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STORY

added value of STORage in distribution sYstems

Deliverable D7.3
Report on large scale impact simulations

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1 Publishable executive summary

STORY project deals with evaluation of the impact of the large-scale deployment of small-scale storage. With the transition of electricity network towards smart grid, amount of smart, flexible and decentralized devices is increasing. In addition to renewable energy sources (RES), energy storage represents one of the biggest actors in developing grid. In STORY, focus was also on the analysis of large-scale implementation of storage networks in the distribution networks. The present report tries to indicate a direction, towards which the future large-scale deployment of small-scale storage will lead, what challenges we can expect and what solutions will be available. In addition to existing challenges of successful grid operation, new actors will bring new demands and conditions regarding power quality, so power system control will have to adapt.

The work described in this document will serve as input for further value analysis in the project. Earlier in the project, we have investigated the expected network development scenarios. Expected consumption, increased in amount and number of consumption points will be accompanied with an increasing share of renewable energy sources, new electric vehicles and sophisticated electrical and thermal storage. To apply future development scenarios, we have defined a representable grid model, which allows scenario application and modelling approach, suitable for the large-scale impact analysis. Once the network and important parameters were defined, we have scanned for proper simulation methodology, which would allow scenario analysis and simulations, considering the uncertainties involved. The result of this research defined simulation platform methodology and network modelling approach, already described in previous documents.

The tasks, described in this report, involved translation of the simulation concept to the functional simulation platform. Based on the defined methodology, defined grid models and network development scenarios, we have developed the simulation platform. It is built in MATLAB and OpenDSS software environment, each responsible for important aspects of the platform. After defining the representative grid model, it was implemented in the platform. The grid model covers all important parts of the distribution systems. Medium- and low voltage (MV and LV) networks are supplied from high voltage (HV) connection point. In the network model we have covered rural and urban configuration on both medium and low voltage section. Detailed model includes three-phase models of consumption, generation and storage as new emerging connected devices. Database based on yearly measurements was used as the simulation input. Household consumption profiles, renewable generation, electric vehicle model and charging strategy were important network parameters in addition to electric energy storage as our main focus. Household model and system units were defined, modelled on real data and equipped with algorithms, developed in STORY project.

After the simulation platform was established, database defined and tuned, test scenarios were run to test the Monte Carlo simulation approach. Monte Carlo simulations allowed us to model uncertainties, such as the location of the implemented storage devices, and the amount of produced and consumed energy at each node in the network. Results of the simulations are the profiles of the network parameters, saved for each iteration and every 15-minute interval within a simulated day. After initial check, tuning of the saving formats, import of newly available measurements, firs group of simulations were performed. Network models were altered through the network development scenarios, and the database allowed for variations and possible deviations of the parameters to be simulated and considered. The first results of the simulations consisted of the initial scenarios, applied to LV and MV levels. Results consisted of

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network parameters, such as voltage levels, losses, loading of the elements and consumption and generation profiles. Scenario results showed how different amount of storage, renewables and electric vehicles, affect the network during different seasons in addition to technical parameters, Key Performance Indicators, defined for demonstration monitoring, were implemented in the platform and used for performance evaluation. Relative grid energy consumption, deviation of the grid energy losses, levels of self-sufficiency and self-consumptions were all compared in various scenarios.

After receiving feedback on the first round of the results, updates were made on the platform and simulations approach. Scenario parameters were updated, several scenarios added, and few removed. Additionally, we have investigated the impact of the On-load tap-changer (OLTC) transformer and its interaction with the implemented storage, which was divided between household implementation or neighbourhood-level battery energy storage system (BESS) unit. Additional Key performance indicators together with their methodology were included in the report. Updated scenarios were implemented and executed using the simulation platform. The results of the distribution system operation are included in this document and the saved database with all the results collected represents a milestone in the STORY project.

Further we have investigated economic potential of the implemented storage. We focused on the Aggregator, operating the storage units, aggregating several units in his portfolio together with other flexible energy sources (demand response or distributed generation units) and cooperate with external actors. The Aggregator would either use Day-ahead electricity market trading or provision of ancillary services (various types of active power reserves), and the storage potential was evaluated for the years 2016, 2017 and 2018 (using realistic European energy market prices). Trading under constraints defined with market rules, boundary conditions in the network was compared to other potential business models available to Aggregator with storage assets: provision of ancillary services towards the Transmission system operator. The Aggregator is remunerated for allocated capacity and for delivered energy in the activation period. Based on realistic tertiary reserve provision market auction prices, the results show that to the Aggregator, provision of active power reserve, in particular FRR and RR is more profitable than providing energy in day-ahead trading.

The results of the large-scale storage implementation simulations will serve as an input for the analysis later in the project. All the results will be collected in the milestone database and will provide foundation for life cycle assessment of the implemented storage, environmental and social analysis and evaluation of overall storage impact on the electricity grid.

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2 Introduction

In this document we present the simulation platform for the large-scale storage impact assessment. In the previous task in Workpackage 7: Extrapolation, representable network sections were defined and modelled afterwards. Four important sectors of the network were considered: Low and Medium Voltage levels, in urban and rural setting. Future network development scenarios were applied to all network section. As a results of the future development process, key scenario parameters were identified and applied to the network in specific scenarios. The simulation platform mainly considers the roll out of community batteries, in combination with household batteries (focus in the Slovenian demo) but can be adjusted to other cases with electrical storage later.

In the document, we describe the selected methodology for the simulation process. A Monte Carlo method was chosen due to unknown characteristics of the future development scenarios such as location of future PV, EV and Storage locations. To successfully implement the MC method, large databases for household domestic profiles were created together with PV generation profiles and EV charging patterns. Seasonality factors were applied to consumption and generation profiles to achieve realistic input data. The simulation platform, defined in multiple software environments is shortly presented together with models and inputs, used for individual network elements. Scenario parameters and defined scenarios are described in the middle section of the report. Key scenario parameters, which defined the scenarios were peak levels of the demand profile, accumulated at the transformer level, installed RES power, EV and Storage installed capacity in the networks. For the initial simulations, 7 scenarios were chosen to present the impact of development scenarios parameters and storage implementation. After the scenarios parameters were defined, the simulations were performed, and technical results gathered. In addition to technical results, which include network voltage levels, electricity losses and transformers power flows, several input parameters are saved for each iteration as well. PV generation profiles, household demand profiles and EV profiles are also part of further analysis, which consists of Key Performance Indicators (KPI) calculation. We compared ratios of peak to average power flows between scenarios, change of Peak power levels and grid losses, grid energy consumption and local self-sufficiency and self-consumption levels.

Results show how each parameter influence the situation in the network, based on the results of the simulations. In lower scenarios, where PV penetration is not at high level yet and existing state is represented, storage implementation brings benefit to the overall situation but in little step. This is a result of conservative power system planning in the past, where power lines and other power delivery elements were often over dimensioned to increase stability and resilience of the network. But even this conservative planning is not sufficient in future development scenarios, where higher level of PV penetration is expected. It results in higher peak levels of element loading, and better network self-consumption and self-sufficiency rates.

Transmission system operation analysis investigated the economic aspect of the influence of the aggregated storage in the distribution network. The influence of distributed storage units, installed in distribution grids, was observed on the transmission level. The distribution storage units were assumed to be aggregated and controlled by the Aggregator, who used this aggregated storage flexibility on the electricity markets. The economic evaluation involved comparison of the Aggregator profits when offering flexible energy on the day-ahead market and when providing ancillary services in the form of tertiary reserve. With the high rates for transmission capacity allocation and relatively high price of

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energy delivered for reserve activation, which is around seven times higher than the prices on the day ahead market, this market promises to be more suitable for storage. Day ahead market yielded lower income to the Aggregator, but still provided a profitable trading outcome even with the assumed 85% round-trip efficiency of storage.

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3 Methodology for Distribution system simulations

3.1 Simulation concept

To perform a large-scale analysis, our simulation approach had to provide the possibility to several network scenarios approach with inclusion of uncertainties in the system. There are several factors in future network development. Location of future RES, EV and storage installations is unknown, and dealing with this uncertainty is the focus and a feature of the proposed simulation approach. The simulation platform must assess the impact of installed units, regardless of the unit's location. This can be achieved with a stochastic Monte Carlo simulation approach, where unit's locations are randomly chosen and installed in the predefined grid model. The network model is developed in the OpenDSS (DSS) software environment. When executing power flow simulations, OpenDSS is called from a MATLAB routine. Load demand in Low Voltage (LV) distribution networks is highly variable, but consumption of a load shows specific patterns over time. Generation from Distributed Generators (DGs) is more predictable, since we only model solar photovoltaic (PV) generation. However, it is still variable, due to weather specifics, namely clouds, snow or dust accumulation. Additionally, Electric Vehicles (EVs) that are also part of our investigation are also highly variable in terms of charging duration and connection time.

3.2 Monte Carlo method description

Due to the characteristics of the modelled network, a stochastic Monte Carlo simulation approach is chosen for the network simulation. It allows proper inclusion of the stochasticity of the loads, DGs, and EVs.

The Monte Carlo method is well known and used in different branches of science when studying systems that cannot be solved analytically. It is also widely used for distribution network calculations [1], [2], [2]–[5]. The whole network calculation procedure consists of repeatedly solving the same network while randomly alternating the key parameters of the elements. Since the definition of these parameters is based on some realistic database also their values for the simulation should not be completely random, but they must follow the same Cumulative Distribution Function (CDF) as the reference values from the database do.

Following parameters are subjected to pseudo-random recalculation for each MC iteration:

- Household consumption:
  - Consumption of each load,
- PV injection:
  - Location of each PV in the network,
  - Generation of each PV,
- EV consumption:
  - Location of each EV in the network,
  - Consumption of each EV,
- Battery injection:
  - Location of each battery in the network,
  - Battery power flow as a function of the network state.

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3.3 Types of data used in the analysis

There are two types of network included in the grid model. One is an artificial synthetic network, which represents a range of different networks. Data was collected from several European DSOs to create a representative case for storage application. It covers all important aspects for the simulations: medium and low voltage networks in urban and rural setting. As the most modelled grid, which is relevant for STORY project, is the real network section, based on the data provided from one of Slovenian DSOs: Elektro Gorenjska (EG). In these two networks, LV Suha village model and EG headquarters complex, a Li-Ion storage will be installed. For that reason, those two networks were included in the simulation platform as well.

3.3.1 Synthetic network database

To properly represent the network's real situation, powers defined to different elements must be realistic. Therefore, a database of the realistic network measurements must be established. Power injections for each MC iteration are then defined based on this database.

In our case, database for each power consumption and generation element of the network consists from:

- Household consumption:
  - Measured daily consumption profiles of 1000 households in 15-minute resolution, for one day simulation interval,
  - Measured power flow through MV/LV transformer in one day resolution for one year,
- PV injection:
  - Measured sun irradiation profile in 15-minute resolution for one year,
- EV consumption:
  - Simulation-based EV consumption profiles in 15-minute resolution, bearing in mind different habits of EV users and EV charging characteristics,

Four season simulations were established for the project. Database must thus be split into sub-groups, each describing appropriate season. This is performed only for household consumption and PV generation database now. Seasonality effect to EVs is neglected.

Database seasonality is achieved by:

- Household injection:
  - Splitting the normalized yearly power flow profile through MV/LV transformer,
- PV injection:
  - Splitting the normalized yearly sun irradiation profile,

In the end base values for each MC iteration are defined as follows:

- Household injection:
  - Based on CDF of 1000 daily profiles additionally scaled with seasonality constant,
- PV injection:
  - Based on CDF from the sun irradiation profile of several consecutive days for a season,

These base values are then additionally weighted. Weight depends on the chosen transformer loading for case.

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3.3.2 Real network database

Real network parameters and measurements are provided from EG.

Household consumption and PV generation in a rural LV network Suha is available as weekly measurements in 15-minute interval, for 4 seasons. Loading for LV network Suha is then defined using these values for each MC iteration. In our model, the loading stays the same for each MC iteration (of course it changes with time in accordance with the provided database). The same goes for PV generation in LV Suha.

The industrial network of EG is modelled as a part of urban network. It consists from measurements of installed Combined Heat and Power (CHP) plant, compressor ice storage facility, transformer station and PV power plant. Yearly measurements in 15-minute interval are available. For every MC iteration, a different day from the appropriate season is chosen for calculation of each of network devices with addition of equivalent residual load, so each MC iteration is performed for different day of the season.

The predefined set of 40 MC iterations is performed for each of the 96-time steps of a day for each season. Later, number of MC iterations can be defined in terms of network parameter change between two consecutive operations. It means that MC simulation ends, when the change of parameter (e.g. mean voltage of bus) between the last two iterations is under the pre-set limit.

After the last MC iteration, the results are displayed in a probabilistic manner, with mean values and the upper/lower boundaries.

3.4 Simulation tools

For the distribution network simulations, in the previous Task 7.2: Network modelling approach, a combination of MATLAB and OpenDSS software environment was set up. OpenDSS is an electric power Distribution System Simulator (DSS) for supporting distributed generation resource integration and grid modernization efforts. Originally developed by Electric Power Research Institute (EPRI), it was deemed an open source program and transferred to public domain, [6]. In our simulation platform, it is used for definition of the network topology; power delivery elements (e.g. power lines and transformers) are defined together with the information about MV side of the network. Connections of the households, photovoltaic (PV) generation units, batteries and electric vehicles are also defined here.

Power flow calculations in OpenDSS are called from MATLAB software environment, which is an integrated environment for rapid development of computing code to analyse and design the systems and products, developed by MathWorks, [7]. MATLAB code contains database with load and PV time series, together with model of the battery and electric vehicles. Control mechanisms of on-load tap changing (OLTC) transformer, Storage inverters and EV charging stations are defined in MATLAB code and are applied to network parameters, send to OpenDSS. The household and RES profiles are from MATLAB code applied to the units, defined in OpenDSS. Initial power flow calculation provides voltage levels, losses, power and currents flows, which are imported from OpenDSS to MATLAB and they serve as an input for battery control algorithm, described in Chapter 4.2.2. After the control algorithm calculates the battery response, storage commands are sent to OpenDSS model and power flows with storage operation

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are performed. Additional storage parameters are calculated with storage model such as State of Charge and losses in the unit.

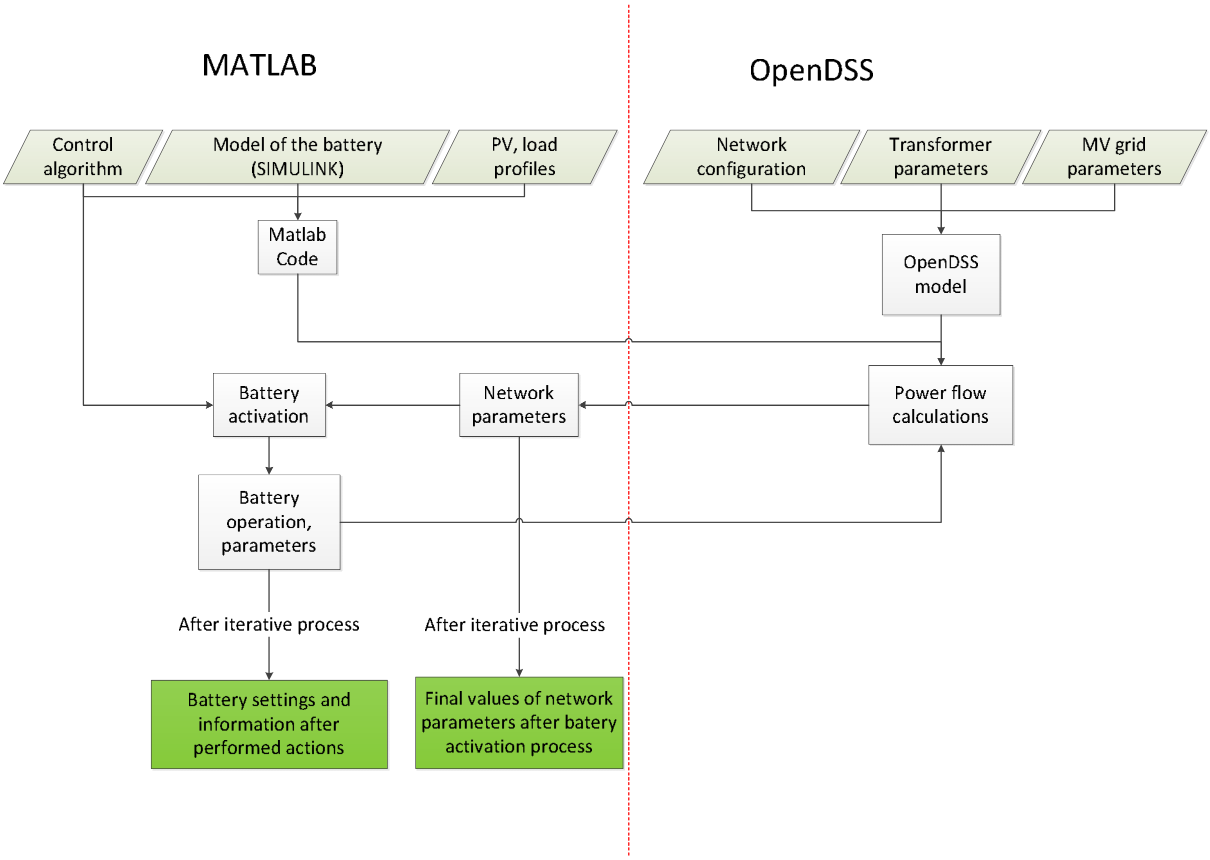

Figure 3.1: Simulation platform flow

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4 Used models and input data

4.1 Load and Generation Database

STORY Monte Carlo database includes diagrams for load and generation profiles.

The household consumption profiles are day-specific, specially profiles differ for week and weekend days. Figure 4.1 represents aggregated profiles of 3000 loads for interval of one week.

The demand diagram shape depends on the type of day, namely they differ during working days or weekend days. In Figure 4.2 seasonality is shown with the yearly profiles of the aggregated load profiles.

Seasonal factor is also present in PV generation profiles. Since irradiation levels are lower in winter, production in this interval is smaller. Additionally, PV generations is closely related to the weather. Both effects are presented on Figure 4.3, where Slovenian irradiation levels on yearly basis is visualized.

PV generation modelling was done with same approach as load modelling and is based on solar irradiation database. In Figure 4.4, sample of PV production for one week is presented.

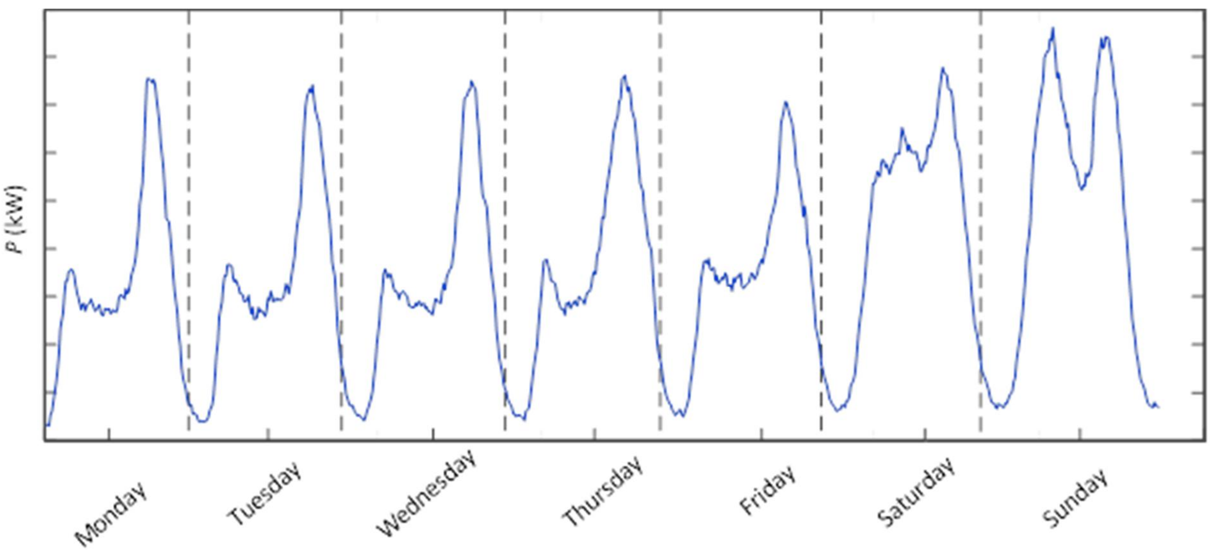

Figure 4.1: Aggregated demand of 3000 households for one week

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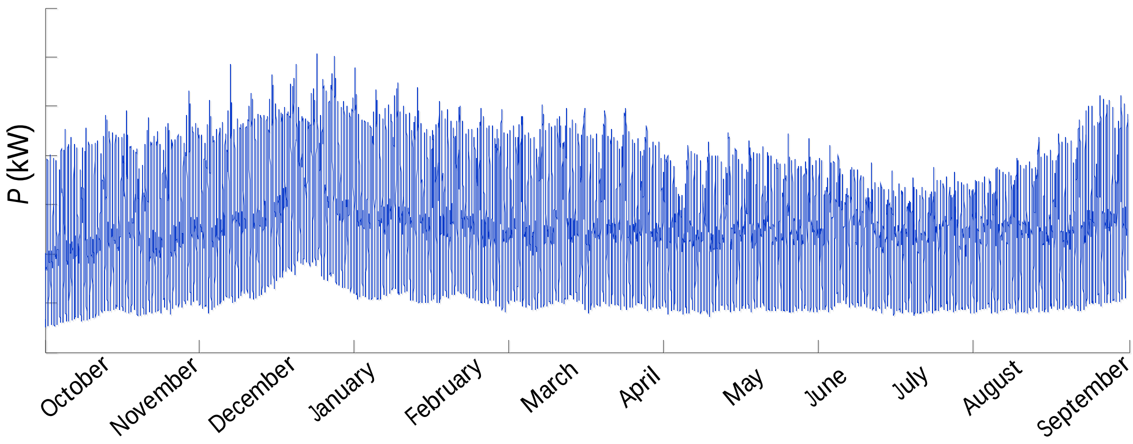

Figure 4.2: Aggregated demand of 3000 households for one year

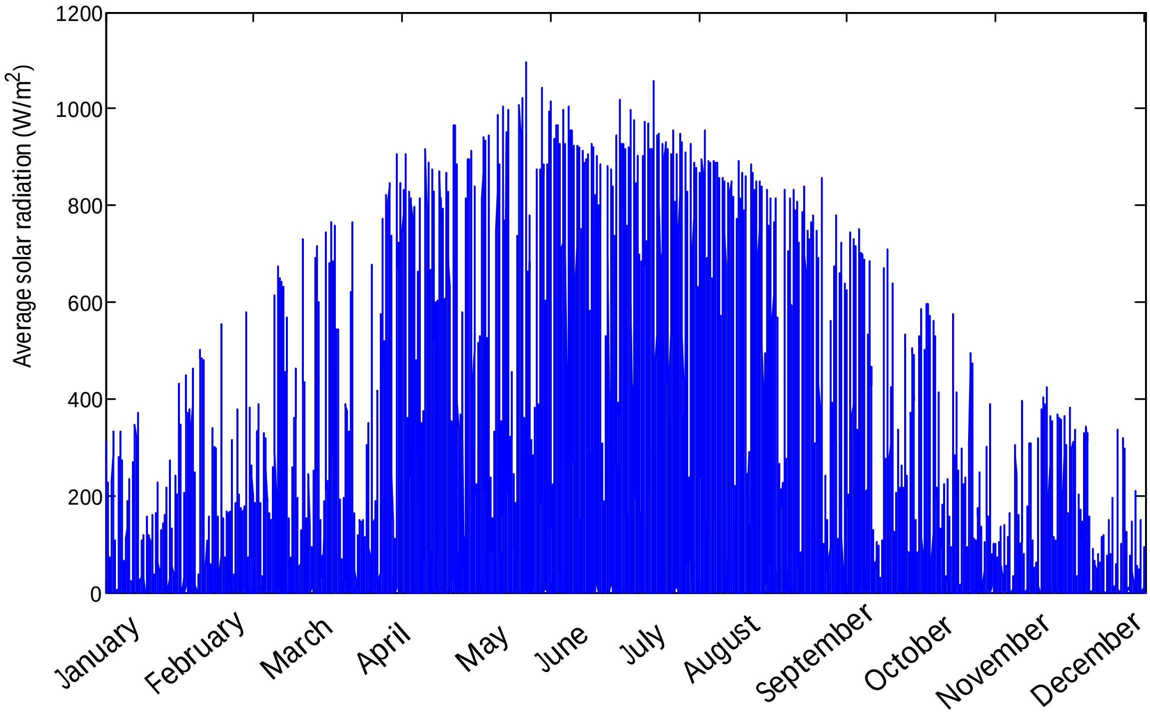

Figure 4.3: Average solar radiation for Slovenia for one year

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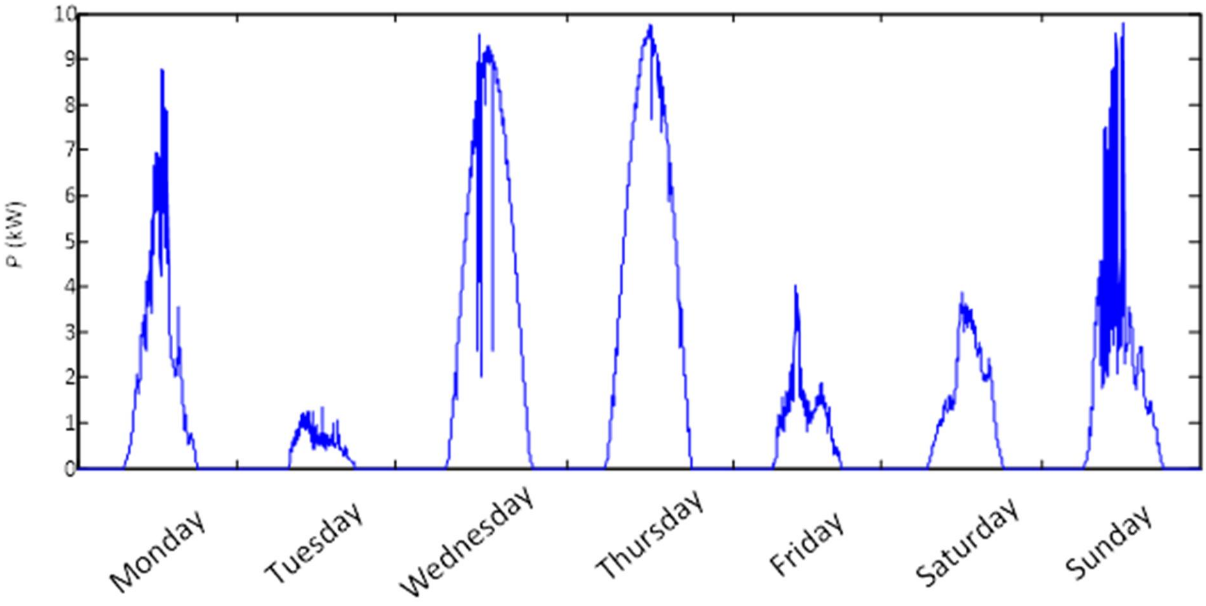

Figure 4.4: Example of PV generation for one week

The inputs to the simulations include:

- **Household consumption:**
  - Measured consumption profiles of 1000 households in 15-minute resolution, for one day,
  - Measured power flow through MV/LV transformer in one day resolution for one year,
- **PV generation:**
  - Based on installed size and measured sun irradiation profile in 15-minute resolution for one year,
- **EV charging profiles**:
  - Simulation-based EV consumption profiles in 15-minute resolution, bearing in mind different habits of EV users and EV charging characteristics,
- **Control algorithms**: including DG, storage, transformer tap-changer.

Evaluation of seasonal and daily effects is achieved with daily simulations, which are executed separately for each season and day. A typical load curve is applied to households in a distribution network and follows shape for one day. To randomly define a load profile in each time instance and achieve cumulative value of loads in the network an appropriate method was used: the inverse transform method for random variate generation.

PV generation experiences daily variations since it highly depends on solar irradiation. The irradiation profiles were used as an input for PV cumulative distribution function calculations. A cumulative density function (CDF) was calculated from predefined span of 20 consecutive days. Profiles of individual PV units are then pseudo-randomly defined using the calculated CDF.

Generation of one PV unit connected at LV network, calculated with the described method, is presented in Figure 4.4. PV units operate with a power factor of 1. Generation of PV is defined for each iteration individually as well as unit's location. In the results and in their analysis, an average value is used. Peak

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power of each PV equals its nominal power, and the number of installed PVs in LV network sections is chosen to achieve the accumulated generation profile of LV network.

4.2 Battery models and control strategy

4.2.1 Types of batteries used

There are two types of batteries present in the simulated network: a MV/LV substation battery and LV household batteries.

The first type (MV/LV substation batteries) are connected to the sending busbar of each MV/LV transformer. When active, these batteries are working in the Peak Shaving mode, reducing the daily peaks of the network consumption. The model is based on the data provided for medium scale storage unit and includes measured charge/discharge curves and efficiency of battery. Storage components are shown in Figure 4.5.

