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METIS 2 - Technical Note T5

Distribution grid module: Methodology and functionalities

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ABBREVIATIONS

Abbreviation	Definition
DCM	Distribution Core Model
EV	Electrical Vehicle
GUI	Graphical user interface
HV	High voltage
KPI	Key performance indicator
LV	Low voltage
MV	Medium voltage
OPF	Optimal power flow
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RES	Renewable energy sources
V2G	Vehicle-to-grid

1 INTRODUCTION

This document describes the newly developed METIS electricity distribution grid module which extends the tool's capability for modelling the European electricity distribution networks. The tool is expanded by the implementation of synthetic networks, denominated "archetypes", that model the electricity distribution systems, together with the inclusion of an optimal power flow model, called Distribution Core Model (DCM), to emulate their operation.

The present document is organised as follows:

- Section 2 is dedicated to the description of the modelling principles used to represent the various types of distribution networks in the METIS platform. It also gives an overview of the library of assets (demand, generation, storage, and EVs) that can be found in a distribution network.
- Section 3 describes briefly the datasets delivered within METIS to perform electrical distribution grid studies.
- Section 4 elaborates on the interaction between the zonal market module[1] (containing models for European day-ahead, intraday and balancing markets) and the distribution module.
- Section 5 describes the main outputs and key performance indicators the distribution module provides.

We note that METIS also embeds a transmission grid module[2] (focusing on electrical transmission networks).

2 GENERAL MODELLING PRINCIPLE

The European distribution grid model is integrated in the METIS platform via the pairing of two concepts, archetypes and climatic zones:

- **Archetypes** are synthetic networks whose aim is to be representative of the electricity distribution grids of a country. We distinguish three types, namely urban, semi-urban and rural, depending on the degree of urbanisation3 of the represented zone. The three types differ with respect to the network's electrical topology, as well as the characteristics of the technical equipment considered. For instance, compared to urban and semi-urban, rural networks are typically characterised by longer electrical conductors, needed to connect more widely distributed consumers.
- **Climatic zones** describe a location's related parameters such as its geographical position, size, and climatic conditions. They are characterised by a set of temperature, solar irradiation, and hourly wind speed profiles, mapped around the urban clusters of the countries and subsequently clustered into representative time series. They are meant to capture how the weather conditions impact the operation of the electrical networks. For example, climatic zones that are warmer during the year will have, in average, a higher demand for air conditioning, while

[1] See the METIS technical notes on the power system module (https://ec.europa.eu/energy/sites/default/files/power_system_module.pdf) and the power market module (https://ec.europa.eu/energy/sites/default/files/power_market_module.pdf) .

[2] The respective technical note is forthcoming.

[3] The degree of urbanisation is a measure of a zone's population density and size. More details can be found in https://ghsl.jrc.ec.europa.eu/degurbaDefinitions.php.

zones with a higher wind speed will present a higher wind energy yield. The number of climatic zones, being different among countries, was decided by expert advice. More detail on the methodology can be found in [1].

For each country, the previously introduced approach is applied to estimate how many (urban, semi-urban and rural) archetypes are contained within each of the climatic zones. This pairing process, that depends on the size and position of the urban, semi-urban and rural grids as well as on the extension of the climatic zone, allows the diversification of the operational parameters of the modelled networks. An urban archetype, for instance, contained in two climatic zones presenting different solar irradiation conditions, will result in two different networks that are equivalent in their electrical topology but different in terms of solar generation potential. This process delivers a number of calibrated networks that can be different by country. France, for example, which features 4 climatic zones containing the 3 types of archetypes will exhibit 12 calibrated networks (cf. Table 1). The outcome for the 34 countries considered in the METIS platform is a total of 288 calibrated[4] networks[5].

Table 1 Summary of the number of archetypes and climatic zones per country

Country	Number of climatic zones	Number of archetypes	Calibrated 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
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

[4] Calibrated networks will also reflect the main electrical characteristics of the country they represent, in a process that is summarised in section 3 and fully described in [1].

[5] A network's electrical characteristics and topology can be modified by a METIS user. However, the number of climatic zones and archetypes are fixed in the tool and therefore cannot be modified.

Country	Number of climatic zones	Number of archetypes	Calibrated distribution networks
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**

The conversion of the calibrated networks into a modelling language, for their utilisation in the METIS platform, was done via Engie Impact's proprietary software Smart Sizing[6] [2]. The tool allows to optimise the investment and operation of a given network while respecting nominal operation criteria. Networks constructed in this way were validated under the EU Reference 2016 scenario for the year 2020 (cf. section 3.1). Under the assumption that distribution grids are correctly designed to support the generation and demand of that year, a power flow simulation to verify that technical constraints respected the nominal limits of the network was carried out for each of them.

A simplified version of the Smart Sizing software, the DCM tool, that enables the METIS platform to simulate the operation of the calibrated networks, will be described in the reaming of the current section: section 2.1 gives an overview of the DCM's modelling philosophy and section 2.2 describes the library of assets contained in the METIS platform allowing the configuration of the calibrated networks.

2.1 Distribution Core Model

The DCM features a simplified optimal power flow formulation, capable of computing the flow of electricity through the network, together with the saturation level of transformers and conductors, and the voltage variation at the different nodes. In parallel, it estimates the cost associated to the losses and the activation of flexibility. While respecting technical network constraints, the model will seek, among all the admissible states of the grid, the one that exhibits the lowest operational costs.

In the current version of the platform, networks are composed of three voltage levels, high, medium and low voltage (HV, MV and LV[7], cf. Figure 1). At each of them, several conductors[8] departing from the substations interconnect their generation/consumption nodes with the substations of the lower level. Transfer of power from one level to the other takes place through substations of voltage conversion, and will depend on the demand and generation mix at each of them, as well as on the physical characteristics of the network (cf. Section 2.1.1). Load shifting, electrical vehicles (EVs) and decentralized storage are considered as well, allowing local flexibility to participate in the balance and operation of the grid.

[6] Smart Sizing is a techno-economic tool, minimizing the investment (CAPEX) and the operation (OPEX) of large-scale distribution networks, respecting security and nominal operation constraints.

[7] The actual voltage values are country-specific and can be found on the network parameters in the platform.

[8] The length of individual conductors was not actually considered, but a "representative" average value was used instead. The estimation procedure followed a top-down approach that computed the total length of the electrical lines at national level, differentiated by network type (i.e., urban, semi-urban and rural), divided by their respective total number of connection points. Assuming these last ones are equally spaced over the network's conductors, this ratio gives an average conductor length between connection points. More details can be found in [1].

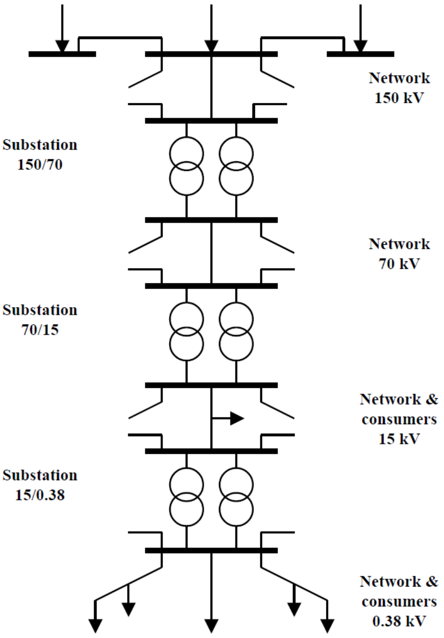


Figure 1: Illustration of the electrical topology of a network modelled in the DCM

The model assumes uniformity both on the network's electrical topology as well as on its operation. For the former, this requires, for example, that at each voltage level nodes and substations are uniformly distributed over the network's surface, and that the technical characteristics of the equipment are the same. For the latter, it requires that all the nodes of a given voltage level exhibit the same consumption and generation profiles. The model is therefore valid for large-scale networks, where such a configuration can be assumed. More specifically, it requires, for each voltage level, the following assumptions:

- Substations are uniformly distributed in the space.
- Nominal power of transformers as well as their number per substation are equal.
- The number of conductors departing from a substation are the same.
- The section and type of those conductors are uniform.
- Nodes of electrical consumption and generation are uniformly distributed in space and among conductors.
- Load and generation profiles of nodes are uniformly distributed and have the same level of flexibility.
- The consumption and generation nodes have respectively the same set of activated flexibilities[9].

It might be noted that previous assumptions are valid for each voltage level individually. Available flexibility, topology and technical characteristics of the network can therefore differ from one level to the other.

2.1.1 OVERALL DESCRIPTION

The DCM is a non-convex optimisation problem that minimises the operational expenditures of an already existing network, by satisfying energy and network restrictions

[9] We note that the actual configuration of the networks, such as the level of flexibilities, can be configurable by the user and will be described later in the text.

criteria. Its objective function is composed of two operational costs: cost of losses and cost of flexibility activation. The problem can be formulated in the following way:

$$\begin{aligned} &\min\ \boldsymbol{cost}(losses) + \boldsymbol{cost}(flexibility) \\ &s.t \\ &\qquad\qquad Power\ balance \\ &\qquad\qquad Nominal\ operation \end{aligned}$$

where losses on the grid can be separated into two elements:

- power line losses: accounting for the active power losses due to the resistive component of lines,
- transformer losses:
  - copper losses: heat losses due to the resistive term of a transformer's windings,
  - iron losses: corresponding to losses due to the magnetic properties of the transformers' components.

Flexibility can be separated into five categories:

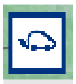
- Load shifting, describing the capacity of consumers to shift their load during a certain period.
- Load shedding, which describes the possibility of reducing load by a certain amount.
- Generation curtailment, referring to the capacity of reducing the output of local sources of renewable energy.
- Decentralised storage, including the operation of, and losses inside, electrical batteries.
- EV flexibility, which is associated to adaptations of their charging profiles and/or the use of the vehicle-to-grid (V2G) functionality.

In terms of model constraints, a first set of power balance restrictions ensures that the network's imports and exports balance out generation, consumption, and power losses across all voltage levels. The second term, described as nominal operation constraints, will ensure that thermal capacities of conductors and transformers, as well as voltage variation limits of the nodes are respected during the operation. For a detailed description of the model, the reader is invited to consult section 7.2.

2.2 ASSET LIBRARY

Distribution network archetypes are represented in METIS by a set of interconnected assets, as shown in Figure 2, which can be summarised as follows:

- The asset on top of the architecture corresponds to the **regional settings asset** . It includes different parameters independent of the voltage level, such as the surface associated to the distribution network, the losses and flexibility costs, Bool variables managing the flexibility activation, etc.
- Below the regional asset, the network's voltage levels HV, MV and LV, are represented by three grey "delivery points", to which different assets are connected: network, demand, production, and storage. Additionally, the LV level hosts four EV assets:
  - The **network assets**  include the topological and the electrical parameters defining the network's physical characteristics at the respective voltage level.

- The **production assets**  host the total production aggregated into a single curtailable generation profile at the respective voltage level.
- The **demand assets**  host the total demand aggregated into a flexible and a non-flexible[10] load profile at the respective voltage level.
- The **storage assets**  represent an aggregated electrical storage and associated parameters at the respective voltage level.
- The **EV assets**  represent the four types of EVs considered by the market module: PHEV home charge, PHEV work charge, BEV home charge and BEV work charge.

• Two **substation assets**  make the interconnection between the HV, MV and LV levels. This type of asset groups the electrical parameters defining a substation, such as the number of hosted transformers as well as their nominal capacities. We distinguish two extra asset types[11] connected to substations:

- The **substation production assets**  host all the substation production aggregated into a single curtailable generation profile at the respective substation. This kind of asset maps the generation that is directly connected to the substations (i.e., without any electrical grid connecting the substation and the production asset).
- The **substation demand assets**  host all the distribution substation demand aggregated in one flexible load profile and one non-flexible load profile at the respective substation. This type of asset maps the demand that is directly connected to the substations (i.e., without any electrical grid connecting the substation and the demand asset).

[10] See section 2.2.3 for more details on the type of demand that is considered by the flexible and the non-flexible part of the load.

[11] These assets might represent either big consumers or producers (e.g., PV centrals) directly connected to distribution substations. Even if they are considered in the modelling structure, their respective production and consumption profiles are set by default to zero and are not considered in any of the Tx-Dx disaggregation routines (cf. section 4.1). They can although be totally configured by a METIS user.

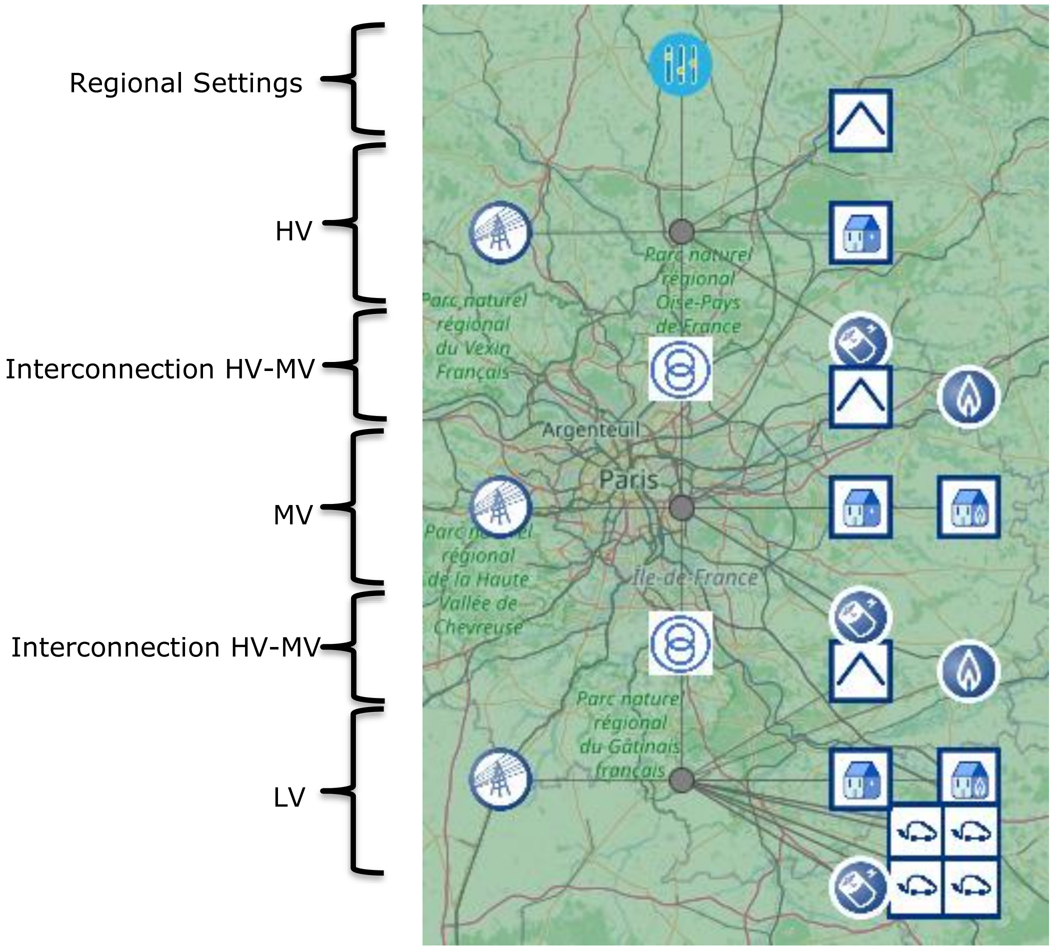


Figure 2: Group of assets representing a distribution network archetype in METIS

We note that even if all networks are represented by a three-voltage level structure, some countries only have two voltage levels, LV and MV[12], on their distribution infrastructure (9 countries over the 34 are concerned, including Belgium, France and Portugal). The reason is that the HV level ranges considered in the modelling are managed by the transmission system operators of those specific countries. For them, a dummy voltage level is used to represent the HV level, similar to a copper plate, that presents no losses or voltage variations.

