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INTERPLAN
INTEgrated opeRation PLAnning tool towards the Pan-European Network

Work Package 5

Operation planning and semi-dynamic simulation

Deliverable D5.4

Control system logics: cluster and interface controllers (final version)

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Table of contents

Abbreviations

AENS	*Average energy not supplied*
AMPL	*A Mathematical Programming Language*
AS	*Ancillary Service*
BESS	*Battery energy storage system*
BSC	*Base showcase*
BUC	*Base use case*
cdf	*Cumulative distribution function*
CF	*Control function*
DER	*Distributed energy resources*
DG	*Distributed generation*
DR	*Demand response*
DSM	*Demand Side Management*
RES	*Renewable energy sources*
DRES	*Distributed renewable energy resources*
DSL	*DIgSILENT Simulation Language*
DSO	*Distribution system operator*
EHV	*Extra high voltage*
ENS	*Energy not supplied*
ENTSO-E	*European Network of Transmission System Operators for Electricity*
EU	*European Union*
EV	*Electric vehicle*
fFRC	*Fast frequency restoration control*
HV	*High voltage*
FFR	*Fast Frequency Response*
IEAR	*Interrupted energy assessment rate*
IEX	*Information exchanged*
INTERPLAN	*Integrated operation planning tool for the pan-European network*
KPI	*Key performance indicator*
LV	*Low voltage*
LF	*Load Flow*
MV	*Medium voltage*
OPF	*Optimal Power Flow*
PF	*Power Flow*
RES	*Renewable energy sources*
RoCoF	*Rate of change of frequency*
SAIDI	*System average interruption duration index*
SAIFI	*System average interruption frequency index*
SI	*System inertia*
SC	*Showcase*
Sync. G	*Synchronous Generator*
TSO	*Transmission system operator*
UC	*Use case*
UFLS	*Under-frequency load shedding*
WP	*Work Package*
WTG	*Wind turbine generator*

Executive Summary

The deliverable provides the presentation, discussion and comparison of the five different showcase (SC) results against the base showcase (BSC) results given by the calculated key performance indicators (KPIs) as well as a proof-of-concept of the INERTPLAN tool for one specific showcase (SC3). The developed cluster and interface controllers have been applied to for the different showcases and the included controllers presented in deliverable D5.3 [1]. As this deliverable is an update of deliverable D5.3, the presentation of these control system logics is also a part of this deliverable D5.4.

The Integrated Network Operation Planning tool developed in INTERPLAN is defined as *a methodology consisting of a set of tools (grid equivalents, control functions) for the operation planning of the Pan-European network by addressing a significant number of system operation planning challenges of the current and the future 2030+ EU power grid, from the perspective of the transmission system, the distribution system, and with a particular focus on the transmission-distribution interface*. In this sense, the main goal of the tool is to achieve the operation planning of an integrated grid from the perspective of a Transmission System Operator (TSO) or a Distribution System Operator (DSO) through handling efficiently and effectively intermittent Renewable Energy Sources (RES) as well as the emerging technologies such as storage, demand response and electric vehicles. In fact, the tool supports utilizing flexibility potential coming from RES, demand side management (DSM), storage and electric mobility for system services in all network control levels.

The INTERPLAN tool consists of three main stages: 1. Simulation functionalities, KPIs and scenario selection, 2. Grid model selection/preparation, 3. Simulation & Evaluation. First of all, the user identified as a TSO or a DSO selects the planning criteria he wants to consider for the network operation planning. This selection is based on a pre-defined list of planning criteria, such as minimizing losses, maximizing share of RES, mitigating grid congestion, assuring transient stability, optimizing TSO/DSO interaction, assuring voltage stability, and minimizing energy interruption.
Under the stage 1, the user selects the simulation functionality (e.g. Optimal Power Flow (OPF), Load Flow Sensitivity, Stability Analysis Functions, and Reliability Assessment), the KPIs and the operating future scenario among the four INTERPLAN scenarios with the related target year. The stage 2 of the INTERPLAN tool is dedicated to the grid model selection and preparation. Under this stage, the user selects the grid model for the simulation phase in the next stage, and it is then adapted to the INTERPLAN scenario selected under the previous stage. If a grid equivalent model is required for the simulation phase, the user can select it from the grid equivalents library consisting of a list of pre-defined grid equivalents, or he/she can generate a grid equivalent model through the grid equivalent generation procedure made available by the INTERPLAN tool. When the grid model is decided, it is then adapted to the scenario selected under stage 1 through the scenario adaptation procedure.
Finally, the stage 3 of INTERPLAN tool is dedicated to the simulation and evaluation phase. Under this stage, the user performs the simulation by using one of the INTERPLAN control solutions (INTERPLAN control functions embedded within the use cases or the showcases) [2] according to the operation challenge that wants to investigate and the choices done in the previous stages. The evaluation phase follows the simulation one. In detail, here, the user makes the evaluation through the KPIs found in the simulation phase. If the user is satisfied with the KPI(s) found, the evaluation is complete and the process stops. Otherwise, the user can decide to investigate further INTERPLAN solutions addressing the same operation challenge under the same planning criteria. In this latter case, the process re-starts from stage 1.

