed to a reduction of 2% and 5% on the generation curtailment and load shedding rates, respectively. Lastly, both mechanisms enabled together allowed to reduce by 4% and 19% the curtailment and shedding, respectively.

Table 15: Summary of the three flexibility configurations and their network problems alleviation outcome, for EU27+UK+6

Flexibility Mechanism	Generation curtailment TWh	Load shedding TWh	Load shifting TWh	EV shifting TWh
No flexibility	71.0	12.5	--	--
Load shifting	69.1 (-3%)	10.5 (-15%)	3.5	--
EV load shifting	69.9 (-2%)	11.8 (-5%)	--	1.7
Full	68.3 (-4%)	10.1 (-19%)	3.0	1.6

In terms of the effectiveness of the flexibility mechanisms, results suggest that load shifting seems to be more effective than EV shifting when it comes to reduce the load shedding rate. One also observes a certain degree of complementarity between both mechanisms as their contributions alone are increased from 15% and 5%, respectively, to 19% when combined. Also, when it comes to generation curtailment reduction, even if no clear tendencies on their complementarity can be concluded, it can be noted that both mechanisms alone contribute similarly to its reduction (3% and 2% for load shifting and EV shifting, respectively). This, even if the total flexible load availability shows to be bigger in magnitude than that of EV.

4.3. Conclusions

Based on the previous discussion, the following conclusion can be summarised:

- Flexibility solutions, in terms of load and EV load shifting, helps to accommodate more renewables in the distribution networks. In some of them, curtailment and shedding reduction are significant. On average, the generation curtailment and load shedding reduction rates were around 11% and 51%, respectively.
- When looking at the EU27+UK+6 (i.e., considering all the distribution networks together), the alleviation observed is around 4% and 19% for curtailment and shedding, respectively. Differences with respect to previous values are due to the relative sizes of the networks with respect to the European electricity mix.
- Load shifting contributes significantly to reduction of load shedding (15%), followed by EV load shifting's contribution (5%). For this type of network problem, both mechanisms showed to be complementary as, when activated together, they were able to reach a 19% of reduction.

- Even if EV's flexibility availability by magnitude is lower than that of other flexible load (in the EUCO3232.5 scenario), both the flexibility solutions contribute in the same order of magnitude to reducing generation curtailment.
- The extent to which flexibility is useful in renewable integration is highly dependent on the characteristics of the network such as its generation mix, inflexible versus, flexible load, and their simultaneity. In particular:
    - The contrition from load shifting towards generation curtailment alleviation seems to be highly limited due to the non-simultaneity of the flexible load and the curtailment need (especially during warmer seasons).
    - Also, in some cases the flexible load is already synchronised with the generation, by decision of the market, and therefore no further redispatch can be activated by the distribution model.
- There is still a need for the introduction of additional flexibility solutions helping to reduce the level of network problems in the system. Different options, that were not included in the current study, can be further assessed via the use of METIS:
    - Air conditioning: Even if this asset is included in the distribution layer (cf. Table 7 and Table 8), in the current study it was considered as non-flexible. Building thermal inertia allows to partially modify air conditioners' consumption pattern without impacting user comfort, and therefore can be considered as a potential source of flexibility. Additionally, this asset is mostly used during the warmer months of the year, which could help to compensate the reduction of the flexible available load that was observed for some networks during those months.
    - Thermosensitive and non-thermosensitive remainder: Some of the components of both assets, which are also considered by the distribution layer as non-flexible (cf. Table 7 and Table 8), can provide flexibility. For instance, cooling in the services sector (included in the thermosensitive remainder [4]) can provide flexibility, thanks to building thermal inertia. Also, the non-thermosensitive remainder includes all electrical loads that are independent of the temperature [4]: household appliances such as dishwashers and washing machines can be therefore considered to further increase the flexibility level.
    - Distributed stationary storage: EUCO3232.5 did not consider a significant amount of distributed storage and was therefore not part of this study. However, the tool includes a module for its simulation and can be included in the assessment for enhancing flexibility.

5. TASK-5: SENSITIVITY ANALYSIS

5.1. METHODOLOGY

To perform a sensitivity analysis according to some vRES, the installed capacity of three different technologies across the whole European grid (Table 16) is modified, to meet the vRES capacities of a scenario reaching more ambitious decarbonisation level in 2030 (-55%). Modifications are performed on the zonal market model which is the source of boundary conditions for both transmission and distribution models. Installed capacities are increased following this table:

Table 16: Summary of the assets whose capacity was increased by the sensitivity

Technology	Installed capacity increased ratio
Solar	+34%
Wind offshore	+25%
Wind onshore	+56%

The resulting increase of installed capacities is uniformly distributed among every zone of the European electricity system.