The calibrated networks of a given country are displayed in a matrix shape in the METIS graphical user interface (GUI), with three columns corresponding to each distribution type (urban, semi-urban and rural) and as many rows as climatic zones are defined on it. There is no connection between the location of the distribution network and the portion of the country displayed below the network itself. An illustration can be seen on Figure 3 for the 12 distribution network generated for France. The assets' IDs are defined by the following structure:

AssetType_Country_ClimaticZone_DistributionType_VoltageLevelNumber,

so that all information about the asset classification can be derived from its name. We note that voltage level numbers 1, 2, 3 are associated to the LV, MV and HV voltage levels and

[12] For those countries, the HV level belongs to their electricity transmission system.

that regional settings are voltage independent and thus have an associated voltage number of 0. Here-below there are some illustrations of distribution asset names:

- "SETTINGS_FR_Z2_RUR_0" is the name of regional settings asset of France, corresponding to the second climatic zone and of rural type.
- "NETWORK_BE_Z1_URB_1" is the name of the Belgian network asset corresponding to the first climatic zone, the urban type and the voltage level LV.
- "CONS_ES_Z3_SEM_2" is the name of the Spanish demand asset corresponding to the third climatic zone, the semi-urban type and the voltage level MV.
- "SUBSTATION_DE_Z1_RUR_2-1" is the name of the German substation asset corresponding to the first climatic zone, the rural type and making the connection between the LV and MV voltage levels.

Figure 3 illustration of the 12 distribution networks for France

The remainder of the current section will elaborate on the main parameters and configurations available for each asset. For their extensive list and detailed explanation, the reader is invited to consult section 7.3.

2.2.1 NETWORK ASSETS

Network assets are described by various parameters characterising the network for a given voltage level:

- The numerical voltage level value, as well as its related voltage variation bounds.
- Topological parameters such as the node density, network length, etc.
- Electrical parameters like the resistance and reactance of conductors, an average yearly power factor, the conductors' nominal power, etc.

Associated parameters:

- *Unconstrained OPF* (bool): this flag allows to loosen constraints related to voltage limits and nominal power of conductors and transformers (cf. section 7.2.1.6). This is especially useful to investigate how far the constraints could be violated if there were no technical bounds on the system.

2.2.2 SUBSTATION ASSETS

This asset models the substations connecting two voltage levels, and their related transformers via parameters such as substation density, number of transformers per substation, copper and iron losses factors, transformers nominal power.

2.2.3 DEMAND AND SUBSTATION DEMAND ASSETS

Demand and Substation Demand assets aggregate, respectively, all the electrical demand at a given voltage level and substation, into a single aggregated profile, without distinction of their type (e.g., air conditioning demand, thermosensitive demand, immediate charging EVs, etc. as considered in the zonal market model). It is constructed by taking a weighted sum[13] over the market demand asset profiles, with the weighting factors being a certain set of disaggregation coefficients (further explained in section 4.1.1) that are dependent of the archetype type, climatic zone, and voltage level of interest.

Associated parameters and profiles[14]:

1. Demand (MW/km2): time series defining the asset's input demand.

- *Non-flexible demand* (MW/km2): time series defining which part of the demand is considered as non-flexible. The model will automatically calculate a flexible demand profile, which is the difference between the demand and the non-flexible demand profiles. How both profiles are treated by the model, in terms of flexibility activation, is configured by the remaining parameters of the list.
- *Non-flex demand* (bool): this flag enables the non-flexible functionality on the demand. When enabled, load shifting and shedding will be applied only on a specific part of demand that will be specified in the subsequent elements of this list.
- *Load shifting* (bool): flag allowing the model to activate load shifting on the demand. The shifting is applied on the entire (flexible plus non-flexible) demand profile, unless the *non-flex demand* flag is activated, in which case the shifting is performed on the flexible part. Also, the shifting is activated within a certain time window[15] provided that the total energy shifted is recovered within that period.
- *Load shedding* (bool): flag allowing the model to activate load shedding on the load. If this flag and the *non-flex demand* flag are enabled, the following parameter allows to specify which part of the demand can be shed:
  - *Non-flex demand shedding option* (integer):
    - Value = 0: the shedding is applied to both the flexible and the non-flexible profiles, without any distinction between them.
    - Value = 1: the shedding is applied only to the non-flexible demand profile.
    - Value = 2: the shedding is applied only to the flexible demand profile.

  If *non-flex demand* is disabled, the shedding is performed over the complete demand profile.

2.2.4 PRODUCTION AND SUBSTATION PRODUCTION ASSETS

Production and Substation Production assets aggregate, respectively, all the electrical generation at a given voltage level and substation, into a single profile, without distinction of their type (e.g., wind, solar, hydro RoR, biomass, waste, etc.). As with the demand assets, its profile is the result of a weighted sum[16] taken across different generation assets based on different disaggregation coefficients (cf. section 4.1.1).

Associated parameters and profiles[17]:

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[13] It might be noted that since market assets are aggregated into a single profile, it is not possible for a METIS user to distinguish among the different technologies considered initially at the market level.

[14] See sections 7.2.1.8.2.1, 7.2.1.8.2.2 and Table 17 for a detailed description.

[15] Set to 24 hours by default.

[16] Market generation asset profiles cannot be either individualised, as they are aggregated into a single profile.

[17] See section 7.2.1.8.2.37.2.1.9.3 and Table 17 for a detailed description.

- *Non-flexible generation* (MW/km2): time series defining which part of the generation is considered as non-flexible. As with the demand, the model will automatically calculate a flexible profile based on both the non-flexible generation and generation profiles.
- *Curtailment* (bool): flag allowing the model to activate curtailment on the generation. Which part of the generation may be curtailed is controlled by the following parameter:
  - *Non-flex generation* (bool): when activated, this flag indicates that only the flexible generation profile can be curtailed.

2.2.5 STORAGE ASSETS

This asset aggregates all the storage capacity at a given voltage level.

Associated parameters[18]:

- Maximum and minimum (dis)charging power (MW/km2), controlling the input and output of power
- Minimum and maximum energy (MWh/km2), defining the limits of the storying capacity.

2.2.6 EV ASSETS

Aggregating the capacity of the specific EV type[19] at the lowest voltage level. It includes two different EV models[20]:

- *EV market*, model that follows the same formulation as that of the market module. It implies that EVs are considered as storage elements required to satisfy a certain energy demand based on given set of driving patterns defined in the market module. V2G functionality is supported in this model.
- *EV as shiftable load* model, representing the EV demand as a simple load, upon which load shifting and shedding actions can be applied. It might be noted that this mode does not respect any driving patter constraint, as the demand is considered as a simple load (and therefore treated under the equivalent formulation as that of a demand asset). When this mode is enabled, the user can configure the flexibility activation with a set of parameters[21] equivalent to the ones found in section 2.2.3. The model does not allow the V2G functionality and is enabled by default in the disaggregation routines defined in section 4.2.

[18] See section 7.2.1.8.3 for a detailed description.

[19] Four types are considered: PHEV home, PHEV work, BEV home, and BEV work.

[20] See section 7.2.1.8.47.2.1.9.3 and Table 17 for a detailed description.

[21] The flexibility options are: EV load profile (MW/km2), EV non-flexible load profile (MW/km2), EV non-flex demand (bool), EV load shifting (bool), EV load shedding (bool), EV non-flex demand shedding (integer).

3 DATA AND SCENARIOS USED IN THE METIS 2 DISTRIBUTION GRID MODULE

Data gathered during the development of the tool was used for two purposes: network construction and validation, and calibration of the DCM's flexibility costs. Details are presented in the following sections.

3.1 NETWORKS CONSTRUCTION AND VALIDATION

A first data collection process aimed to map as close as possible to reality macro-parameters concerning the topology of the distribution networks, as well as the electrical characteristics of their equipment. The process followed a top-down approach, whose starting point was three representative European urban, semi-urban and rural topologies, as proposed by [3]. The next step was their individualisation at the country level, based on country-specific data, creating synthetic networks denominated "archetypes". The methodology ensured that the archetypes' aggregated macro-parameters respect the real values collected for each of the countries.

The details of the data collected as well as of the methodology followed for archetype construction could be found in [1], the following list gives an overview of the data collected for each country:

- Topology, involving all the parameters needed to reconstruct the connected graph of the network. For each HV, MV and LV level:
  - Length of conductors between consumers
  - Number consumers
  - Number of substations

  Additional parameters involved the surface covered by the networks as well as their voltage levels.
- Equipment, which maps the electrical characteristics of conductors and substations. For each HV, MV and LV level:
  - Average yearly power factor
  - Conductor resistance, reactance, ampacity, and nominal voltage
  - Conductor power vs section ratio
  - Admissible voltage rise and drop on the conductors
  - Overhead/underground conductor ratios[22]

  For HV/MV and MV/LV substation transformers:
  - Nominal voltage and capacities
  - Equivalent resistivity, for copper losses calculation
  - Iron losses coefficients
  - No load losses used for iron losses calculation

  Additionally, the average number of transformers and departing conductors per substations were collected as well.

Data sourcing relayed strongly on the JRC Data Observatory database (see [3] and [4]), as well as on public data sources (see [1] for details on the references).

As previously mentioned in section 2, constructed networks in this way were validated from an operational point of view by verifying that their technical constraints were respected during their operation. This was simulated using the EU Reference 2016 scenario (based on the PRIMES model, see [5] for references) for the year 2020 as a basis. The scenario is

[22] Underground and overhead electrical lines are characterized by different physical characteristics (e.g., reactance, resistance). Since the model does not account for different type of conductors, the ratio was used to calculate an average value.

derived and implemented into METIS based on a standardized methodology used for numerous METIS studies [6].

3.2 Flexibility cost calibration

Calibration of the DCM's flexibility costs (cf. section 4.1.2) was performed using the METIS-EUCO3232.5 scenario for the year 2030. It includes 34 zones corresponding to the EU27+UK (scope of PRIMES scenario[23]) and is complemented with data for 6 additional countries[24], which enables a better representation of power exchanges within Europe.

4 Interaction with the zonal market module

The interaction between the market model and the distribution module is unidirectional[25]. Information from the market is projected over the distribution layer via a disaggregation process that estimates which part of the market's demand and generation belongs to the distribution system. The following sections describe the main methodology behind it (section 4.1) and the script managing its launching (section 4.2).

4.1 Methodology

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. The DCM will in principle reflect 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 least intrusive way from the initial dispatch produced by the METIS market model.

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

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

[25] The interaction in the opposite sense is, however, not implemented in the platform. Aggregating back to the market information managed at the distribution level increased the complexity both from a software and a conceptual perspective, and it was therefore disregarded from the scope of the project.

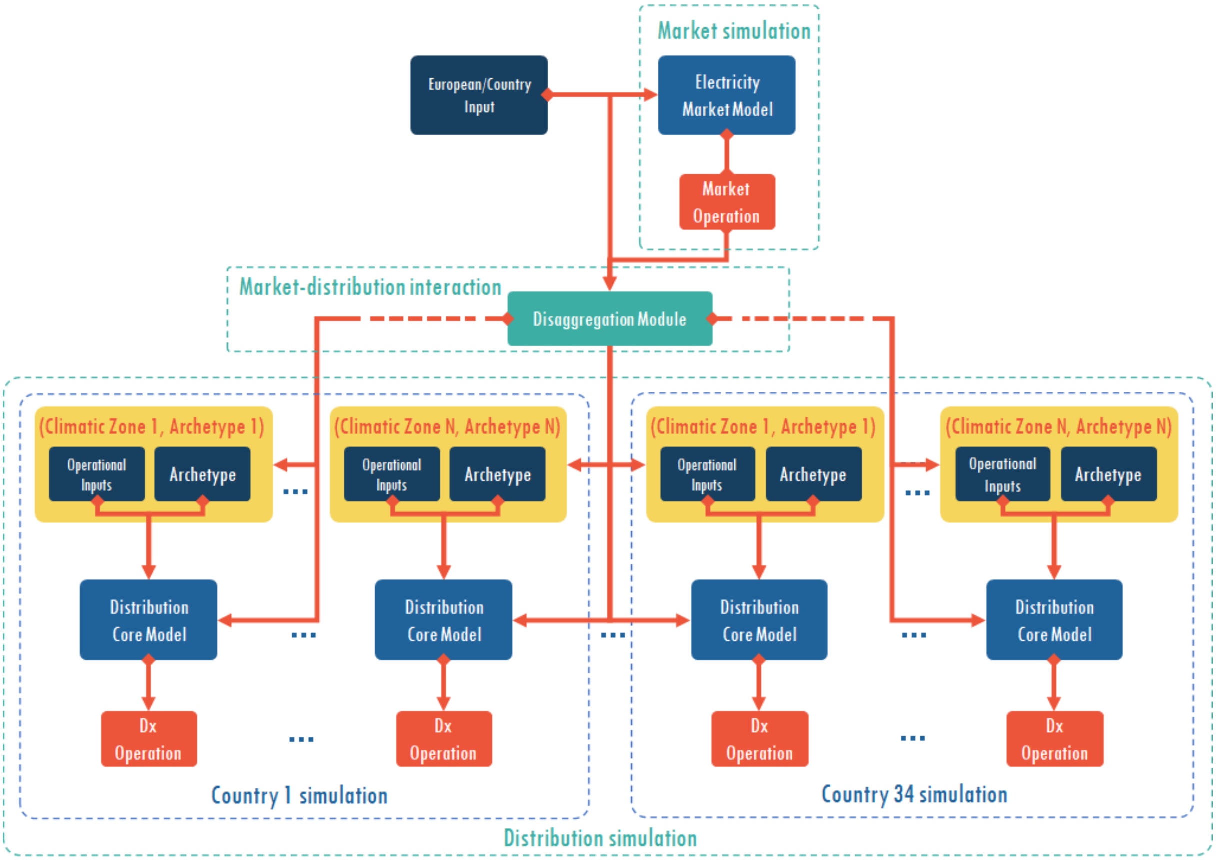

Figure 4 DCM interaction diagram

A diagram describing the interaction between the market model and the distribution grid module is presented in Figure 4. The process can be divided into three main steps:

- Market simulation: The process starts by solving the zonal market model. This will give the optimised dispatch of each country according to the operational restrictions and techno-economic parameters[26] defined in the market model.
- Market – distribution grid interaction: the market's dispatch is projected over the archetypes of each country. This process will determine the operational information needed for an archetype to be launched under the DCM. Examples of this information are dispatched generation/consumption profiles of different market assets.
- Distribution grid simulation: It corresponds to the archetype optimisation process by means of DCM simulations. A single DCM must be launched for each network. A total of 288 DCM runs will be needed to simulate the ensemble of countries within the METIS platform.