The deliverable includes the application of the control system logics through cluster and interface controllers (described in deliverable D5.3 [1]) to the five INTERPLAN SCs (documented in deliverable D5.1 [3]) including:

1. SC1: Low inertia systems
2. SC2: Effective distributed energy resources (DER) operation planning through active and reactive power control
3. SC3: TSO-DSO power flow optimization
4. SC4: TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles
5. SC5: Optimal energy interruption management

The proof of concept for the INTERPLAN tool is presented in chapter 5 exemplary for SC3. Here, all the different steps of the INTERPLAN tool are described regarding the three main stages explained before from a perspective of an identified user. The detailed presentation and discussion of the results for the different SCs by the herein presented KPIs is given by this deliverable in chapter 6. The comparison of the regarded KPIs to the BSC simulation show that the developed controllers fulfil their tasks regarding the different objectives of the SCs presented in chapter 4.

1. Introduction

1.1 Purpose and scope of the document

This document falls in the scope of INTERPLAN activities on operation planning and semi-dynamic simulation.
As a result of the related work, the methodology to implement the control functions related to the five INTERPLAN showcases has been established and the simulation results are reported through KPI calculation. The list of the showcases is as follows:

1. Low inertia systems
2. Effective DER operation planning through active and reactive power control
3. TSO-DSO power flow optimization
4. TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles
5. Optimal energy interruption management

The main goals of deliverable D5.4 are described as follows:

- Definition of the proper control functions for all seven use cases listed as follows:
    1. Coordinated voltage/reactive power control
    2. Grid congestion management
    3. Provision of tertiary control reserve based on coordinated TSO-DSO optimal power flow calculations
    4. Fast Frequency Restoration Control
    5. Power balancing at DSO level
    6. Inertia management
    7. Optimal generation scheduling and sizing of DER for energy interruption management
- Establish the implementation method for applying control functions in use cases and then in showcases.
- Identify the final structure of each showcase based on the chosen control functions.
- Specify the interaction among control functions and cluster and interface controllers.
- Finalize the detailed method to implement control functions on the INTERPLAN showcases.
- Identify the properties of the test cases and grid equivalenting method needed to perform the simulations for showcases.
- Perform showcases simulations and calculate the KPIs.
- Compare the KPIs after simulation of showcases and base showcases.
- Conduct a proof-of-concept for one of showcases to prove the applicability and compatibility of the showcases simulation within the INTERPLAN tool platform.

Deliverable D5.4 presents the updated version of a previous deliverable of the INTERPLAN control system logics D5.3 [1] in which the simulation results and proof-of-concept are added. The validation of all showcase simulations are presented in another deliverable named "D.6.4 Report on the validation tests.

1.2 Structure of the document

The deliverable consists of eight chapters. The purpose and scope of the deliverable are described in the first chapter. The second chapter consists of a short description of the INTERPLAN project. In the third chapter, the methodology used to develop control functions within the showcases are presented.
The fourth chapter presents the detailed description of the developed control function logics in the

five INTERPLAN showcases. In the fifth chapter, the proof-of-concept for the showcase 3 is conducted.The sixth chapter includes the showcases simulation results, KPIs calculation, and the relevant discussion regarding the KPIs. Chapter 7 is a summary of the report. In chapter 8, the references are presented, whereas in the Annex 1, the glossary of the terms and definitions used in the INTERPLAN project can be found.

2. INTERPLAN project

The European Union (EU) energy security policy faces significant challenges as we move towards a pan-European network based on the wide diversity of energy systems among EU members. In such a context, novel solutions are needed to support the future operation, resilience and reliability of the EU electricity system in order to increase the security of supply and also accounting for the increasing contribution of renewable energy sources (RES). The goal of the INTERPLAN project is to provide an INTEgrated opeRation PLAnning tool towards the pan-European Network, with a focus on the TSO-DSO interfaces to support the EU in reaching the expected low-carbon targets, while maintaining the network security and reliability.