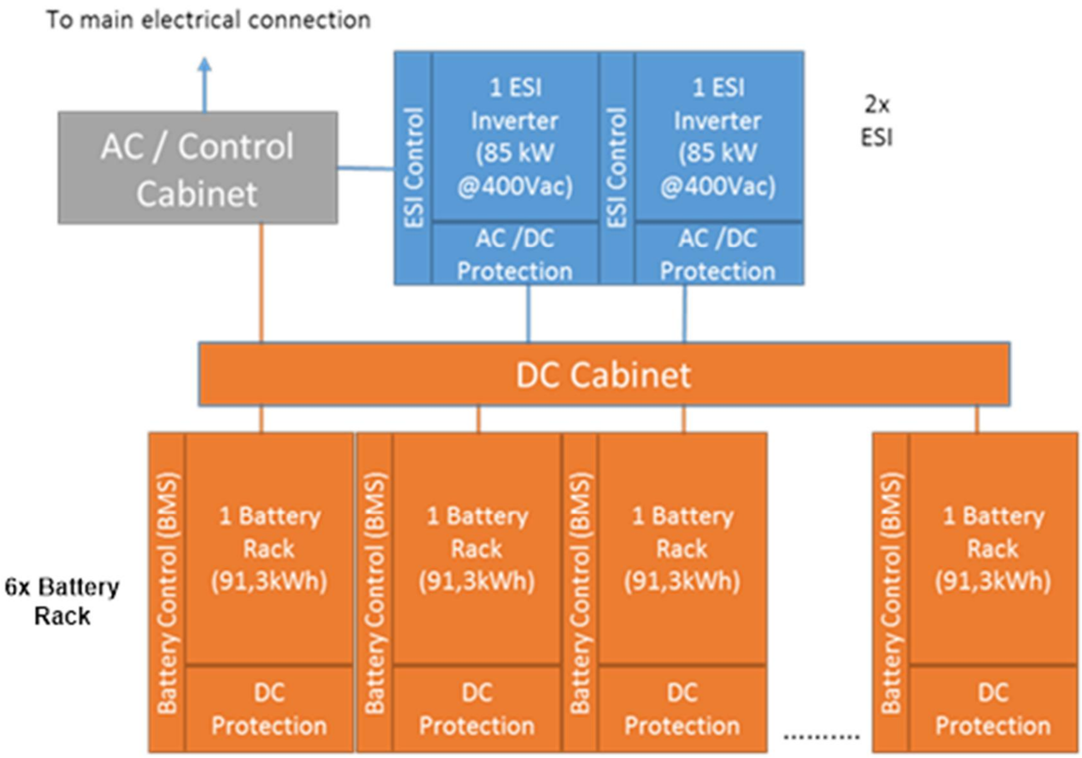

Figure 4.5: MV/LV substation battery example, used in EG demo cases

Operational constraints of the MV/LV sub battery are as follows:

- SOC min: 25%
- SOC max: 98%
- Capacity: 320 kWh, reduced due to 4-wire connection of the system
- Rated Power: 170 kW

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Losses calculation is based on the following battery parameters:

- Inverter losses: 2.5% of Losses @ Rated Power
- Battery parasitic losses: 2% of Losses @ Rated Energy
- Auxiliary losses: 1.5% of Losses @ Rated Power

Additionally, there are also LV household batteries in the simulated network, which are installed at LV customers. Consequently, they are of lower power and capacity, compared to the MV/LV sub batteries.

Location of these batteries' changes over the different MC iterations, similar as it is the case with the DGs. Nominal (peak) power of each installed battery is defined in advance (in our case it equals 15 kW for each installed 3-phase battery). The number of installed batteries in a LV network is then defined based on the previously defined nominal power of each battery and nominal power of the MV/LV transformer to achieve the aggregated peak power of batteries in a LV network.

When the number of batteries in a LV network is determined, battery locations are defined. In the first step location of each battery is randomly chosen among locations that already have DG installed. If the number of batteries in the network is larger than number of DGs, remaining batteries are randomly distributed over the rest of the LV network.

The capacity of each battery is also predefined and, in our case, equals to 16 kWh. The nominal power and capacity values are based on the parameters presented in [9], which additionally provides the information about the battery losses, also incorporated in our model. Charge/discharge curves were adopted from the MV/LV sub batteries.

Operational constraints of each LV battery are as follows:

- SoC min: 35%
- SoC max: 99%
- Capacity: 16 kWh
- Power: 15 kW

Losses calculation is based on the following battery parameters:

- Charge: 76%
- Discharge: 88%
- Auxiliary losses: 0 kW

Currently there are two different battery modes in use with the LV batteries.

- For the batteries operating in combination with a DG (DG and battery at the same location), batteries are balancing the difference between DG generation and load consumption. In case of adequate capacity and power of batteries there is no power flow between the grid and the consumer. The grid only serves for voltage support in this case.
- For the batteries in stand-alone operation (no DG on location, only battery and load) operation mode is different. Standalone battery charges with cheaper power during the night and supplies power during the day, when the energy from the grid is more expensive. The consumer – battery owner is taking advantage of price difference between day and night. In case of adequate capacity

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and power of batteries, the consumer does not consume any power from the grid during the day and the battery is fully charged during the night.

4.2.2 Battery operating modes

Substation batteries connected to secondary bus bar of MV/LV transformer are operating in the Peak Shaving mode. In this mode, the battery reduces the LV network power injection to the MV network. It stores the energy during the peak of DG generation (thus reducing the injection towards the MV network) and then releases the stored energy during the peak of demand (and reducing the injection from the MV network). Consequently, the peak in the network is reduced, and as a result so is the peak in the HV/MV substation. When the DG generation level is lower (winter and intermediate seasons), the battery is used for load shifting: it stores the energy during the off-peak period (night, morning) and releases it during the peak hours, thus reducing the peak.

Household batteries in the LV network are currently operating in two different manners, depending the household type.

- If a battery is installed in the household, that also has a PV installed, then this battery stores the surplus between the generated and consumed energy of this household during the day. Stored energy is then released during the night. Ideally, this household doesn't consume any power from the grid.
- In case the battery is installed in a household without PV, then it is used to utilize the difference between the energy price at the peak and the off-peak period. The battery is charged when the electricity prices are the lowest (during the night) and discharged when the prices are the highest (during the daily hours).

4.3 Simulated Network structure

The MV and low voltage (LV) network simulation approach is presented in this chapter. Simulation of both, MV and LV networks, is carried out simultaneously. For the evaluation of scalability of any network solution, a typical substation is modelled and the cumulative effect of the investigated solution (distribution level, transmission level) is obtained by summation of the typical network.

The modelled MV network is presented in Figure 4.6. It is represented with two feeders modelled in detail, an urban and a suburban feeder. The remaining load of the substation is represented with an equivalent load. An equivalent load model is necessary to properly set the loading levels of HV/MV and MV/LV transformer to observe appropriate power flows and losses through supplying transformer. With the scenario development approach, consumption of the equivalent load also increased. For every two feeders there is one LV network modelled in detail (marked in red).

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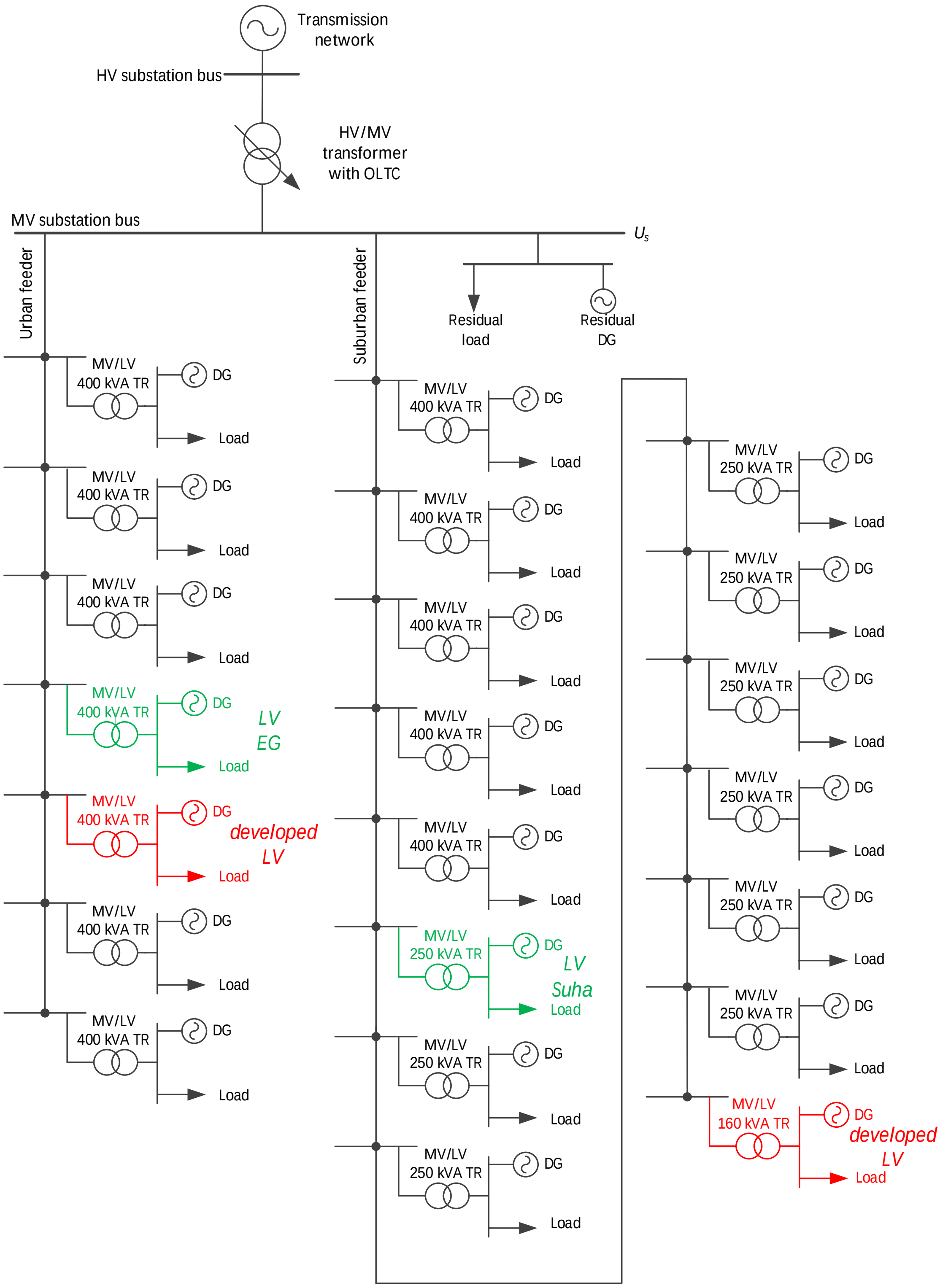

Figure 4.6: Single-line MV distribution network scheme with two feeders. Location of fully modelled synthetic LV networks (red) and real networks (green) are also shown.

The LV network topology is shown in Figure 4.7 for an urban LV network and in Figure 4.8 for rural LV network. The other LV networks, connected to the MV level, are simulated as equivalent loads. The

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load profile of the equivalent loads is defined as aggregated power flow of virtual LV elements for each of the LV substations. Simulation of both MV and LV networks is carried out simultaneously.

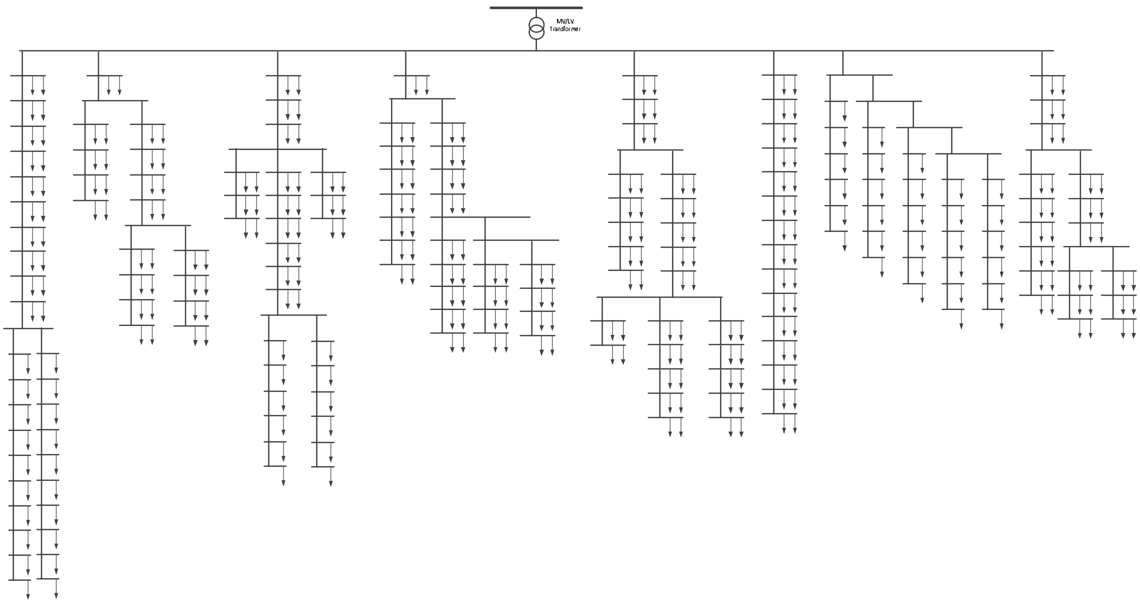

Figure 4.7: Urban LV network configuration

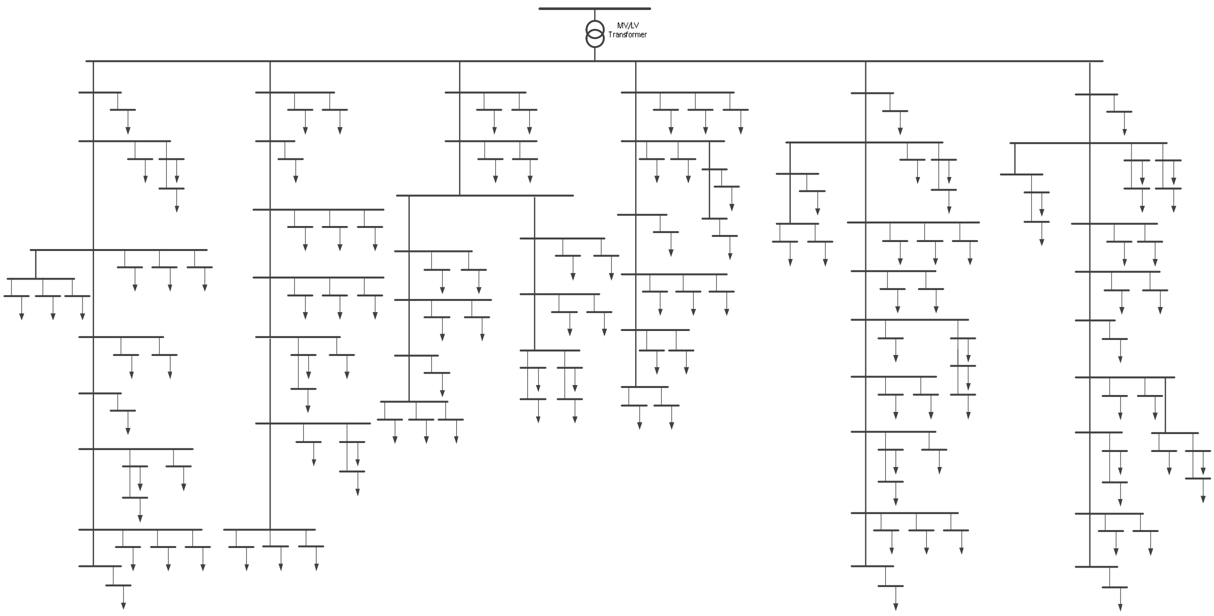

Figure 4.8: Rural LV network configuration

Load and generation variations are evaluated by means of Monte Carlo (MC) simulations, when different loading and generation data is used for every MC simulation. The load and generation variations are derived from load and generation profiles. When evaluating the influence of future distributed generation (DG), also the location of the DG is varied as it is not known.

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4.4 Simulation parameters

4.4.1 Simulation interval

All the available data, that we have received from the partners (network measurements of loads and DGs), or have derived by ourselves, through the additional simulations (charge curves of EVs) is of different length, all in a 15-minute resolution. It means 96 data samples per day. Therefore, we have adopted this value, for our simulation interval. The span of each MC iteration is one day (daily load flow simulations). Seasonal difference can be observed by simulating different seasons separately (using distinguished seasonal measurements for the inputs).

4.4.2 Network parameters – OLTC transformer

The transformer modelled in the HV/MV substation has the OLTC capability enabled during the simulation. The tap is manipulated via the OLTC algorithm implemented in the MATLAB code. In every time step the algorithm checks whether the voltage is within the permissible limits and if not, it issues the tap change command. Transformer has 13 taps ranging from -6 to +6 with also tap 0 in the middle of the interval. Voltage difference between the two consecutive taps equals 0.0133 p.u. Algorithm issues a tap change, if the voltage exceeds the following pre-set conditions:

$$0.93pu < U_{boundary} < 1.07pu \qquad (1)$$

Algorithm inputs are measured voltages at the secondary busbar of the HV/MV transformer along with the calculated voltages at the end of the feeder. The latter ones are derived using the secondary current measurements and some predefined feeder impedance value.

Initially the transformer is set at tap -3, which sets the secondary voltage to 1.04 p.u.

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5 Selected network development scenarios

For the central, northern, and southern region network development scenarios were applied to distribution network model, scenario database was tuned for each region accordingly and daily simulations were performed for all four seasons. Scenarios were defined with following parameters:

- **Location** of the grid, which introduces geographical variations in the simulations. Based on location, database for demand and generation profiles is updated and calibrated.
- **Load peak power** value calibrates the aggregated demand profiles for sub section of the network. It is based on nominal power of the MV/LV transformer, which supplies individual sector of the network. Once the aggregated demand profile is known, the power demand in each instance is distributed among loads in the network.
- **Distributed Generation Installed Power** in each sector of the network is defined with percentage of transformer nominal power. Small, dispersed, 3 phase generation unit are randomly installed in network until installed capacity is met. DG units are predefined, 6 kW, 3 phased photovoltaic plants.
- **Electric vehicles** in the network are defined with aggregated amount of nominal power of the units. Charging stations of the EV are randomly placed, each unit is 3phase connected with nominal power of 7 kW. The charging process also considers random charging intervals of the EV, with emphasis on overnight charging due to two tariff pricing schemes.
- **Storage installed capacity** is similarly defined to transformer nominal power rating. We have assumed 3-phase battery units installed in random households in the network or a community-size battery energy storage system (BESS), connected at MV/LV transformer station, supplying the LV network

OLTC transformer connects HV grid source and MV sections of the grid. According to network voltages in MV section, taps on the secondary side are adjusted. Operation was described in Chapter 4.4.2. to determine the impact of the OLTC unit, additional scenarios were defined and applied to the network with 55% peak demand value in all scenarios. Scenarios are described below in Table 5.1. Scenarios were added to the initial set, and results are included in the main results sections in later chapters.

Table 5.1: OLTC scenarios

Scenario	**RES installed power**	**EV installed capacity**	**Storage installed capacity**	**Allowed Voltage range [p.u.]**
1	110 %	40 %	0 %	*No OLTC*
2	110 %	40 %	0 %	0.93 – 1.07-
3	110 %	40 %	0 %	0.98 – 1.02
4	110 %	40 %	80% (Grid Unit)	*No OLTC*
5	110 %	40 %	80% (Grid Unit)	0.93 – 1.07-
6	110 %	40 %	80% (Grid Unit)	0.98 – 1.02

In Table 5.2, a short summary about final scenarios is presented. Each of the parameters was defined based on the results from Task 7.1: Selection of cases, where development scenario approach is

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described in detail and on feedback received in earlier stages of the simulations. After initial scenarios were defined, updated table was defined and reorganized for better grouping of the results.

Table 5.2: Central Europe scenarios overview

(Parameters, given in percentage of Transformer nominal power rates)

Scenario	Peak demand value	RES installed power	EV installed capacity	Storage installed capacity (Unit type)	OLTC
1	55 %	40%	5%	0%	0.93 – 1.07
2		40%	5%	15% (Household)	0.93 – 1.07
4		40%	5%	30 % (Household)	0.93 – 1.07
6		110%	40%	0%	0.93 – 1.07
11		110%	40%	0%	OLTC off
12		110%	40%	0%	0.97 - 1.03
3		110%	40%	15% (Grid)	0,93 - 1,07
7		110%	40%	30 % (Household)	0.93 – 1.07
9		110%	40%	80% (Household)	0.93 – 1.07
10		110%	40%	80% (Grid)	0,93 - 1,07
13		110%	40%	80% (Grid)	OLTC off
14		110%	40%	80% (Grid)	0.97 - 1.03

Scenarios were repositioned to match the Storage increased levels through the scenarios, but initial design is still marked with colours. Scenarios in green represent states without BESS systems and Household installations. Blue scenarios represent OLTC variation in different Storage installation and RES impact. Purple scenarios present Grid storage, operating with advanced peak shaving algorithm. The Table 5.2 is the result of the scenario update process. Two of the initial scope of scenarios, 5 and 8 are left out as they represent most unlikely situation. Scenario 5 included installation of system unit at transformer station, while grid stability was not questionable. And similarly, for scenario 8, it represented similar setting as in updated scenario 3: high RES setting and smaller storage unit.

From the Table 5.2, peak values of all key network elements can be observed. Following is a brief explanation of the element definition.

Peak demand value

Peak consumption of the network loads is defined in terms of the yearly peak consumption, compared to the MV/LV transformer nominal power. In our case, this, lets name it loading rate, is maintained at 55% for all modelled scenarios [8]. Since the consumption is defined in terms of yearly peak in kW, the actual consumption peak varies from season to season, with maximal value in the winter and the minimal in the summer season. In addition to peak level, seasonal variations energy consumption in kWh is different between seasons as well.

RES installed power

RES generation peak is defined in terms of the annual peak solar irradiance, compared to the MV/LV transformer nominal power. This *generating rate* varies between different scenarios, as can be seen in

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the Table 5.2. Since the RES generation is defined in terms of yearly peak, the actual generation peak varies from season to season, with maximal value in the summer and the minimal in the winter season.

EV installed capacity

Aggregated capacity of the installed EVs is also defined in terms of their nominal power, compared to the transformer nominal power. This parameter isn’t seasonally related.

Storage installed power

In case of the central BESS (Battery Energy Storage System) installed at the MV/LV transformer substation, the battery parameters are fixed for all batteries and are equal to the ABB BESS mentioned in Chapter 4.2. Capacity of these batteries equals 320 kWh and their peak power limited is 170 kW. BESS parameters aren’t related to any other variable (season). If installed power differs from given storage dimension, the unit is proportionately scaled to the desired installed power of the unit

In case of the LV batteries, installed at the households, their aggregated power is defined in terms of their nominal power, compared to the transformer nominal power. This parameter isn’t seasonally related.

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6 Technical results

Each of the scenarios was simulated for all 4 seasons and multiple simulation results are saved in result matrix. Results are saved in 15-minute simulation time step, for each Monte Carlo iteration as a separate line of results. After simulations, average results values are calculated, together with the minimum and the maximum parameter value in the shape of percentile.

Percentiles for voltage profiles provide border values which define 90% of voltage values, which are above the lower percentile value and below higher threshold of 90%. In addition to limit values, entire **voltage profile series** are saved as well and available for further analysis. **Electrical losses** in the network are saved as cumulative sum, line specific and transformer specific. Fully modelled LV urban and rural networks losses are also separately defined and saved. **Transformer's powers** are recorded on several locations:

- HV/MV Main supply transformer
- MV/LV Supplying rural network on rural feeder
- MV/LV Supplying urban network on urban feeder

Similarly, **storage unit power** data is separated in three sectors:

- Household storage units in urban and rural LV network,
- Central storage units, placed on each MV/LV node, modelled with the network equivalent node.

Inputs for the simulations, which are important for the analysis are also stored in each iteration:

- **PV generation profiles** for units located in LV urban and rural network, and accumulated generation diagrams for MV network equivalent models on MV urban and rural feeder.
- **Load profiles** for households, located on LV networks and equivalent model's diagrams, connected to MV feeder.
- **Charging profiles of EV** which are installed in each of the network sections.

Parameters, which defined all the calibration of the input data were following:

- HV/MV transformer, which had rated power of 30 MVA.
- MV/LV transformer, which supplied urban grid had rated power of 400 kVA.
- MV/LV transformer of the LV rural network had rated power of 160 kVA.
- RES generation in LV networks was scaled from installed power of 40% of transformer capacity to 110% of transformer capacity.
- Peak demand value was set to 55% of transformer capacity and accumulated profiles were scaled appropriately in both rural and urban LV grids.
- Battery capacity installed in network was varied from 0%, to values of 15%, 30%, 40% and 80% of supplying transformer capacity. In case 7, where central unit was used a storage model, based on ENS storage model was used at each of MV node of MV network.
- EV installation capacity varied from 5 % of transformer capacity to 40 % of capacity.
- OLTC default threshold values were chosen at 0.93 and 1.07 p.u.

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6.1 Voltage levels

In this chapter we present first segment of the results: the voltage levels. In table we have collected minimum and maximum value of voltage profile throughout the day, for all for seasons.

Table 6.1: Winter season voltage limits

Winter	V_{max} 90% (MV)	V_{min} 90% (MV)	V_{max} 90% (LV)	V_{min} 90% (LV)
Scenario	**[p.u.]**	**[p.u.]**	**[p.u.]**	**[p.u.]**
1	1.0695	1.0041	1.0692	0.9490
2	1.0695	1.0038	1.0691	0.9488
4	1.0695	1.0037	1.0690	0.9486
6	1.0695	1.0055	1.0708	0.9508
11	1.0355	**0.9825**	1.0708	**0.9151**
12	1.0462	0.9886	1.0653	0.9254
3	1.0693	1.0038	1.0705	0.9464
7	1.0695	1.0057	1.0708	0.9506
9	1.0691	1.0047	1.0706	0.9503
10	1.0542	1.0030	1.0680	0.9404
13	1.0353	0.9926	1.0680	0.9256
14	1.0328	0.9926	1.0680	0.9256

Table 6.2: Spring season voltage limits

Spring	V_{max} 90% (MV)	V_{min} 90% (MV)	V_{max} 90%(LV)	V_{min} 90% (LV)
Scenario	**[p.u.]**	**[p.u.]**	**[p.u.]**	**[p.u.]**
1	1.0505	1.0039	1.0830	0.9638
2	1.0506	1.0037	1.0829	0.9634
4	1.0506	1.0032	1.0828	0.9630
6	1.0644	0.9655	1.0583	0.9499
11	1.0442	0.9979	1.0857	0.9516
12	1.0338	**0.9648**	1.0558	**0.9170**
3	1.0643	0.9756	1.0589	0.9587
7	1.0644	0.9665	1.0586	0.9507
9	1.0644	0.9679	1.0601	0.9560
10	1.0387	0.9922	1.0784	0.9453
13	1.0434	0.9972	1.0853	0.9508
14	1.0344	**0.9639**	1.0552	0.9211

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Table 6.3: Summer season voltage limits

Summer Scenario	V_{max} 90% (MV) [p.u.]	V_{min} 90% (MV) [p.u.]	V_{max} 90% (LV) [p.u.]	V_{min} 90% (LV) [p.u.]
1	1.0415	1.0047	1.0818	0.9567
2	1.0415	1.0047	1.0818	0.9567
4	1.0415	1.0047	1.0818	0.9569
6	1.0497	0.9568	**1.0576**	0.9454
11	1.0473	1.0046	**1.0857**	0.9567
12	1.0332	0.9702	**1.0470**	0.9338
3	1.0419	0.9672	1.0574	0.9528
7	1.0494	0.9581	1.0613	0.9471
9	1.0396	0.9582	1.0625	0.9489
10	1.0390	0.9829	1.0685	0.9337
13	1.0431	1.0109	1.0847	0.9619
14	1.0305	0.9677	1.0441	0.9297

Table 6.4: Fall season voltage limits

Fall Scenario	V_{max} 90% (MV) [p.u.]	V_{min} 90% (MV) [p.u.]	V_{max} 90% (LV) [p.u.]	V_{min} 90% (LV) [p.u.]
1	1.0650	1.0029	1.0610	0.9479
2	1.0650	1.0018	1.0605	0.9478
4	1.0650	1.0017	1.0604	0.9478
6	1.0697	1.0059	1.0638	0.9564
7	1.0695	1.0057	1.0634	0.9566
9	1.0686	1.0060	1.0630	0.9562
11	1.0365	0.9908	1.0638	0.9273
12	1.0342	0.9908	1.0545	0.9273

Voltage levels drop to the lowest point in winter and spring interval, when the consumption is the highest and RES production is at the lowest point at yearly production curve. It dropped to 0.94 p.u. in LV network and to 0.973 p.u. in MV network. In both networks, increasing capacity of storage from provides slightly improvement at lowest voltage value. Highest voltage points in MV network reached 1.07 level and OLTC mechanism lowered the tap, so highest recorded value is 1.0697 p.u. and in LV network, voltage rose up to 1.0857 p.u. in the summer interval. OLTC impact is seen in summer, LV section, in scenarios 6, 11 and 12, where steps from defaults value setting to disabling and narrowing the bandwidth can be observed in that order.