The remainder of the section is organised as follows: section 4.1.1 explains the general principles governing the disaggregation process that will project the zonal market profiles over the distribution layer, while section 4.1.2 gives an overview of the cost structure associated to flexibility activation.

[26] See note on the market power module
https://ec.europa.eu/energy/sites/default/files/power_system_module.pdf

4.1.1 MARKET ASSETS DISAGGREGATION

The current section explains the disaggregation process, in charge of projecting zonal market information over the distribution layer. This information corresponds mainly to dispatched profiles, as dispatched at market level, which are hourly time-series defining the operation of the different assets of a country. For that purpose, disaggregation coefficients are calculated, which allow the breakdown of those profiles among different voltage levels, archetypes and climatic zones.

The remainder of the section is organised as follows: section 4.1.1.1 describes how the demand and generation is split into voltage levels, ranging from transmission to distribution, while section 4.1.1.2 elaborates on how the profiles are allocated into each archetype and climatic zone. The description elaborates on how disaggregation coefficients are calculated only from a qualitative point of view. For more details on the methodology, the reader is invited to consult [1].

4.1.1.1 Voltage level breakdown

The disaggregation performs a first breakdown of demand and generation into transmission and distribution and, within the distribution system itself, between HV, MV and LV levels. Concerning the load, the methodology takes as input the demand of a reference country for which the split is historically already known. Then, for the remaining countries the breakdown is extrapolated by using coefficients based on residential, commercial, and industrial sector demand ratios. Coefficients are categorised in representative periods of hours, days, weeks, and seasons. In this way, the disaggregated information can maintain an hourly resolution, while daily, weekly and seasonal effects can be captured. Also, coefficients are assumed to be independent of the simulation year itself, as historical data was used for their construction. Additional considerations were taken as well depending on the type of demand asset that was threated. For instance, heat pumps were assumed to be connected to the lowest distribution voltage level, whereas for air conditioners demand a certain split between LV and MV was assumed (see Table 3, last column, for an overview of the split).

With respect to the generation, yearly coefficients were calculated depending on the type of market asset that was disaggregated. The methodology uses a fixed yearly split between transmission and distribution taken from the reference country, which was further broken down into HV, MV, LV levels and individualised for each country based on installed capacities that were found in. Table 2 shows a summary with the allocation coefficients that were calculated.

Table 2: Allocation coefficients for generation assets

Market asset	Distribution - LV	Distribution – MV	Distribution - HV	Transmission
Wind onshore fleet	5.4%	20.4%	9.2%	65.0%
Solar fleet	67.9%	25.5%	1.6%	5.0%
Hydro ROR fleet	25.4%	58.0%	6.6%	10.0%
Biomass fleet	13.2%	49.4%	22.3%	15.0%
Waste fleet	2.4%	51.9%	30.7%	15.0%

We would like to stress the fact that contrary to the demand, generation disaggregation coefficients are fixed (i.e., time-independent). This means that the allocated profiles will be different in magnitude from the ones present in the market but equal in shape.

4.1.1.2 Archetype and climatic zone breakdown

In parallel with the previous split, disaggregation coefficients are calculated to estimate how much electricity is produced/consumed by each archetype and climatic zone. Allocation keys are calculated for this purpose, which are percentual factors dependent on the following parameters:

- Population of the zone of interest, depending on the type of zone (urban, semi-urban and rural) and the climatic cluster under analysis. Data sourced from [7].
- Surface and size of the network. The first parameter computes the area covered by the archetype, whereas the second refers to how many urban, semi-urban and rural clusters can be found within the climatic zone. Both parameters are estimated from [7].
- Industrialisation level, based on the zone's estimated gross value added [8].
- Solar irradiation, wind speed and outdoor temperature profiles, extracted from [9] (see also [10] and [11]).

Previous parameters are used by considering proportionality ratios. For instance, the number of heat pumps is considered to be proportional to the archetypes' and climatic zones' population. In this way, a network aggregating 20% of the country's population, will therefore be allocated with 20% of the asset's demand[27]. Also, since a heat pump's operation is correlated with the outdoor temperate, it is assumed its demand is proportional to a given temperature coefficient[28].

Table 3 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	Wind speed and Size	LV, MV, HV
Solar fleet	Surface	Irradiation and Size	LV, MV, HV
Hydro ROR fleet	Surface	Size	LV, MV, HV
Biomass fleet	Surface	Size	LV, MV, HV
waste fleet	Surface	Size	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

[27] The complete hourly profile is scaled by a constant factor of 20%, in this case.

[28] The electricity demand (heat pumps and air conditioners) for space climatization is assumed to be a function of the temperature that increases when the value deviates from a reference point around 19°C (see [14]). Given an hourly temperature profile, the response of the demand can be therefore modelled all along during the year. The average of this profile is then taken and normalized among the different climatic zones, resulting in a temperature coefficient used for disaggregation. In this way, zones whose demand for climatization is, in average, bigger will allocate a higher percentage of the demand coming from heat pumps and air conditioning.

An overview of which allocation keys are assigned, as well as the spread among voltage levels, in function of the asset type is shown in Table 3. We note that factors are normalised across the archetypes and climatic zones of the country. As such, the absolute values of the coefficients are therefore not relevant, but their relative weight compared with the rest of the distribution networks (see also [1]).

We would like to highlight that the allocation keys are constant and calculated with the information of a specific year. For the disaggregation process to be valid for subsequent periods, it is assumed that even if the coefficients evolve, the proportion between them remains the same[29]. We stress as well the fact that, since they are constant, coefficients will scale the market asset profile but will not change its original shape.

4.1.2 FLEXIBILITY COST STRUCTURE

The DCM is formulated as a minimisation problem searching to reduce the cost associated to flexibility activation and losses on the network (cf. section 2.1.1). As such, it will activate a flexibility mechanism when it sees there is an economic benefit for doing so. For instance, facing an excess of local generation, the model could choose to charge a set of available EVs, provided that the cost related to the charging process and network losses of this extra energy is lower compared to the cost of curtailing it. In this sense, the DCM can operate independently of the market, as it follows its own optimisation criteria.

The hierarchy defined in section 4.1 states that the distribution modules should follow in principle what is dispatched (and subsequently disaggregated) by the market. This calls for a definition of the cost structure defined at the DCM, that would allow it to prioritise the market's dispatch over its own cost minimisation criteria. This is done by making use of its flexibility unitary costs, that are the cost factors associated to the activation of each of the flexibilities considered by the model. They increase the DCM's objective function following a linear relationship by computing the total activation of a given flexibility, in terms of energy (MWh) aggregated during the optimisation period, and multiplying it by the unitary cost (€/MWh) itself (cf. section 7.2.1.9). The following costs are considered, which are related with four types of flexibilities managed by the model[30](cf. section 7.2.2.2.8): $C_{shifting}$, $C_{EV\ shifting}$[31], $C_{shedding}$ and $C_{curtailment}$. Together with this, we find the C_{losses} term, which is the unitary cost associated with the electrical losses encountered during the network operation.

They way unitary costs are used is to define priorities between the different mechanisms. For instance, if the shedding cost is bigger than that of shifting, $C_{shedding} > C_{shifting}$, the model will dispatch in priority load shifting instead of shedding, as the first one will increase in lower magnitude the model's objective function. Given this consideration, these priorities are defined in the following way[32]:

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

The indicated ranking has the following implication: whenever the model identifies a need for flexibility activation (i.e., for prevention of network constraint violations), it will

[29] For instance, even if the population changes in time, it is assumed that the spread among urban, semi-urban and rural stays constant, and so do the disaggregation coefficients related to it.

[30] Flexibility related to decentralized storage was not considered, as EUCO3232.5 considered a negligible storage capacity per country.

[31] We note it is implicitly assumed that the *EV as shiftable load* model is used.

[32] Numerical values can be fully parametrised in the platform.

prioritise EV shifting and load shifting actions above shedding and curtailment. Also, their actual numerical values are calibrated[33] in a way that the model does not see an economic benefit from activating any of their associated decision variables, and therefore, will do it only to prevent violations of physical constraints from occurring. In this way, the model will try to respect the initial market dispatch as much as possible, as any extra deviation introduced by means of flexibility activation will have a negative impact on the model's objective function.

Table 4 Summary of decision variables unitary cost

Unitary cost	€/MWh
$C_{shedding}$	20000
C_{losses}	10000
$C_{curtailment}$	9990
$C_{shifting}$	9890
$C_{EV\ shifting}$	9880

The actual values used in the current version of the tool are the same for each distribution network and can be found in Table 4. They were calibrated with respect to the order of magnitude of the model's objective function and the optimiser tolerance, using the METIS-EUCO3232.2 scenario for the year 2030 (cf. section 3.2).

4.2 Disaggregation script

A script controlling the disaggregation process can be launched from the METIS platform. It will first create a new set of distribution networks of the countries being simulated in the current context of the study together with defining their electrical characteristics (as mapped in section 3). Then, it will populate their demand, generation, and EV assets according to the disaggregation methodology defined in section 4.1.1. It can be divided into the following steps:

- Market dispatched demand to distribution demand. This action disaggregates the market's dispatched demand to populate the distribution demand assets with flexible and non-flexible demand profiles:
  - The flexible demand profile contains the disaggregated profiles from the market Heat-pumps and Sanitary Hot Water assets.
  - The non-flexible demand profile is defined based on the disaggregation of the market Air Conditioning, Thermosensitive Reminder, Non-thermosensitive Reminder and Hybrid and Battery immediate-charging EV assets.
- Market dispatched production to distribution production. This action populates the distribution production assets with a flexible generation profile, based on the disaggregation of the market Wind Onshore, Solar, Hydro RoR, Biomass and Waste assets.
- Market dispatched EV to distribution EV load: this action projects the market EV dispatch into the EV assets. It populates the distribution EV assets with a flexible EV load profile and activates the *Shiftable load EV* (section 2.2.6) model:
  - The flexible EV profile is defined by the disaggregation of the market assets Plug-in Hybrid EV and Battery EV, either defined at home and work.

[33] Actual values are calibrated for the 288 networks of the METIS platform, based on EUCO3232.5's demand and generation profiles.

- As previously mentioned, the Immediate Charging EV market assets are disaggregated and added to the distribution demand assets.
- Cost propagation: definition of the operational costs for load shifting and shedding, generation curtailment, EV shifting and energy losses according to Table 4.

We note that EUCO3232.5 considered a neglectable capacity of decentralised storage only in Portugal. This asset was therefore not considered in the disaggregation process for any of the concerned countries.

5 KPIs

The following section describes key performance indicators (KPIs) included in the distribution module, all of them indexed by:

- Scope
- Country
- Distribution Climatic Zone
- Distribution Type (Rural, Urban, Semi-Urban)
- Testcase[34]

It might occur that the optimisation of some of the 288 archetypes does not converge, e.g., due to unrealistic input data, a lack of flexibility or even numerical issues. If so, the METIS platform log will indicate the networks encountering troubles and a related KPI will allow to visualize whether the results are available for a given network or not. KPIs are computed based on converged networks only.

The following section will give an overview of the main distribution KPIs. For the integrity of them, the reader is invited to consult section 7.1.

5.1 Load shedding

The following section elaborates on the KPIs related to load shedding on demand assets (see Annex for demand load shifting and EV-related KPIs).

5.1.1 Total load shedding

This KPI returns the total load shedding for a given index:

$$totalLoadShedding = \sum_{t,i} loadShedding_i[t]$$

with $\text{loadShedding}_i[\text{t}]$ being the load shedding profile at voltage level i and time t.

5.1.2 Peak Load Shedding

This KPI returns the peak of load shedding for a given index:

[34] Testcases allow the user to modify one or several parameters/profiles without modifying the overall context of the study.

$$peakLoadShedding = \max_t \left(\sum_i loadShedding_i[t] \right)$$

with $loadShedding_i[t]$ being the load shedding profile at voltage level i and time t.

5.1.3 RELATIVE LOAD SHEDDING

This KPI returns the ratio between the load shedding and the demand profile values for a given index:

$$relativeLoadShedding = \frac{\sum_{i,t} loadShedding_i[t]}{\sum_{i,t} demand_i[t]}$$

with $loadShedding_i[t]$ being the load shedding profile at voltage level i and time t and with $demand_i[t]$ being the raw demand profile at voltage level i and time t.

5.2 VIOLATION FREQUENCY

Four KPIs allow to measure during which percentage of a network's operation (of typically one year), values are not within the nominal range (i.e., a technical violation is happening). We distinguish two types of metrics: under/over voltage frequency and the conductors/substations overload frequency.

We note that these KPIs are only relevant when the optimal power flow DCM is unconstrained so that the KPI can compare the unconstrained results with the bounds that would be activated normally.

5.2.1 OVERVOLTAGE AND UNDERVOLTAGE VIOLATION FREQUENCY

These two KPIs measure the violation frequency with respect to the maximum and minimum nominal voltage values of the network, respectively. They are related to the same parameter $voltageDrop_i[t]$ (%) which is the postprocessed voltage drop based on DCM results. They count the number of timesteps impacted by an over/under voltage issue in at least one voltage level and put it into relation to the total number of timesteps.

$$underVoltageFrequency = \frac{\underset{t}{sum}\left(\underset{i}{OR}(voltageDrop_i[t] > 100 * maxVoltageDrop_i)\right)}{len(horizon)}$$

$$overVoltageFrequency = \frac{\underset{t}{sum}\left(\underset{i}{OR}(voltageDrop_i[t] < -100 * maxVoltageRise_i)\right)}{len(horizon)}$$

where $maxVoltageDrop_i$ ([0,1]) and $maxVoltageRise_i$ ([0,1]) are the admissible voltage drop and rise at level i and the horizon is the set of all timesteps. We note that the factor 100 is used to scale the values to percentages (%).

5.2.2 CONDUCTOR AND SUBSTATIONS OVERLOAD FREQUENCY

These two KPIs measure the overload with respect to the nominal capacities of conductors and substations in the network, respectively. They will basically count the number of timesteps impacted by an over/under voltage issue in at least one voltage level and put it into relation to the total number of timesteps

$$conductorOverloadFrequency = \frac{\underset{t}{sum}\left(\underset{i}{OR}(conductorLoadRate_i[t] > 100)\right)}{len(horizon)}$$

$$conductorOverloadFrequency = \frac{\underset{t}{sum}\left(\underset{i}{OR}(substationLoadRate_i[t] > 100)\right)}{len(horizon)}$$

where $conductorloadRate_i[t]$ (%) and $substationloadRate_i[t]$ (%) are the conductor and substation load rates postprocessed based on DCM results and the horizon is the set of all timesteps.