INTERPLAN project looks at the potential operation challenges which TSOs and DSOs are called to address in the 2030+ power system. In fact, the ongoing deployment of the pan–European Network strongly depends on different potential scenarios related to the RES share in generation and installed capacity, as well as penetration of emerging technologies, such as storage and demand response (DR). Although these factors represent the preferential patterns to meet the EU decarbonized energy targets for 2030 and 2050, they bring new challenges for the energy system, which will outline the key operational needs of the European grid operators in the near future.
In such a context, TSOs will need to evolve progressively from a "business as usual approach" to a proactive approach in order to avoid a bottleneck effect in the future European grid, and this could be addressed through a proper system operation planning. As for the distribution networks, they have been traditionally designed and treated to transport electrical energy in one direction, i.e., from the generation units connected to the transmission system to the end-users. However, with the growing share of non-dispatchable distributed generation, customers are increasingly generating electricity themselves, and, by becoming "prosumers", they are shifting from the end point to the center of the power system. As a result, DSOs will need to actively manage and operate a smarter grid through appropriate system control logics, by utilizing the flexibility potential in the grid, with the aim to optimize the distribution network performance. Furthermore, an additional critical issue is the interface between transmission and distribution systems, which is expected to evolve in the near future through a mutual cooperation between TSOs and DSOs, with the aim to address operational challenges as congestion of transmission and distribution lines and at the interface among them, voltage support between TSOs and DSOs, and power balancing concerns. The increasing complexity of the grids requires control and operation planning tools even more advanced and homogenous among European countries.

With these premises, the INTERPLAN idea was born. In such a framework, the projects aims to develop control system logics which suit the complexity of the integrated grid, while managing all relevant flexibility resources as "local active elements" in the best manner. Moreover, by looking at the 2030+ power system, the project also addresses policy and regulation aspects aiming to identify a set of possible amendments to the existing grid codes, reflecting the developments achieved in INTERPLAN through its tool, use cases and showcases. The aim of this analysis is to break down the current barriers to the integration of emerging technologies and to foster TSO-DSO cooperation in managing grid operation challenges.

In detail, a methodology for a proper representation of a "clustered" model of the pan-European network is provided, with the aim to generate grid equivalents as a growing library able to cover a number of relevant system connectivity possibilities occurring in the real grid, by addressing a number of operation planning issues at all network levels (transmission, distribution and TSO-DSO interfaces). In this perspective, the chosen top-down approach leads to an “integrated” tool, both in terms of voltage levels, moving from high voltage level down to low voltage level up to end user, as well as in terms of developing a bridge between static, long-term planning and operational issues considerations, by introducing proper control functions in the operation planning phase. Therefore, in the project, novel control strategies and operation planning approaches are investigated in order to ensure the security of supply and resilience of the interconnected EU electricity power networks, based on a close cooperation between TSOs and DSOs, thereby responding to the crucial needs of the ongoing pan-European network and its operators.