Then, the zonal market model is re-run to obtain a new optimisation of the European electricity market through the year 2030, considering the new levels of installed capacity.

Finally, computations of task 3 and 4, assessing the impact of flexibilities for both transmission and distribution networks, are re-run, starting from the new market outputs. The results of these new computations are compared to previous results to assess the sensitivity of the results obtained in this study to the assumptions related to the installed capacities of solar and wind assets.

5.2. Results for transmission

5.2.1. Effect on loss of load and curtailment

Figure 44 introduces the average difference of loss of load and curtailment decrease between the central results of this study, without new vRES installed capacities, and sensitivity analysis study, with new installed vRES capacities. That is, for each assessment and each snapshot, the reduction of loss of load in percentage of consumption thanks to a given flexibility solution is computed. The average level of reduction among the 6 snapshots is then computed.

For example, on the figure below one can see that, in the sensitivity analysis, the reduction of the loss of load thanks to general redispatch is higher by 1.8% in terms of total consumption than in the central case. The reduction of curtailment thanks to general redispatch is found to be lower by 1.5% in terms of production in the sensitivity analysis compared to our central results.

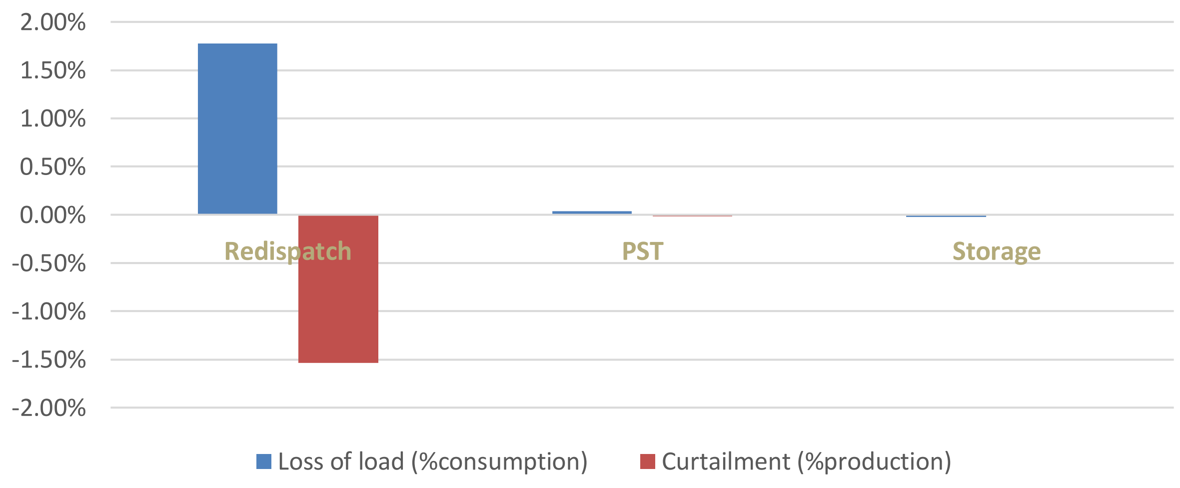

Figure 44: Average difference of loss of load and curtailment decrease between base study and sensitivity analysis

For general redispatch flexibility, a higher variable RES development results in larger decrease of loss of load and smaller decrease of curtailment. Therefore, higher vRES penetration does not weaken the capability of the network to avoid load shedding using general redispatch. However, the capacity of general redispatch to avoid the curtailment of some power sources is somehow weakened when solar, wind offshore and wind onshore capacities are increased. This conclusion could be challenged if one were to introduce additional flexibility solutions such as flexible electrolysers.
In both base and sensitivity studies, PST and storage flexibilities have a relatively little impact on loss of load and curtailment. Differences between the results obtained in the sensitivity and the ones of the central configuration are also limited as shown on the figure above.

5.3. RESULTS FOR DISTRIBUTION

Results of the sensitivity shows an overall increase of 21.0% (from 955.4 TWh to 1159.0 TWh, cf. Table 17) on the yearly generation for EU27+UK+6 at the distribution level. However, distribution demand is increased only by 0.1%, mainly due to a marginal change of dispatch of the zonal market model. In the configuration without flexibility, the generation curtailment needs are then increased by 87%, whereas that of load shedding are reduced by 30%. The reduction in load shedding is due to the simultaneity and increase in generation. Values are summarised in Table 17.