5.3 Violation Intensity

Four KPIs allow to calculate 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, when the violation is happening. We distinguish two metric types: under/over voltage intensity and the conductors/substations overload intensity.

We note that these KPIs are only relevant when the optimal power flow DCM is unconstrained so that the KPI can compare the unconstrained results with the bounds that would be activated normally.

5.3.1 Overvoltage and undervoltage violation intensity

These two KPIs measure the intensity of the violation with respect to the maximum and minimum voltage values of the network, respectively. They have the same algorithmic structure respectively based on the computation of the $underVoltageValue_i[t]$ and $overVoltageValue_i[t]$:

$$underVoltageValue_i[t] = max(0, (voltageDrop_i[t] - 100 * \ maxVoltageDrop_i)/maxVoltageDrop_i)$$
$$overVoltageValue_i[t] = max(0, (-voltageDrop_i[t] - 100 * maxVoltageRise_i)/maxVoltageRise_i)$$

where $maxVoltageDrop_i$ ([0,1]) and $maxVoltageRise_i$ ([0,1]) are the admissible voltage drop and rise at level i and $\mathrm{voltageDrop}_i[\mathrm{t}]$ (%) is the postprocessed voltage drop based on DCM results. Then, the related KPIs are only the mean of these indicators:

$$underVoltageIntensity = \underset{i,t}{mean}(underVoltageValue_i[t])$$
$$overVoltageIntensity = \underset{i,t}{mean}(overVoltageValue_i[t])$$

5.3.2 Conductor and substations overload intensity

Conductor and substations overload intensity measure the intensity of the violation with respect to the nominal capacities of conductors and substations of the network, respectively.

$$conductorOverloadValue_i[t] = max(0, conductorloadRate_i[t] - 100)$$
$$substationOverloadValue_i[t] = max(0, substationloadRate_i[t] - 100)$$

where $conductorloadRate_i[t]$ (%) and $substationloadRate_i[t]$ (%) are the conductor and substation load rates postprocessed based on DCM results. The related KPIs are computed as the mean of these indicators:

$$conductorOverloadIntensity = \underset{i,t}{mean}(conductorOverloadValue_i[t])$$
$$substationOverloadIntensity = \underset{i,t}{mean}(substationOverloadValue_i[t])$$

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7 ANNEX

7.1 KPIs

7.1.1 INPUT

7.1.1.1 Total Raw Consumption

Total raw consumption for a given index:

$$totalRawConsumption = \sum_{i,t} demand_i[t]$$

with $demand_i[t]$ being the raw demand profile at voltage level i and time t.

7.1.1.2 Total Raw Production

Total raw production for a given index:

$$totalRawProduction = \sum_{i,t} production_i[t]$$

with $production_i[t]$ being the raw production profile at voltage level i and time t.

7.1.1.3 Total Raw EV Consumption

Total raw EV consumption for a given index:

$$totalRawEVConsumption = \sum_{i,t} EVConsumption_i[t]$$

with $EVConsumption_i[t]$ being the raw EV demand profile at voltage level i and time t.

7.1.1.4 Peak Raw Consumption

Peak of raw consumption for a given index:

$$peakRawConsumption = \max_t \left(\sum_i demand_i[t] \right)$$

with $demand_i[t]$ being the raw demand profile at voltage level i and time t.

7.1.1.5 Peak Raw Production

Total raw production for a given index:

$$peakRawProduction = \max_t \left(\sum_i production_i[t] \right)$$

with $production_i[t]$ being the raw production profile at voltage level i and time t.

7.1.1.6 Peak Raw EV Consumption

Total raw EV consumption for a given index:

$$peakRawEVConsumption = \max_t \left(\sum_i EVConsumption_i[t] \right)$$

with $EVConsumption_i[t]$ being the raw EV demand profile at voltage level i and time t.

7.1.1.7 Surface

This KPI returns the surface of the network for a given index.

7.1.2 Output

Here below are defined the KPIs directly linked to an output of the DCM.

7.1.2.1 Total load shifting

Total load shifting for a given index:

$$totalLoadShifting = \sum_{i,t} positiveLoadShifting_i[t]$$

with $positiveLoadShifting_i[t]$ being the positive load shifting profile at voltage level i and time t.

7.1.2.2 Total curtailment

Total generation curtailment for a given index:

$$totalCurtailment = \sum_{i,t} curtailment_i[t]$$

with $curtailment_i[t]$ being the curtailment profile at voltage level i and time t.

7.1.2.3 Total EV load shifting

Total EV load shifting for a given index:

$$totalEVLoadShifting = \sum_{i,t} positiveEVLoadShifting_i[t]$$

with $positiveEVLoadShifting_i[t]$ being the positive EV load shifting profile at voltage level i and time t.

7.1.2.4 Peak positive Load Shifting

Peak of positive load shifting for a given index:

$$peakPositiveLoadShifting = \max_t \left(\sum_i positiveLoadShifting_i[t] \right)$$

with $positiveLoadShifting_i[t]$ being the positive load shifting profile at voltage level i and time t.

7.1.2.5 Peak Negative Load Shifting

Peak of negative load shifting for a given index:

$$peakNegativeLoadShifting = \max_t \left(\sum_i negativeLoadShifting_i[t] \right)$$

with $negativeLoadShifting_i[t]$ being the negative load shifting profile at voltage level i and time t.

7.1.2.6 Peak Curtailment

Peak of curtailment for a given index:

$$peakCurtailment = \max_t \left(\sum_i curtailment_i[t] \right)$$

with $curtailment_i[t]$ being the curtailment profile at voltage level i and time t.

7.1.2.7 Peak EV positive Load Shifting

Peak of positive EV load shifting for a given index:

$$peakPositiveEVLoadShifting = \max_t \left(\sum_i positiveEVLoadShifting_i[t] \right)$$

with $positiveEVLoadShifting_i[t]$ being the positive EV load shifting profile at voltage level i and time t.

7.1.2.8 Peak EV Negative Load Shifting

Peak of negative EV load shifting for a given index:

$$peakNegativeEVLoadShifting = \max_t \left(\sum_i negativeEVLoadShifting_i[t] \right)$$

with $negativeEVLoadShifting_i[t]$ being the negative EV load shifting profile at voltage level i and time t.

7.1.2.9 Relative positive Load shifting

This KPI returns the ratio between the positive load shifting and the demand profile values for a given index:

$$relativePositiveLoadShifting = \frac{\sum_{i,t} positiveLoadShifting_i[t]}{\sum_{i,t} demand_i[t]}$$

with $positiveLoadShifting_i[t]$ being the positive load shifting profile at voltage level i and time t and with $\mathrm{demand}_i[\mathrm{t}]$ being the raw demand profile at voltage level i and time t.

7.1.2.10 Relative negative Load shifting

Ratio between the negative load shifting and the demand profile values for a given index:

$$relativeNegativeLoadShifting = \frac{\sum_{i,t} negativeLoadShifting_i[t]}{\sum_{i,t} demand_i[t]}$$

with $negativeLoadShifting_i[t]$ being the negative load shifting profile at voltage level i and time t and with $demand_i[t]$ being the raw demand profile at voltage level i and time t.

7.1.2.11 Relative curtailment

Ratio between the curtailment and the production profile values for a given index:

$$relativeCurtailment = \frac{\sum_{i,t} curtailment_i[t]}{\sum_{i,t} production_i[t]}$$

with $negativeLoadShifting_i[t]$ being the negative load shifting profile at voltage level i and time t and with $production_i[t]$ being the raw production profile at voltage level i and time t.

7.1.2.12 Peak Curtailment

Peak of curtailment for a given index:

$$peakRawProduction = \max_t \left(\sum_i curtailment_i[t] \right)$$

with $curtailment_i[t]$ being the curtailment profile at voltage level i and time t.

7.1.2.13 Total conductor losses

Total conductor losses for a given index:

$$totalCableLosses = \sum_{i,t} conductorLosses_i[t]$$

with $conductorLosses_i[t]$ being the conductor losses profile at voltage level i and time t.

7.1.2.14 Total copper losses

Total copper losses for a given index:

$$totalCopperLosses = \sum_{i,t} copperLosses_i[t]$$

with $conductorLosses_i[t]$ being the substation copper losses profile at substation voltage level i and time t.

7.1.2.15 Total iron losses

Total iron losses for a given index:

$$totalIronLosses = \sum_{i,t} ironLosses_i[t]$$

with $ironLosses_i[t]$ being the substation iron losses profile at substation voltage level i and time t.

7.1.2.16Total fictitious conductor losses

Due to the internal DCM's conductor losses formulation, it might happen that the solver would prefer to artificially increase the losses on the system rather than respect their analytical value. The following KPI allows the user to calculate the amount of fictious losses created for a given index:

$$totalFictitiousCableLosses = \sum_{i,t} conductorLosses_i[t] - postproConductorLosses_i[t]$$

With $conductorLosses_i[t]$ being the conductor losses decision variable as output of the DCM, and $postproConductorLosses_i[t]$ corresponding to the exact conductor losses calculated analytically.

7.1.2.17Total fictitious copper losses

As with the previous KPI, the solver could eventually create fictious copper losses on the transformers. The following KPI allow to quantify their amount for a given index:

$$totalFictitiousCopperLosses = \sum_{\mathrm{i,t}} \mathrm{copperLosses}_i[\mathrm{t}] - \mathrm{postproCopperLosses}_i[\mathrm{t}]$$

with $copperLosses_i[t]$ and $postproCopperLosses_i[t]$ being, respectively, the substation copper losses decision variable and the exact copper losses calculated analytically.

7.2 DCM MATHEMATICAL SPECIFICATIONS

The DCM tool is a mathematical model that optimises the hourly dispatch of an already existing electrical grid. The decision variables of the model control how much power is consumed and generated by the different assets of the grid, ensuring that energy balance equations, network constraints and security restrictions[35] are respected. A constrained power flow formulation, that models the flow of electricity through the elements of the network, allows to estimate energy losses and ensure nominal operation. Finally, the model leverages different flexibility levels (e.g., load shifting, batteries, V2G) to optimise its own objective function, which aggregates all the expenditures related to the operation of the grid.

The description of the DCM's mathematical formulation is presented in the upcoming paragraphs. First, a general description of the model's objective function as well as its modelling philosophy and assumptions will be provided, followed by an explanation of the equations modelling both the physical and the cost dimension of the grid whose operation is optimised. The chapter finalises with an overview of all the parameters and decision variables managed by the model, as well as with a discussion about the validity of its implicit assumptions.

[35] In the current version of METIS security constraints are disabled. See sections 7.2.1.5.1 and 7.2.1.5.2 for a detailed description.

7.2.1 *MATHEMATICAL MODELLING*

7.2.1.1 Objective function

The model's objective function is composed of two operational costs: costs of losses and cost of flexibility. The former considers all the costs associated to the energy losses experienced during the network operation, while the latter corresponds to the cost of activating flexibility on the different assets. The problem can be formulated in the following way:

$$
\begin{aligned}
&min\ \boldsymbol{cost}(losses) + \boldsymbol{cost}(flexibility) \\
&s.t \\
&\qquad\qquad Energy\ balance \\
&\qquad\qquad Nominal\ Operation \\
&\qquad\qquad Secury\ constraints
\end{aligned}
$$

where losses on the grid can be separated in two different elements:

- Power line losses: accounting for the active power losses due to the resistive component of lines.
- Transformer losses, which can be separated in:
  - Copper losses: heat losses due to the resistive term of transformer's windings.
  - Iron losses: corresponding to current losses due to the magnetic properties of the material of transformers.

Similarly, flexibility of assets can be separated in different categories:

- Load shifting, term applied for describing the capacity of consumers to shift their load consumption during a certain time window.
- Load shedding, which describes the possibility of reducing load consumption by a certain amount.
- Generation curtailment, which refers to the capacity of reducing the effective output of local sources of renewable energy.
- Decentralised storage, including the operation of, and losses inside, electrical batteries.
- EV flexibility, which is associated to adaptations of their charging profiles and/or the use of the vehicle-to-grid (V2G) functionality.

The optimisation is performed in a way that constraints of energy supply, nominal operation and security restrictions are respected. In the first place, electrical demand of consumers together with its potential flexibility should be satisfied at every moment of the simulation. Then, the power transmitted through the lines and the transformers, together with the voltage drop along the network, should respect nominal ranges of operation. Finally, such process should be carried out by reserving enough capacity on feeders and transformers to support a failure on an arbitrary substation.

Different dispatches of the grid will have different economical and technical outcomes. For instance, reducing peak load on the grid can be performed by either increasing the shedding of loads or increasing the level of local generation. In the first case, power losses will decrease but the cost associated to shedding will increase. In the second case, peak shaving will be performed (at typically zero cost) whereas the level of the voltage at that point of the network will raise. Therefore, in order to achieve the best trade-off between costs and technical constraints, an optimal arbitration is needed. Such is the role of the model described in the current text.

7.2.1.2 General description of the network and assumptions

The network considered in the model is composed of several voltage levels interconnected by means of substations. Several feeders departing from the substations of a given voltage level connect the consumption and generation nodes with the substations of the lower level. Feeders can be interconnected as well, depending on the specific characteristics of the topology, providing support in case of substation failure.

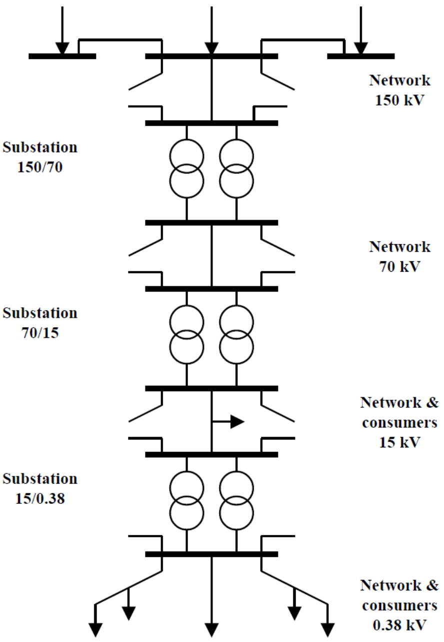

Figure 5 – Representation of a network with several voltage levels and conversion substations.

More specifically, substations are composed of transformer cabins performing the conversion of voltage from one level to the next one. They are mainly characterized by the number of transformers they contain together with their nominal rate of operation. Additionally, feeders are made up of electrical conductors performing the transmission of power between nodes, and are described by a cross-section, a length and a nominal power parameter. Nodes connected to a feeder can either produce or consume energy according to their own net profiles. The sum of these profiles generates an aggregated profile of consumption and generation, allowing the computation of the energy balance through feeders and substations. Finally, as already mentioned, flexibility in terms of load shifting and shedding, generation curtailment, storage and EVs is considered as well, allowing local nodes to participate on the balance and operation of the grid.