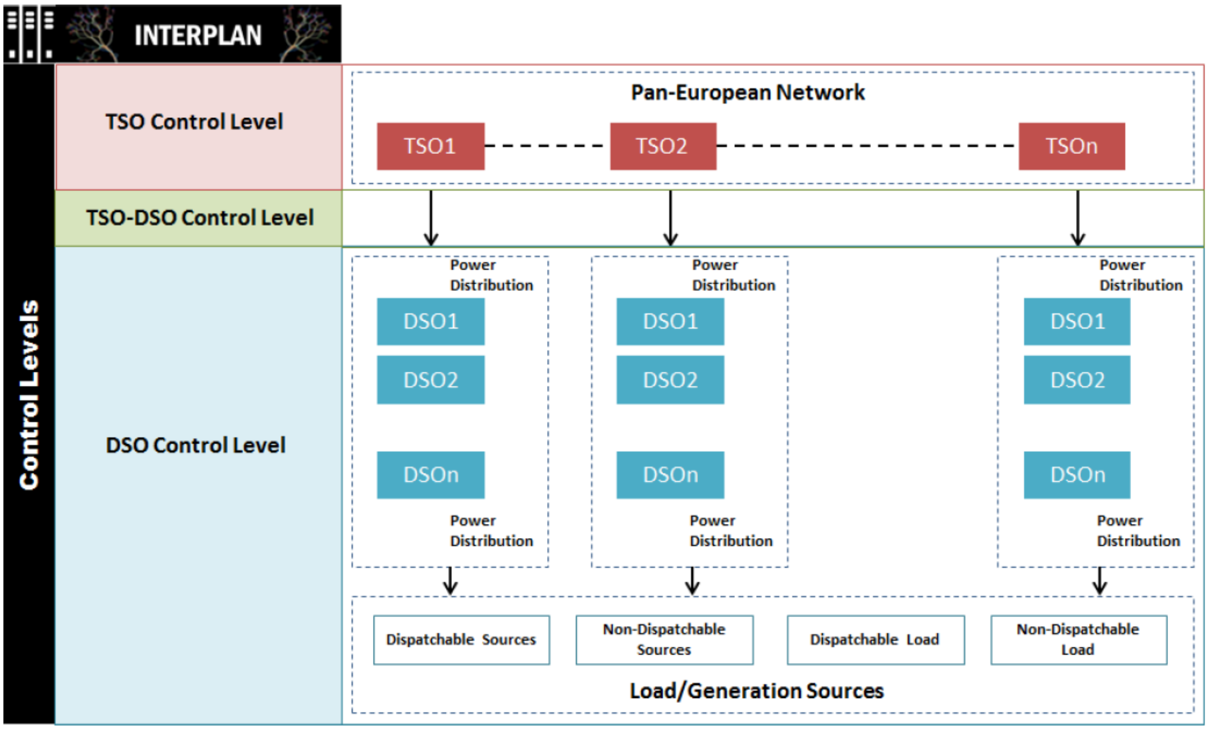


Figure 1: INTERPLAN concept

3. Methodology

3.1 Summary of the INTERPLAN Integrated Network Operation Planning tool

The integrated network operation planning tool developed in INTERPLAN consists of the following stages, which are presented in Figure 2 [4]:

- Stage 1: Simulation functionalities, KPIs and scenario selection;
- Stage 2: Grid model selection/preparation;
- Stage 3: Simulation & Evaluation.

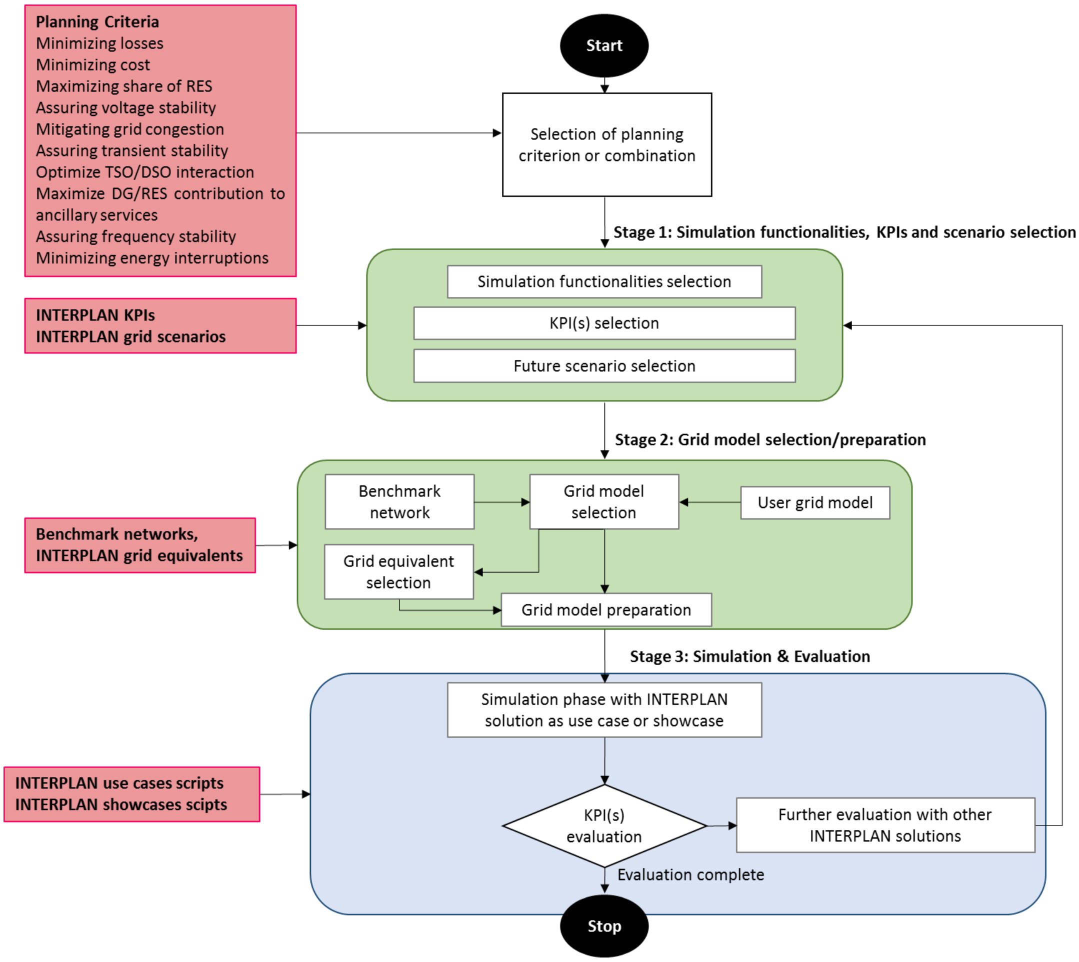


Figure 2: INTERPLAN tool overview [4]