Table 17: Overview of the effects of increased generation with respect to the reference situation (no flexibility)

Generation TWh	Generation curtailment TWh	Load TWh	Load shedding TWh
955.4 → 1159.0 (+21%)	71.0 → 133.0 (+87%)	2793.3 → 2797.1 (+0.1%)	12.5 → 8.7 (-30%)

In the full flexibility configuration, before the introduction of the increased vRES generation (with respect to the central configuration based on EUCO3232.5), the amount of generation curtailment reduction was about 4% (i.e. 2.7 TWh of reduction over 71 TWh of curtailment needs, cf. Table 17 and Table 18). In the sensitivity analysis this rate is reduced now to around 3% (i.e., 3.8 TWh over 133 TWh of curtailment needs). It is therefore observed that even if the curtailment needs are increased (by 87%) the curtailment reduction capacity does not decrease proportionally (i.e., from 4% to 3%), suggesting that there is still a remaining capacity to allocate extra generation.

Table 18: Overview of the effects of increased generation with respect to the generation curtailment and load shedding alleviation, in the full flexibility configuration

Generation curtailment alleviation TWh	Generation curtailment alleviation %	Load shedding alleviation TWh	Load shedding alleviation %
2.7 → 3.8	4 → 3	2.4 → 1.8	19 → 21

A similar exercise shows that the networks' capacity to allocate demand is increased, but this time thanks to a reduction of the shedding needs. Indeed, 19% of load shedding reduction (i.e. 2.4 TWh of reduction over 2793.3 TWh of shedding needs, cf. Table 17 and Table 18) was observed for the full flexibility scenario, whereas an equivalent value of 21% (i.e., 1.8 TWh over 2797.1 TWh of shedding needs) is now shown in the sensitivity analysis. This positive impact on the load shedding capacity is explained mainly by a reduction of the shedding needs (-30%), as less networks violations are encountered thanks to an increase of demand and generation simultaneity.

6. TASK-6: SYNTHESIS

This task synthesises the key learnings of the METIS-2 Study S1 exercise on the role and the magnitude of the different flexibility measures to support renewable integration to decarbonise the European energy system, while considering constraints emerging from the consideration of power flows in the transmission and distribution grids.

6.1. SYNTHESIS OF THE ROLE OF FLEXIBILITY TECHNOLOGIES IN EUROPEAN TRANSMISSION GRID WITH REGARD TO RENEWABLE INTEGRATION

This study builds on the introduction of two new modules to simulate the European transmission and distribution networks. This allows to perform more detailed simulation of the operations of the European power system, recognising the role physics plays in the flow of electricity, and the associated limitations that cannot be identified and assessed when treating bidding zones as copper plates.

This study focused on simulations of the European grid in the context of the EUCO3232.5 scenario, especially regarding congestion issues and how different flexibility solution can combine to solve them. This section synthesises the contributions of these flexibility solutions towards transmission grid congestion alleviation.

By disaggregating the zonal market model to a nodal network model for a given snapshot (hour of the year), the transmission module simulates the operation of the European network and the activation of flexibility solutions to alleviate constraints that may emerge because markets do not consider potential congestions on transmission grids. Six KPIs have been chosen to assess the impact of the activation of flexibility solutions: number of congested lines, transmission usage distribution, curtailment, loss of load, production mix and total production costs, as detailed in Task 1.

In Task 2, analysed the reference situation, i.e., the simulation of the grid for 6 different snapshots, without any flexibilities activated has been analysed. The results show that, for each snapshot, even for non-stressed situations such as average winter or summer load, congestions, loss of load and curtailment occurs on the grid. Therefore, the zonal market output cannot be operated by the network without the activation of flexibility solutions.

Task 3 has focussed on analysing the impacts of three different types of flexibility solutions through DCOPF computations, following an "all-but-one" approach:

- Redispatch: allowing the redispatch between different technologies of production inside the same network zone.
- Storage: allowing storage units to deviate from zonal market output increasing or decreasing their exchange of energy with the grid.
- Phase-Shifting Transformer (PST): allowing PSTs to modify their shifting angle.

Task 3 results illustrate the importance of redispatch flexibility to alleviate congestions and to reduce loss of load and curtailment. Storage and Phase-Shifting Transformer flexibilities also allow to solve congestions and to reduce loss of load and curtailment but at a more local scale, and with a lower intensity. In the scenarios that have been investigated, storage assets and PSTs have a relative impact three times lower than redispatch. For certain snapshots, results show that PST optimisation allows to increase RES participation (for hydro power plant, solar energy sources and wind-based energy sources).