6.2 Losses in the network

Losses in the network were recorded as average value of sum of all losses in the network, average transformer and power line losses, power line losses in urban and rural LV network. Only summer and winter interval are included in comparison, as those two seasons present most extreme situations and

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highest and lowest rates occur in that interval. To get a realistic feeling what these loss rates represent, in Chapter 7.4 energy delivered from the grid is presented. For example, at HV level, power flow within given period was in range of 160 - 200 MWh and LV networks around 1 MWh on same interval.

Table 6.5: Winter season electric losses

Winter	Entire grid	Transformer losses	Power line losses	LV urban losses	LV rural losses
Scenario	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**
1	6088.68	3510.99	2577.69	62.79	40.16
2	6052.96	3500.83	2552.12	62.42	40.02
4	6029.92	3494.32	2535.59	61.98	39.96
6	6382.78	3566.80	2815.98	66.61	41.32
11	6314.43	3498.54	2815.89	66.36	40.86
12	6303.15	3487.32	2815.83	66.27	40.75
3	6597.27	3697.40	2899.86	67.79	42.85
7	6263.37	3531.05	2732.31	64.51	40.99
9	6104.43	3476.05	2628.38	62.33	40.56
10	6241.20	3477.20	2764.00	65.48	41.64
13	6236.26	3463.32	2772.94	65.55	41.57
14	6220.70	3448.39	2772.31	65.49	41.45

Table 6.6: Summer season electric losses

Summer	Entire grid	Transformer losses	Power line losses	LV urban losses	LV rural losses
Scenario	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**	**[kWh/day]**
1	3842.94	2834.00	1008.95	28.64	30.99
2	3809.29	2829.11	980.19	28.47	30.80
4	3800.48	2827.96	972.52	28.37	30.76
6	5826.41	3254.07	2572.34	56.17	36.93
11	5682.74	3308.16	2374.58	53.32	36.82
12	5805.08	3228.29	2576.79	56.15	36.68
3	5668.09	3183.78	2484.30	54.30	37.02
7	5611.71	3197.17	2414.54	52.74	36.31
9	5346.61	3115.95	2230.66	49.46	35.53
10	4970.69	2844.72	2125.97	48.91	35.29
13	4972.09	2897.66	2074.43	48.33	35.52
14	5034.05	2785.47	2248.58	50.61	35.26

Losses are higher in winter interval due to lack of local production from RES and more energy travels from HV level down to end user. Power delivery systems are loaded to higher level and as a result, loss rates are high. The RES produce at highest rates in summer and more local energy is provided to users,

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thus lowering the network losses. With storage implementation and control, we lowered the loss rates further on. With increased storage installed power, losses are reduced, although the storage impact is slightly overshadowed with RES influence on the power flows.

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7 KPI calculations

Key performance indicators further enable evaluation and comparison on network condition and status between several cases, where different technologies impact is tested. In this report we include present calculations of peak to average ratio, relative peak power change, change of grid losses, energy supplied from main grid and self-sufficiency and self-consumption rates. All the calculations were performed with the Value analysis tool, developed in MATLAB.

7.1 Relative Peak Power change

Relative peak power change is defined as a change of peak power flows in the network, before and after implementation, compared to peak power levels before the storage technology implementation.

$$\Delta RPP(\%) = \frac{P_{CS} - P_{BC}}{P_{BC}} \cdot 100\%$$

$\Delta RPP(\%)$ Relative peak power change,

P_{CS} Grid peak power [kW] in Case Study and

P_{BC} Grid peak power [kW] in Base Case.

Peak power levels for entire grid, LV urban and rural grids were defined as average of the maximum transformers loading of each iteration. For HV/MV transformer, minimal loading level is also recorded. Loading levels are included in the appendix section. In following tables, relative peak power change is presented.

Table 7.1: Relative peak power change in winter

Winter	**Transformer location**		
Scenario	ΔRPP **(HV/MV)**	ΔRPP **(MV/LV Urban)**	ΔRPP **(MV/LV Rural)**
1	0.0%	0.0%	0.0%
2	-1.3%	-2.4%	-1.5%
4	-2.2%	-4.6%	-2.2%
6	13.9%	18.9%	11.3%
11	5.5%	13.8%	6.5%
12	8.2%	15.3%	8.1%
3	9.7%	13.7%	3.2%
7	11.7%	14.3%	8.6%
9	7.7%	7.4%	4.2%
10	-27.4%	-31.4%	-25.5%
13	-28.2%	-31.8%	-30.0%
14	-28.1%	-31.8%	-29.7%

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Table 7.2: Relative peak power change in spring

Spring	Transformer location		
Scenario	ΔRPP **(HV/MV)**	ΔRPP **(MV/LV Urban)**	ΔRPP **(MV/LV Rural)**
1	0.0%	0.0%	0.0%
2	-1.4%	-2.4%	-1.7%
4	-2.4%	-4.4%	-2.4%
6	21.1%	26.4%	17.0%
11	15.7%	22.8%	13.7%
12	15.7%	22.8%	13.7%
3	17.2%	22.7%	23.3%
7	18.1%	21.6%	13.0%
9	13.2%	13.2%	7.8%
10	-30.7%	-33.9%	-30.2%
13	12.6%	21.0%	20.7%
14	12.6%	21.0%	20.7%

Table 7.3: Relative peak power change in summer

Summer	Transformer location		
Scenario	ΔRPP **(HV/MV)**	ΔRPP **(MV/LV Urban)**	ΔRPP **(MV/LV Rural)**
1	0.0%	0.0%	0.0%
2	-1.2%	-2.1%	-1.7%
4	-2.0%	-4.0%	-2.4%
6	24.0%	31.6%	20.9%
11	23.2%	30.8%	20.1%
12	23.2%	30.8%	20.1%
3	11.5%	9.2%	28.0%
7	21.0%	26.9%	16.1%
9	16.2%	18.4%	11.1%
10	-34.1%	-41.7%	-25.0%
13	-33.0%	-41.3%	-10.7%
14	-33.9%	-41.0%	-17.9%

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Table 7.4: Relative peak power change in fall

Summer	Transformer location		
Scenario	ΔRPP **(HV/MV)**	ΔRPP **(MV/LV Urban)**	ΔRPP **(MV/LV Rural)**
1	0.0%	0.0%	0.0%
2	-1.5%	-2.6%	-1.8%
4	-2.5%	-4.9%	-2.5%
6	19.8%	24.5%	15.6%
11	12.0%	19.7%	10.9%
12	12.0%	19.7%	10.9%
7	17.0%	19.8%	11.6%
9	11.8%	11.7%	6.7%

Overall, storage implementation throughout the cases indicates influence on peak loading levels, although relative change is higher than 10% in LV urban section. As expected, in scenario 6, PV increase rises RPP levels up to 24.5%, while storage implementation in scenarios 7 and on lowers the change to the range of 6 to 12 % of relative peak power increase. Scenarios in purple in blue, with system unit implementation in the grid, achieve highest impact, due to the size of the units. In minimum loading of HV/MV transformer we observed larger impact on reverse power flows or negative loadings of the transformer. To observe comparison on the absolute values of the loading parameters, see Table 12.1 in appendix section.

7.2 Change of peak-to-average demand ratio

Change of peak to average demand ratio is defined as ratio between peak value of demand profile and average value of consumption. Ratios before and after implementation are compared to provide relative change of peak to average ratio.

$$\Delta PAR_{Demand}(\%) = \frac{\left[\left({|P_p|}/{\overline{P}} \right)_{BC} - \left({|P_p|}/{\overline{P}} \right)_{CS} \right]}{\left({|P_p|}/{\overline{P}} \right)_{BC}} \cdot 100\%$$

$\Delta PAR_{Demand}(\%)$ Change of Peak-to-Average Ratio of power demand increment referred to the Case Study and Base Case,

$\left({|P_p|}/{|\overline{P}|} \right)_{BC}$ Base case average demand and peak power (P) ratio, where $|P_p|$ represents peak power and $|\overline{P}|$ represents average demand in selected time interval

$\left({|P_p|}/{|\overline{P}|} \right)_{CS}$ Case study average demand and peak power (P) ratio, where $|P_p|$ represents peak power and $|\overline{P}|$ represents average demand in selected time interval.

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For each case of network development, we compared maximum and average loading of the transformers and afterwards, relative comparison to initial network status was calculated by provided equation.

Table 7.5: Peak to average ratio for individual networks in winter

Winter	Peak to average			Relative change		
Scenario	**HV**	**LV urban**	**LV rural**	**HV**	**LV urban**	**LV rural**
1	2.08	2.06	2.07	0.0%	0.0%	0.0%
2	2.05	2.02	2.04	-1.2%	-2.3%	-1.4%
4	2.03	1.97	2.02	-2.0%	-4.4%	-2.1%
6	2.49	2.64	2.42	19.9%	28.0%	17.0%
11	2.38	2.58	2.36	14.6%	24.9%	14.0%
12	2.44	2.61	2.39	17.4%	26.5%	15.7%
3	2.20	2.33	1.94	5.7%	13.0%	-6.0%
7	2.45	2.55	2.36	17.8%	23.3%	14.2%
9	2.37	2.40	2.27	14.0%	16.2%	9.9%
10	1.49	1.40	1.43	-28.4%	-32.1%	-31.0%
13	1.47	1.39	1.34	-29.0%	-32.5%	-35.1%
14	1.48	1.39	1.35	-28.7%	-32.4%	-34.7%

Table 7.6: Peak to average ratio for individual networks in spring

Spring	Peak to average			Relative change		
Scenario	**HV**	**LV urban**	**LV rural**	**HV**	**LV urban**	**LV rural**
1	2.89	2.85	2.99	0.0%	0.0%	0.0%
2	2.79	2.70	2.88	-3.2%	-5.3%	-3.7%
4	2.74	2.56	2.83	-5.2%	-10.1%	-5.3%
6	11.86	14.49	15.16	311.0%	408.9%	407.2%
11	12.07	13.59	13.94	318.2%	377.3%	366.5%
12	12.58	15.55	16.46	335.9%	446.2%	450.7%
3	8.06	9.95	7.78	179.2%	249.4%	160.3%
7	10.67	11.26	13.07	269.6%	295.3%	337.2%
9	8.88	8.00	10.20	207.7%	181.0%	241.2%
10	4.54	4.76	4.01	57.2%	67.1%	34.0%
13	7.98	9.33	7.47	176.5%	227.6%	150.1%
14	8.38	10.33	8.22	190.5%	262.7%	174.9%

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Table 7.7: Peak to average ratio for individual networks in summer

Summer	Peak to average			Relative change		
Scenario	HV	LV urban	LV rural	HV	LV urban	LV rural
1	3.25	3.29	3.53	0.0%	0.0%	0.0%
2	3.13	3.07	3.36	-4.0%	-6.7%	-4.9%
4	3.05	2.87	3.28	-6.4%	-12.7%	-7.0%
6	-171.34	-38.73	-24.27	-5364.0%	-1278.6%	-788.0%
11	-143.59	-56.74	-32.65	-4511.4%	-1826.7%	-1025.3%
12	-81.90	-36.23	-23.25	-2616.3%	-1202.5%	-758.9%
3	26.87	188.59	26.53	725.5%	5638.8%	651.8%
7	-215.54	-29.45	-32.93	-6722.1%	-996.2%	-1033.4%
9	45.11	29.80	-74.85	1285.8%	806.9%	-2221.5%
10	8.62	10.50	8.56	164.8%	219.6%	142.6%
13	8.25	9.76	9.27	153.5%	197.1%	162.8%
14	10.08	14.54	11.45	209.6%	342.3%	224.7%

Table 7.8: Peak to average ratio for individual networks in fall

Fall	Peak to average			Relative change		
Scenario	HV	LV urban	LV rural	HV	LV urban	LV rural
1	2.08	2.09	2.10	0.0%	0.0%	0.0%
2	2.04	2.03	2.06	-1.6%	-3.1%	-2.0%
4	2.02	1.97	2.04	-2.8%	-5.7%	-2.9%
6	2.67	2.88	2.61	28.6%	37.7%	24.1%
11	2.57	2.81	2.54	23.5%	34.5%	20.9%
12	2.60	2.84	2.56	24.9%	35.7%	21.9%
7	2.60	2.74	2.51	25.3%	31.1%	19.5%
9	2.47	2.52	2.39	19.1%	20.4%	13.5%

PAR is highly sensitive to RES production and was anticipated to increase in summer and spring intervals, where production is most effective. In summer and spring interval, 2 factors increase PAR value. High rates of production cause reverse power flows, and average power flow is decreased, or it is even reversed. Due to that fact, PAR value rises because the average value is very small and sometimes even negative. PAR values are always to be considered with relative peak change in my mind, to have the understanding what happened in the network.

7.3 Change of grid losses

Change of grid losses is defined as deviation of losses in the network before implementation and after implementation of storage. This KPI is suited to be on transformer level, or PCC, if applicable. Due to reduced power flow through the transformer, or PCC, there will be lower electricity losses on the complete power infeed line (HV/MV transformer and 20 kV line and MV/LV transformer).

For example of transformer: losses are negligible on the infeed line and will be measured only for the MV/LV transformer.

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$$\Delta P_{loss}(\%) = \frac{P_{loss,BC} - P_{loss,CS}}{P_{loss,BC}} \cdot 100\%$$

$\Delta P_{loss}(\%)$ Relative change of grid losses in %

$P_{loss,BC}$ Losses through transformer prior to implementation of storage and control

$P_{loss,CS}$ Losses in study case

In following Table 7.9 and

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Table 7.10, comparison of grid loss change is presented. For the base case, Scenario 1, full values are given, and for later scenarios, their deviation from the initial value is calculated.

Table 7.9: Grid losses comparison in winter

Winter	Entire grid	Transformer losses	Power line losses	LV urban losses	LV rural losses
Scenario	**[kWh]**	**[kWh]**	**[kWh]**	**[kWh]**	**[kWh]**
1	6088.68	3510.99	2577.69	62.79	40.16
2	-0.59%	-0.29%	-0.99%	-0.59%	-0.34%
4	-0.97%	-0.47%	-1.63%	-1.30%	-0.50%
6	4.83%	1.59%	9.24%	6.08%	2.88%
11	3.71%	-0.35%	9.24%	5.68%	1.76%
12	3.52%	-0.67%	9.24%	5.54%	1.49%
3	8.35%	5.31%	12.50%	7.96%	6.71%
7	2.87%	0.57%	6.00%	2.73%	2.08%
9	0.26%	-1.00%	1.97%	-0.74%	1.00%
10	2.51%	-0.96%	7.23%	4.28%	3.68%
13	2.42%	-1.36%	7.57%	4.40%	3.52%
14	2.17%	-1.78%	7.55%	4.30%	3.21%

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Table 7.10: Grid losses comparison in summer

Summer	Entire grid	Transformer losses	Power line losses	LV urban losses	LV rural losses
Scenario	**[kWh]**	**[kWh]**	**[kWh]**	**[kWh]**	**[kWh]**
1	3842.94	2834.00	1008.95	28.64	30.99
2	-0.88%	-0.17%	-2.85%	-0.60%	-0.61%
4	-1.10%	-0.21%	-3.61%	-0.95%	-0.74%
6	51.61%	14.82%	154.95%	96.12%	19.19%
11	47.87%	16.73%	135.35%	86.18%	18.82%
12	51.06%	13.91%	155.39%	96.05%	18.38%
3	47.49%	12.34%	146.23%	89.60%	19.46%
7	46.03%	12.81%	139.31%	84.16%	17.20%
9	39.13%	9.95%	121.09%	72.68%	14.68%
10	29.35%	0.38%	110.71%	70.78%	13.89%
13	29.38%	2.25%	105.60%	68.75%	14.63%
14	30.99%	-1.71%	122.86%	76.71%	13.79%

On Figure 7.1: Loss rates comparison between scenarios in summer, we see impact of different scenario parameters on the losses. Scenarios 1 to 3 show low PV penetration and household storage installation reduces losses by a few percent of the original values of Scenario 1. Scenarios 1 and 6 show the direct impact of increased PV production, and in Scenarios 6, 11 and 12 to 6 we see how OLTC operation has impact on the loss rates. More effective is storage implementations in the network with high RES. Implementation of the 15 % of household solutions to 80 % on the grid can be compared in scenarios 3, 7, 9 and 10, while last 3 again show the impact of OLTC in fully upgraded network.

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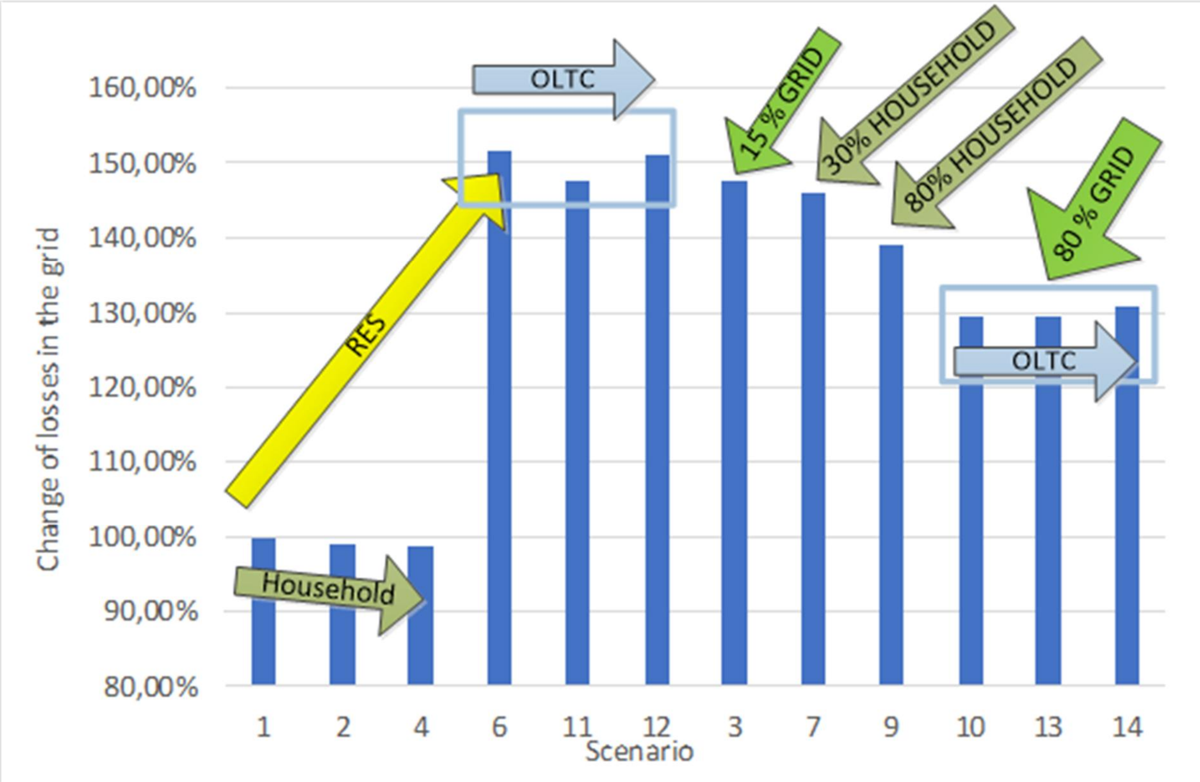

Figure 7.1: Loss rates comparison between scenarios in summer

7.4 Grid Energy Consumption

Grid energy consumption change KPI is comparison of grid-injected energy before and after storage implementation. With this KPI, we monitor the energy exchanged between the monitored region/section and the rest of the distribution grid.

$$\Delta E_{Grid}(\%) = \frac{\Delta E_{Grid,Use\ Case} - \Delta E_{Grid,Base\ Case}}{\Delta E_{Grid,Base\ Case}} * 100\%$$

Where

$\Delta E_{Grid}(\%)$ Relative change of grid-supplied energy,

$\Delta E_{Grid,Use\ Case}$ Energy supplied from the main grid during implementation of storage

$\Delta E_{Grid,Base\ Case}$ Energy supplied from the grid before implementation.

Amount of grid supplied energy is determined as average value of positive sum of respective transformer active power flows.

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Table 7.11: Grid Supplied energy in winter

Winter	Grid supplied energy [MWh/day]		
Scenario	HV	LV urban	LV rural
1	222.382	2.867	1.169
2	222.214	2.865	1.168
4	222.093	2.864	1.166
6	211.958	2.745	1.089
11	205.404	2.696	1.069
12	205.778	2.697	1.069
3	230.835	3.146	1.177
7	211.154	2.732	1.083
9	210.268	2.717	1.080
10	225.653	3.096	1.181
13	224.934	3.091	1.181
14	224.116	3.082	1.180

Table 7.12: Grid Supplied energy in spring

Spring	Grid supplied energy [MWh/day]		
Scenario	HV	LV urban	LV rural
1	123.004	1.591	0.661
2	124.254	1.605	0.677
4	125.334	1.614	0.696
6	116.687	1.531	0.601
11	114.669	1.519	0.594
12	113.282	1.506	0.590
3	123.815	1.726	0.630
7	114.653	1.505	0.583
9	110.962	1.456	0.569
10	98.659	1.410	0.527
13	118.513	1.670	0.612
14	117.069	1.655	0.608

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Table 7.13: Grid Supplied energy in summer

Summer	Grid supplied energy [MWh/day]		
Scenario	**HV**	**LV urban**	**LV rural**
1	94.334	1.185	0.492
2	95.119	1.193	0.504
4	95.970	1.200	0.522
6	93.006	1.198	0.468
11	93.938	1.208	0.470
12	92.377	1.194	0.466
3	97.893	1.374	0.481
7	91.423	1.177	0.455
9	88.657	1.140	0.444
10	75.979	1.068	0.397
13	76.939	1.087	0.400
14	74.127	1.052	0.386

Table 7.14: Grid Supplied energy in fall

Fall	Grid supplied energy [MWh/day]		
Scenario	**HV**	**LV urban**	**LV rural**
1	182.239	2.345	0.960
2	182.423	2.350	0.965
4	182.697	2.353	0.969
6	171.787	2.232	0.882
11	167.394	2.199	0.868
12	165.697	2.185	0.862
7	171.080	2.216	0.878
9	171.157	2.209	0.891

Grid supplied energy is mainly affected by amount of RES in the network. Their production rates vary a lot because of seasonality span which is quite wide. For example, in base scenario 1, LV rural network consumes 1.169 MWh/day in winter day and 0.661 MWh/day during spring interval. Same network decreases daily grid injected energy with increase of installed RES from 40% to 110% of installed power of transformer capacity. Storage implementation at that level further decreases injection needed from the main grid.

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7.5 Self-consumption level (SCL) and Self-sufficiency level (SSL)

Associated with the STORY aim (Business Requirement), Increase of RES share in total consumption, this KPI measures the self-consumption of locally produced energy by the loads in the network and self-sufficiency level of local assets.

Self-consumption level SCL is defined as ratio between self-consumed (or local consumption) locally produced energy and total amount of locally produced energy, of which the surplus is injected to the rest of the main grid. Self-sufficiency level SSL is defined as a ratio between consumption, covered by local production and total production over certain monitored interval.

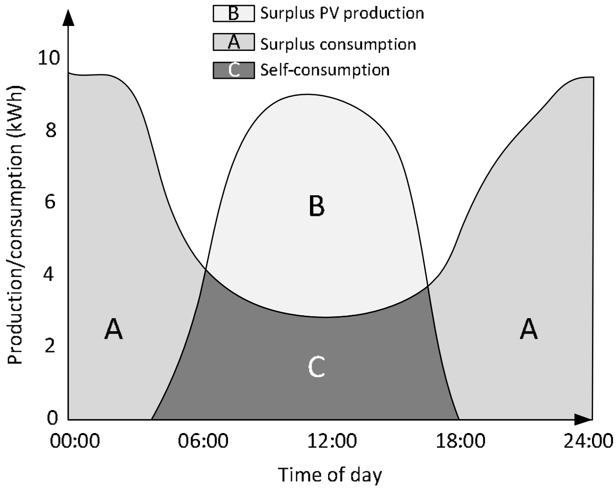

Figure 7.2: Visualization of SSL and SCL (SCL=C/(C+B); SSL=C/(C+A))

$$\mathrm{SCL}(\%) = \frac{E_{Local,Consumed}(T)}{E_{Local,Produced}(T)} \cdot 100\%$$

SCL(%) Self-consumption level

$E_{Local,Consumed}(T)$ Locally generated energy, which is used for consumption within monitored sector in defined time interval T in [kWh].

$E_{Local,Produced}(T)$ Total amount of locally produced energy [kWh] in defined interval T.

$$\mathrm{SSL}(\%) = \frac{C_{Locally\ covered}(T)}{C_{Total}(T)} \cdot 100\%$$

SSL(%) Self-sufficiency level

$\mathrm{C}_{\mathrm{Locally\ covered}}(\mathrm{T})$ Consumption in the network [kWh] in defined interval (24 hours), which is covered by local sources and

$\mathrm{C}_{\mathrm{Total}}(\mathrm{T})$ Total consumption [kWh] in interval T (24 hours) in the network.

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Self-sufficiency and self-consumption rates are presented only for LV networks, since MV equivalent loads are scaled diagrams of these 2 networks and have similar ratios.

Table 7.15: Winter SCL and SSL levels

Scenario	SSL Urban [%]	SSL rural [%]	SCL Urban [%]	SCL rural [%]
1	8.1	9.1	100.0	100.0
2	8.2	9.1	100.0	100.0
4	8.2	9.1	100.0	100.0
6	19.9	20.1	97.7	96.3
11	19.9	20.1	97.7	96.3
12	19.9	20.1	97.7	96.3
3	19.9	20.1	97.7	96.3
7	20.3	20.5	99.5	98.4
9	20.4	20.9	100.0	99.9
10	19.9	20.1	97.7	96.3
13	19.9	20.1	97.7	96.3
14	19.9	20.1	97.7	96.3

Table 7.16: Spring SCL and SSL levels

Scenario	SSL Urban [%]	SSL rural [%]	SCL Urban [%]	SCL rural [%]
1	34.4	36.0	95.2	90.1
2	34.5	36.4	96.4	92.3
4	34.4	36.5	97.1	93.1
6	44.3	43.9	49.8	48.5
11	44.3	43.9	49.8	48.5
12	44.3	43.9	49.8	48.5
3	44.3	43.9	49.8	48.5
7	46.2	45.8	52.9	51.4
9	49.0	49.3	57.8	57.2
10	44.3	43.9	49.8	48.5
13	44.3	43.9	49.8	48.5
14	44.3	43.9	49.8	48.5

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Table 7.17: Summer SCL and SSL levels

Scenario	SSL Urban [%]	SSL rural [%]	SCL Urban [%]	SCL rural [%]
1	39.0	40.5	85.2	79.9
2	39.4	41.3	87.3	83.0
4	39.5	41.5	88.8	84.1
6	46.3	46.0	41.8	41.0
11	46.3	46.0	41.8	41.0
12	46.3	46.0	41.8	41.0
3	46.3	46.0	41.8	41.0
7	48.4	48.0	44.8	43.8
9	51.5	51.9	49.6	49.4
10	46.3	46.0	41.8	41.0
13	46.3	46.0	41.8	41.0
14	46.3	46.0	41.8	41.0

Table 7.18: Fall SCL and SSL levels

Scenario	SSL Urban [%]	SSL rural [%]	SCL Urban [%]	SCL rural [%]
1	10.3	11.6	100.0	100.0
2	10.3	11.5	100.0	100.0
4	10.3	11.5	100.0	100.0
6	23.8	23.8	93.1	91.4
11	23.8	23.8	93.1	91.4
12	23.8	23.8	93.1	91.4
7	24.8	24.8	97.3	95.3
9	25.2	25.6	99.9	99.2

The self-consumption level indicates how much of the local production can be consumed on site. In summer and spring intervals, up to 40% of the energy is not locally consumed and it is injected in the main grid. In lower scenarios, small improvement was detected, self-sufficiency levels are further improved in higher scenarios, where storage prevents reverse power flows in the system. It can enhance SSL for up to 10% in spring and summer interval, when most of the energy would flow into the main grid otherwise.

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8 Transmission system simulation

Modern power grids are complex systems, balancing energy generation and consumption in real time. Transmission system operators must manage a varied mix of power generation technologies to meet a constantly shifting demand, and with the rise of small-scale renewable sources and energy storage the complexity of power grid operation will only increase. Currently, the grids experience a continuous imbalance between the power they produce and its consumption because of the millions of devices that are turned on and off in an unrelated way. The imbalance can cause frequencies to deviate, which can affect equipment and potentially hurt the stability of the grid. Energy storages can assist in this situation and help lower the demand or increase it, depending on the needs of the system.

As storage costs decrease, more customers will begin to see economic benefits, and existing storage users will see the optimum size of energy storage increase. Lastly, energy storage will impact electricity grids, because it provides more function than just power on demand. Batteries can provide the grid with ancillary services like frequency regulation because of their rapid response time and their ability to charge and discharge efficiently, and should be compensated to do so.

8.1 Ancillary services and storage potential

Ancillary services are all services required by the transmission or distribution system operator to enable them to maintain the integrity and stability of the transmission or distribution system as well as the power quality. Having in mind the three main characteristics of the grid, ancillary services can be classified in three main groups: frequency control, voltage control and system restoration services [10].

8.1.1 Frequency control services

In a synchronized transmission system, variations in active power affect the frequency change of the system. Unexpected changes cause system instability, which must be corrected in real time.

For example, if there is a lack of load in the system, i.e. consumers consume less energy than planned, the frequency value will increase. If there is a lack of production, generators generate less quantity of active power than announced in the daily plans, the frequency will decrease.