Briefly, after the selection of planning criteria, each stage includes:

- ✓ **Stage 1**: A simulation functionality is selected from the list of simulation functionalities used for INTERPLAN use cases and showcases. The KPIs and scenario can also be selected from INTERPLAN KPIs and INTERPLAN scenarios.
- ✓ **Stage 2**: The user can select the grid model for simulation in this stage by using an own grid model or a benchmark. If a grid equivalent is required, the user can select one in the library or using the grid equivalent procedure available in the tool.
- ✓ **Stage 3**: The user performs the simulation either directly without selecting any of the INTERPLAN solutions or by using one of them according to the operation challenge he/she wants to investigate.

The current deliverable presents the INTERPLAN solution methods in stage 3 shown in Figure 3, which correspond to the control system logics embedded in INTERPLAN use cases and showcases.

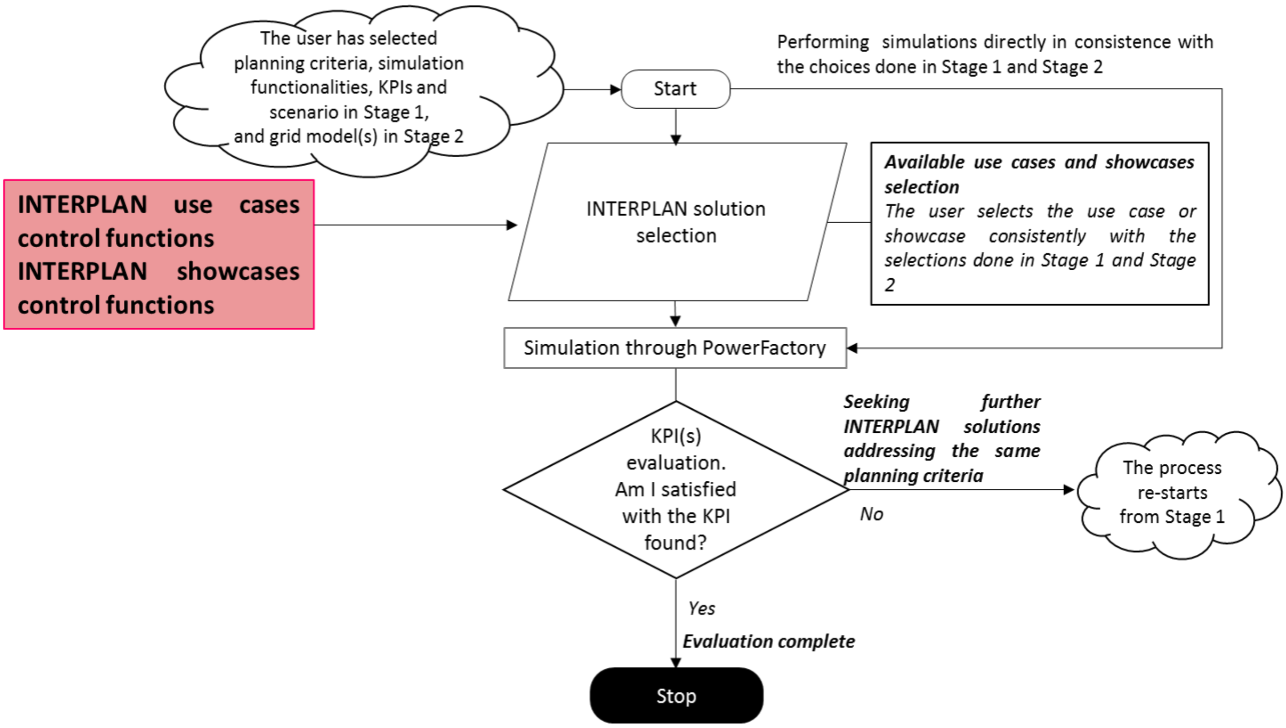


Figure 3: Stage 3 of INTERPLAN tool [4]

3.2 Development of control system logics

3.2.1 Cluster and interface controllers

Control functions are a set of functions and set points defined for specific elements of the network such as RES and loads in order to reach the goal of a use case or showcase. According to Figure 4, a cluster controller, that can be a central controller in a substation, aggregates the signals of control functions in a part of the network. More cluster controllers in a larger part of the network can be interconnected with interface a controller, which can facilitate the exchange command among cluster controllers. The interface controller can be, for example, a transmission operator acting as an interface between several cluster controllers.