7.2.1.2.1 Assumptions & pre-requisites

The model assumes uniformity on the network's topology as well as on it operation. For the former, this requires, for example, that at each voltage level nodes and substations are uniformly distributed over the network's surface and that the technical characteristics of the equipment are the same. For the latter, it requires that all the nodes of a given voltage level exhibit the same consumption and generation profiles. The model is therefore valid for large-scale networks, where such a configuration can be assumed. More specifically, it requires, for each voltage level, the following assumptions:

- substations are uniformly distributed in the space
- nominal power of transformers as well as their number per substation are equal
- the number of feeders departing from a substation are the same
- the section and type of those conductors are uniform
- nodes of electrical consumption and generation are uniformly distributed in the space and among feeders

- load and generation profiles of nodes under a given voltage level are uniformly distributed and have the same level of flexibility with the voltage level
- consumption and generation nodes have respectively the same level of flexibility

7.2.1.3 Main definitions

7.2.1.3.1 Topology

A schematic of the network considered is presented in Figure 6. A voltage level will be identified by the label i, where $i \in [1, \dots, \mathrm{I}]$ and I correspond to the total number of voltage levels. Following this notation, a substation that is present at the interface of levels $i+1$ and i will be identified by the label $(i+1)/i$.

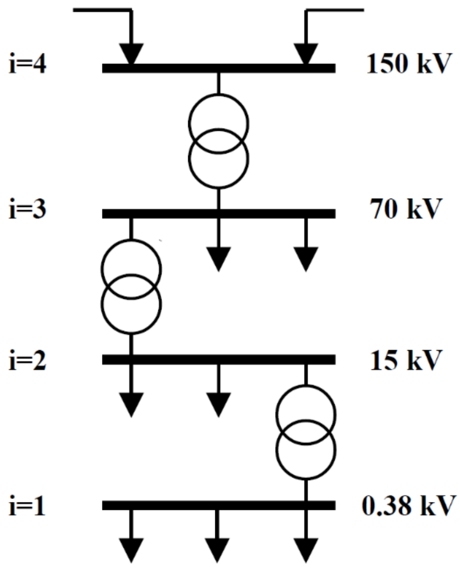

Figure 6 – Schematic representation of the network.

For the sake of simplicity, the upper network of a given voltage level i will be henceforth identified by the label j, i.e., $j = i + 1$.

7.2.1.3.2 Time structure

The model simulates an operation over a horizon of one year. This year is separated in several periods p of different length, each of them composed by consecutive timeslots of one hour. Such timeslots represent the elementary time unit of the model and are identified by the label t. A period p can then formally defined as a set of timeslots $p = (t \in [1, \dots, t_{max}])$ where t_{max}[36] is the maximum time slot of the period.

Periods are not necessarily linked between each other, and they not necessarily cover the whole horizon of simulation. To compensate that, for a given period p a parameter τ_p is defined, which will represent its percentage of occurrence during the year. Such parameter τ_p will then change the relative importance that the period p will have on the overall cost function of the problem. Contrary to periods, time slots within a period are consecutive, meaning that there is a strict temporal relation between them. Load and generation profiles will therefore be expressed in function of those timeslots, for each of the simulated periods.

[36] We note that, following the zonal market approach, the current version of the tool considers a period of 8760 timesteps.

7.2.1.4 Energy balance

In the following section, equations for the transmission of power between and within voltage levels are described in detail. Figure 7 shows a schematic of the process of transmission of power between different levels.

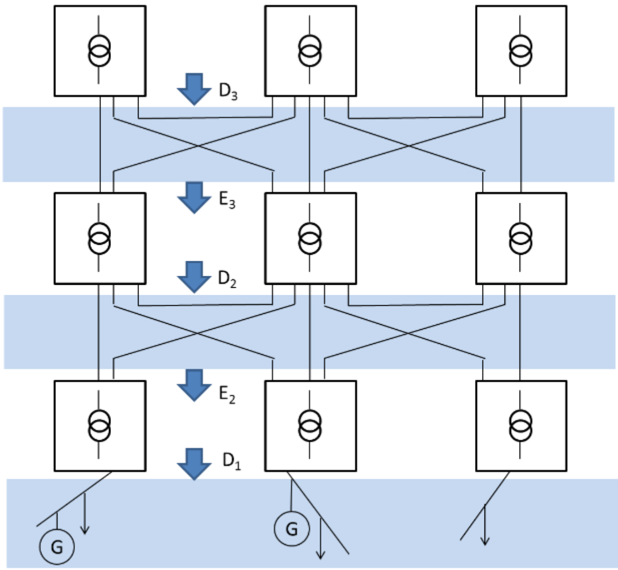

Figure 7 – Energy flow through voltage levels and substations.

Let $D_i(t)$ and $E_i(t)$ denote the power per-surface unit respectively entering and leaving network level i. For every time step t, the first power balance equation states that

$$D_i(t) = E_i(t) + NC_i(t) + \mathrm{NSt_i}(t) + \mathrm{NEV_i}(t) + \Psi_i(t)$$

where $NC_i(t)$, $\mathrm{NSt_i}(t)$, $\mathrm{NEV_i}(t)$ and $\Psi_i(t)$ denotes respectively the net load, the net storage consumption, the net EV consumption, and the conductor power losses of level i. The net load term accounts for the total generation and consumption of nodes of the voltage level, whereas net storage and net EV aggregates all its storing and EV capacities. Finally, power losses accounts for the dissipated power on the feeders of the respective level.

One notes that the power $E_{i+1}(t)$ leaving voltage level $i+1$ is the same as the power entering substations $(\mathrm{i}+1)/\mathrm{i}$ Hence, second power balance equation can be formulated as

$$E_{i+1}(t) = D_i(t) + R_i(\mathrm{t}) + \Gamma_{i+1}(t) + \Phi_{i+1}$$

Where $\Gamma_{i+1}(t)$ and Φ_{i+1} account for the power losses at the level of substations (e.g., transformer iron and copper losses) and $R_i(\mathrm{t})$ represents the net load directly connected to them.

7.2.1.5 Nominal operation

7.2.1.5.1 Nominal power of substations

The maximum power handled by substations will depend on two constraints. The first one will control the transformers' load rate at the substation level. The second, will limit the flow of power in a way that there is enough reserve in case of contingency: if a transformer of a substations fails, a certain number of supporting transformers will increase their load rate to compensate for the lost capacity. This action is called mutual support of substations, and it is possible if neighbouring substations are connected by means of one or several electrical lines.

7.2.1.5.1.1 Substation nominal power

The nominal power of a substation $\mathrm{i}/(i-1)$ corresponds to the aggregated nominal power of the m_i transformers that compose it. For those transformers, if one sets p_i and ξ_i[37] to be their nominal power and maximum load rate respectively, then the power that can be transmitted through that substation is bounded by

$$\forall t: \quad m_j p_j \xi_j \geq \frac{E_j(t)}{\mu_j}$$

$$\forall t: \quad m_j p_j \xi_j \geq \frac{-D_i(t)}{\mu_j}$$

where μ_i denotes the number of substations $i/(i-1)$ per unitary surface. One notes that the term $-D_i(t)$ accounts for possible reverse flows on that specific level.

7.2.1.5.1.2 Mutual support: transformer load rate

Let c_i be the number of substations $i/(i-1)$ that can participate in a mutual support procedure during a contingency. In case of failure in one of their transformers, the fault power can be reported to the rest $c_i m_i - 1$ transformers having a power reserve $1-\xi_\mathrm{i}$. This leads to the following constraint,

$$(c_i m_i - 1)(1-\xi_i) \geq \xi_i$$

This set equations is disabled in the current version of the model.

7.2.1.5.2 Nominal power in conductors

As with substations, nominal power of lines must respect two constraints during a normal operation. In the first place, a constraint will limit the maximum power that lines can transport in terms of a security parameter called reliability coefficient. Such reliability coefficient gives an effective margin between the nominal power of the conductor and their actual operating point. A second constraint will limit the power through them to assure operation in case of failure: load rates on conductors will be decreased in order to leave enough reserve power to allow mutual support of substations. In the following sections, P_i will denote the nominal power of conductors at voltage level i.

7.2.1.5.2.1 Nominal power and security margin

Let λ_i be the reliability coefficient of the conductors (i.e., inverse of the load rate) at voltage level i. For the k_i feeders departing from substations $(i+1)/i$, the total power $D_i(t)$ flowing thought them should respect

$$\forall t: \; P_i \geq \lambda_i \frac{|D_i(t)|}{k_i \mu_j}$$

In the same way, the power of feeders arriving to a substation will be constrained by

$$\forall t: \; P_i \geq \lambda_i \frac{|E_i(t)|}{\mu_i}$$

[37] Unless the *unconstrained OPF* (section 7.2.1.6) option is enabled, the default value is $\xi_\mathrm{j} = 1$.

where the absolute value is introduced to consider possible reverse flows on the grid.

The reader might notice that if $\lambda_i > 1$[38], the coefficient acts as a security margin, imposing a gap between the nominal rate of the feeder and the actual power that is being transferred.

7.2.1.5.2.2 Mutual support: load on the lines

In case of mutual support of substations, the fault power evacuated to neighbouring stations causes the lines to be more loaded. This leads to a more stringent constraint on the power through the lines

$$\forall t\ i \in [1, I-1], P_i \geq \frac{|D_i(t)|}{k_i \mu_j} + \left(1 - \frac{1}{c_j}\right)\frac{1}{k_i d_i} p_j$$
$$\forall t\ i \in [1, I-1], P_j \geq \frac{|E_j(t)|}{\mu_j} + \left(1 - \frac{1}{c_j}\right)\frac{1}{k_j d_j} p_j$$

where the term d_i measures, for every mutual support substation, the real proportion of feeders participating on the support action.

This set of equations is disabled in the current version of the model.

7.2.1.5.3 Voltage variation

Variations on the magnitude of the voltage along a feeder occurs due to the influence of active and reactive elements of the electrical conductor. The sign of this variation will depend on the direction of the flow $D_i(t)$ of energy. If this last one goes, as typically observed, from substations of the upper level $i+1$ to the nodes and substations of the current level i, a certain voltage drop will be observed. By the contrary, if the flow reverses and goes from nodes and substations of level i up to substations of level $i+1$, a certain rise on the voltage will occur.

According to the previous description, the relative voltage variation can be modelled by the following equations,

$$\forall t: \quad \frac{1}{V_i^2}\rho_i \frac{l_i}{k_i \mu_j}\frac{1}{S_i}\left[\frac{D_i(t)}{k_i \mu_j}\right] cos\,\phi_i + \frac{1}{V_i^2}\chi_i \frac{l_i}{k_i \mu_j}\frac{1}{S_i}\left[\frac{D_i(t)}{k_i \mu_j}\right] sin\,\phi_i \leq VOLT_i$$
$$\forall t: \quad -\frac{1}{V_i^2}\rho_i \frac{l_i}{k_i \mu_j}\frac{1}{S_i}\left[\frac{D_i(t)}{k_i \mu_j}\right] cos\,\phi_i - \frac{1}{V_i^2}\chi_i \frac{l_i}{k_i \mu_j}\frac{1}{S_i}\left[\frac{D_i(t)}{k_i \mu_j}\right] sin\,\phi_i \leq VOLTRISE_i$$

where $VOLT_i$ and $VOLTRISE_i$ correspond respectively to the maximum allowed voltage drop and rise observed at the end of the feeder. These variations depend on the physical characteristics of the feeders, such as their resistance ρ_i and reactance χ_i, together with their length l_i and cross-sectional area S_i.

7.2.1.6 Unconstrained operation

The *unconstrained OPF* flag loosens conductor and transformer bounds to allow an unconstrained power flow to be launched. More specifically when enabled,

[38] Unless the *unconstrained OPF* (section 7.2.1.6) option is enabled, the default value is $\lambda_i = 1$.

- the maximum allowed power on transformers and conductors becomes 10 times their nominal capacity, i.e., $\xi_j = 10$ and $\lambda_i = 1/10$, respectively (cf. section 7.2.1.5.1.1 and 7.2.1.5.2.1) and,
- the maximum allowed voltage relative variation on conductors becomes 100% i.e., $VOLT_i = VOLTRISE_i = 1$ (cf. section 7.2.1.5.3).

7.2.1.7 Power losses on the network

In the present section a description of the equations describing the power losses on conductors and substations is performed. For a given voltage level i and time t, these equations will calculate the power lost in a per-surface unit of the ensemble of feeders and substations of the respective level.

7.2.1.7.1 Power line losses

Line losses $\Psi_i(t)$ due to power transmission are bounded by the following set of inequalities

$$\forall t:\quad \Psi_i(t) \geq \left(\frac{D_i(t)}{k_i\mu_j}\right)^2 \frac{1}{V_i^2}\frac{\rho_i l_i}{S_i}$$
$$\forall t:\quad \Psi_i(t) \geq \left(\frac{E_i(t)}{\mu_i}\right)^2 \frac{1}{V_i^2}\frac{\rho_i l_i}{S_i}$$

The first term on the right-hand side of the equation $\left(\frac{D_i(t)}{k_i\mu_j}\right)^2 \frac{1}{V_i^2}$ corresponds to the current entering the feeder from substations of the upper level. In case of reverse flow, the term $\left(\frac{E_i(t)}{\mu_i}\right)^2 \frac{1}{V_i^2}$ will be the one accounting for the current entering the feeder. Finally, $\frac{\rho_i l_i}{S_i}$ represents an equivalent resistance of the conductor.

7.2.1.7.2 Transformers copper losses

In the same way as in the precedent section, losses $\Gamma_i(t)$ by cooper effect are bounded by two inequalities accounting for possible reversing on the flow at the respective level

$$\forall t:\quad \Gamma_i(t) \geq E_i(t)^2 \frac{T_i}{m_i p_i \mu_i}$$
$$\forall t:\quad \Gamma_i(t) \geq D_{i-1}(t)^2 \frac{T_i}{m_i p_i \mu_i}$$

For such equations, T_i is the equivalent resistivity of the transformer of substation $i/(i-1)$.

7.2.1.7.3 Transformer iron losses

Contrary to the previous variables, losses by iron effect are time-independent variables since they are defined exclusively by the physical configuration of the transformer. For the transformers of substations $i/(i-1)$, such losses are calculated by

$$\Phi_i = \mu_i m_i \left(u_i{}^1 + u_i{}^2 p_i{}^{u_i{}^3}\right)$$

where $u_i{}^1, u_i{}^2$ and $u_i{}^3$ are coefficients experimentally determined.

7.2.1.8 Flexibility management

The current section will elaborate on the way flexibility is captured by the model, which are grouped into five concepts: load shedding, load shifting, generation curtailment, storage dispatch and EV dispatch. They are modelled by means of time-dependent decision variables that can be activated depending on the state of the grid and its associated costs. Commissioning of those variables will be defined by the model according to the best economic outcome.