To prevent such frequency variations, there are three levels of frequency control, namely: **Frequency Containment Reserve (FCR)**, **Frequency Restoration Reserve (FRR)** and **Replacement Reserve (RR)**.

Frequency Containment Reserve (FCR): Frequency containment reserve determines the ability of the system to recover from unexpected load/production changes. This reserve is activated immediately after the appearance of an unexpected change in the system and acts on the generator by adjusting the power output because of the system frequency deviation. By applying FCR, the frequency is not allowed to decrease or increase beyond the permitted limits. In general, FCR should be fully delivered by synchronous generators connected to the transmission grid within 30 seconds.

Frequency Restoration Reserve (FRR): The activation of the frequency restoration reserve will be simultaneously and continuously as a response to small power abnormalities (which inevitably occur during normal operation of the system), but also in response to major disruptions (generator failure or disconnection of part of the network). The purpose of the FRR is to restore the reserve available for FCR

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and to bring the system frequency to setpoint. In general, FRR should be fully delivered to the system within 15 minutes and can be triggered automatically or manually.

Replacement reserve (RR) is the reserve used to restore the levels of the FCR and FRR. RR reserves are manually activated by the TSO. Main characteristic of this reserve is that is market based. A typical time frame for its application is 5-15 minutes to more than 1 hour, which is in line with the possibilities of inert production units and consumers. This reserve replaces FRR and returns the frequency to the nominal value.

The balancing energy control required to compensate the balance between production and consumption is carried out through a variety of control mechanisms determined based on their role and based on their characteristic response time. The frequency reserves can be activated automatically: FCR (0 – 30 sec) and automatic FRR (30 sec – 15 min) and manually: manual FRR and RR performed by the system operator in accordance with the automatic control.

There are significant differences between manual and automatic frequency control. Namely, in the case of manual control, the actual supply of balancing energy requires the TSO to choose the right offer from the balancing market in real time, while in automatic control the true delivery of the balancing energy is automatic. The automatic reserve will be delivered from spinning reserve and the manual reserve can be either from spinning or from standing reserves. Spinning reserve means an increase or decrease of generation or reduction in consumption that can be provided at short notice carried out by partially loaded generating units and interruptible consumers (loads). Standing reserve involves increase in generation or a reduction in consumption by those generating units that are not synchronously on-line, or by interruptible consumers (loads).

The goal of tertiary control is to compensate for the errors made in load forecasts. It also restores the appropriate backup for secondary control and returns the frequency to the default value.

Manual tertiary control can be fast tertiary control, which is used for short-term imbalances and slow tertiary control used for long-term imbalances.

Fast tertiary control

Fast tertiary control is activated manually, after the operation of the automatic control. It is characterized by a fast reaction time, generally shorter than 15 minutes for complete delivery.

Fast tertiary control is provided by production units that can be synchronised fast (e.g. hydropower plants) and generators that are already synchronized to a network.

Slow tertiary control

Slow tertiary control is the last backup, which can be activated if necessary. It takes a long time for its activation, generally about 1 hour or more.

One of its roles is the renewal of the fast restoration reserve. The units used for slow tertiary control are inert and require a longer activation time than the fast tertiary control (for example, thermal power plants and generators that are not synchronized in a network).

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8.1.2 Voltage control services

System voltage is also an important technical challenge for the grid to maintain its stability. Keeping the voltage within some range values in every power system node is crucial to maintain power quality and to avoid damage to some components of the network or at the consumers. Voltage is directly influenced by the reactive power which can be easily generated wherever needed.

Voltage can be controlled by injecting or absorbing reactive power at a given node in the grid by synchronous sources, tap changing transformers in the substations, transmission lines’ switching, virtual power plants including demand facilities, static VAR compensators, HVDC and other FACTS devices. If necessary, even load shedding could be an option.

Storage units, installed throughout the network, impact the voltage levels with active and reactive injection of power into the grid. Inverter connected devices, such as RES and storage units, connected in the distribution network, can manipulate voltage with reactive power profile as well. Depending on the characteristic of the inverter, they can be able of full inductive to fully capacitive reactive power operation.

Injection of the reactive power into the grid, for the needs of reactive power compensation, could cause potential voltage problems. Ideally reactive power compensation units are installed near central voltage regulator, like OLTC at HV/MV bus. If they are installed at far end of the feeder, storage is located close or very close to electricity end-users and may be especially attractive because reactive power cannot be transmitted efficiently over long distances without incurring large active and reactive power losses. Notably, many major power outages are at least partially attributable to problems related to transmitting reactive power to load centres. So, distributed storage, located within the load centres where most reactance occurs, provides particularly helpful voltage support. Several control strategies and concepts for local utilization are being develop to more actively involve RES and Storage and other flexible device in local provision of network quality[11].

In HV networks, reactive power influences voltage levels, and active power influences frequency. In MV and LV networks the line characteristics are different. In MV, the ratio of resistance of the line compared to reactance part is 1:1, and in LV networks this ratio is even higher. In LV networks, voltage control is more efficient with active power control than reactive power control, as active power control does not lead to reactive power flow over the grid, minimizing the corresponding active power losses. Reactive power injection by the invertor-connected generation also leads to reduced active power injection. Therefore, in our analysis we have limited our scope to active power control, since reactive power control has been the topic of many other investigations. While curtailing active power injection from distributed RES generators may look less desirable now in some countries, this will change with the large-scale penetration of DRES, when DRES generators will assume the scheduling responsibility instead of preferential dispatch and will need to be able to manage their active power injection.

In our calculations here we focused on services, which can be offered towards the TSO and other sectors of the grid on the existing global market. Local operation would allow reactive power compensation, and voltage control, offered on the local energy market. Global market operation and provision of services towards the grid, put active power control and of active reserve in focus of the analysis. Active power can be transmitted to higher voltage levels without causing problems in the network.

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8.1.3 System restoration services

Black start is used in the power system restoration phase, defined as "a set of actions implemented after a disturbance with large-scale consequences to bring the system from emergency or blackout system state back to normal state. Actions of restoration are launched once the system is stabilised. Restoration of the system consists of a very complex sequence of coordinated actions whose framework is studied and, as far as possible, prepared in advance". (ENTSO-E OH, Policy 5, Appendix) Black start resources must be able to start up without power from the grid and must be able to operate in standby mode, while disconnected from the grid, until they are called upon. In most cases, the black start service is provided by specially-equipped generators. Black start capability of a generator is defined as: The capability of a generating unit to start up without an external power supply, which makes storages ideal for providing this service. Most storage types are well-suited to serve as black start resources because, unlike generators, they do not need special equipment, and storage does not have to operate while awaiting dispatch.

One reason for the optimistic outlook on battery storage's role with providing ancillary services is the progress lithium-ion batteries have made in recent years. In 2015, lithium-ion batteries were responsible for 95% of energy storage at both the residential and grid levels. The reason for the increase in popularity is due to the price dropping, safety improving and better performance characteristics. All these qualities are leading to lithium-ion batteries being suitable for stationary energy storage across the grid; ranging from large-scale installations and transmission infrastructure to individual and residential use, even without being appropriately compensated for ancillary services.

The most important aspect is the large-scale deployment of energy storage that could overturn the status quo for many electricity markets. In developed countries, central or bulk generation traditionally has been used to satisfy instantaneous demand, with ancillary services helping to smooth out discrepancies between generation and load; energy storage is well suited to provide such ancillary services. Eventually, as costs fall, it could move beyond that role, providing more and more power to the grid, displacing synchronous generation plants; however, that time has not yet come although approaching quickly. It is important to recognize that energy storage has the potential to overturn the industry structures, both physical and economic, that have defined power markets for the last century or more.

Energy storage is especially well-suited to provide all necessary ancillary services needed for an efficient, stable and reliable electricity grid. Using storage for ancillary services reduces the need and cost for generation capacity and operation, reduces fuel use, reduces air emissions and frees-up existing generation to do generation is best at – generating electric power and energy. All this is to say, if utilities provide appropriate price signals to the market, customers will respond by installing battery storage where and how they can be compensated. If the storage is distributed, it can provide other benefits, and/or it can provide superior ancillary services.

8.1.4 Storage prices

The price of the battery storage units has always played a major role, since depending on its purchase price, will be decided whether the investment in the battery storage is worth it. According to a study published by McKinsey & Company, it is foreseen that battery prices will go down [12]. Figure 8.1 shows average prices per kWh of storage batteries from 2010 to 2016 .

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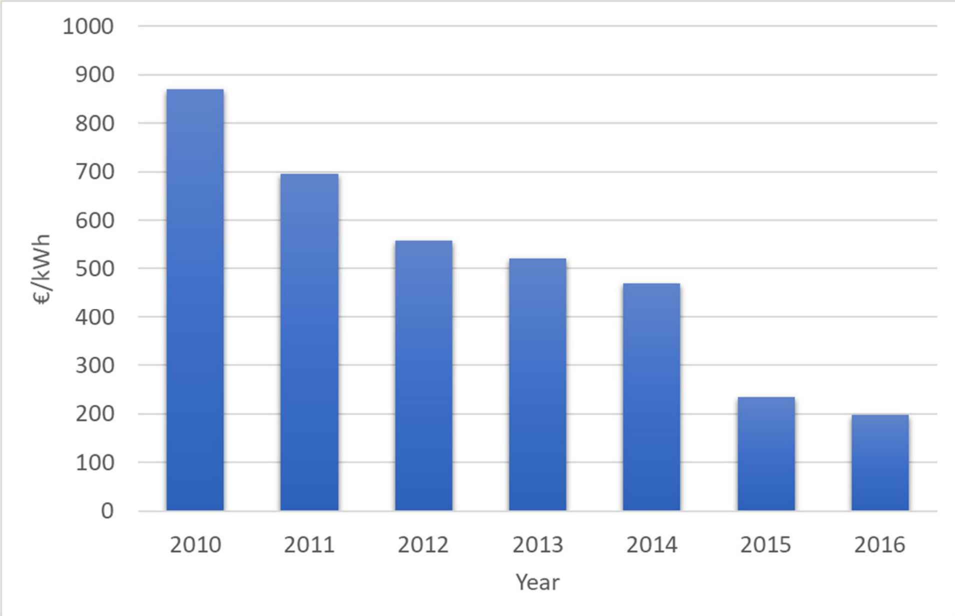

Figure 8.1: Average battery storage prices

From the figure, it can be noticed that the prices of battery storage units in the last decade have fallen sharply. According to research data, by 2025, prices should fall below 100 € / kWh [13]. Tesla have of one of the lowest current prices per kWh of the battery storage, around 150 € / kWh [12].

However, the above prices are only batteries in the battery storage, but not the entire product (inverter, housing, meters, electronics...). So, the price of the entire battery storage is much higher

8.1.5 Boundary conditions

Stability of the electricity grid cannot be reinforced with one central storage unit in similar fashion as OLTC transformer regarding voltage conditions. With central BESS unit, the potential of installed capacity isn't fully utilized and without proper installation location, additional power flows and network current congestions can occur in the network. This could lead to overloading of the network elements when delivering the powers from locations with stored energy to locations with lack of energy. This effect can be mitigated to some extend by utilization of smaller, dispersed units, installed throughout the system. This also bring the higher availability rate in case of servicing the units or failures of the individual units as opposed to blackout of one, central unit. Due to the novelty of the BESS in the distribution systems now grid standards are available currently on the European level. Each system operator has different approach. In Slovenia electricity grid, storage unit follow the requirements, defined for connecting the generator to the main grid.

On the Slovenian power exchange BSP, as well on the other PXs in Europe, electricity is traded in units. One unit is 1 MWh and it is the smallest offered quantity. In this case, small electricity providers i.e. energy storage units, who cannot reach a total power output of at least 1 MW on its own portfolio, would not be able to participate in the PXs even though they will help stabilize the electricity network.

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However, there is a different trading approach in Belgium at BELPEX, where the basic unit/portion of trading is equal to 0.1 MWh. All other trading rules are the same. With such a trading approach, nothing would change for major electricity providers, and small electricity providers would be able to participate at the PXs – an option for additional earnings.

8.1.6 Legislation requirements for new users of the electricity grid

The debut of the energy storage systems into the electricity networks brings a lot of new challenges for their integration having in mind the legislation obstacles which are the first barrier towards its full implementation. The recognition of energy storages has been hindered by the support for the RES generation, regulated electricity prices and green fees. At European level there is no consistency regarding the legislation covering this issue. There are different practices the way storage is treated that vary from one country to the other. In several countries' storage facilities are considered both as generators and consumers so they pay double fees to the grid, in other countries they are treated only as generators or have special regimes [14]. As in most cases energy storage is considered as a generation, its connection to the grid is covered by the network codes for generation systems. According to EUROBAT storage should be considered as a fourth component of the energy system, after generation, transmission and distribution, with its characteristics, properties and services considered. A clear definition of energy storage should be included in the Electricity Directive [15]. It should emphasise the storage ability to shift between generation and consumption of energy. Additionally, it should be technologically neutral and should not make any distinction between different storage types. Energy storage units should be allowed to provide several services to TSOs and DSOs and be compensated for that, actively participate in the energy markets and be enablers of higher amount of RES by contributing to decarbonisation of the electricity system or of other economic sectors.

The future legislation, the Electricity Regulation under the Clean Energy Package, should unify the different legislations among the European countries and should provide a clear picture on the status of the energy storage units, covering not only the benefits they can provide to the electricity network, but their contribution to the electric vehicles and industries overall.

8.2 Simulation approach

Simulations on the distribution section of the electricity grid defined the impact of increased RES, EV and storage in the network. With detailed model of electricity network, we observed system stability and operation of the system locally through technical results. Goal of the transmission system simulation is the assessment of storage on the electricity system from the economical point of view and market operation. Instead of detailed modelling of the interaction between the DSO towards the TSO, focus is on the calculation of the potential of the aggregated storage on the various electricity markets and provision of ancillary services to the DSO and TSO as an alternative to the traditional service providers on the market. The analysis was performed for the same scenarios as defined in Chapter 5. As a most realistic and viable operation of the storage, markets were identified for simulations and analysis in this task:

- **Tertiary reserve provision**, due to manual activation request and activation time up to 15 min
- **Day-ahead Market,** where energy is bought for following day in one-hour resolution.

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8.2.1 Electricity prices

Electricity prices for Day-ahead market were collected from Slovenian BSP Energy Exchange. BSP is the regional energy exchange organizer, which supervises the electricity trading. On Figure 8.2 and Figure 8.3 we can see typical price curves and yearly variation.

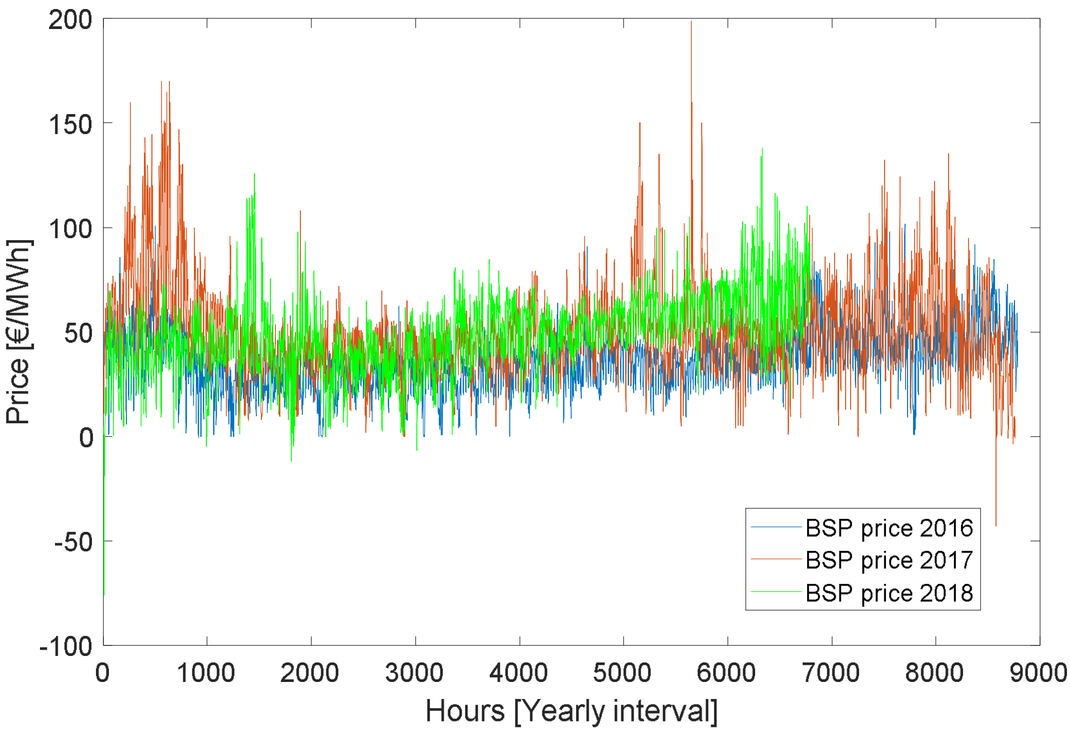

Figure 8.2: BSP Day-ahead market prices data from 2016 to 2018

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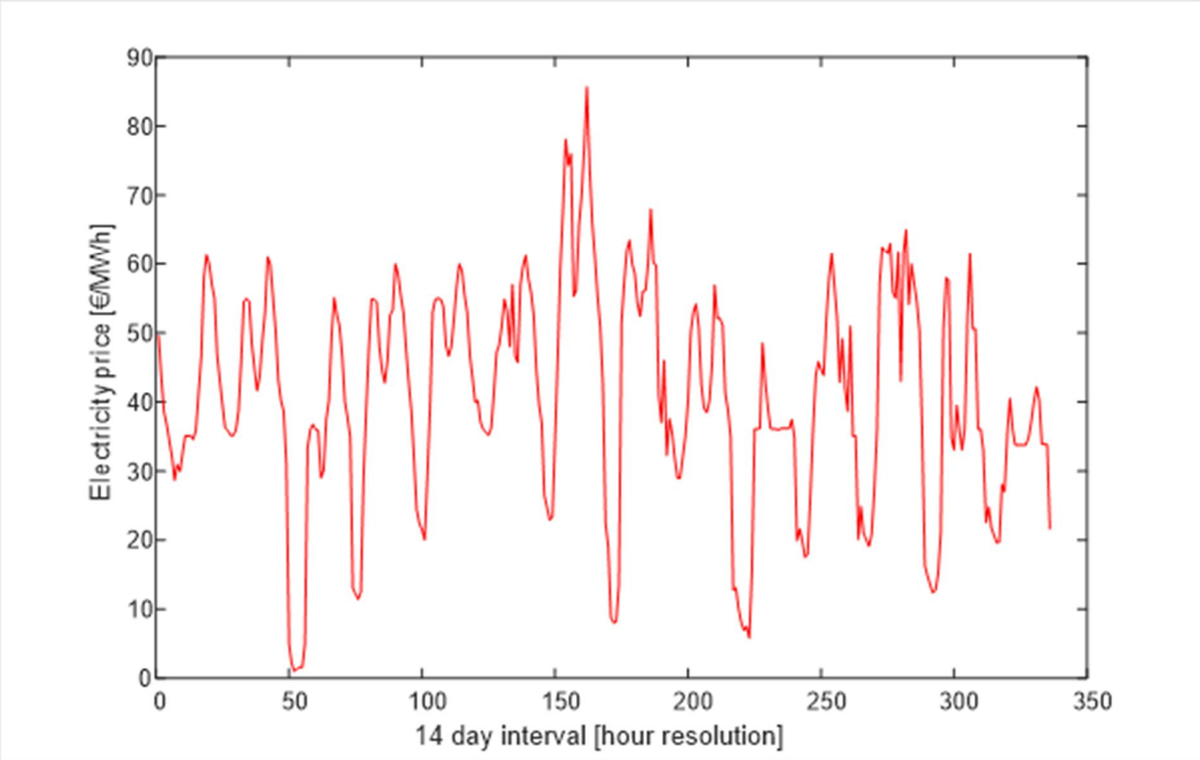

Figure 8.3: Day Ahead 14 days price rates, January 2016

Aggregator will bid his available capacity to maximize the profits with purchases of the electricity. Within 24-hour interval, storage will be charged with purchased energy while prices are low and discharged back when energy prices are on highest level. If within 24 hour there is no profitable solution storage will not trade that day. Profitable solution is defined as outcome, where sold energy cover the expenses of the purchases, considering efficiency factors of the storage.

Tertiary reserve market prices were taken from Slovenian TSO ELES auction [16] and are presented in Table 8.1

Table 8.1: Results of the TSO auction for tertiary reserve

Amount [MW]	Price of reservation [€/MW/h]	Energy price [€/MWh]
9	4.43	249,50
27	4.49	259.50

To successfully enter the auction, our aggregator will match lowest provider and will provide capacity based on those prices.

8.2.2 Scenarios and aggregators business cases

MV section of the network, visualized in Figure 4.6, will serve as a business portfolio definition. The aggregator has installed storage units in all MV/LV busses, installed power and storage capacity are

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defined with scenarios in Chapter 5. ABB storage unit was scaled accordingly to define the units and capacities operated by aggregator. In Table 8.3, scenarios and Aggregator's business pool details are given. Percentages, which are defined for storage, are based on transformer installed powers on two feeders. Urban Feeders consists of 7 400 kVA transformers and rural feeder has 4 400 kVA and 10 250 kVA transformers. Total transformer installed power on these 2 feeders is 6.9 MVA. Parameter values are rounded due to market rules and granularity of the products offered on the markets. For the definition of the capacity, 3 phase connection of the storage was assumed, and BESS parameters are given in Table 8.2

Table 8.2: Single BESS parameters

Installed power [kW]	170 kW
Installed capacity [kWh]	552kWh
Total Usable Energy BOL	82% @BoL
Round trip efficiency [%]	>85 %

Based on single unit parameters, aggregators energy pool was defined for each of the scenarios, presented in Table 8.3.

Table 8.3: Scenario parameters

Scenario	**Storage installed power (% of the grid power)**	**Installed power in MV grid (MW)**	**Installed capacity (MWh)**	**Available capacity (MW)**
1	15 %	1	3.31	2.71
2	30 %	2	6.62	5.45
3	80 %	5.5	17.66	14.48

If we distribute round-trip efficiency of the storage equally to charging and discharging process, both processes have 92% efficiency of each process. This defines energy which needs to be purchased to fully charge BESS and amount of energy, which can be offered from storage

8.3 Results of the trading on electricity markets

BESS operation on the markets is defined with system efficiency and effective capacity. Time to fully charge and discharge BESS is defined with rated power and capacity:

$$t_{CH} = \frac{0.82 * 552\ kWh}{170\ kW} = 2.66\ h = 160 min$$

$$t_{DCH} = \frac{0.82 * 0.85 * 552\ kWh}{170\ kW} = 2.26\ h = 135 min$$

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For market operation we will assume that Aggregator charges storage for 3 hours and can sell his energy for 2 hours to take into account market product definition.

8.3.1 Day-Ahead electricity market trading

Due to the definition of the day ahead energy product, we will define only standard product trading. However, storage owner could offer custom product on the market as well, fit to his portfolio. Standard power exchange hourly product (1 MW x 1 h) will be used. This defines the amount of energy, which can be traded by the aggregator, presented in Table 8.4.

Since storage unit cannot sell all the energy stored in shape of defined market products, we assume that the Aggregator covers the deviation with other flexible energy sources in his portfolio. Remaining energy is used for internal use of the storage unit and other purposes outside of the Day-ahead market. Operation limits discharge unit due to energy product limitations. For example of Scenario 1: with installed capacity aggregator purchases 3 MWh of energy, with 85% round trip efficiency, he could sell 2.5 MWh but offered energy is limited to 2 MWh on the day ahead market. Results represent only electricity, traded on Day-ahead market.

Table 8.4: Buy and Sell products for 1 MWh products

Scenario	**Installed P** [MW] / **Available Energy** [MWh]	**Buy products:** Duration (hours) x purchased power (MW)	**Sell products:** Duration (hours) x offered power (MW)
1	1 MW / 2.71 MWh	3 MWh	2MWh
2	2 MW / 5.45 MWh	6 MWh	5MWh
3	5.5 MW / 14.48 MWh	16 MWh	13 MWh

In Table 8.5, Table 8.6 and Table 8.7, monthly results are presented for 2016 to 2018 data for all three scenarios.

Table 8.5: Scenario 1 profits in [€] on Day-ahead Market

Month	**2016**	**2017**	**2018**
Jan	1981	3609	2258
Feb	1762	1861	1650
Mar	1345	1676	2458
Apr	954	1416	1538
Maj	1180	1280	2204
Jun	1159	1441	1301
Jul	1095	1538	401
Aug	915	3023	770
Sep	1353	1760	2338
Oct	1677	2641	
Nov	1627	3241	
Dec	1529	2921	

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Yearly	16577	26408	14917

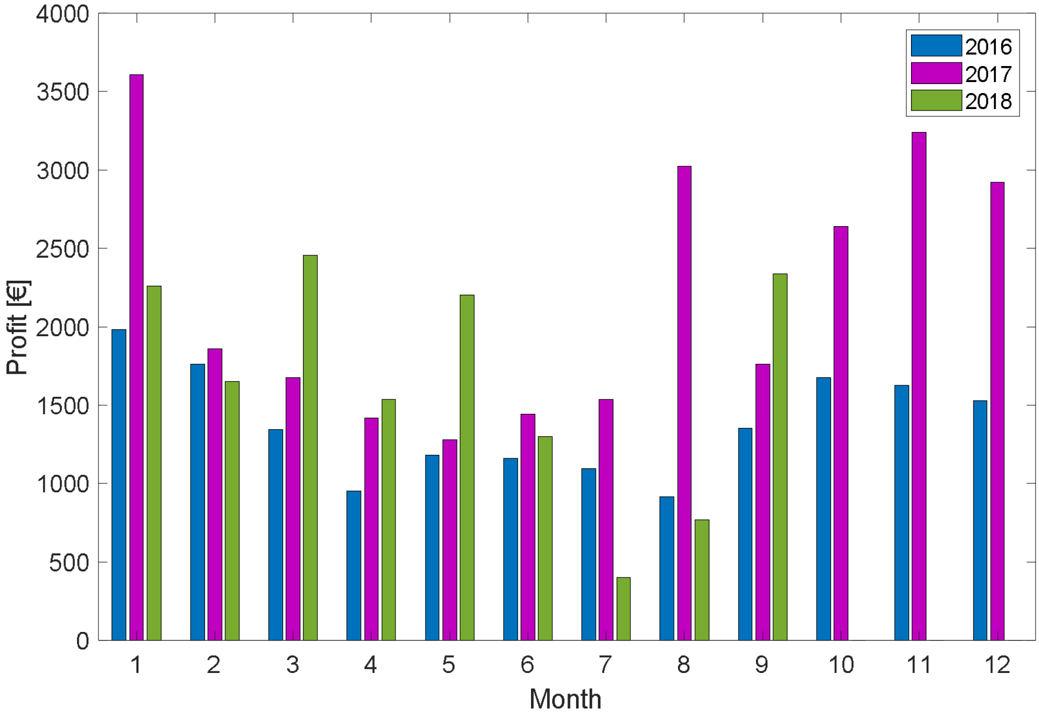

Figure 8.4: Profits per month in €, Scenario 1

Table 8.6: Scenario 2 Profits in [€]

Month	2016	2017	2018
Jan	3206	4222	7432
Feb	2730	3376	4091
Mar	1840	2526	3330
Apr	1194	2003	2936
Maj	1861	2502	2865
Jun	1908	2593	3211
Jul	1574	2400	3505
Aug	1492	2229	6292
Sep	1726	2759	3613
Oct.	2098	3315	
Nov	2481	3416	
Dec	2397	3532	
Yearly	**24508**	**40783**	**21591**

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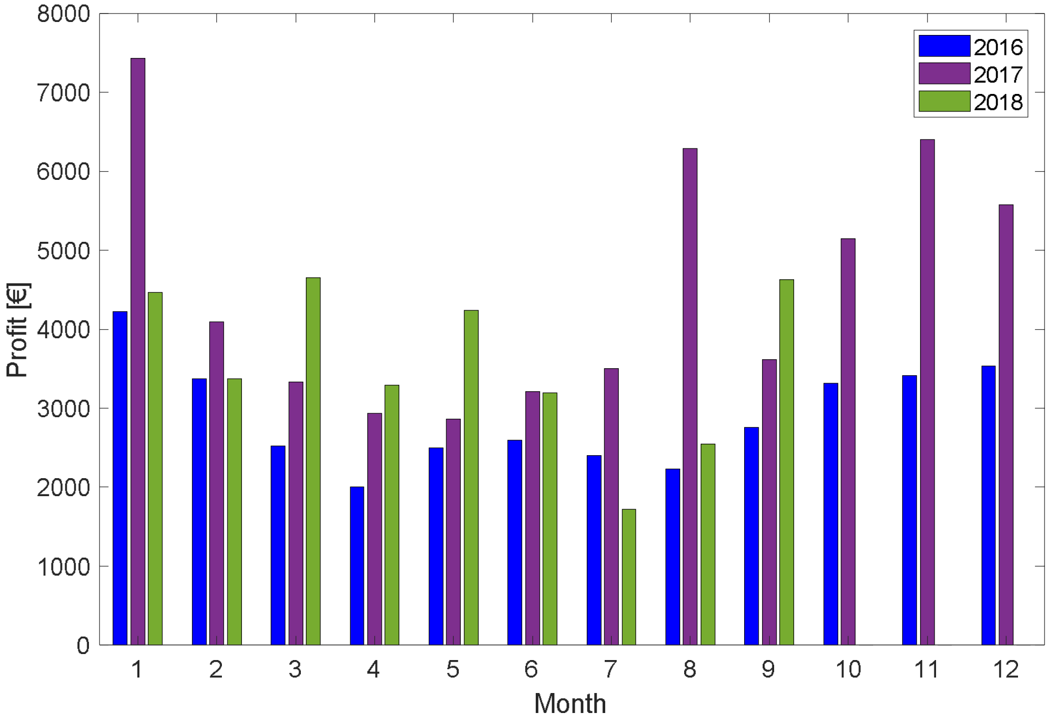