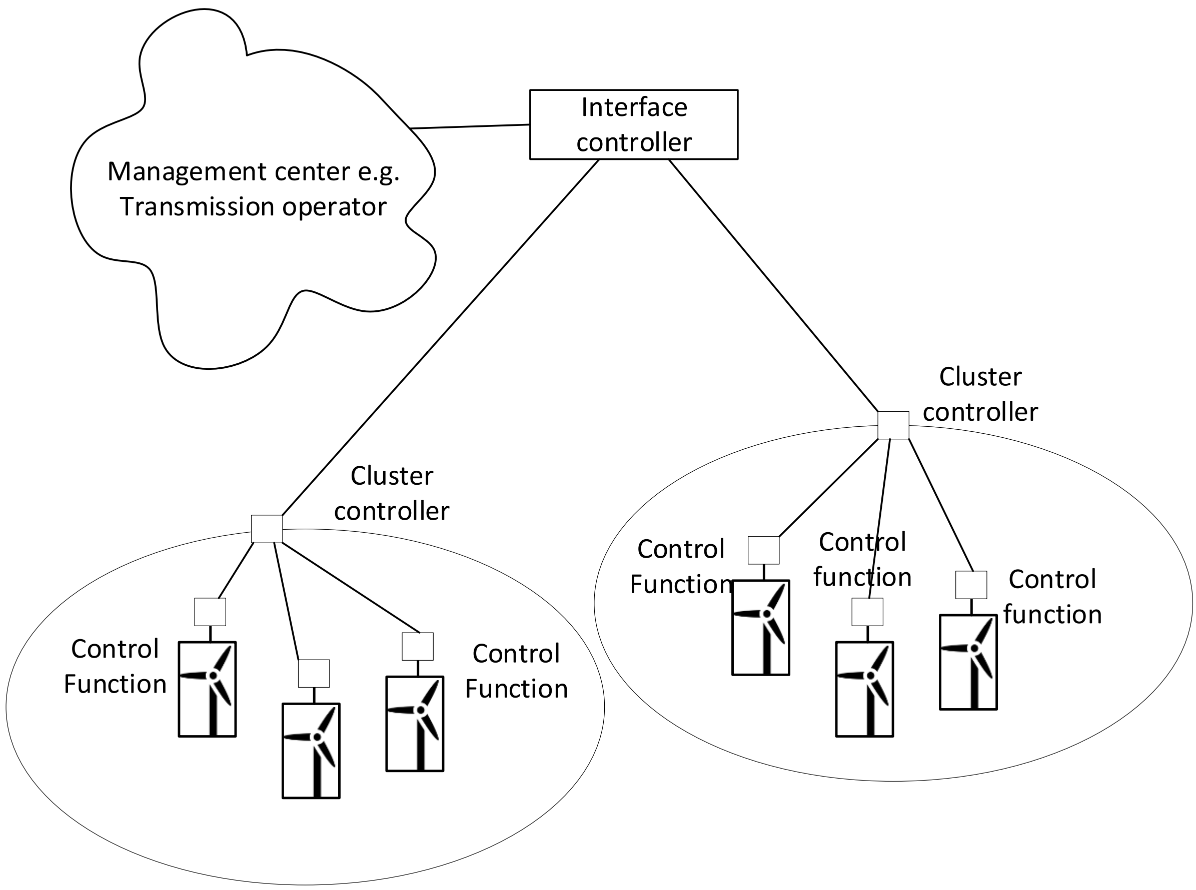


Figure 4: Cluster and Interface controllers

3.2.2 Control functions development

As documented in D5.2 [4], the INTERPLAN base showcases have been implemented without employing control functions. It means that the grid status was analysed and possible critical operational issues were discovered. The control functions here are designed to overcome critical issues as well as to meet the requirements of the planning criteria. The list of planning criteria is as follows:

1. Minimize losses
2. Minimize costs
3. Maximize share of RES
4. Assure voltage stability
5. Mitigating grid congestion
6. Assure transient stability
7. Optimize TSO/DSO interaction
8. Maximize distributed generation (DG)/RES contribution to ancillary services
9. Assure frequency stability
10. Minimize energy interruptions

The control functions for each showcase need to be developed in a way that those challenges can be covered. Since each showcase contains one or more use cases as depicted in Figure 5, the control functions need to be first designed and implemented in use cases. Afterwards, use cases with related control functions can be combined to form the relevant showcase. The assigned planning criteria for each showcase are also depicted in Figure 5.