Task 5 results give a view on how the role of flexibility solutions is impacted by an increased penetration of three different RES: solar, wind offshore and wind onshore. Results show that adding additional RES capacity does not weaken the capability of the three kinds of studied flexibilities to solve congestions and to reduce the loss of load and the curtailment.

Table 19: Key characteristics of the three flexibility mechanisms studied

Flexibility	Impact order of magnitude	Local or global impact	May substantially increase RES participation	Robust to higher RES capacity
Redispatch	3	Global		x
Storage	1	Local		x
PST	1	Local	x	x

Table 19 summarises key characteristics of the three studied flexibilities in the EUCO3232.5 scenario and in the sensitivity analysis assuming higher variable RES deployment. The second column provides a high-level estimate of the order of magnitude of the impact of each family of flexibility solution. The third column indicates if the given flexibility has an impact on the whole European grid or if it typically acts only rather close to its device. An "x" in the fourth column shows that this flexibility is able to substantially increase RES participation, at least for certain snapshots. The fifth column indicates that the flexibility is robust to a higher penetration of RES along the whole European grid.

6.2. SYNTHESIS OF THE ROLE OF FLEXIBILITY TECHNOLOGIES IN EUROPEAN DISTRIBUTION GRID WITH REGARD TO RENEWABLE INTEGRATION

The distribution networks of the EU27+UK+6 countries are modelled by means of 288 archetypes that reflect the topology and the technical characteristics of the European distribution networks. They in turn are country, climatic zone as well as type of load (rural, urban, semiurban) specific. The study allows to draw some conclusions about operating the European grid in the context of the EUCO3232.5 scenario, especially regarding congestion issues and how some kind of flexibilities can solve them at the distribution level.

Task 2 shows that among the four types of constraints studied in the distribution network, overvoltage due to injections is the main driver of constraint violations, followed by overload on substations. Cable overload and undervoltage were encountered for some countries but remain negligible compared to the former constraints. Based on the EUCO3232.5 scenario, our model shows that 7.4% (71.0 TWh) of total distribution network generation is curtailed and 0.4% (12.5 TWh) of total distribution network load is shed, respectively, to avoid violation of grid constraints. This happens despite the yearly demand per country being bigger than generation. Germany, Spain and Great Britain are the countries presenting more than 10% of curtailment with respect to Europe's total distribution network generation. Greece, Cyprus, Latvia, Denmark, Spain, Germany and Austria are the countries presenting more than 10% of curtailment with respect to their own total distribution network generation.

Task 4 shows that flexibility can help accommodate more renewables in distribution networks. At European level, load shifting, by means of heat pump and sanitary hot water, particularly in France and UK, contributes significantly to reduction of load shedding (15%) followed by EV shifting's contribution (5%). However, the contribution from load shifting towards reduction in generation curtailment is limited to 3% due to non-simultaneity between flexible load (heat pump and sanitary hot water) seasonal availability and curtailment need (especially during summer). EV shifting as well contributes limitedly, 2%, to the reduction of generation curtailment. It is worth noting that even if EV's flexibility availability by magnitude is lower than that of flexible load (in the EUCO3232.5 scenario), both assets contribute in the same order of magnitude to the reduction of generation curtailment. However, it is important to note that, in some of the individual distribution networks, curtailment reduction and shedding reduction due to flexibility is significant (network-wise, around an average and a maximum of 11% and 37% for curtailment, and an average and a maximum of 51% and 100% for shedding) even though their contribution at Europe level is low.

Task 5, where a sensitivity analysis to the deployment of variable RES has been performed, gives a view on how flexibilities are sensitive to an increased penetration (when compared to EUCO3232.5 scenario) of three different RES: solar, wind offshore and wind onshore. The available load and EV flexibility remain the same as in the EUCO3232.5 scenario. The sensitivity analysis, carried out with an increase of generation by 21% at the distribution level compared to the one in Task 2, shows that the curtailment reduction by means of flexibility is comparable to the results of the simulations based on the EUCO3232.5 scenario (approx. 3 %). That is, despite an increase of generation by 21%, the capability of flexibility measures to accommodate the higher level of renewable generation does not decline linearly. In other words, adding additional RES capacity does not weaken the capability of the flexibility measures to solve congestions and to reduce load shedding and curtailment.

The extent to which flexibility is useful in renewable integration is highly dependent on the characteristics of the network such as its generation mix, inflexible load, flexible load and equally importantly the simultaneity between the availability of flexible load and the renewable generation. This makes the distribution module integrated to the METIS platform useful to quantify the benefits of flexibility network by network or by group of networks.

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