7.2.1.8.1 Net load

The net load $NC_i(t)$ variable represents the net power consumption of the ensemble of nodes at voltage level i. It can be expressed as a function of the initial load demand $C_i(t)$, a load shifting term $\Delta C_i(t)$ capturing and a shed load term $CS_i(t)$, together with the amount of distributed generation $G_i(t)$ and its level of curtailment $\Delta G_i(t)$

$$NC_i(t) = [C_i(t) + \Delta C_i(t) - CS_i(t)] - [G_i(t) - \Delta G_i(t)]$$

Among these variables, the only ones corresponding to input profiles are $C_i(t)$ and $G_i(t)$.

7.2.1.8.2 Net load directly connected to substations

It is assumed that a certain net load can be imposed directly to the substations (i.e., no electrical grid is present between the substation and the generation/consumption node itself). Such a load may represent a certain set of big consumers or generators (e.g., wind and solar plants).

As in the previous section, a net load term $R_i(t)$, associated to substations $(i+1)/i$, can be defined by

$$R(t) = [RC_i(t) + \Delta RC_i(t) - RCS_i(t)] - [RG_i(t) - \Delta RG_i(t)]$$

where $\Delta RC_i(t)$ and $RCS_i(t)$ denotes, respectively, the shifting and shedding elements on the load $RC_i(t)$. In addition, $RG_i(t)$ and $\Delta RG_i(t)$ correspond, respectively, to the generation and generation curtailment elements.

We highlight the importance of distinguishing this flexibility from the one presented in section 7.2.1.8.1, as their associated costs can differ.

7.2.1.8.2.1 Load shedding

Two load shedding variables, $CS_i(t)$ and $RCS_i(t)$, are associated to the distributed load $C_i(t)$ and the substation load $RC_i(t)$, respectively. They are bounded by the following equations

$$\forall t: \; 0 \leq CS_i(t) \leq C_i(t) + \Delta C_i(t)$$
$$\forall t: \; 0 \leq RCS_i(t) \leq RC_i(t) + \Delta RC_i(t)$$

where $\Delta C_i(t)$ and $RC_i(t)$ correspond respectively to the net load shifting and substation load shifting terms (cf. section 7.2.1.8.2.2).

One extra set of upper bounds can be applied if the *non-flex load* flag is enabled and depending on the values defined by *non-flex load shedding option* (cf. Table 13):

- Value = 0: no extra restriction on the shedding. Load shedding can be applied on both the flexible and the non-flexible contributions of the load.
- Value = 1: load shedding can only be applied to the non-flexible part of the load:

$$\forall t: \; CS_i(t) \leq non\_flex\_load\_i(t)$$

$$\forall t:\ RCS_i(t) \le non\_flex\_R\_load_i(t)$$

- Value = 2: load shedding can only be applied to the flexible part of the load:

$$\forall t:\ CS_i(t) \le C_i(t) - non\_flex\_load\_i(t)$$
$$\forall t:\ RCS_i(t) \le RC_i(t) - non\_flex\_R\_load_i(t)$$

where $non\_flex\_load\_i(t)$ and $non\_flex\_R\_load_i(t)$ are profiles defining which part of the load and the substation load, respectively, is considered as non-flexible.

7.2.1.8.2.2 Load shifting

As with load shedding, the model manages two decision variables defining the load shifting, mechanism. The first one, $\Delta C_i(t)$, models the shifting applied to the distributed load $C_i(t)$, whereas the second one, $\Delta RC_i(t)$, applies to the substation load $RC_i(t)$.

The shifting process consists in rescheduling the load (either in the future or in the past, with respect to the actual time step t)[39] within a given time window. Conservation of the shifted energy within that time window is imposed:

$$\forall k \in \{1, \dots, t_{max}/fw\}, \quad \sum_{t=(k-1)*fw+1}^{k*fw} \Delta C_i(t) = 0$$
$$\forall k \in \{1, \dots, t_{max}/fw\}, \quad \sum_{t=(k-1)*fw+1}^{k*fw} \Delta RC_i(t) = 0$$

where fw is the shifting time window length, and $\Delta C_i(t)$ and $\Delta RC_i(t)$ are the net load shifting terms associated to the distributed and substation loads, respectively. These variables are split into their positive and negative terms, with the negative part being bounded by the demand load profile:

$$\forall t:\ \Delta C_i(t) = \ \Delta C_i^+(t) + \ \Delta C_i^-(t)$$
$$\forall t:\ \Delta RC_i(t) = \Delta RC_i^+(t) + \ \Delta RC_i^-(t)$$
$$\forall t:\ \Delta C_i^+(t) \ge \ 0 \text{ and } \Delta RC_i^+(t) \ \ge \ 0$$

By default, the negative load shifting is only bounded between minus the load and 0

$$\forall t:\ \ -C_i(t) \le \ \Delta C_i^-(t) \le 0 \text{ and } -RC_i(t) \le \ \Delta RC_i^-(t) \le 0$$

Although, if then *non-flex load* flag (cf. Table 13) is enabled, the following shifting bounds are applied,

$$\forall t:\ \ -C_i(t) + non\_flex\_load_i(t) \ \le \ \Delta C_i^-(t) \le 0$$
$$\forall t:\ -RC_i(t) + \mathrm{non}\_flex\_R\_load_i(t) \le \ \Delta RC_i^-(t) \le 0$$

where $non\_flex\_load_i(t)$ and $non\_flex\_R\_load_i(t)$ correspond to the profiles describing the non-flexible part of $C_i(t)$ and $RC_i(t)$, respectively

7.2.1.8.2.3 Generation curtailment

The curtailment variables, $\Delta G_i(t)$ and $\Delta RG_i(t)$, will managed the curtailed energy of the distributed generation $G_i(t)$ and substation generation $RG_i(t)$, respectively:

[39] The anticipation type is managed by the variable $load\ shifting\ type$ (see Table 13).

$$\forall t:\ 0 \le \ \Delta G_i(t) \le \ G_i(t)$$
$$\forall t:\ 0 \le \Delta RG_i(t) \le RG_i(t)$$

When the *non-flex generation* flag is enabled (cf. Table 13), the following extra set of equations is applied

$$\forall t:\ 0 \le \ \Delta G_i(t) \le \ G_i(t) - non\_flex\_gen_i(t)$$
$$\forall t:\ 0 \le \Delta RG_i(t) \le RG_i(t) - non\_flex\_R\_gen_i(t)$$

where $non\_flex\_gen_i(t)$ and $non\_flex\_R\_gen_i(t)$ denotes the non-flexible part of the distributed generation and substation generation profiles, respectively.

7.2.1.8.3 Storage

The storage variable $\mathrm{NSt_i}(t)$ is a net load term accounting for the utilisation of the ensemble of electrical batteries at a single voltage level i. This variable is divided into two different terms, controlling the charging $\Delta\mathrm{St}_i^+(\mathrm{t})$ and discharging $\Delta\mathrm{St}_i^-(t)$ process, according to

$$\mathrm{NSt_i(t)} = \Delta\mathrm{St}_i^+(\mathrm{t}) + \Delta\mathrm{St}_i^-(\mathrm{t})$$

Both terms accounts for the power per-surface unit that is injected and extracted from the storage units, and are bounded according to their physical characteristics

$$\forall t:\ 0 \le \Delta\mathrm{St}_i^+(\mathrm{t}) \le \mathrm{Ps}_i^{\max}$$
$$\forall t:\ -\mathrm{Ps}_i^{\max} \le \Delta\mathrm{St}_i^-(\mathrm{t}) \le 0$$

In accordance with this definition, the state of charge of the storage $ESt_i(t)$ can be calculated as follows

$$\forall t > 0:\ ESt_i(t) = ESt_i(t-1) + \eta_{\mathrm{St}}\Delta\mathrm{St}_i^+(\mathrm{t}) + \frac{\Delta\mathrm{St}_i^-(\mathrm{t})}{\eta_{\mathrm{St}}}$$

where η_{St} represents the storage charging and discharging and $ESt_i(0) = ISC_i$ its initial state of charge. As with the power, the stored energy must respect a set of maximum and minimum bounds

$$\forall t:\ ESt_i^{min} \le ESt_i(t) \le ESt_i^{max}$$

In addition, the state of charge is forced to come back to its original value every s_w time steps (i.e., within the storage window). This constraint is expressed as

$$\forall k \in \{1, \dots t_{max}/s_w\}:\ ESt_i(ks_w) = ISC_i$$

The reader should note that this formalism allows $\Delta St_i^+(t)$ and $\Delta St_i^-(t)$ to be non-zero at the same time, which is not physically possible. Therefore, artificial losses in the storage may happen. However, this happens rarely in practice, so that the non-linear constraints required to prevent it were not implemented.

7.2.1.8.4 EV

Electrical vehicles are handled by two models. The first one, reproduces the mathematical formulation managed at market level, with the objective of respecting the same operational constraints when the distribution model redispatch this asset. The second, considers the EV demand as a simple load upon which load shedding and shifting mechanisms can be imposed. Which model is selected is controlled by the parameter ev_model (cf. Table 15).

7.2.1.8.4.1 EV market model

The model optimises a fleet of electrical vehicles considering a given set of departure and arrival patterns. It is assumed that vehicles (typically parked at private areas) depart from their charging point, travel a given distance, and subsequently park at another station (for instance, placed at work) following an hourly pattern dependent on the day of the week. Before leaving the second charging point (for commuting back to their original location), vehicles must have their batteries charged with the energy that was discharged during the travelling time. As long as there is enough time and power for the vehicle to be charged back, the charging pattern can be piloted to produce benefits over the electrical network optimised by the tool. Such is the type of flexibility that can be managed by the model.

The following assumptions summarise the described behaviour:

- The fleet is composed of vehicles having all the same technical characteristics (e.g., charging capacity, buffer size, journey discharge).
- Vehicles follow a predefined arriving and departing pattern, describing how many of them arrive at and depart from a charging point at a given time of the day.
- Upon connection, the model will take decisions on their charging patterns through decision variables.
- Before departure, vehicles must be charged with the journey energy discharged during the commuting time[40].

Before describing the model's mathematical formulation, the following definitions are needed: for a given voltage level i,

- $totalEV_i$: total number of vehicles
- $initialConnectedEV_i$: percentage of connected EVs at $t = 0$
- $arrivals_i(t)$: time series describing the percentage of vehicles arriving at a charging point
- $departures_i(t)$: time series describing the percentage of vehicles leaving from a charging point
- $evRecharge_i$: average journey discharge, considering the average energy used for commuting
- $evStorageCapacity_i$: EV storage capacity
- $evPmaxIn_i$: EV maximum charging capacity
- $evPmaxOut_i$: EV minimum discharging capacity
- $\eta^+_{EV_i}$: EV charging efficiency
- $\eta^-_{EV_i}$: EV discharging efficiency

The percentage of EVs connected to a charging point at a given time can be expressed as

$$connected_i(t) = initialConnectedEV_i + \sum_{k=0}^{t} \left(arrivals_i(k) - departures_i(k)\right)$$

If the EV charges at maximum power, the number of time steps needed to recharge it after an average journey can be computed by

$$nbTsRecharge_i = \left\lceil \frac{evRecharge_i}{evPmaxIn_i \cdot inputEfficiency_i} \right\rceil$$

Apart from considering the charging and discharging flows from the grid, namely $\Delta EV_i^+(t)$ and $\Delta EV_i^-(t)$, the EV buffer equation considers the energy needed for driving after departures $\Delta departure(t)$, as well as the remaining buffer of the arriving vehicles $\Delta \mathrm{arrival}(\mathrm{t})$:

[40] For this to be satisfied, one must assure that there is enough charging time between arrivals and departures, as well as sufficient power charging capacity

$$\forall t > 0:\ EEV_i(t) = EEV_i(t-1) + \eta^+_{EV\,i}\Delta EV_i^+(t) + \frac{\Delta EV_i^-(t)}{\eta^-_{EV\,i}} + \Delta arrival_i(t) + \Delta departure_i(t)$$
$$\forall t:\ 0 \le EEV_i(t) \le connected_i(t) \cdot totalEV_i \cdot evStorageCapacity_i$$
$$\forall t:\ \Delta arrival_i(t) = arrivals_i(t) \cdot totalEV_i \cdot (evStorageCapacity_i - evRecharge_i)$$
$$\forall t:\ \Delta departure_i(t) = -departures_i(t) \cdot totalEV_i \cdot evStorageCapacity_i$$

with $EEV_i(0) = connected_i(0)$.

Three different charging modes can be selected[41]:

- Deterministic charging: EVs are recharged immediately after arrival and at maximum power:

$$\forall t:\ \Delta EV_i^+(t) = \sum_{k=0,t-k\ge 0}^{tnbTsRecharge_i-2} arrivals_i(t-k) \cdot totalEV_i \cdot evPmaxIn_i + \sum_{k=nbTsRecharge_i-1,t-k\ge 0}^{tnbTsRecharge_i-1} arrivals_i(t-k) \cdot totalEV_i \cdot \left(evStorageCapacity_i - evRecharge_i\right)$$
$$\forall t:\ \Delta EV_i^-(t) = 0$$

- Smart charging: the charge is optimised, while injection in the grid is not allowed:

$$\forall t:\ \Delta EV_i^+(t) \le evPmaxIn_i \cdot connected_i(t)$$
$$\forall t:\ \Delta EV_i^-(t) = 0$$

  The reader should notice that positiveness of the variable $EEV_i(t)$ ensures that EVs will be sufficiently charged before leaving a charging point.

- V2G: charge and discharge are both optimised:

$$\forall t:\ \Delta EV_i^+(t) \le evPmaxIn_i \cdot connected_i(t)$$
$$\forall t:\ -evPmaxOut_i \cdot connected_i(t) \le \Delta EV_i^-(t) \le 0$$

Finally, we note that the EV net demand can be calculated according to

$$NEV_i(t) = \Delta EV_i^+(t) + \Delta EV_i^-(t)$$

7.2.1.8.4.2 *EV as load* model

The EV net demand is modelled by

$$NEV_i(t) = EV_i(t) + \Delta EV_i(t) - EVS_i(t)$$

where $EV_i(t)$ represents an input demand, upon which load shifting $\Delta EV_i(t)$ and load shedding $EVS_i(t)$ terms can be applied. These last two terms, which are managed by an equivalent set of equations as defined in sections 7.2.1.8.2.2 and 7.2.1.8.2.1, are described in the next subsections.

[41] See *ev_mode* in Table 15

7.2.1.8.4.2.1 EV load shedding

The shedding terms is bounded by

$$\forall t:\ \ 0 \le EVS_i(t) \le EV_i(t) + \Delta EV_i(t)$$

If the *EV non-flex load* flag is enabled an extra constrains can be added depending on the value of *EV non-flex load shedding option* (cf. Table 15):

- Value = 0: no extra restriction on the shedding.
- Value = 1: load shedding can only be applied to the non-flexible part of the load:

$$\forall t:\ \ EVS_i(t) \le EV\_non\_flex\_load_i\ (t)$$

- Value = 2: load shedding can only be applied to the flexible part of the load:

$$\forall t:\ \ EVS_i(t) \le EV_i(t) - EV\_non\_flex\_load_i(t)$$

where $EV\_non\_flex\_load\_i(t)$ defines wich part of the load is considered as non-flexible.