Figure 8.5: Scenario 2 monthly profits comparison [€]

Table 8.7: Scenario 3 Profits in [€]

Month	**2016**	**2017**	**2018**
Jan	3206	5481	3572
Feb	2730	2892	2420
Mar	1840	2435	3608
Apr	1194	1826	2474
Maj	1861	1894	3178
Jun	1908	2204	1889
Jul	1574	2509	503
Aug	1492	5624	1135
Sep	1726	2436	2813
Oct.	2098	3715	
Nov	2481	5091	
Dec	2397	4677	
Yearly	**24508**	**40783**	**21591**

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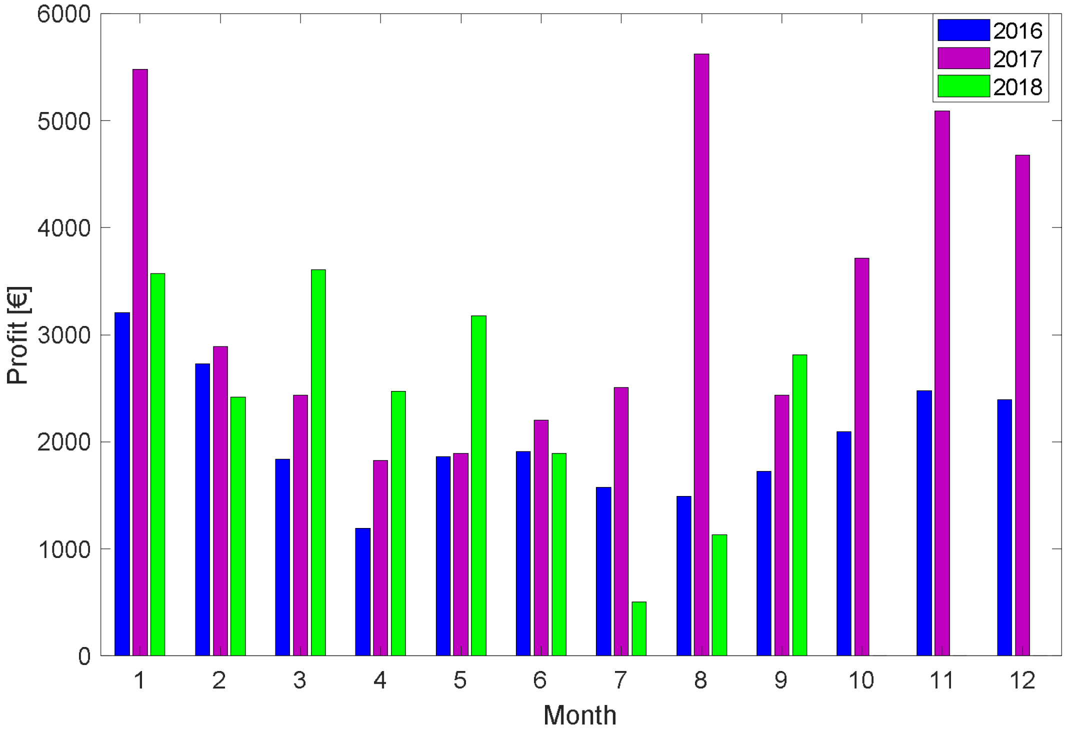

Figure 8.6: Scenario 3 trading profits in €

Figure 8.7 present comparison between yearly income for scenarios for years 2016 - 2018.best profits had scenario 2, where storage unit capacity is must utilized on the market. Aggregator purchases 6 MWh and is able to sell 5 MWh, which give him better trading position than in scenario 1 (3 MWh – 2 MWh) and Scenario 3 (15 MWh -13 MWh). Scenario 3 was expected to yield best income but due to higher loss of trading potential due to efficiency and longer selling and purchase interval, storage did not generate more revenues with this trading algorithm compared to smaller unit. In 2016 units did generate highest revenues in beginning of the year, 2017 was most profitable in winter months and august as well, while 2018 resulted in good first 5 months and with rising trend for end of the year.

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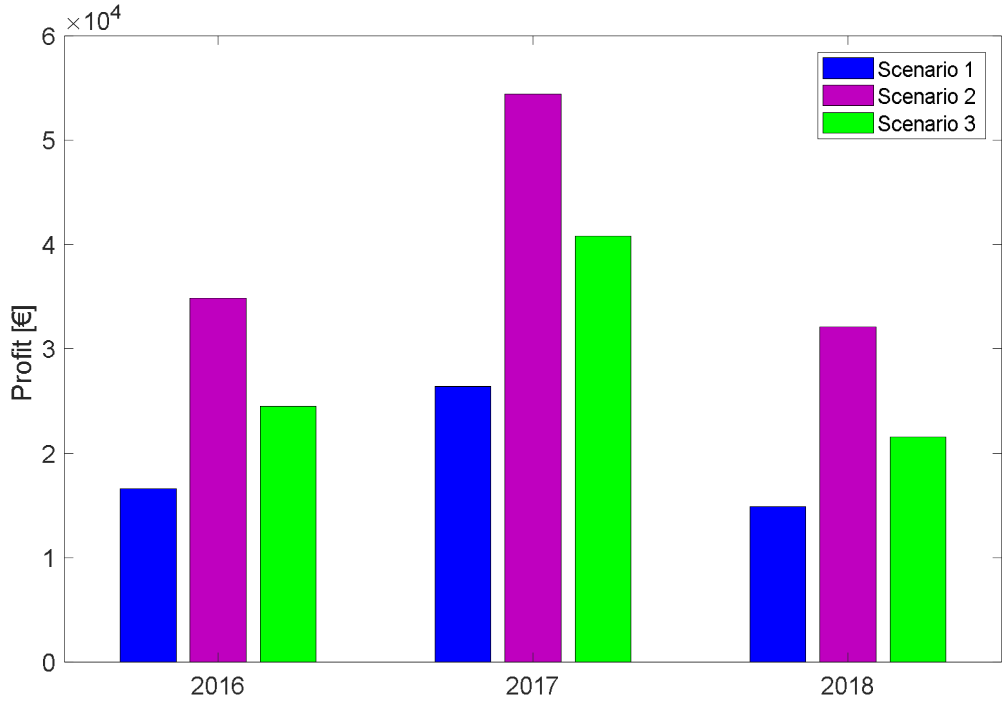

Figure 8.7: Yearly comparison for scenarios

8.3.2 Reserve provision

Based on the auction results in Table 8.1 we prepared auction offers for all scenarios in Table 8.8. From the [17] we collected historical data about reserve activation in 2017and 2018.

Table 8.8: Scenario Auctions

Scenario	Amount of power [MW]	Price of reservation [€/MW/h]	Energy Price [€/MWh]
1	1	4.43	249,00
2	2	4.43	249,00
3	5	4.43	249,00

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Table 8.9: Reserve market monthly profits [€]

	2017			2018		
Month	**S1**	**S2**	**S3**	**S1**	**S2**	**S3**
Jan	4829	9877	25021	3734	7687	19108
Feb	3415	7049	17513	5824	11429	30434
Mar	3729	7459	18647	4167	8335	20837
Apr	4285	8350	21423	3628	7255	18138
Maj	3734	7468	18670	5486	10315	25897
Jun	3190	6379	15948	4066	7912	20328
Jul	3515	7030	17575	3296	6592	16480
Aug	3734	7468	18670	3291	6583	16457
Sep	4504	8788	22956	3847	7912	19671
Oct.	3300	6601	16502			
Nov	4285	8131	19233			
Dec	4172	8344	20422			
Total	46691	92944	232578	37339	74020	187350

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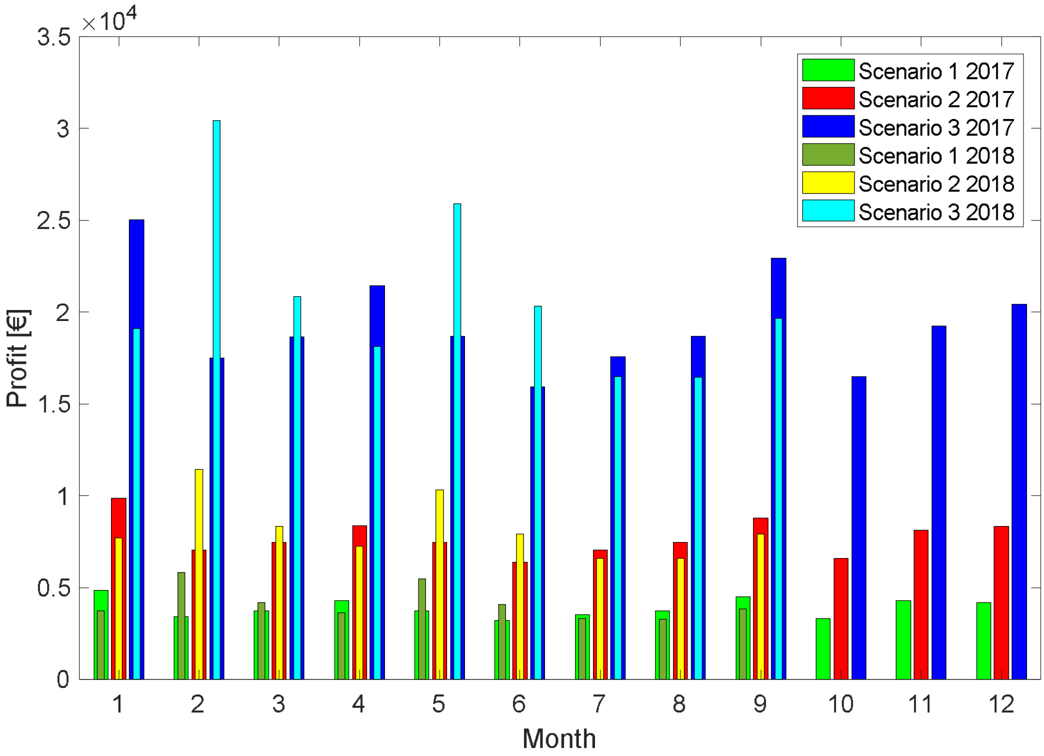

Figure 8.8: Reserve provision trading profits

Reserve marker operation proved to be more profitable and stable business. Income didn’t fall below certain threshold, obtained via availability income. This level proved to be higher than the lowest day-ahead market incomes in months with less favourable price profiles. Difference between monthly income in individual scenario occurs in correlation with frequency of activation. With higher amount of reserve activation, aggregator generates more income. Here our biggest unit of scenario 3 proved to be most effective due to highest amount of reserve offered and higher capacity offered

Transmission system economic evaluation proved Reserve marked to be more profitable option for the Storage owners. With high rates for capacity allocation and relatively high price of energy delivered for reserve activation, which is around seven times higher than prices on day ahead market this market proved to be more suitable for storage as in reality it really is. Day ahead market yielded lower income, but still profitable trading outcome even with 85% round trip efficiency. Storage did not trade on the days where price curve was too flat to create positive sales.

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9 Conclusions

Future network development is affected by integration of renewables, electric vehicles and storage solutions. How each of those technologies will impact network status is determined through simulations of future power flows. A simulation platform was established and utilized for assessment of future development scenarios impact.

This document outlines the results of the large-scale simulation in distribution grid. We aim to assess the large-scale impact of rollout of storage, spread throughout the LV networks as household installations or system wide, central unit solutions. We compare the impact of storage solution, based on installed capacity in the network and in combination with different technologies. Impact of different storage installations capacities were tested for existing network conditions and for various RES and network development scenarios, from the vantage point of the Aggregator, using the flexibility provided by the storage units on the day-ahead electricity market or to provide ancillary services to the TSO.

The integration of battery storage devices has a considerable impact on the power system on different levels. In STORY, we have devised a method to assess the impact of large-scale implementation of distributed storage in the power system. We compare the results of scenarios assuming different number of installed household storage units, PV units and centralized storage units in the network.

The summer and winter intervals represent most extreme network settings. PV production receives a lot of solar radiation in summer. In winter, demand is high due to low temperatures and high overall energy consumption. Network losses had similar trends throughout the whole system.

On Figure 9.1 we observe general trend of the storage impact. Results showed how each parameter influence the situation in the network. In lower scenarios, where PV penetration is not at high level yet and existing state is represented, storage implementation brings benefit to the overall situation but in little scale. This is a result of conservative power system planning in the past, where power lines and other power delivery elements were often over dimensioned to increase stability and resilience of the network. But even this reserved planning is not enough in future development scenarios, where higher level of PV penetration is expected. It results in higher peak levels of element loading, higher loss rates and better self-sufficiency rates but lower network self-consumption. In higher scenarios, storage implementation improves network parameters and is further enhanced by the operation of OLTC transformer

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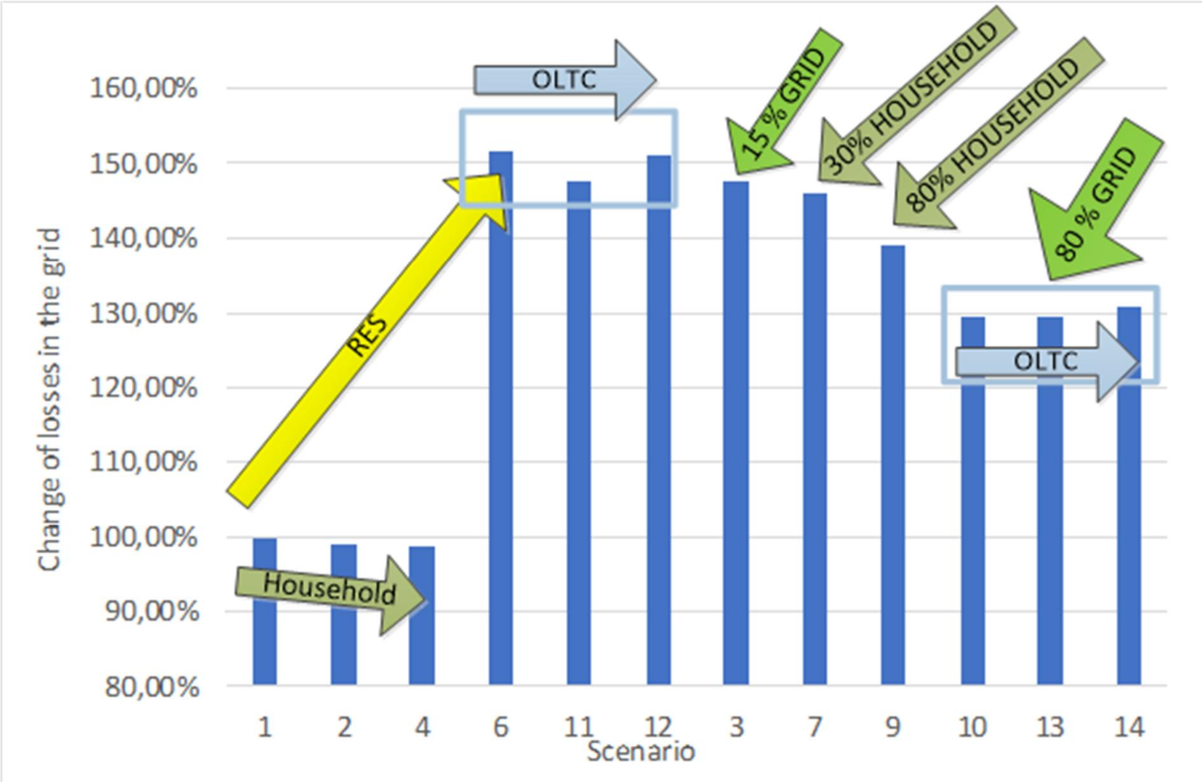

Figure 9.1: Loss rates comparison between scenarios in summer

Transmission system economic evaluation proved Reserve marked to be more profitable option for the Storage owners. With high rates for capacity allocation and relatively high price of energy delivered for reserve activation, which is around 7 time higher than prices on day ahead market this market proved to be more suitable for storage as in reality it really is. Day ahead market yielded lower income, but still profitable trading outcome even with 85% round trip efficiency. Storage did not trade on the days where price curve was too flat to create positive sales.

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10 Acronyms

AS	Ancillary Service
BRP	Balance Responsible Parties
CDF	Cumulative Distribution Function
DA	Day-Ahead
DG	Distributed Generation
DRES	Distributed Renewable Energy Sources
DSO	Distribution System Operator
EED	External Energy Dependence
EG	Elektro Gorenjska
ENTSO-E	European Network of Transmission System Operators for Electricity
E/P	Energy Delivered to Consumers / Peak power Ratio
EV	Electric Vehicles
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
GHG	Greenhouse Gas
HV	High Voltage
ID	Intra-Day
KPI	Key Performance Indicator
LV	Low Voltage
mFRR	manual Frequency Restoration Reserves
MV	Medium Voltage
OLTC	On load tap changer
PAR	Peak to Average Ratio
PCU	Power Conversion Unit
PV	Photovoltaic
PX	Power Exchange
R1	Primary Reserve
R2	Secondary Reserve
R3	Tertiary Reserve Generation
RR	Reserves Replacement
RT	Real-Time
SI	System Imbalance
TSO	Transmission System Operator

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11 Literature

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[17] https://transparency.entsoe.eu/

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12 Appendix: Visualizations of the results

Visualization of results

In this appendix we include additional loading values and visualization of the LV voltage profiles, and power flows through the MV/LV transformers, supplying urban and rural network. Winter and summer seasons are presented for scenarios 1, 6, 9, and 10. In comparison of scenario 1 and 6 we see impact of res on the network, scenario 9 present mitigation of this PV impact with household storage, while scenario 10 presents system storage unit.

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12.1 Loading levels of the transformers in the networks

Table 12.1: Peak transformer loading levels [% of nominal power] in simulations

Winter	Loading level of transformers			
Scenario	Minimum HV/MV [%]	Maximum HV/MV [%]	Maximum Urban [%]	Maximum Rural [%]
1	14,30%	66,50%	62,82%	61,73%
2	16,04%	65,66%	61,35%	60,82%
4	16,07%	65,18%	59,92%	60,39%
6	-6,47%	74,74%	74,68%	68,70%
11	-6,47%	69,23%	71,51%	65,76%
12	-6,80%	70,99%	72,44%	66,71%
3	-1,74%	73,41%	71,46%	63,68%
7	-4,23%	73,40%	71,82%	67,02%
9	0,94%	70,98%	67,46%	64,32%
10	18,64%	47,68%	43,11%	46,02%
13	18,64%	47,00%	42,84%	43,24%
14	18,33%	47,00%	42,85%	43,37%
Scenario	Spring			
1	-9,12%	49,80%	48,21%	47,28%
2	-9,11%	49,20%	47,07%	46,46%
4	-9,06%	48,83%	46,08%	46,14%
6	-54,06%	59,66%	60,94%	55,32%
11	-55,47%	56,72%	59,22%	53,74%
12	-54,25%	56,72%	59,22%	53,74%
3	-46,71%	58,79%	59,14%	58,29%
7	-53,31%	58,33%	58,62%	53,45%
9	-52,65%	56,16%	54,59%	50,97%
10	-29,68%	34,10%	31,85%	33,02%
13	-49,68%	54,52%	58,32%	57,08%
14	-49,07%	54,51%	58,32%	57,08%
Scenario	Summer			
1	-15,07%	39,84%	38,56%	37,50%
2	-14,93%	39,40%	37,77%	36,87%
4	-14,90%	39,11%	37,04%	36,62%
6	-61,25%	49,28%	50,75%	45,32%
11	-63,47%	48,32%	50,46%	45,05%
12	-61,68%	48,32%	50,46%	45,05%
3	-56,88%	46,39%	42,11%	48,00%
7	-61,37%	48,25%	48,93%	43,55%
9	-60,95%	45,97%	45,66%	41,67%
10	-35,82%	25,95%	22,48%	28,14%
13	-36,12%	26,21%	22,63%	33,47%
14	-36,10%	26,60%	22,76%	30,79%
Scenario	Fall			
1	10,87%	55,33%	52,27%	51,34%

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2	12,19%	54,36%	50,89%	50,40%
4	13,00%	53,67%	49,72%	50,04%
6	-7,71%	65,06%	65,08%	59,35%

12.2 Storage impact on voltage levels and loading of the elements

On Figure 12.1 we see the power flows of active and reactive power through the MV/LV transformer, which supplies the urban LV network. We observe slight revers power flows and high evening peak.

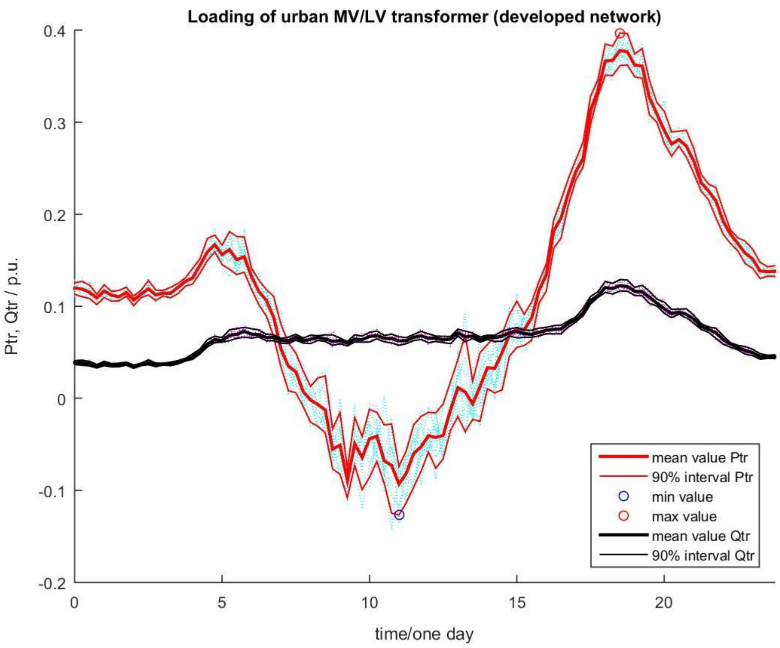

Figure 12.1: Original power flow, Scenario 1

On Figure 12.2 we see the impact of RES increase in the network on the transformer profile. Reverse power flows increased from 10% of rated power of the transformer to 60% of rated power in intervals with high production. Evening peak increase from 40 % to 55%, and overall system condition worsened.

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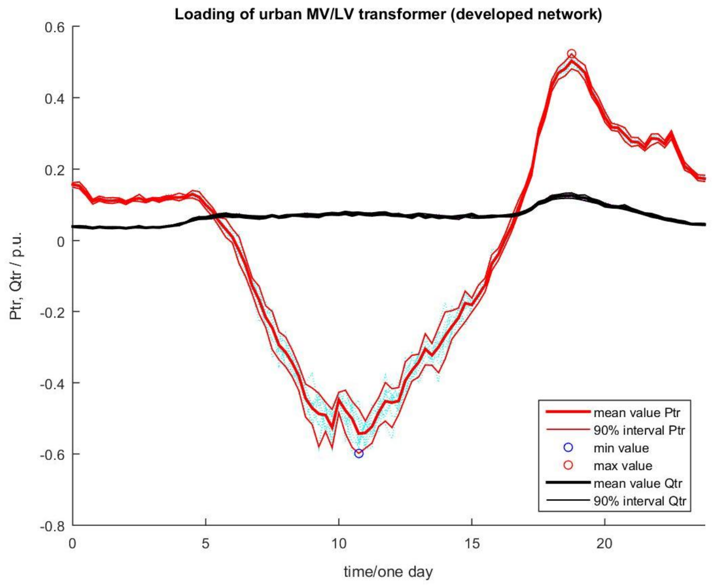

Figure 12.3 and Figure 12.4 represent the power flows through transformer station with implemented storage solution. We can see the difference between both storage types. While central unit, is more system oriented the transformer power flow profile is flattened, reverse power flow and evening peak reduced to 30 % of rated power, household solution only brings slight evening peak decrease. Household solutions are more user oriented and their benefits are observed on other sector, self-sufficiency and self-consumption levels are increased to higher level, compared to system unit in seasons with moderate production, such as winter and fall, while in summer interval system unit was beneficent on all aspects with proper peak shaving strategy.

Figure 12.2:increased RES, Scenario 6

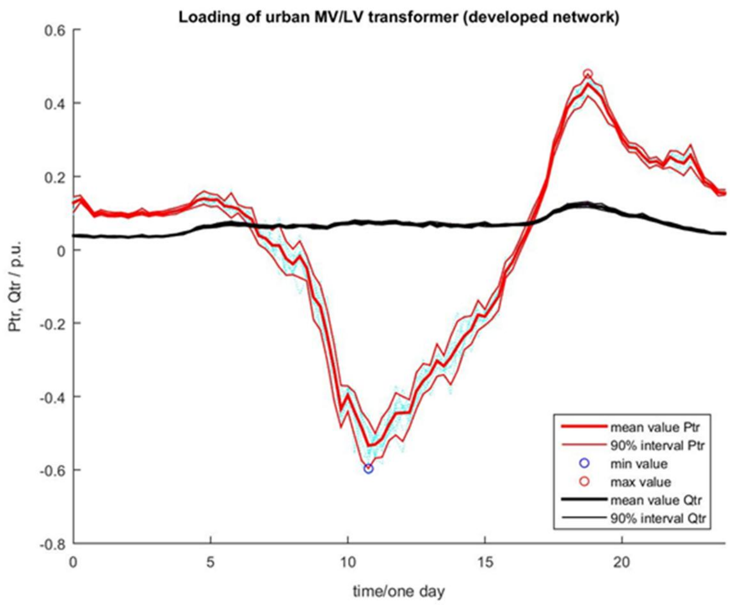

Figure 12.3: Household Storage solutions, Scenario 9

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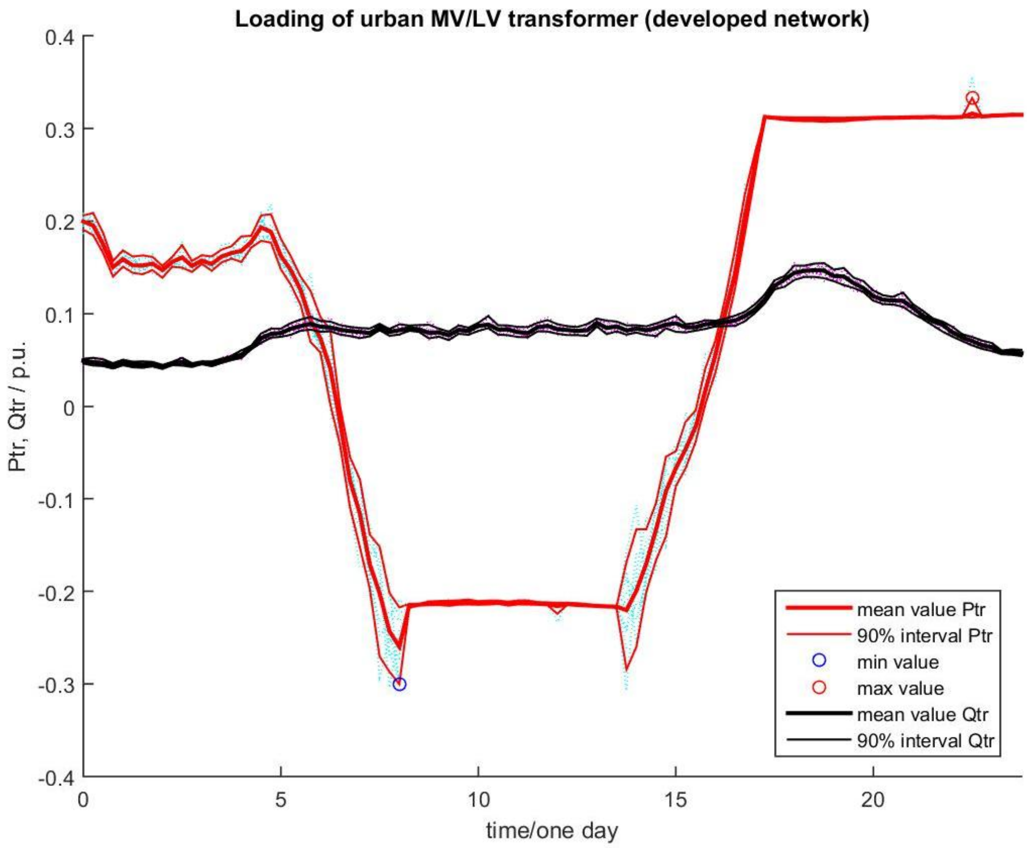

Figure 12.4: System unit solution, Scenario 10

Voltage profiles is affected by many factors. Figure 12.5 show initial voltage rise during the day due to RES production. Figure 12.6 shows how the system responds to increased RES injection. Voltage rise forces OLTC to adjust taps to keep voltages in allowed levels. How this tap changes is seen on MV level is seen on Figure 12.7, where we can see voltage drop with OLTC activation. Lower voltage levels in MV level means higher energy losses in the network. How this effect is mitigated, we can see on Figure 12.8 where system unit was implemented and performs peak shaving.