7.2.1.8.4.2.2 EV load shifting

The shifting term $\Delta EV_i(t)$ is defined by a positive and a negative contribution according to

$$\forall t:\ \ \Delta EV_i(t) = \ \Delta EV_i^{+}(t) + \ \Delta EV_i^{-}(t)$$

where $\Delta EV_i^{+}(t) \ge 0$ and $-EV_i(t) \le \Delta EV_i^{-}(t) \le 0$.

As with load shifting (cf. section 7.2.1.8.2.2), energy conservation of the shifted energy within a given time window fw_{EV} must be respected:

$$\forall k \in \{1, \dots, t_{max}/fw_{EV}\}: \sum_{t=(k-1)*fw_{EV}+1}^{k*fw_{EV}} \Delta EV_i(t) = 0$$

Finally, when the *EV non-flex load* flag is enabled, the sifting can be applied only on the flexible part of the demand

$$\forall t:\ \ -EV_i(t) + EV\_non\_flex\_load_i(t)\ \le\ \Delta EV_i^{-}(t) \le 0$$

7.2.1.9 Cost function

The model's objective function is composed of several elements reflecting the operational costs of the optimised network. Each of them is associated to either a decision variable or the network power losses of the system. They are proportional to a given unitary cost factor c^k, which is assumed to be independent of the voltage level itself. A description of each cost element is provided in the following paragraphs.

7.2.1.9.1 Energy losses

Let c^8 be the associated unitary costs related to the energy losses due to power dissipation. The total cost is calculated by

$$c^8 \sum_t \left(\sum_{i=1}^{I} \Psi_i + \sum_{i=2}^{I} \Gamma_i + \sum_{i=2}^{I} \Phi_i \right)$$

7.2.1.9.2 Load shedding

Costs are calculated based on

$$c^9 \sum_{i,t} CS_i(t)$$
$$c^{9R} \sum_{i,t} RCS_i(t)$$

where the unitary costs c^9 and c^{9R} are associated to load shedding and substations load shedding, respectively.

7.2.1.9.3 Load shifting

For the load shifting, the associated costs are considered only on its negative term

$$-c^{11} \sum_{i,t} \Delta C_i^-(t)$$
$$-c^{11R} \sum_{i,t} \Delta RC_i^-(t)$$

Where c^{11} and c^{11R} are the unitary costs associated to load shifting and substation load shifting.

7.2.1.9.4 Generation curtailment

Curtailment costs are calculated by

$$c^{10} \sum_{i,t} \Delta G_i(t)$$
$$c^{10R} \sum_{i,t} \Delta \mathrm{R} G_i(t)$$

Based on the unitary costs for curtailment and substation curtailment, c^{10} and c^{10R}, respectively.

7.2.1.9.5 Storage

Costs are split into two elements. The first one measures the actual rate of utilisation of the storage,

$$c^{12} \sum_{i,t} \left(\Delta St_i^+(t) - \Delta St_i^-(t) \right)$$

where c^{12} is the unitary costs associated with the total charged and discharged energy. It is worth noting that, differently from a load shifting process, costs are associated to both the positive and the negative terms of the mechanism. The second, considers the cost of energy losses due to inefficiencies in the charging and discharging process,

$$c^{13} \sum_{i,t} (1 - \eta_{\mathrm{St}}) \left(\Delta St_i^+(t) - \frac{\Delta St_i^-(t)}{\eta_{\mathrm{St}}} \right)$$

where c^{13} represents the unitary costs of the lost energy.

7.2.1.9.6 EV

Costs are considered differently depending on the selected EV model[42].

7.2.1.9.6.1 EV market

The cost element is based on the utilisation rate of the EV storage system,

$$(1 - ev\_model) \cdot c^{14} \sum_{i,t} \left(\Delta EV_i^+(t) - \Delta EV_i^-(t) \right)$$

where c^{14} correspond to the unitary cost associated to charging and discharging.

7.2.1.9.6.2 EV as load

This factor considers a load shedding and a load shifting term,

$$ev\_model \left[c^{15} \sum_{i,t} EVS_i(t) - c^{16} \sum_{i,t} \Delta EV_i^-(t) \right]$$

where c^{15} and c^{16} are the unitary costs for EV load shedding and shifting, respectively.

7.2.1.9.7 Overall cost function

The overall costs function of the model can be written as follows

$$\begin{aligned}\frac{8760}{t_{max}} \sum_p \tau_p \Bigg\{ & c^8 \sum_{t=1 \dots t_{max}} \left(\sum_{i=1}^{I} \Psi_i + \sum_{i=2}^{I} \Gamma_i + \sum_{i=2}^{I} \Phi_i \right) + c^9 \sum_{i,t} CS_i(t) + c^{9R} \sum_{i,t} RCS_i(t) + \; c^{10} \sum_{i,t} \Delta G_i(t) \\ & + c^{10R} \sum_{i,t} \Delta RG_i(t) - c^{11} \sum_{i,t} \Delta C_i^-(t) - c^{11R} \sum_{i,t} \Delta RC_i^-(t) + c^{12} \sum_{i,t} \left(\Delta St_i^+(t) - \Delta St_i^-(t) \right) \\ & + c^{13} \sum_{i,t} (1 - \eta_{St}) \left(\Delta St_i^+(t) - \frac{\Delta St_i^-(t)}{\eta_{St}} \right) + (1 - ev_{model}) \cdot c^{14} \sum_{i,t} \left(\Delta EV_i^+(t) - \Delta EV_i^-(t) \right) \\ & + ev\_model \left[c^{15} \sum_{i,t} EVS_i(t) - c^{16} \sum_{i,t} \Delta EV_i^-(t) \right] \Bigg\}\end{aligned}$$

where the term τ_p denotes the percentage of occurrence of period p during the year.

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[42] $ev\_model = 0$ for EV market model, and $ev\_model = 1$ for EV as load model. See in Table 15.

7.2.2 Input, output and parameters of the model

7.2.2.1 Decision variables

Table 5: Summary of decision variables

Variable	Description
$E_i(t)$	Power output from network at voltage level i [MW/km^2]
$D_i(t)$	Power input to network at voltage level i [MW/km^2]
ξ_i	Maximum allowed load rate of transformers in substations (i/i-1) [pu]
$NC_i\ (t)$	Net load [MW/ km^2]
$CS_i\ (t)$	Shed load [MW/ km^2]
$\Delta C_i\ (t)$	Net shifted load [MW/ km^2]
$\Delta C_i^+(t)$	Positive shifted load [MW/ km^2]
$\Delta C_i^-\ (t)$	Negative shifted load [MW/ km^2]
$\Delta G_i\ (t)$	Curtailed generation [MW/ km^2]
$R_i\ (t)$	Load at substation (i+1/i) (to be added to D_i) [MWh/km^2]
$RCS_i\ (t)$	Shed load at substation (i+1/i) [MW/ km^2]
$\Delta RC_i\ (t)$	Net load at substation (i+1/i) [MW/ km^2]
$\Delta RC_i^+\ (t)$	Positive shifted load at substation (i+1/i) [MW/ km^2]
$\Delta RC_i^-\ (t)$	Negative shifted load at substation (i+1/i) [MW/ km^2]
$\Delta RG_i\ (t)$	Generation curtailment at substation (i+1/i) [MW/ km^2]
$\Gamma_i\ (t)$	Transformer copper losses at substation (i/i-1) [MW/km^2]
Φ_i	Transformer iron losses at substation (i/i-1) [MW/km^2]
$\Psi_i\ (t)$	Conductor losses at voltage level i [MW/km^2]
$NSt_i(t)$	Net storage load [MW/ km^2]
$\Delta St_i^+(t)$	Storage charging power [MW/ km2]
$\Delta St_i^-(t)$	Storage discharging power [MW/ km2]
$ESt_i(t)$	Storage stage of charge [MWh/ km2]
$NEV_i(t)$	EV net load [MW/ km2]
$\Delta EV_i^+(t)$	EV charging power [MW/ km2]
$\Delta EV_i^-(t)$	EV discharging power [MW/ km2]
$EEV_i(t)$	EV stage of charge [MWh/ km2]
$\Delta EV_i(t)$	EV load shifting term [MW/ km2]
$EVS_i(t)$	EV load shedding term [MW/ km2]

7.2.2.2 Coefficients and parameters

7.2.2.2.1 General parameters

Table 6: General parameters of the model

Parameter	Description
i	Voltage level index
j	Voltage level index i+1
V_i	Nominal voltage at level i [kV]
I	Total number of voltage levels
MU	Monetary unit
t	Timeslot index. It represents the elemental time unit of the model (typically one hour).
t_{max}	Number of timeslots per period p. Timeslots within a period are successive.
p	Number of periods per year. Periods are independent i.e., there are no constraints linking them.
τ_p	Percentage of occurrence of period p in a year. The sum of the percentages must be a 100%.

7.2.2.2.2 Network topology

Table 7: Parameters describing the network's topology.

Parameter	Description
N_i	Total density of nodes at voltage level i [1/km2]
μ_i	Density of substations at voltage level i [1/km2]
k_i	Number of feeders emerging from a substation (i+1/i) in voltage level i
m_i	Number of transformers per substation (i/i-1) [pu]
S_i	Conductor section at voltage level i [mm²]
l_i	"Equivalent" length of the network at voltage level i [km/km2]

7.2.2.2.3 Profiles associated to demand, generation and EVs

Table 8: Input profiles associated to demand and generation

Profile	Description
$C_i(t)$	Input load demand [MW/km²]
$non\_flex\_load\_i(t)$	Non-flexible part of $C_i(t)$ [MW/km2]
$G_i(t)$	Input generation [MW/km²]
$non\_flex\_gen_i(t)$	Non-flexible part of $G_i(t)$ [MW/km2]
$RC_i(t)$	Input load connected at substation (i+1)/i [MW/km²]
$non\_flex\_R\_load_i(t)$	Non-flexible part of $RC_i(t)$ [MW/km2]
$RG_i(t)$	Input generation at substation (i+1/i) [MW/km²]
$non\_flex\_R\_gen_i(t)$	Non-flexible part of $RG_i(t)$ [MW/km2]

Table 9: Input profiles associated to EV.

Profile	Description
$arrivals_i(t)$	Percentage of vehicles arriving at a charging point [%]
$departures_i(t)$	Percentage of vehicles departing from a charging point [%]
$EV_i(t)$	Input EV demand [MW/km²]
$EV\_non\_flex\_load_i\ (t)$	Non-flexible part of the $EV_i(t)$ demand [MW/km²]

7.2.2.2.4 Network characteristics coefficients

Table 10: Parameters describing the network's physical characteristics

Parameter	Description
ρ_i	Conductor resistivity [Ωmm²/km]
η_i	Voltage drop coefficient in network at level i
χ_i	Conductor reactance [Ωmm²/km]
$cos\Phi_i$	Cosine of the voltage-current angle
$VOLT_i$	Admissible voltage drop in network at level i [pu]
$VOLTRISE_i$	Admissible voltage rise in network at level i [pu]

7.2.2.2.5 Coefficients for system operation

Table 11: Parameters describing the nominal operation of the system

Parameter	Description
c_i	Number of substations (i/i-1) with mutual support
P_i	Conductors' nominal power at voltage level i [MVA]
p_i	Nominal power of a transformers in substation (i/i-1) [MVA]
d_i	Proportion of feeders at voltage level i which can participate in mutual support between substations (i+1/i) [pu]
λ_i	Capacity reserve factor for feeders at level i [pu]

7.2.2.2.6 Physical characteristics of transformers

Table 12: Coefficients for transformers

Parameter	Description
T_i	Equivalent resistivity for a transformer, used for copper loss calculation [pu]
u_i^1	Constant factor used for iron loss calculation [MW]
u_i^2	Proportional factor for iron loss calculation [MW/MVA]
u_i^3	Exponential factor used in relationship "iron loss power-nominal power"

7.2.2.2.7 Flexibility

Table 13: Parameters for load shifting, shedding and generation curtailment configuration

Parameter	Description
f_w	Load shifting time window (in number of time steps). It must be a divisor of t_{max}.
$load\ shifting\ type\ (FA)$	Flag representing the type of load shifting FA = 1: No anticipation is allowed in the load modulation FA = 2: Anticipation is forced in the load modulation FA = 3: No restrictions based on anticipation (free shifting)
$substation\ load\ shifting\ type\ (FAR)$	Flag representing the type of substation load shifting FAR = 1: No anticipation is allowed in the load modulation FAR = 2: Anticipation is forced in the load modulation FAR = 3: No restrictions based on anticipation (free shifting)
$non\_flex\_load\_flag$	Activation flag of the non-flexible load functionality
$non\_flex\_load\_shedding\_option$	Non-flexible load shedding management Value = 0: no restriction on load shedding Value = 1: shedding upper-bounded by non-flex load profile Value = 2: shedding bounded between non-flex profile and load profile
$non\_flex\_R\_load\_flag$	Activation flag of the substation non-flexible load functionality

$non\_flex\_R\_load\_shedding\_option$	Non-flexible substation load shedding management Value = 0: no restriction on load shedding Value = 1: shedding upper-bounded by non-flex load profile Value = 2: shedding bounded between non-flex profile and load profile
$non\_flex\_gen\_flag$	Activation flag of the non-flexible generation functionality
$non\_flex\_R\_gen\_flag$	Activation flag of the substation non-flexible generation functionality

Table 14: Coefficients for storage configuration

Parameter	Description
s_w	Storage time window (in number of time steps). It must be a divisor of t_{max}.
η_{St}	Storage charging and discharging efficiency [pu]
ISC_i	Initial storage state of charge [MWh/km2]
Ps_i^{min}	Minimum charging and discharging power [MW/km^2]
Ps_i^{max}	Maximum charging and discharging power [MW/km^2]
Es_i^{min}	Minimum state of charge [MWh/km^2]
Es_i^{max}	Maximum state of charge [MWh/km^2]

Table 15: Coefficients for EV operation

Parameter	Description
ev_model (EV as $shiftable$ $load$)	Value = 0: EV market Value = 1: EV as load
EV as load	
fw_{EV}	EV load shifting window (in number of time steps). It must be a divisor of t_{max}.
$EV\_non\_flex\_load\_flag$	Activation flag of EV non-flexible load functionality
$EV\_non\_flex\_load\_$ $shedding\_option$	EV non-flexible load shedding management Value = 0: no restriction on load shedding Value = 1: shedding upper-bounded by non-flex load profile Value = 2: shedding bounded between non-flex profile and load profile
EV market	
$totalEV_i$	Total number of vehicles divided by the networks surface [1/km2]
$initialConnectedEV_i$	Percentage of connected EVs at t=0 [%]
$evRecharge_i$	Average journey discharge, considering the average energy used for transport [kWh]
$evStorageCapacity_i$	Maximum state of charge [kWh]
$evPmaxIn_i$	EV maximum charging capacity [kW]
$evPmaxOut_i$	EV maximum discharging capacity [kW]
$\eta_{EV\,i}^{+}$	EV charging efficiency [%]
$\eta_{EV\,i}^{-}$	EV discharging efficiency [%]
ev_mode	EV charging mode: Value = 0: deterministic charging Value = 1: smart charging Value = 2: V2G

7.2.2.2.8 Cost factors

Table 16: Operational costs of the network

Parameter	Description
INT	Interest rate (%)
DUR	Equipment life duration [years]
c^8	Unitary cost of energy losses [MU/MWh]

c^9	Unitary cost of load shedding [MU/MWh]
c^{10}	Unitary cost of distributed generation curtailment [MU/MWh]
c^{11}	Unitary cost of load shifting [MU/MWh]
c^{9R}	Unitary cost of load (directly connected to the substation) shedding [MU/MWh]
c^{10R}	Unitary cost of distributed generation (directly connected to the substation) curtailment [MU/MWh]
c^{11R}	Unitary cost of load (directly connected to the substation) shifting [MU/MWh]
c^{12}	Unitary cost of storage charging and discharging rate [MU/MWh]
c^{13}	Unitary cost of energy losses due to storage charging and discharging inefficiency [MU/MWh]
c^{14}	Unitary cost of EV charging and discharging rate [MU/MWh]
c^{15}	Unitary cost of EV load shedding [MU/MWh]
c^{16}	Unitary cost of EV load shifting [MU/MWh]

7.2.3 IMPLICIT ASSUMPTIONS

The following paragraphs will elaborate on the model's implicit assumptions and simplifications.