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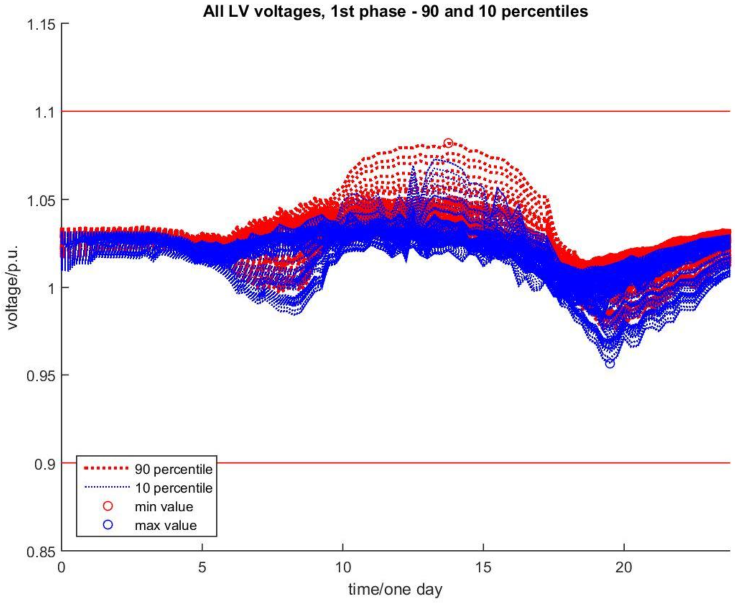

Figure 12.5: Initial LV voltage profiles

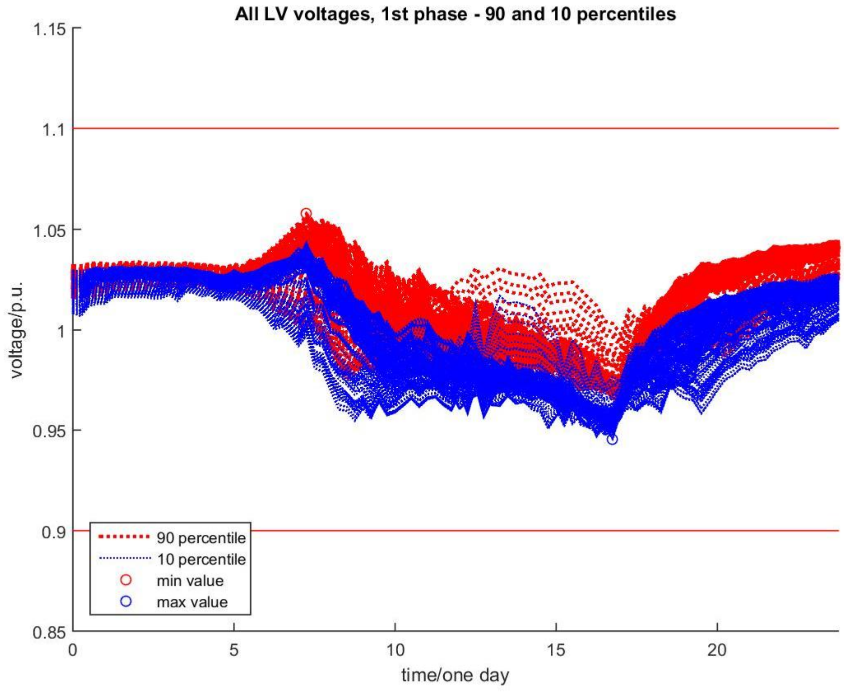

Figure 12.6: RES increase impact on Voltage profile

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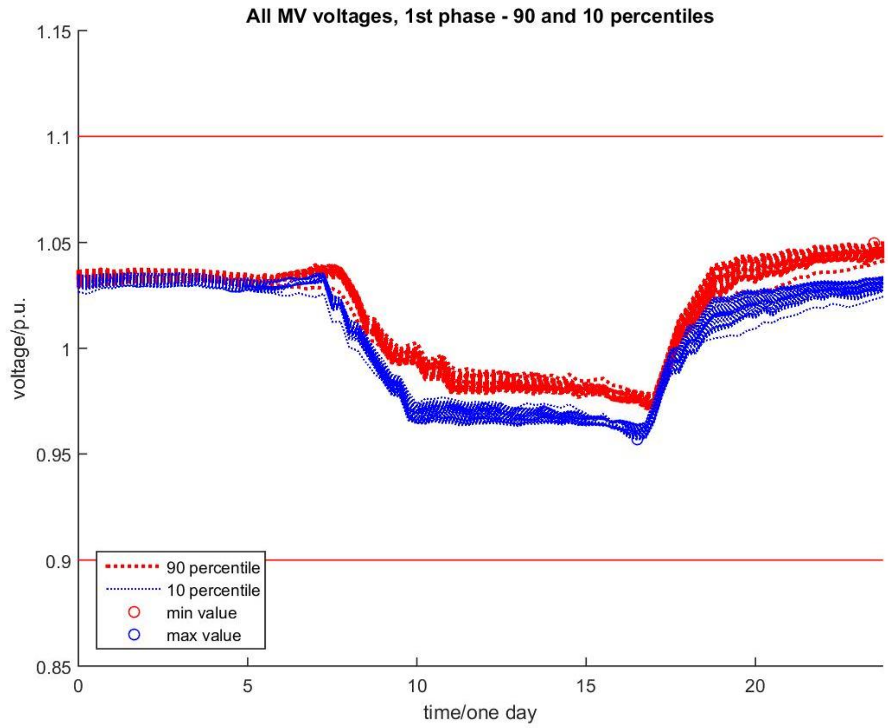

Figure 12.7: MV voltage with RES impact

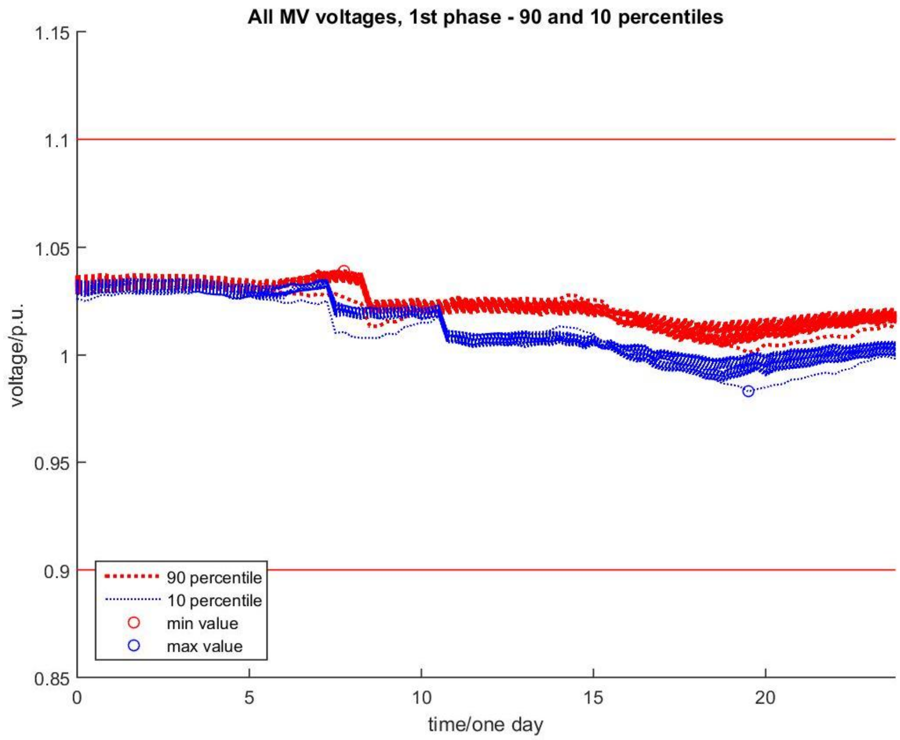

Figure 12.8: MV voltage profile with system unit and peak shaving algorithm

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How OLTC implementation impacts voltage levels is presented in Figure 12.9, Figure 12.10 and Figure 12.11 where different OLTC settings were applied. We see that the OLTC with narrowest bandwidth provided best voltage in LV network.

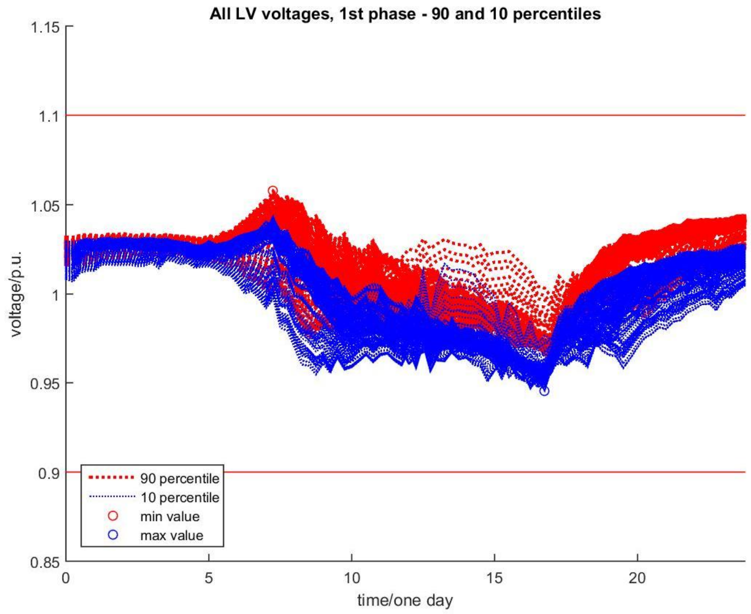

Figure 12.9: Low voltage levels OLTC (0.93 pu - 1.07 pu)

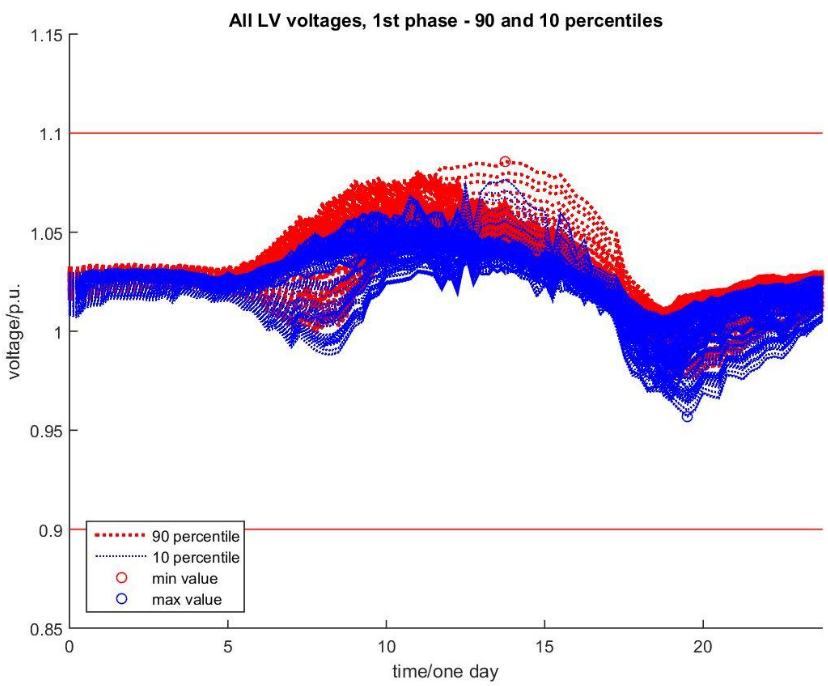

Figure 12.10: Low voltage profiles with no OLTC

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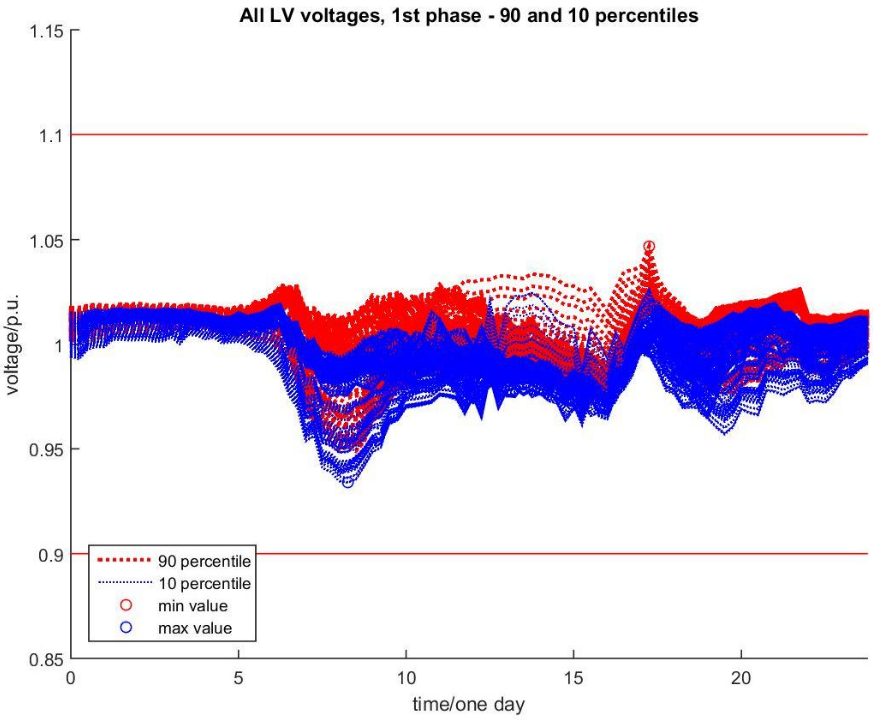

Figure 12.11: Low voltage levels OLTC (0.97 pu - 1.03 pu)

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12.3 Scenario visualizations

12.3.1 Scenario 1

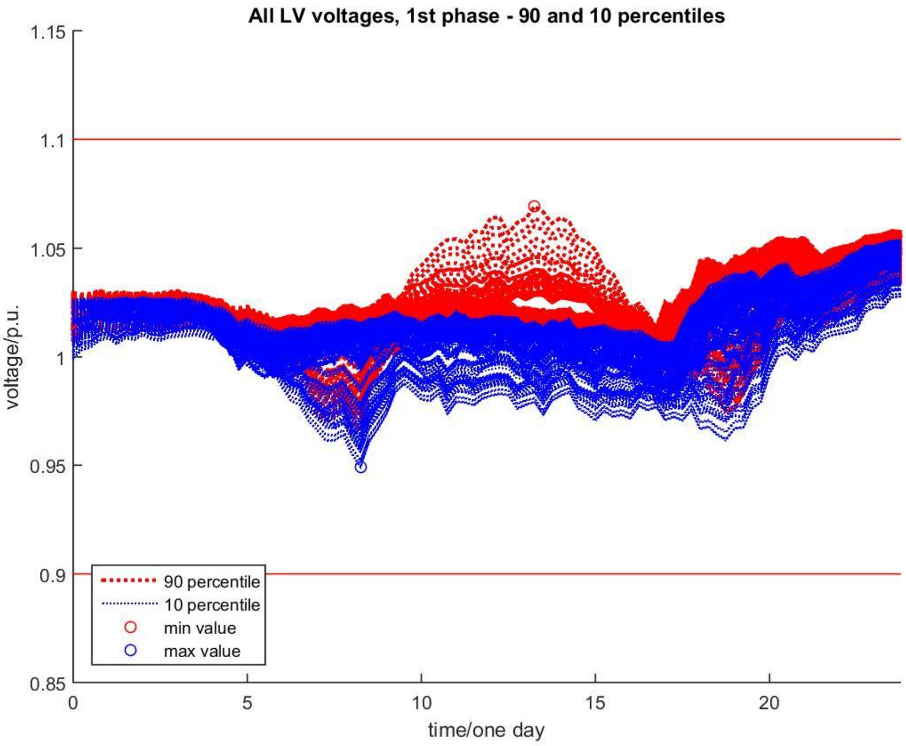

Figure 12.12: LV voltages, Scenario 1, winter

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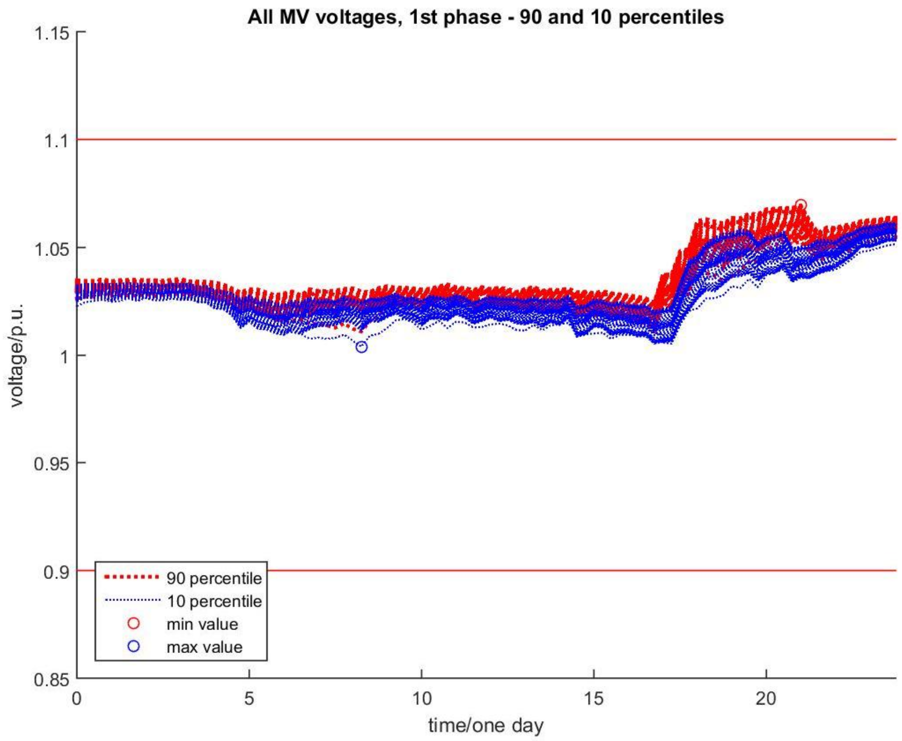

Figure 12.13: MV voltage profiles, Scenario 1, winter

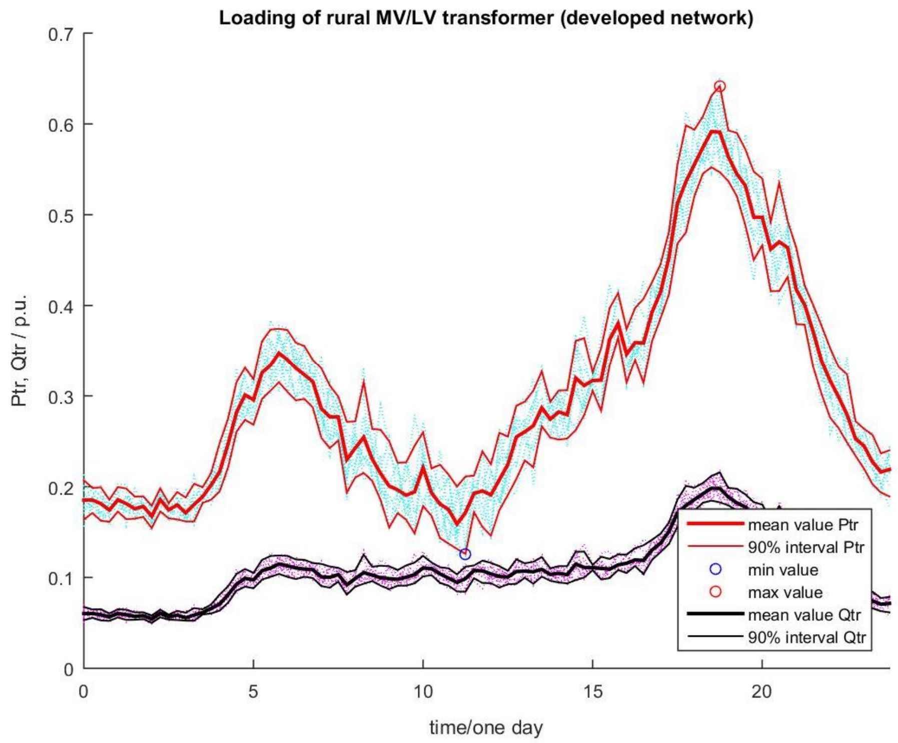

Figure 12.14: Rural transformer, Scenario 1, winter

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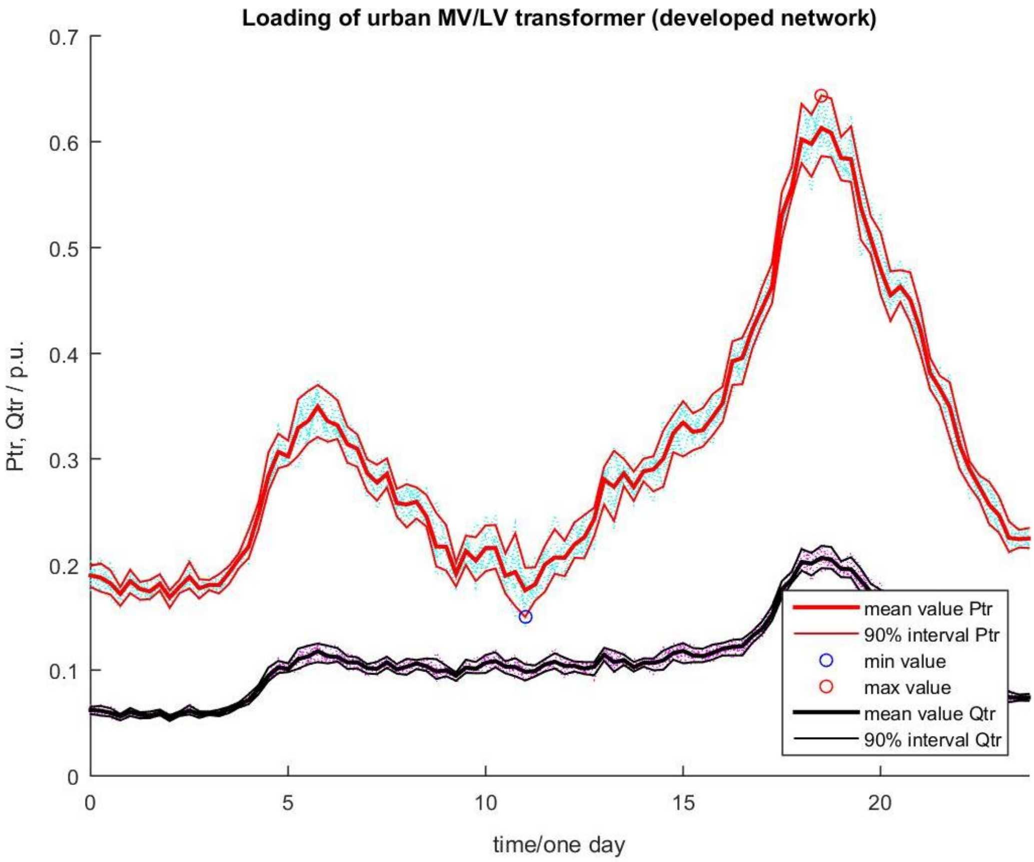

Figure 12.15: Urban transformer, Scenario 1, winter

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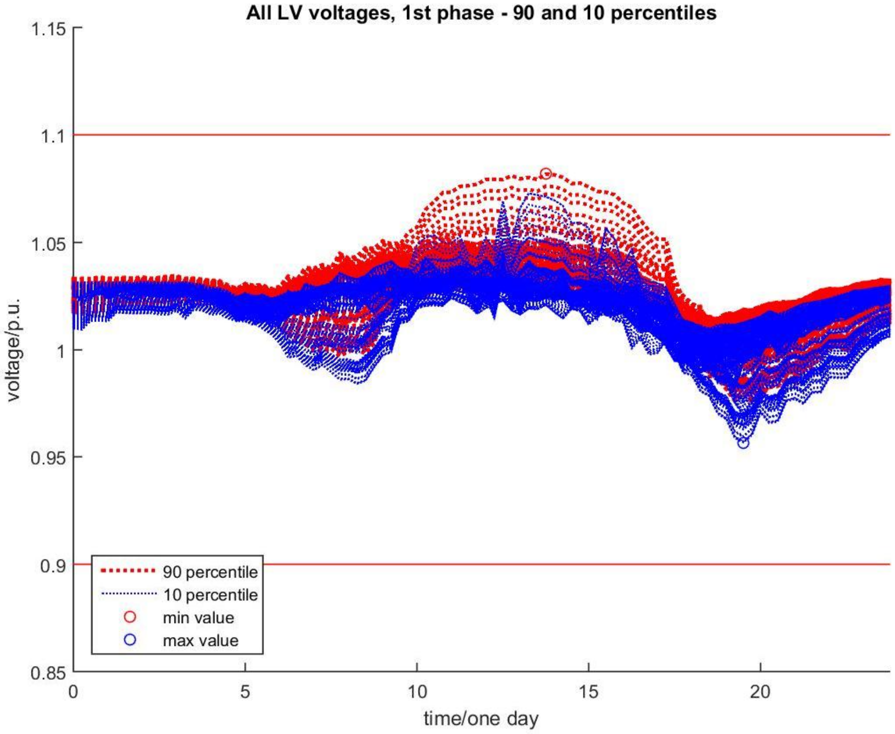

Figure 12.16: LV voltages, Scenario 1, summer

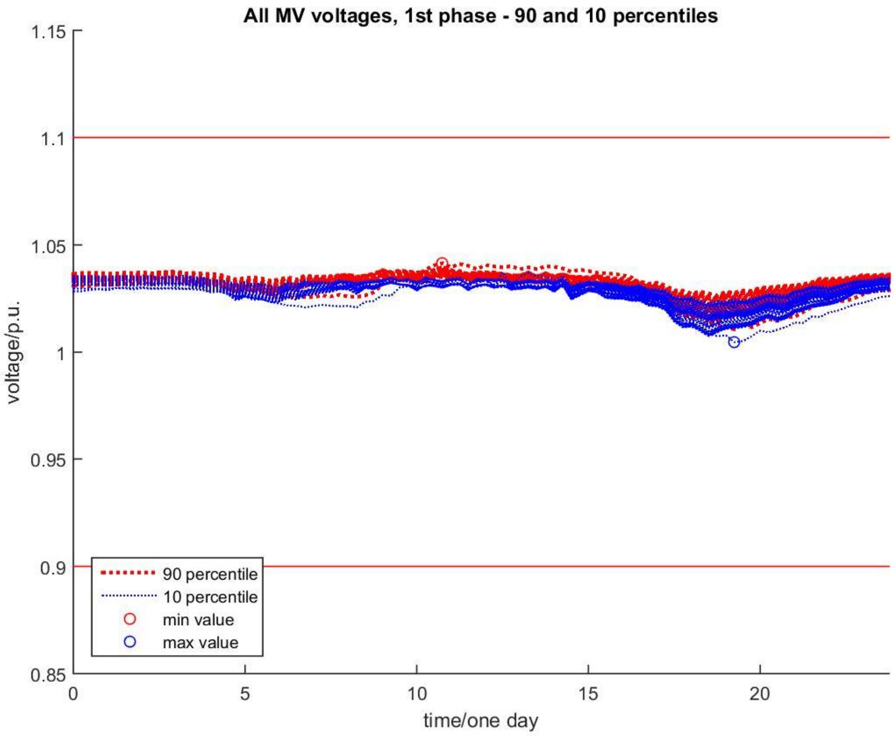

Figure 12.17: MV voltages, Scenario 1, summer

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646426

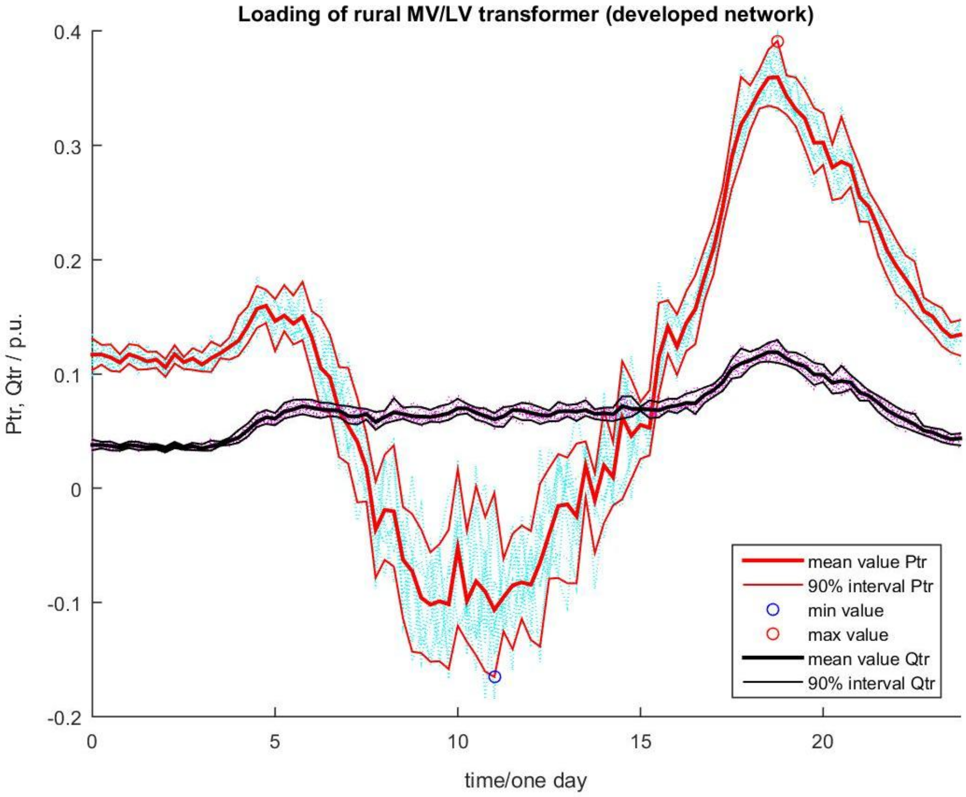

Figure 12.18: Rural transformer, Scenario 1, summer

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646426

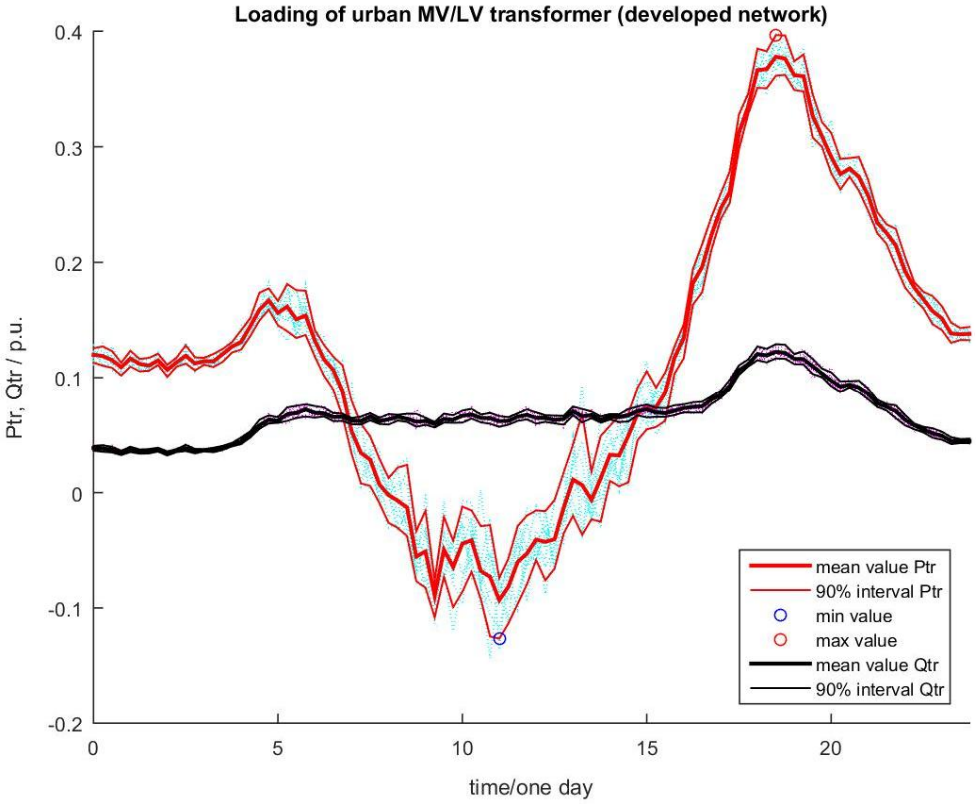

Figure 12.19: Urban transformer, Scenario 1, winter

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12.3.2 **Scenario 6**

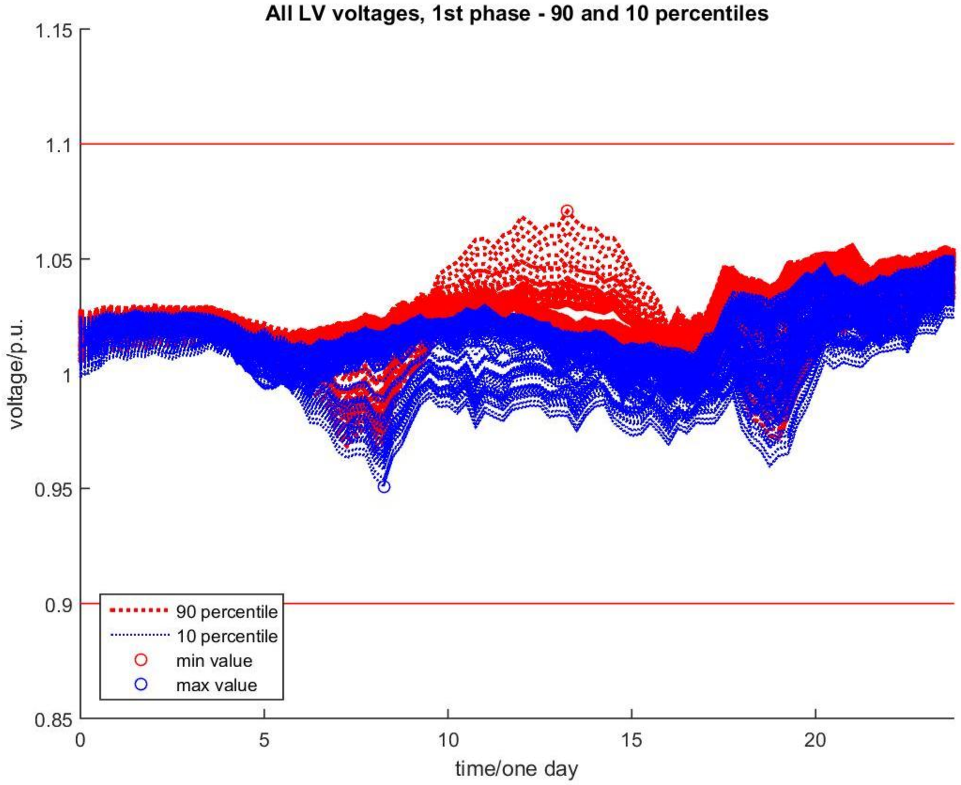

Figure 12.20: LV voltages, Scenario 6, winter

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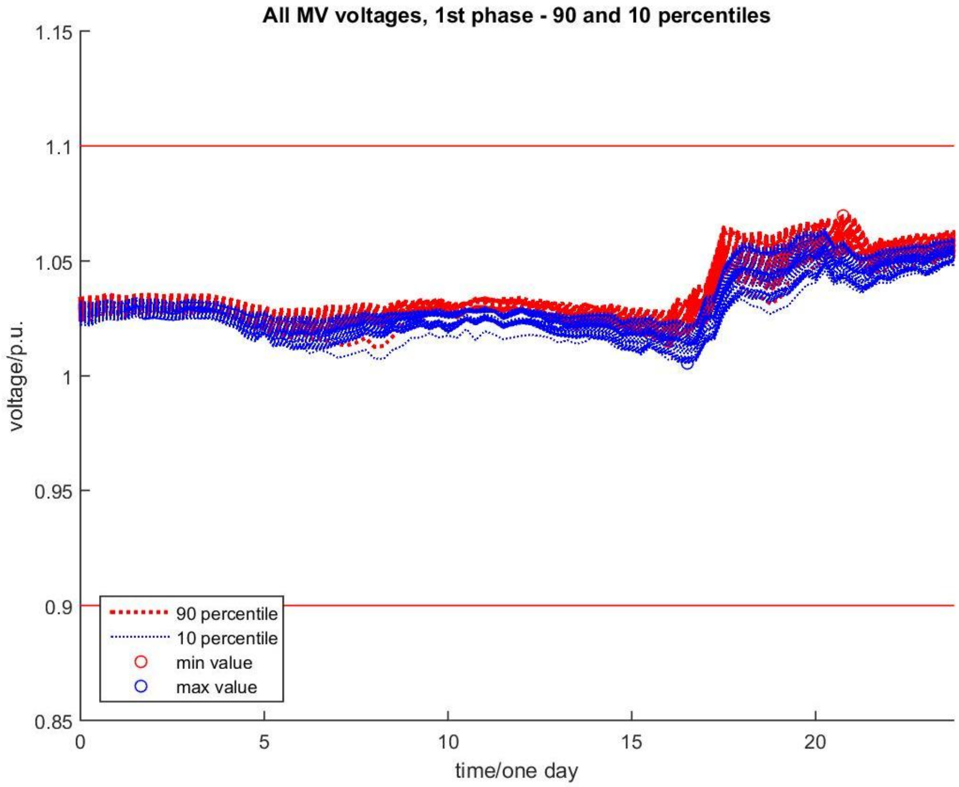

Figure 12.21: MV voltages, Scenario 6, winter

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research and innovation programme under grant agreement No 646426

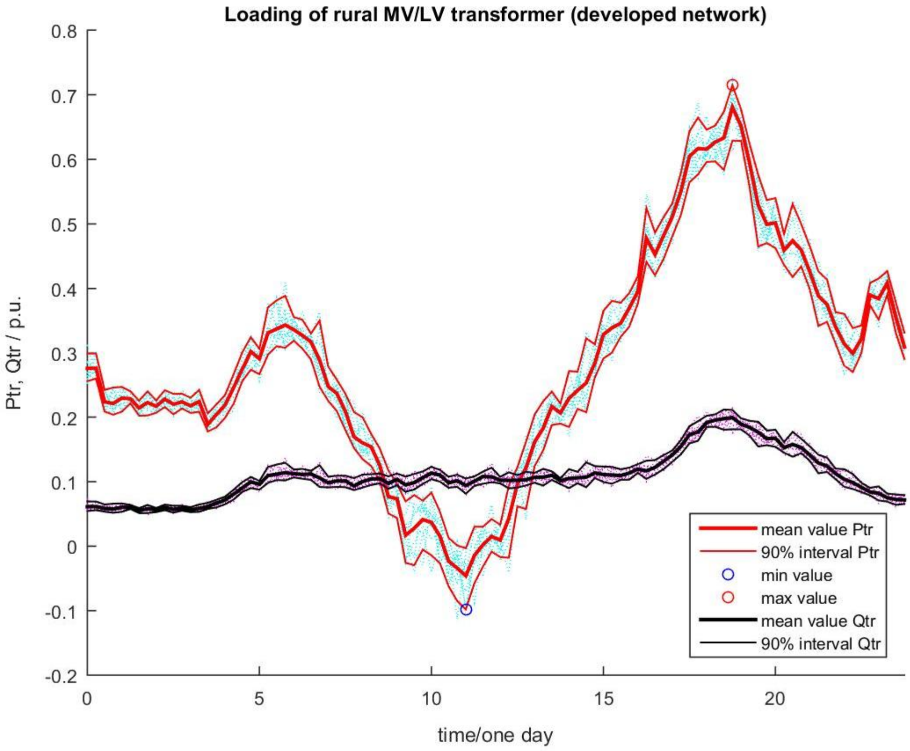

Figure 12.22: Rural transformer, Scenario 6, winter

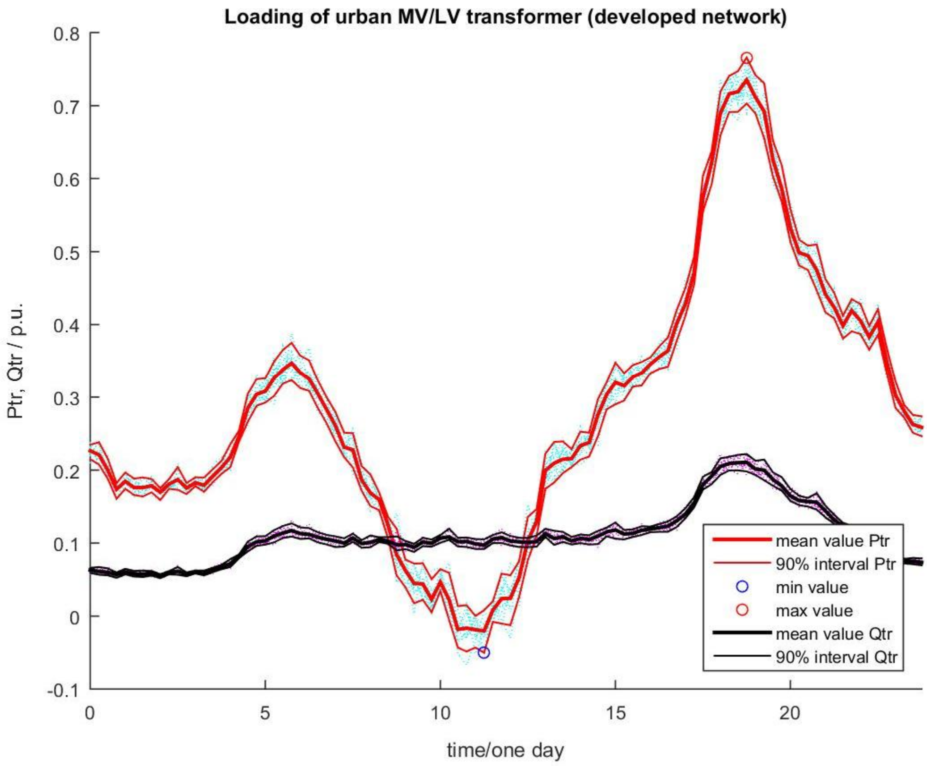

Figure 12.23: Urban transformer, Scenario 6, winter

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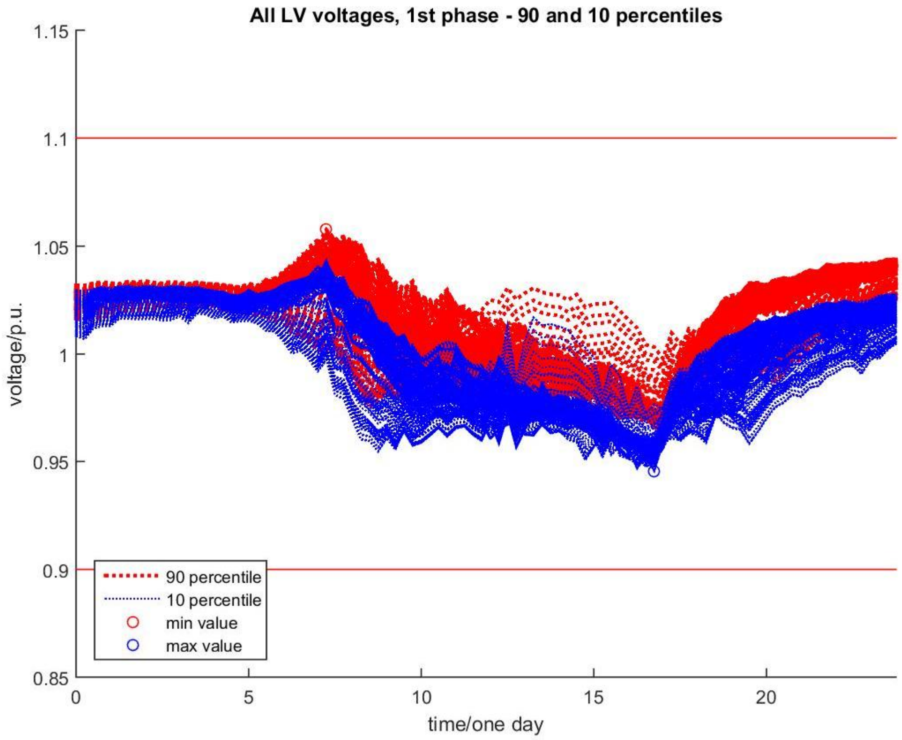

Figure 12.24: LV voltages, Scenario 6, summer

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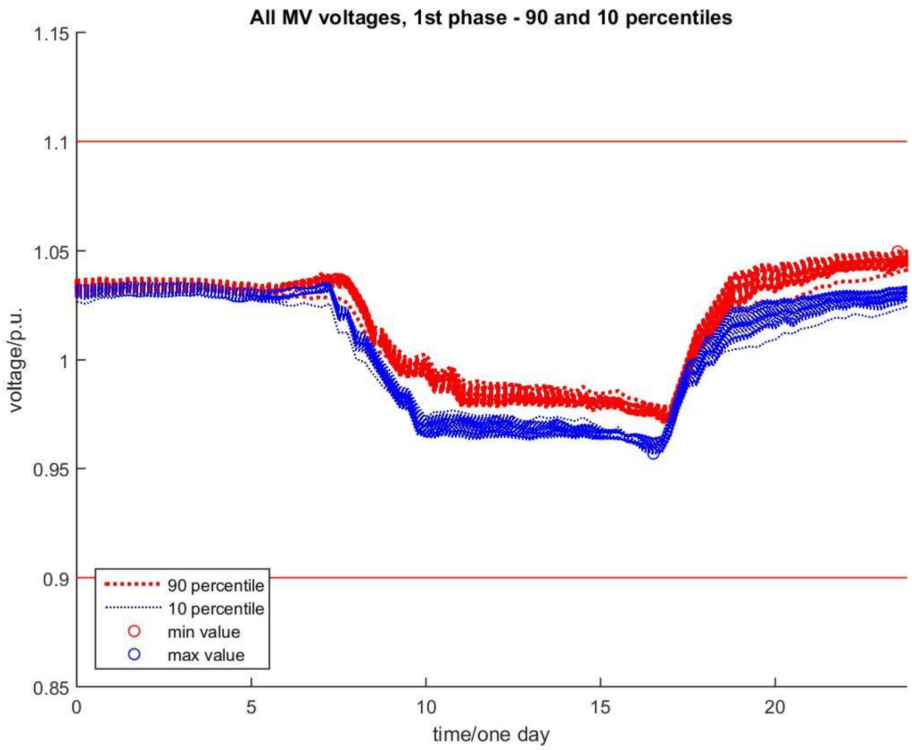

Figure 12.25: MV voltages, Scenario 6, summer

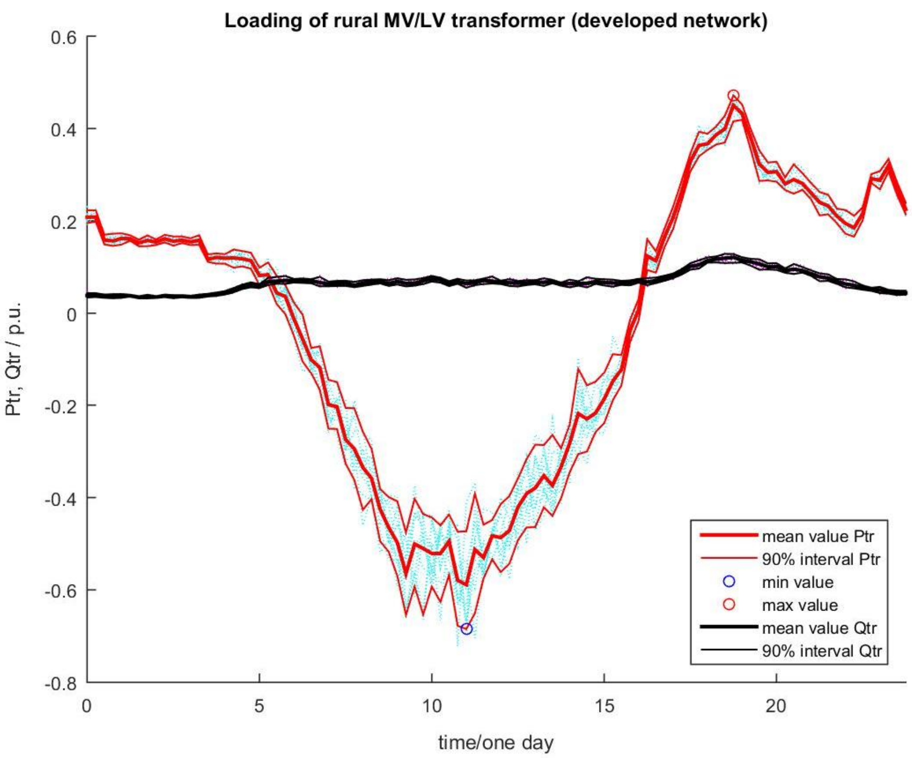

Figure 12.26: Rural transformer, Scenario 6, summer

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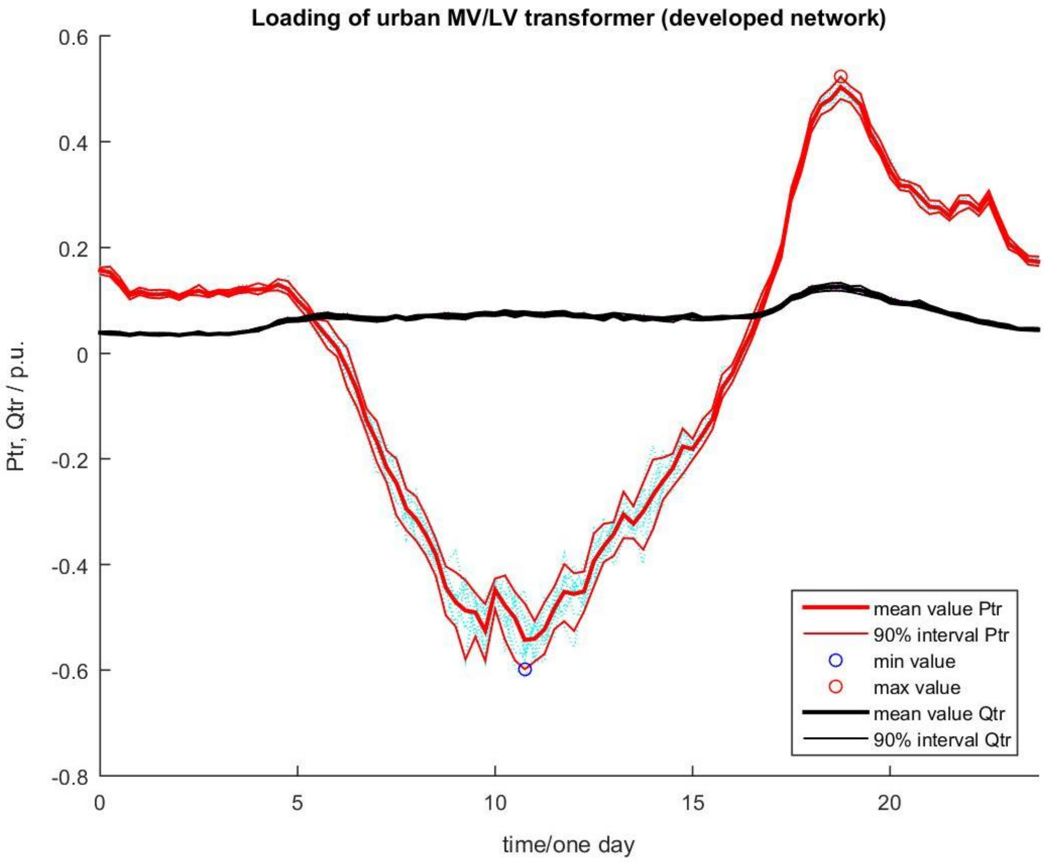

Figure 12.27: Urban transformer, Scenario 6, summer

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12.3.3 **Scenario 9**

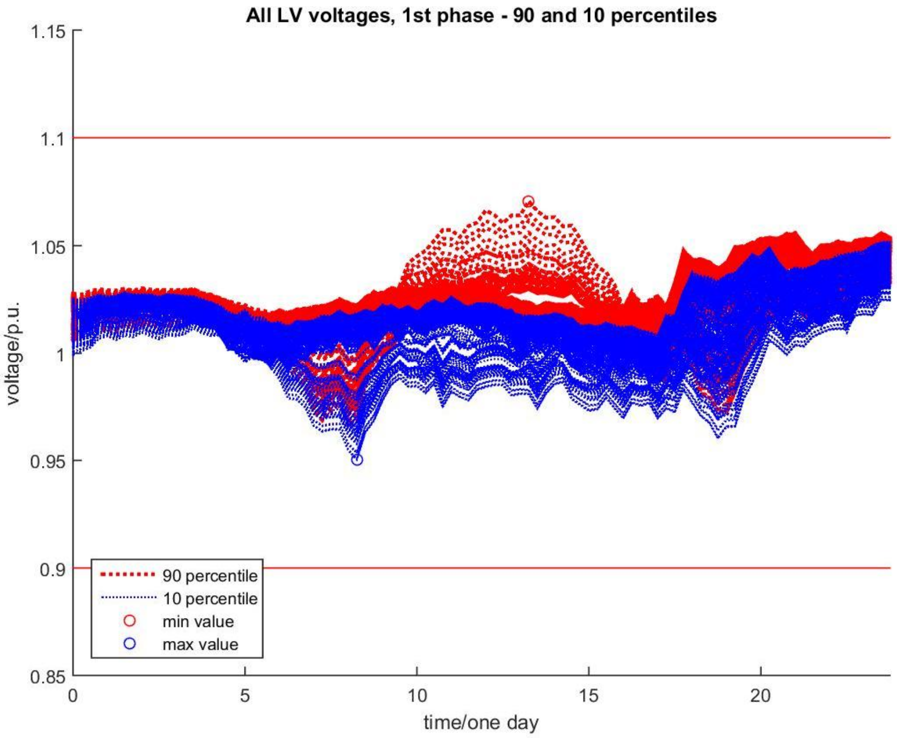

Figure 12.28: LV voltages, Scenario 9, winter

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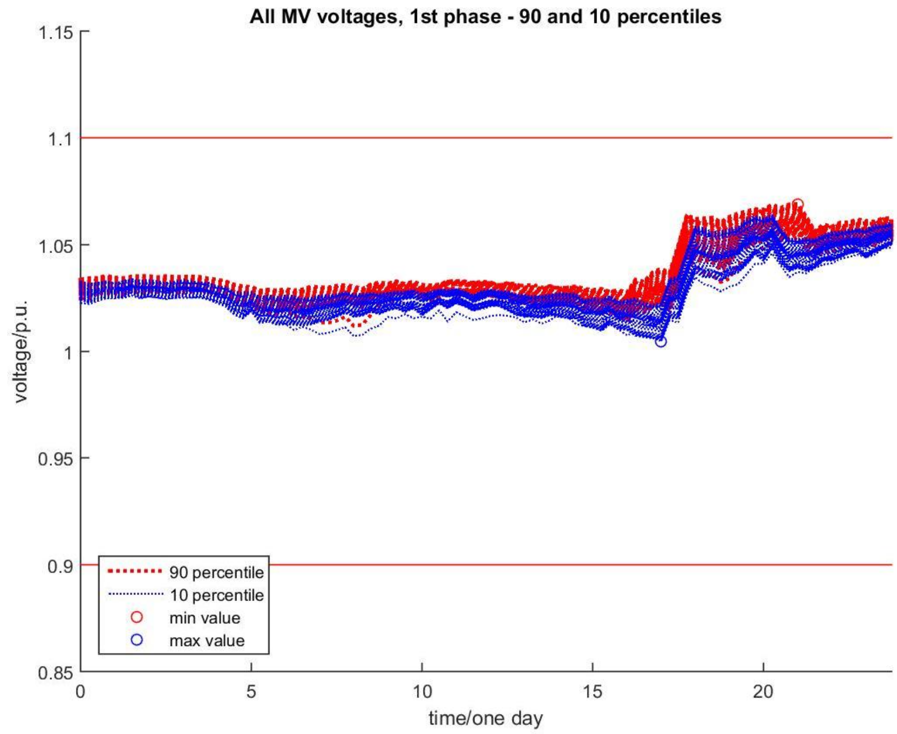

Figure 12.29: MV voltages, Scenario 9, winter

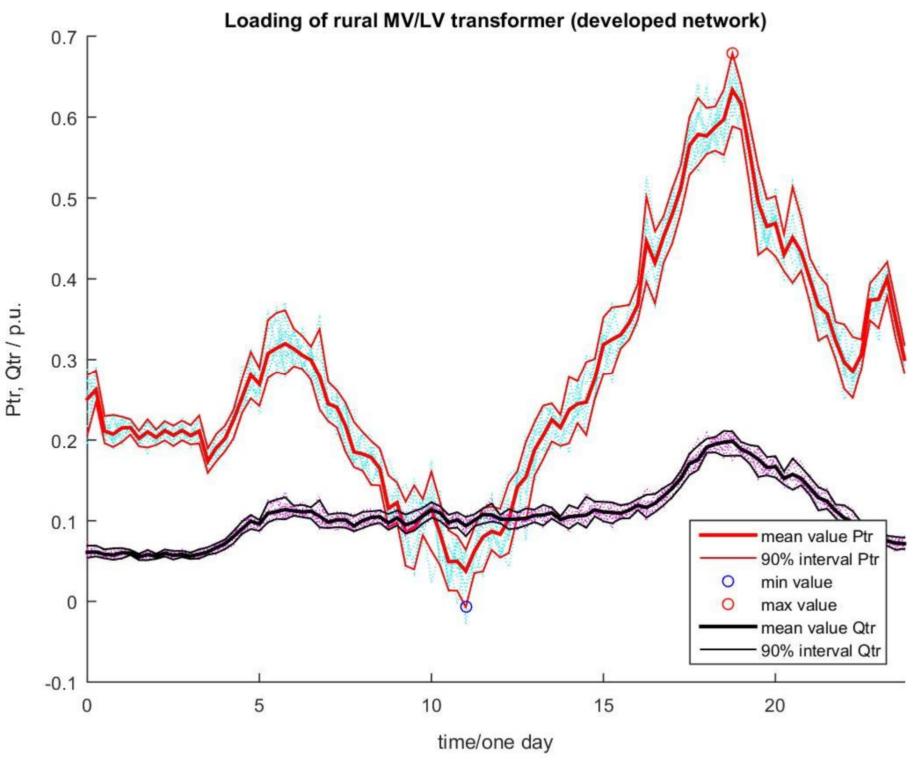

Figure 12.30: Rural transformer, Scenario 9, winter

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research and innovation programme under grant agreement No 646426