7.2.3.1 Mutual support procedure

A mutual support procedure is a contingency manoeuvre performed whenever a single transformer is lost at a certain substation. During the procedure, lines and transformers, which are already prepared to participate in the support, deliver extra power without surpassing their maximum nominal power and load rate. Such is the role of equations in sections 7.2.1.5.1.2 and 7.2.1.5.2.2.

In section 7.2.1.5.1.2, a certain capacity in the load of lines was reserved for mutual support. Such margin was established by means of an inequality to prevent overload on feeders whenever they supply extra power. Such inequality assumes that feeders are interconnected during the failure, without specifying the points of connection nor the nature of this connection. Under the current formulation of the model, it is assumed that previous connections are only stablished in case of emergency. This is, lines or conductors connecting mutual support feeders are linked through a circuit that is normally open.

7.2.3.2 Voltage variation

Equations in section 7.2.1.5.3 controlling voltage variations are based upon a simplification of the electrical phenomena: actual variations depend strongly on the specificities of the apparent flow of power along the feeder, together with the active and reactive components of the line. The following section presents the specific assumptions made for the derivation of such equations:

- Voltage variation equations are constructed by measuring the difference of voltage between the ends of the feeder. However, strictly speaking, such variation should be controlled at every point of it. To tackle this, the model assumes the current $I(x)$ along the feeder is linear. Under such assumption, it is trivial to see that any variation between two arbitrary points of the line is bounded by the variation between its ends.
- Moreover, previous assumptions allow to get an analytical expression of the overall voltage variation, giving birth to the equations in section 0. Such assumptions can be satisfied if: i) nodes connected to the feeder are equally spaced and, ii) they consume or produce simultaneously in the same sign and magnitude. The reader should notice that, under these assumptions, it is not

possible to have a mix of different type of nodes along a feeder. If the contrary was true, the flow of current $I(x)$ would lose its linearity.

- Impedance of lines is modelled by a short-line approximation, which assumes a certain resistance R and reactance χ per unit of length. No shunt elements are assumed to be present.
- Equation governing the voltage drop dV over a differential element of line is assumed to be

$$dV = I(x)(R\cos\phi + \chi\sin\phi)dx$$

  where dx is the differential length of the element. Such equation corresponds to an approximation, which assumes a power factor around 0.85 [12].
- Because of the presence of the term V_i in the above-mentioned equations, it is assumed that substations are always capable of supplying nominal voltage level at their lowest voltage side. Such assumption can be satisfied if a control system for tap changers is implemented, which would allow to dynamically adjust the conversion ratio of transformers to compensate for voltage deviations at the high-voltage side of them. Rationale behind this is that if voltage deviations at one side of the transformer are sufficiently bounded, then the tap changer system will have enough transformation margin to provide nominal voltage at the other side of it.

7.2.3.3 Power line losses

Like voltage drop, estimation of power losses is a sensitive procedure, as they depend on the flow of current at every segment of the feeder.

- Equations in section 7.2.1.7.1 are calculated under the same assumption of current variation along a feeder as in the previous section. This is, the current will linearly increase or decrease along a feeder. Upon this approximation, an analytical expression of the overall power losses can be calculated.
- The expression estimating power losses in case of reverse flow uses the term $\left(\frac{E_i(t)}{\mu_i}\right)^2\frac{1}{V_i^2}$ to estimate the current entering a feeder of level i. Such expression has two implicit assumptions: i) there is always a substation $i/(i-1)$ connected at the low-voltage side of a feeder and, ii) the level of voltage at that connection point is nominal V_i, i.e., voltage variations are neglected.

7.3 PLATFORM MODEL PARAMETERS

Table 17: Platform parameters classified by asset

Parameter	Unit	Description
		Settings asset
surface	km2	Surface of the network
mu 0	1/km2	Nodes density at the lowest voltage level: number of consumption and generation nodes at the lowest voltage level divided by the network surface
mu n+1	1/km2	Injection points density: number of Tx-Dx connection points divided by the network surface
Losses cost	MU[43]/MWh	Time series describing the energy losses cost profile
Curtailment flag	bool	Flag enabling generation curtailment on the production assets
Curtailment cost	MU/MWh	Time series describing the curtailment cost profile of the production assets
Load shedding flag	bool	Flag enabling load shedding on the consumption assets

[43] MU: monetary unit

Parameter	Unit	Description
Load shedding cost	MU/MWh	Time series describing the load shedding cost on the consumption assets
Load shifting flag	bool	Flag enabling load shifting on the consumption assets
Load shifting type	{1, 2, 3}	Load shifting anticipation parameter: Value = 1: anticipation is not allowed Value = 2: anticipation is forced Value = 3: no restriction
Load shifting cost	MU/MWh	Time series describing the load shifting cost profile of the consumption assets
Storage efficiency	pu	Round-trip storage efficiency
Storage cost	MU/MWh	Time series describing the storage OPEX cost profile
Storage losses cost	MU/MWh	Time series describing the storage energy losses cost profile
EV storage cost	MU/MWh	Time series describing the EV OPEX cost profile
EV as shiftable load	bool	Flag enabling the *EV as shiftable load* model. When enabled, the EV load profile is considered as a simple load upon which load shifting and shedding mechanisms can be applied. No respect of driving patterns is therefore assured.
EV load shedding flag	bool	Flag enabling load shedding on EV assets. Valid when EV as shiftable load = 1
EV load shedding cost	MU/MWh	Time series describing the EV load shedding cost. Valid when EV as shiftable load = 1
EV load shifting flag	bool	Flag enabling load shifting on EV assets. Valid when EV as shiftable load = 1
EV load shifting cost	MU/MWh	Time series describing the EV load shifting cost. Valid when EV as shiftable load = 1
EV non-flex demand flag	bool	Flag enabling the non-flexible functionality on the EV assets' load profile: Value = 0: both load shedding and shifting are applied on the total EV (flexible + non-flexible) load profile Value = 1: load shifting is applied only on the flexible EV load profile, whereas load shedding is applied on different parts of the profile depending on the value of the *EV non-flex demand shedding* option
EV non-flex demand shedding option	{0, 1, 2}	Value = 0: load shedding is applied to both the EV flexible and the EV non-flexible profiles, without any distinction between them Value = 1: load shedding is applied only on the EV non-flexible demand profile Value = 2: load shedding is applied only on the EV flexible demand profile Valid when EV as shiftable load = EV non-flex demand flag = 1
EV load flexibility window	h	Time interval during which the shifted energy must be recovered. Valid when *EV as shiftable load* = 1
Non-flex demand flag	bool	Flag enabling the non-flexible functionality on the demand assets Value = 0: both load shedding and shifting are applied on the total (flexible + nonflexible) demand profile Value = 1: load shifting is applied only on the flexible demand profile, whereas load shedding is applied on different parts of the demand depending on the value of the n*on-flex demand shedding option*

Parameter	Unit	Description
Non-flex demand shedding option	{0, 1, 2}	Value = 0: load shedding is applied to both the flexible and the non-flexible profiles, without any distinction between them Value = 1: load shedding is applied only on the non-flexible demand profile Value = 2: load shedding is applied only on the flexible demand profile Valid when *non-flex demand flag* = 1
Non-flex generation flag	bool	Flag enabling the non-flexible functionality on the production assets: Value = 0: generation curtailment is applied on the total (flexible + nonflexible) generation profile Value = 1: generation curtailment is applied on the flexible generation profile
Unconstrained OPF flag	bool	Flag enabling the unconstrained optimal power flow mode. When enabled, this mode loosens constrains on the maximum power of cables and transformers, as well as on the maximum voltage rise and drop variations allowed
Substation curtailment flag	bool	Flag enabling generation curtailment on the substation production assets
Substation curtailment cost	MU/MWh	Time series describing the curtailment cost profile of the substation production assets
Substation load shedding flag	bool	Flag enabling load shedding on the substation consumption assets
Substation load shedding cost	MU/MWh	Time series describing the load shedding cost profile of the substation consumption assets
Substation load shifting flag	bool	Flag enabling load shifting on the substation consumption assets
Substation load shifting type	{1, 2, 3}	Substation load shifting anticipation parameter: Value = 1: anticipation is not allowed Value = 2: anticipation is forced Value = 3: no restriction
Substation load shifting cost	MU/MWh	Time series describing the load shifting cost profile of the substation consumption assets
Non-flex substation demand flag	bool	Flag enabling the non-flexible functionality on the substation demand assets: Value = 0: both load shedding and shifting are applied over the total (flexible + nonflexible) demand profile Value = 1: load shifting is applied only on the flexible demand profile, whereas load shedding is applied on different parts of the demand depending on the value of the *non-flex substation demand shedding option*
Non-flex substation demand shedding option	{0, 1, 2}	Value = 0: load shedding is applied to both the flexible and the non-flexible profiles, without any distinction between them Value = 1: load shedding is applied only to the non-flexible demand profile Value = 2: load shedding is applied only to the flexible demand profile Valid when *non-flex substation demand flag* = 1
Non-flex substation generation flag	bool	Flag enabling the non-flexible functionality on the substation production assets: Value = 0: generation curtailment is applied over the total (flexible + nonflexible) generation profile

Parameter	Unit	Description
		Value = 1: generation curtailment is applied over the flexible generation profile
	Network	
voltage level	V	Nominal voltage value of the level
conductor resistivity	Ohm mm2/km	Conductor resistivity
conductor reactance	Ohm mm2/km	Conductor reactance
voltage drop	pu	Admissible voltage drop
voltage rise	pu	Admissible voltage rise
power factor	pu	Average power factor
admissible overload	pu	Admissible overload on conductors: conductor maximum load = conductor nominal power*(1+admisible overload)
node density	1/km^2	Number of connection points (i.e., consumption and generation, together with substations nodes) divided by the network surface
conductor nominal power	MW	Nominal power of conductors
conductor cross section	mm2	Cross section of conductors
length between nodes	km/km2	Average conductor length between connection points
length substation and first node	km/km2	Average conductor length between a substation and its first connection point
number of feeders per substation	-	Average number of feeders departing from the substations of the upper level
	Substation asset	
Copper equivalent resistivity	pu	Equivalent resistivity of transformers, used for copper losses calculation
Iron losses constant factor	MW	Constant factor used for iron losses calculation
Iron losses proportional factor	MW/MVA	Proportional factor for iron losses calculation
Iron losses exponent factor	-	Exponential factor used in the iron loss power-nominal power relationship
Number of transformers per substation	-	Average number of transformers in substations
Transformer nominal power	MVA	Nominal power of transformers
Transformer load rate	pu	Maximum allowed load rate on transformers
Density substation	1/km2	Number of substations divided by the network surface
	Production and Substation production asset	
Generation profile	MW/km2	Generation profile aggregating all the technologies disaggregated from the market
Max curtailment	MW/km2	Maximum curtailment power
Non-flexible generation profile	MW/km2	Part of the generation profile considered as non-flexible
Including EV dispatch	Bool	Bool indicating whether the market's dispatched EVs are considered as part of the generation profile during the disaggregation process
	Consumption and substation consumption asset	
Demand profile	MW/km2	Load profile
Max load shifting	MW/km2	Maximum positive load shifting
Non-flexible demand profile	MW/km2	Part of the load profile considered as non-flexible
Including EV dispatch	bool	Bool indicating whether the market's dispatched EVs are considered as part of the demand profile during the disaggregation process
	Storage asset	
Consumption	MW/km2	Dispatched consumption profile

Parameter	Unit	Description
Production	MW/km2	dispatched reinjection profile
Minimum dis-charging	MW/km2	Minimum charging and discharge power
Maximum dis-charging	MW/km2	Maximum charging and discharging power
Initial energy	MWh/km2	Stored energy at t = 0. It aggregates all the storying capacity of the respective voltage level divided by the network surface.
Minimum energy	MWh/km2	Minimum allowed storage level. It aggregates all the storying capacity of the respective voltage level divided by the network surface.
Maximum energy	MWh/km2	Maximum allowed storage level. It aggregates all the storying capacity of the respective voltage level divided by the network surface.
		EV asset
Total number of EV	1/km2	Number of EVs divided by the network's surface
Percentage of connected EV at t=0	%	Percentage of the total number of EVs connected at charging stations at t = 0
Percentage of EV arriving at terminal	%	Time series describing the percentage of arrivals at charging stations of the total number of EVs at each time step
Percentage of EV leaving from terminal	%	Time series describing the percentage of departures from charging stations of the total number of EVs at each time step
EV storage capacity	kWh	Storage capacity per EV
Average journey discharge	kWh	Average journey energy used per EV. It corresponds to the energy needed for daily displacement and storage losses.
Average charging capacity	kW	Maximum charging power per EV
Charging and discharging efficiency	%	EV battery charging and discharging efficiency
Average V2G discharging capacity	kW	Maximum discharging power
EV mode	{0, 1, 2}	Value = 0: deterministic charging Value = 1: smart charging Value = 2: V2G Valid when *EV as shiftable load* = 0
EV_LOAD_PROFILE	MW/km2	EV fleet's load profile
EV_NON_FLEX_LOAD_PROFILE	MW/km2	Part of the load profile considered as non-flexible Valid when EV as shiftable load = 1