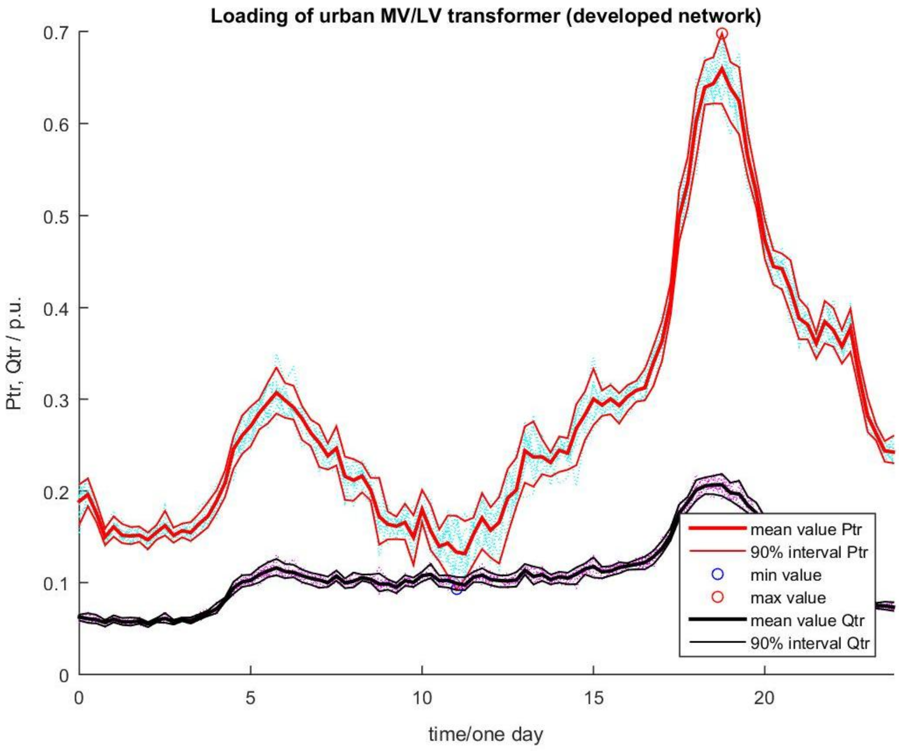

Figure 12.31: Urban transformer, Scenario 9, winter

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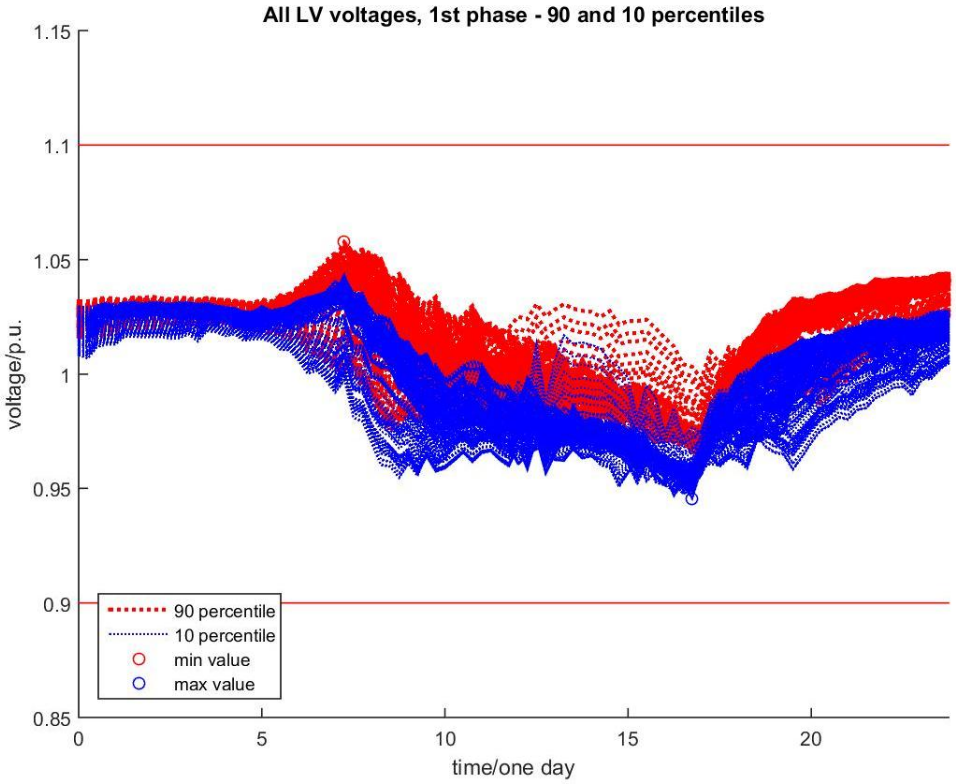

Figure 12.32: LV voltages, Scenario 9, summer

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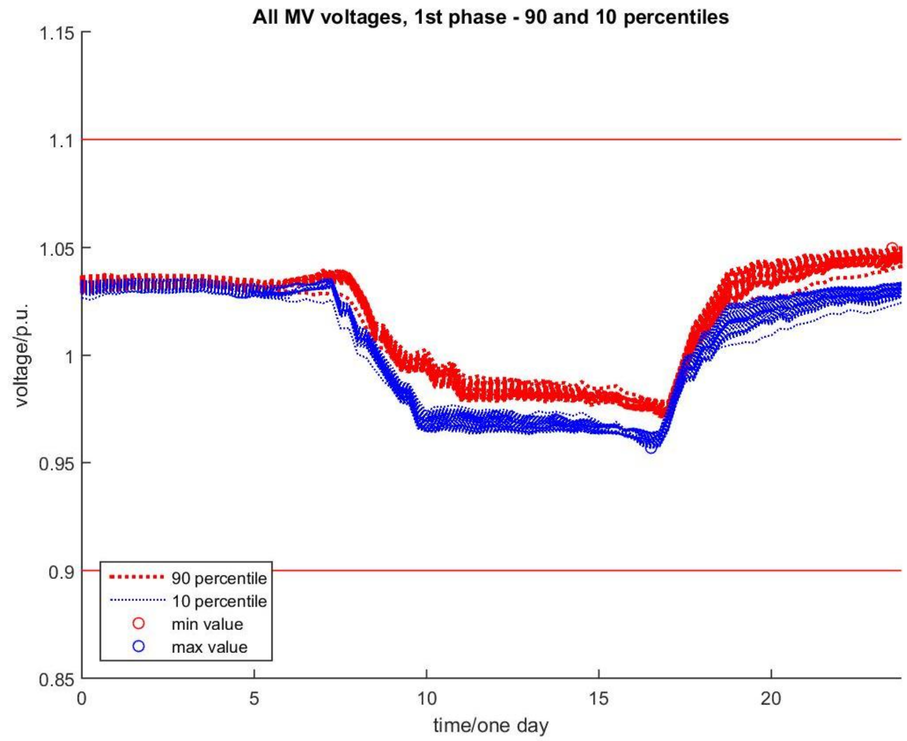

Figure 12.33: MV voltages, Scenario9, summer

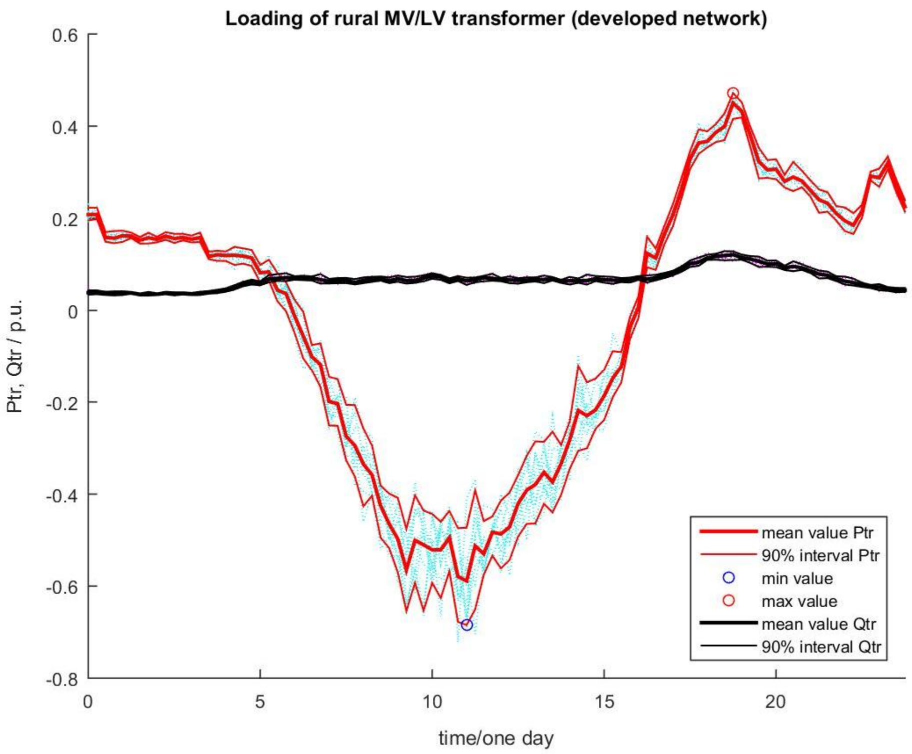

Figure 12.34: Rural transformer, Scenario 9, summer

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research and innovation programme under grant agreement No 646426

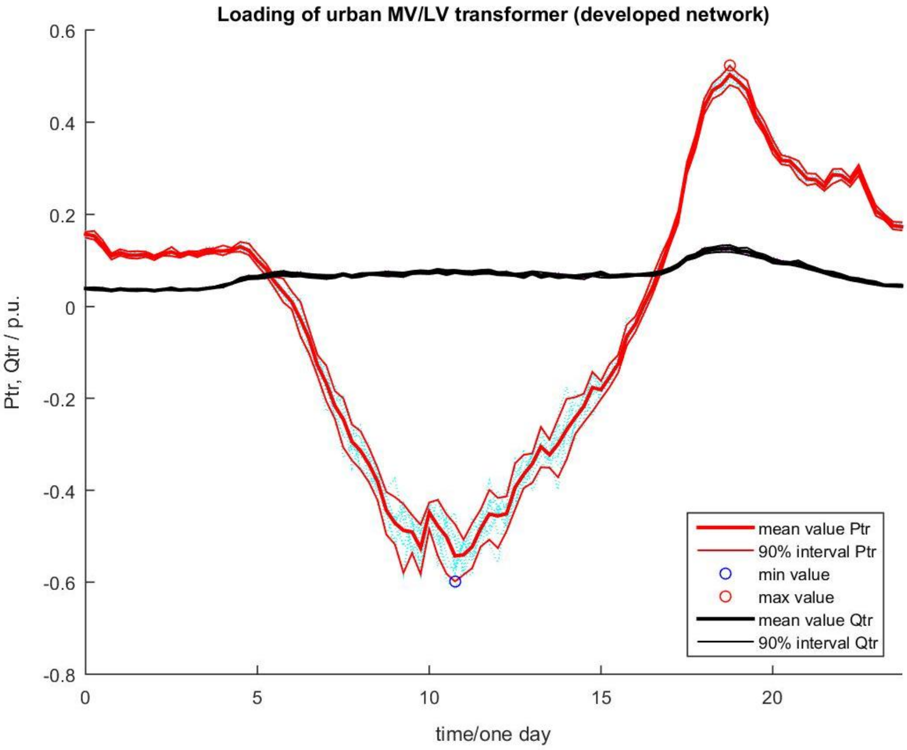

Figure 12.35: Urban transformer, Scenario 9, summer

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12.3.4 Scenario 10

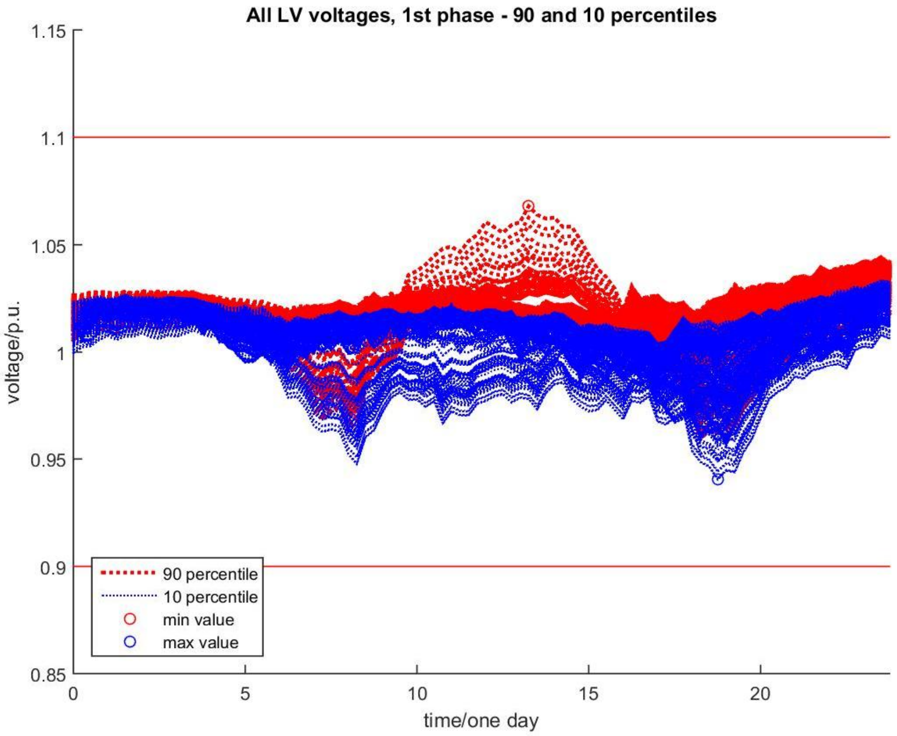

Figure 12.36: LV voltages, Scenario 10, winter

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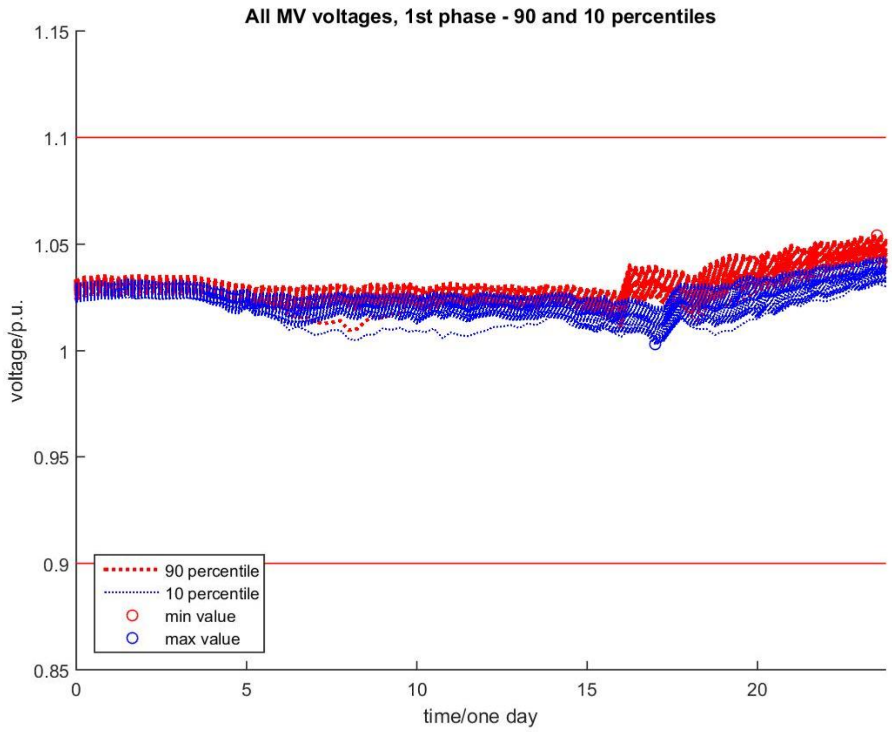

Figure 12.37: MV voltages, Scenario 10, winter

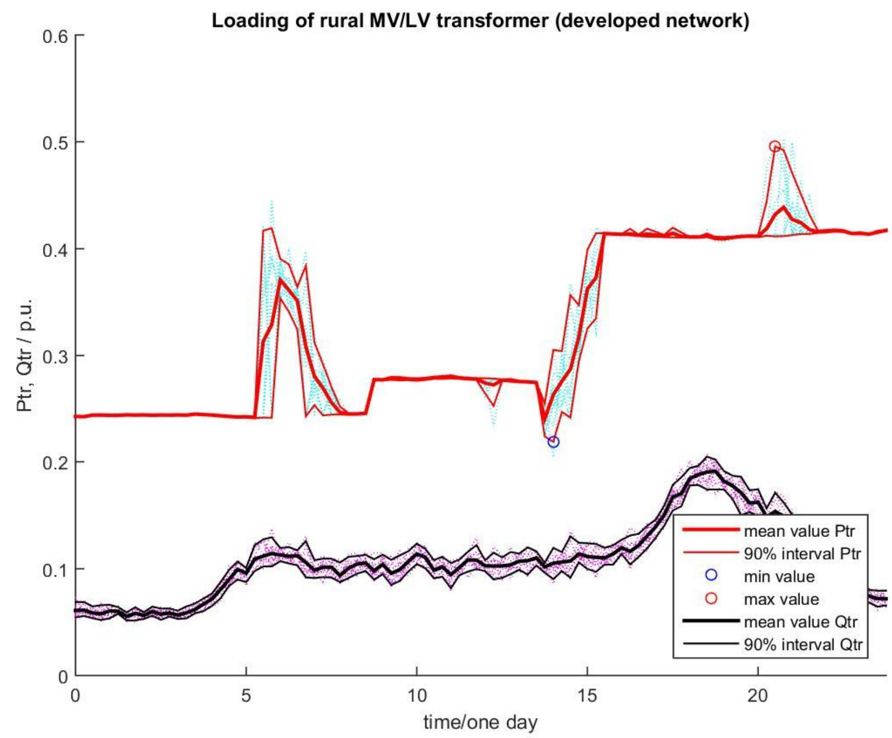

Figure 12.38: Rural transformer, Scenario 10, winter

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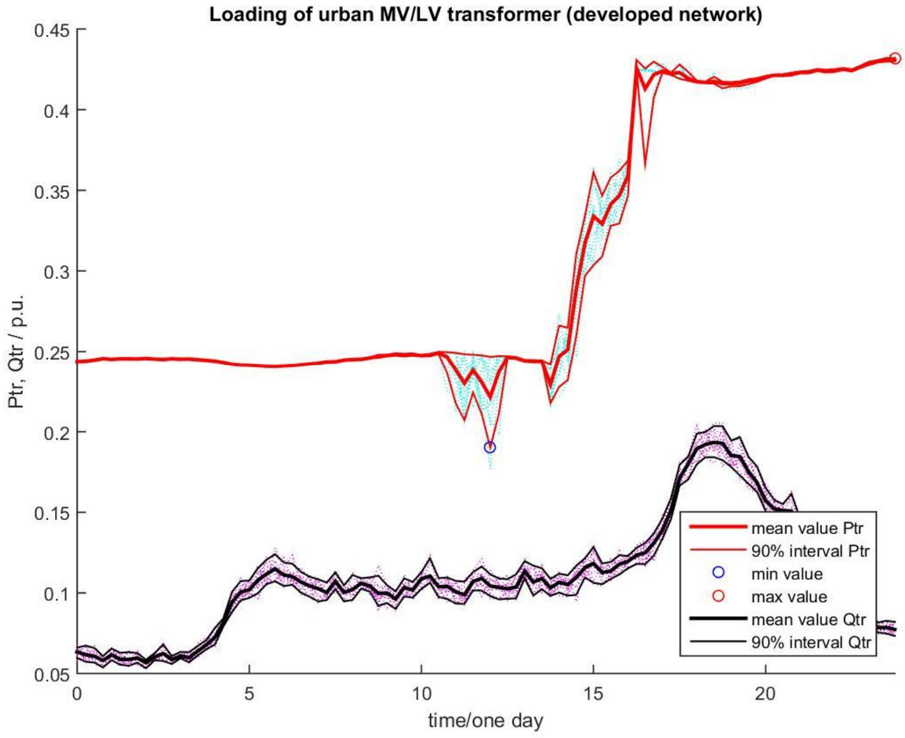

Figure 12.39: Urban transformer, Scenario 10, winter

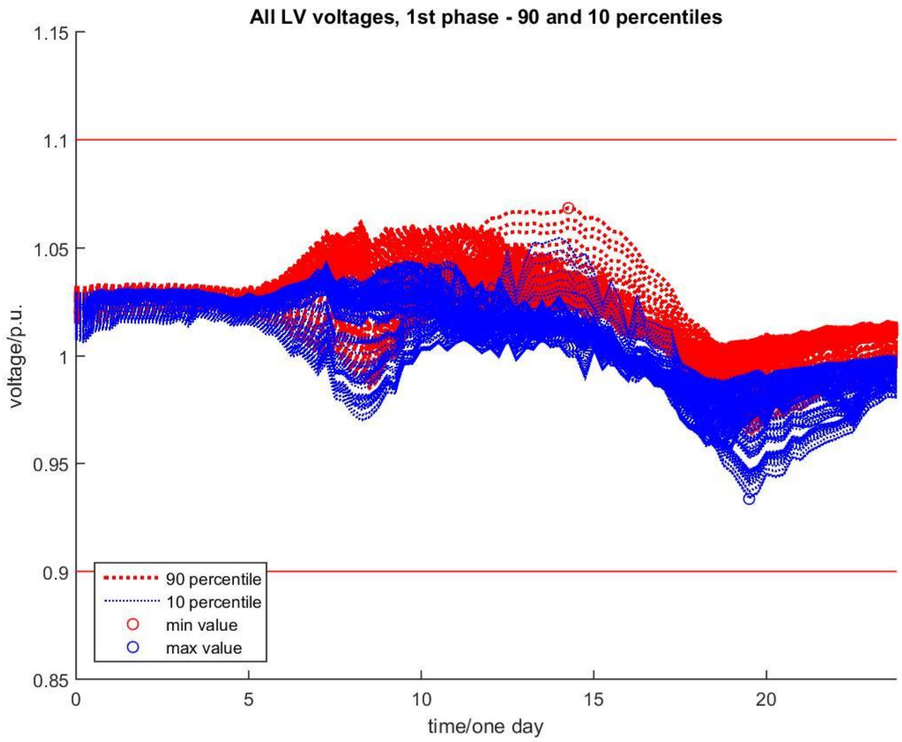

Figure 12.40: LV voltages, Scenario 10 summer

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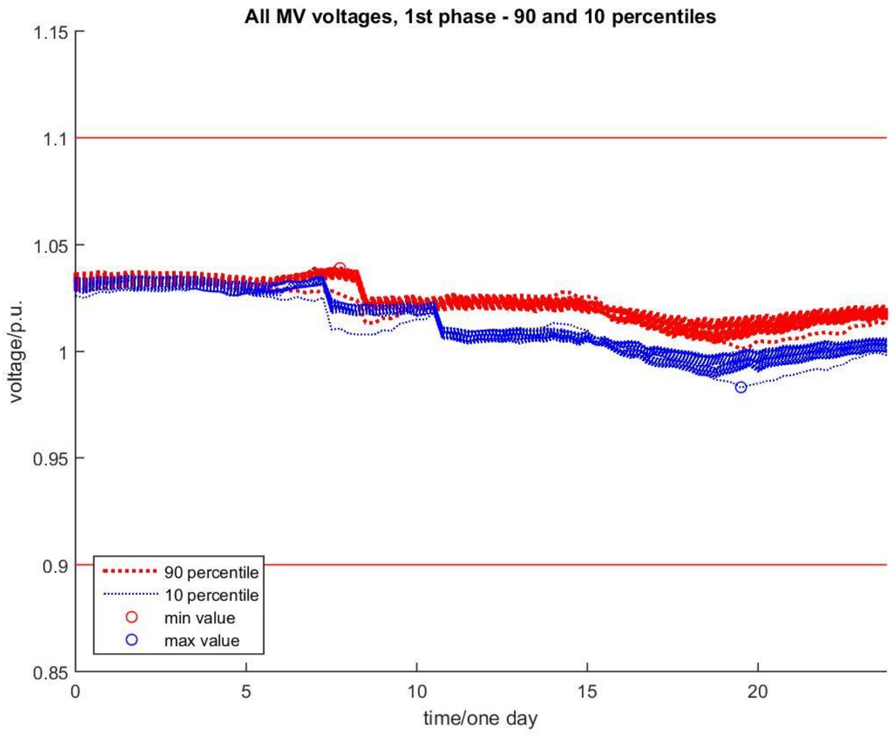

Figure 12.41: MV voltages, Scenario 10, summer

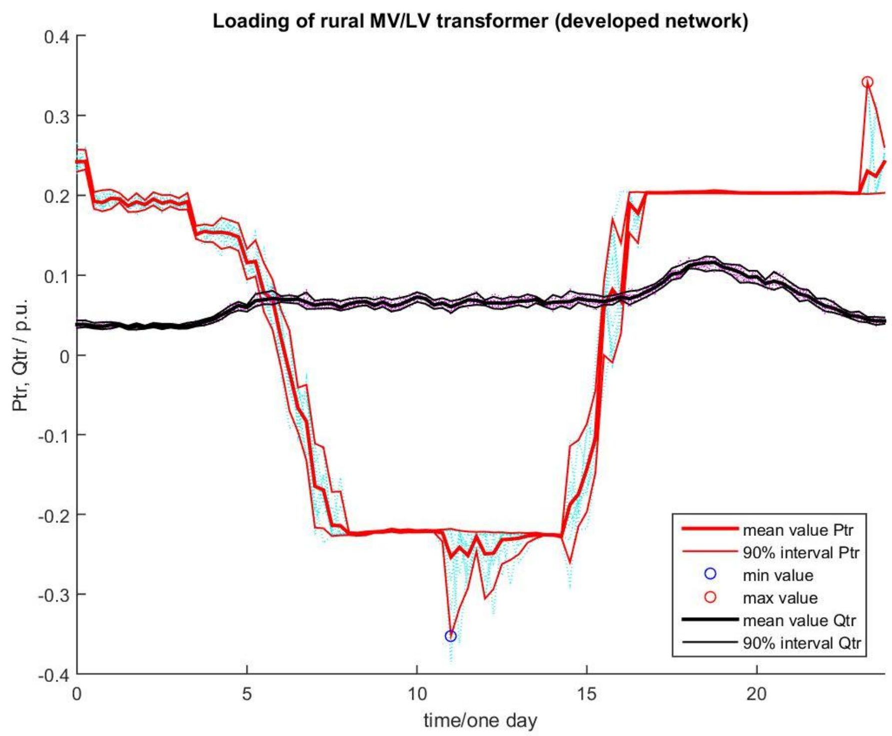

Figure 12.42: Rural transformer, Scenario 10, summer

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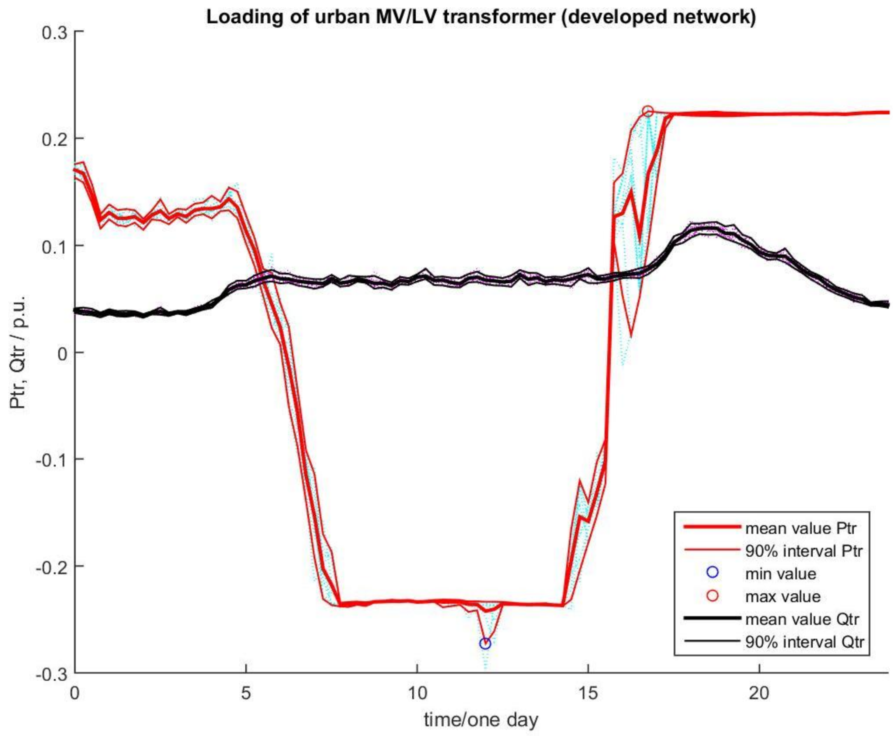

Figure 12.43: Urban transformer, Scenario 10, winter

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