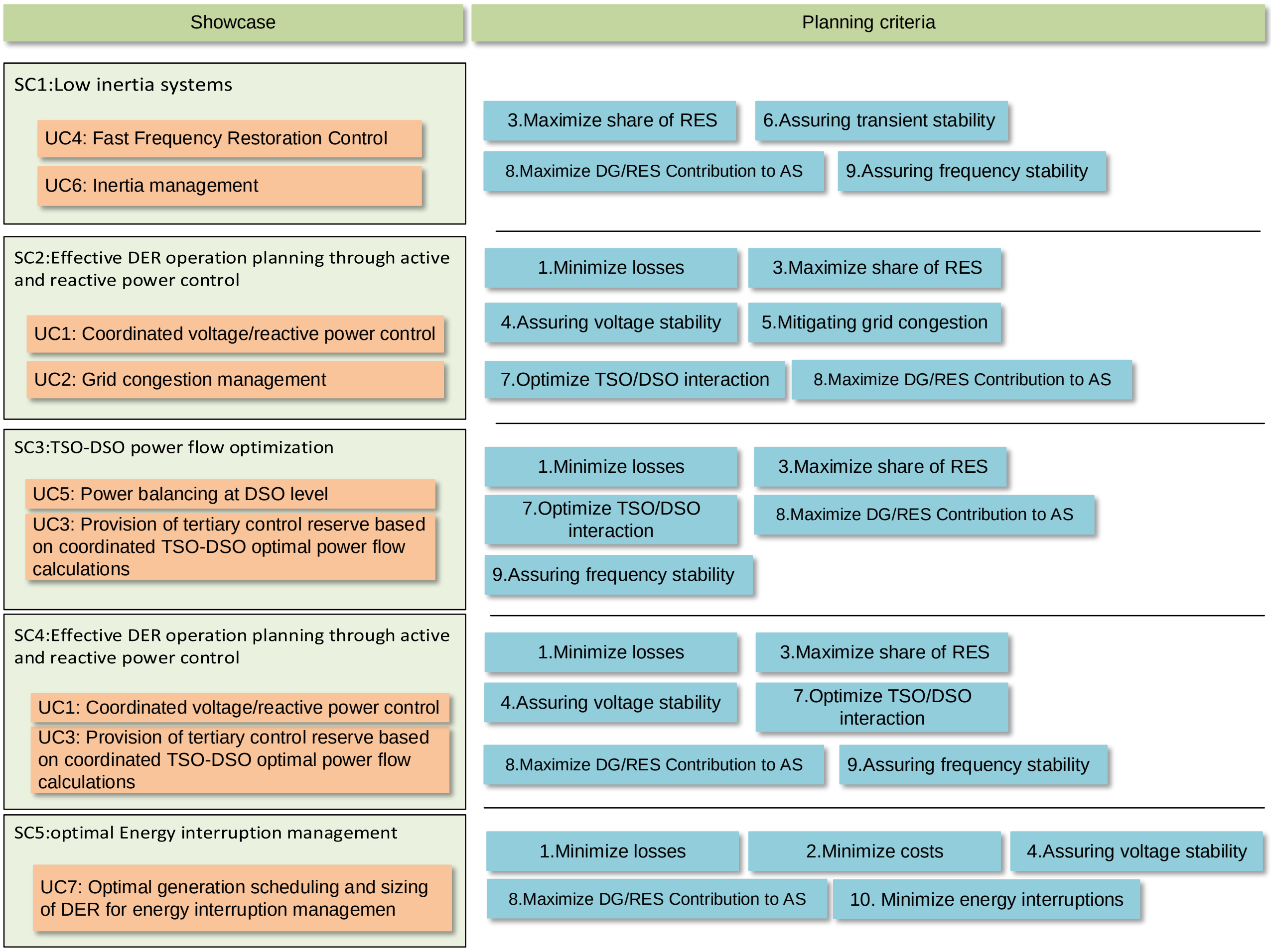


Figure 5: Relevant planning criteria and use cases for each showcase

Table 1 below presents the developed control functions for each use case and relevant showcase by indicating their benefits to meet the planning criteria and the programming language to implement. The development of control functions for each use case has been performed by entire consortium as follows:

- Use case 1: DG and renewable resource dispatch are used to manage reactive power while minimizing the total network losses.
- Use case 2: In order to overcome the grid congestion, active power management in DG is taken into consideration as proper control function.
- Use case 3: Optimization of power flow is applied in the network with high share of RES and DG to maximize the share of RES in providing tertiary reserve and minimize the power losses.
- Use case 4: To restore frequency stability, active power management in DG is performed.
- Use case 5: Storage systems and DG are used to maximize the local usage of energy within the DSO grid and minimize the energy exchange between TSO and DSO, while minimizing power losses and maximizing share of RES.
- Use case 6: Synthetic inertia (SI) is implemented in order to support frequency as local and central control function, to assure required RoCoF (rate of change of frequency).
- Use case 7: Three control functions are applied: the first control function is load shedding to solve under voltage problems during a contingency. To solve the over-voltage problem during a contingency, two control functions including PV curtailment and DG redispatch are employed as the second and third control functions, respectively.

Table 1: Control functions and their benefits in each use case and showcase

Showcase	Use case	Proposed control function	Benefits of control function	Programming language
SC1	UC4	DG	Active power management to restore frequency stability	Python, DSL(DIGsILENT simulation language) model (PowerFactory)
	UC6	SI controllers	Local controllers integrated into inverters for inertial support	DSL
		SI controller	Central controller for managing RoCoF in a chosen time window	Python
SC2	UC1	RES & DG	Reactive power management	PowerFactory/Ampl
	UC2	DG	Active power management to solve/mitigate congestions problems	Python
SC3	UC5	DG & storage systems	Minimizing power flow through 110 kV transformers and maximizing local usage of the energy in the DSO grid, as well as minimizing losses and maximizing share of RES	Python
	UC3	RES & DG, Demand response	Optimization of power flow to maximize the share of renewable energy sources in providing tertiary reserve and minimize the power losses	Python + PowerFactory
SC4	UC1	RES & DG	Reactive power management	PowerFactory/Ampl
	UC3	RES & DG, Demand response	Optimization of power flow to maximize the share of renewable energy sources in providing tertiary reserve and minimize the power losses	Python + PowerFactory
SC5	UC7	Load shedding	Load shedding to solve under voltage problems during a contingency	Python+OPF (PowerFactory)
		PV curtailment	Active power curtailment to solve voltage problems during a contingency	Python+QDSL model (PowerFactory)
		DG redispatch	Active power redispatch to solve and under voltage problems during a contingency	Python+OPF (PowerFactory)

4. Showcases control functions

As mentioned in the previous section, a showcase consists of one or several use cases with different control functions. Based on the characteristics and goals of the composing use cases, the relevant showcase may need to perform a grid equivalenting method [5].Eventually, the showcase needs to be implemented on a test case with specific features in order to evaluate the effectiveness of the developed control functions. Therefore, this section presents the control functions developed for the following showcases:

1. Low inertia systems;
2. Effective DER operation planning through active and reactive power control;
3. TSO-DSO power flow optimization;
4. TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles;
5. Optimal energy interruption management;

To run the simulation of showcases, detailed features of the showcases including control functions properties within each use case and the implementation procedure of showcases need to be specified in line with goals of INTERPLAN tool. To this end, each showcase is presented in this section through five tables analysing: 1- properties, 2- control functions, 3- showcase structure, 4- test cases and 5- summary. The content of each table is summarized as follows:

1. Showcase properties: In this part, the motivation and objective of the showcase is described and the solution to reach the objective of showcase is presented.
2. Control functions: As showcases include one or several use cases, the control functions for each use case are presented in this part. Control functions are developed to reach the objectives of use cases and showcases; therefore, all the data associated with their development such as the controllable variables, the tools/actors as well as the specific assumptions and requirements to implement them are introduced. Since all control functions are mathematically formulated for the simulation of showcases, the input data, formulations as well as simulation environment and type are stated. If any use case needs to apply a grid equivalenting method to implement the control functions, the reason and the method of grid equivalenting is described in this part.
3. Showcase structure: The different steps of showcase implementation with regards to developed control functions for the use cases need to be organized to understand the applicability of showcase simulation. Therefore, the steps of showcase implementation are described such that input data, output data, grid area, and actions for each step are specified.
4. Test case: The selected grid model to simulate the showcase is presented in this part. The reason and suitability of the test case for showcases are stated together with the features of the grid model. The KPIs to be calculated in the next stage of the project are also presented.
5. Summary: This part presents the achievements, the lessons learned from the development of control functions for each showcase, and the way each showcase is included and considered in the INTERPLAN tool.

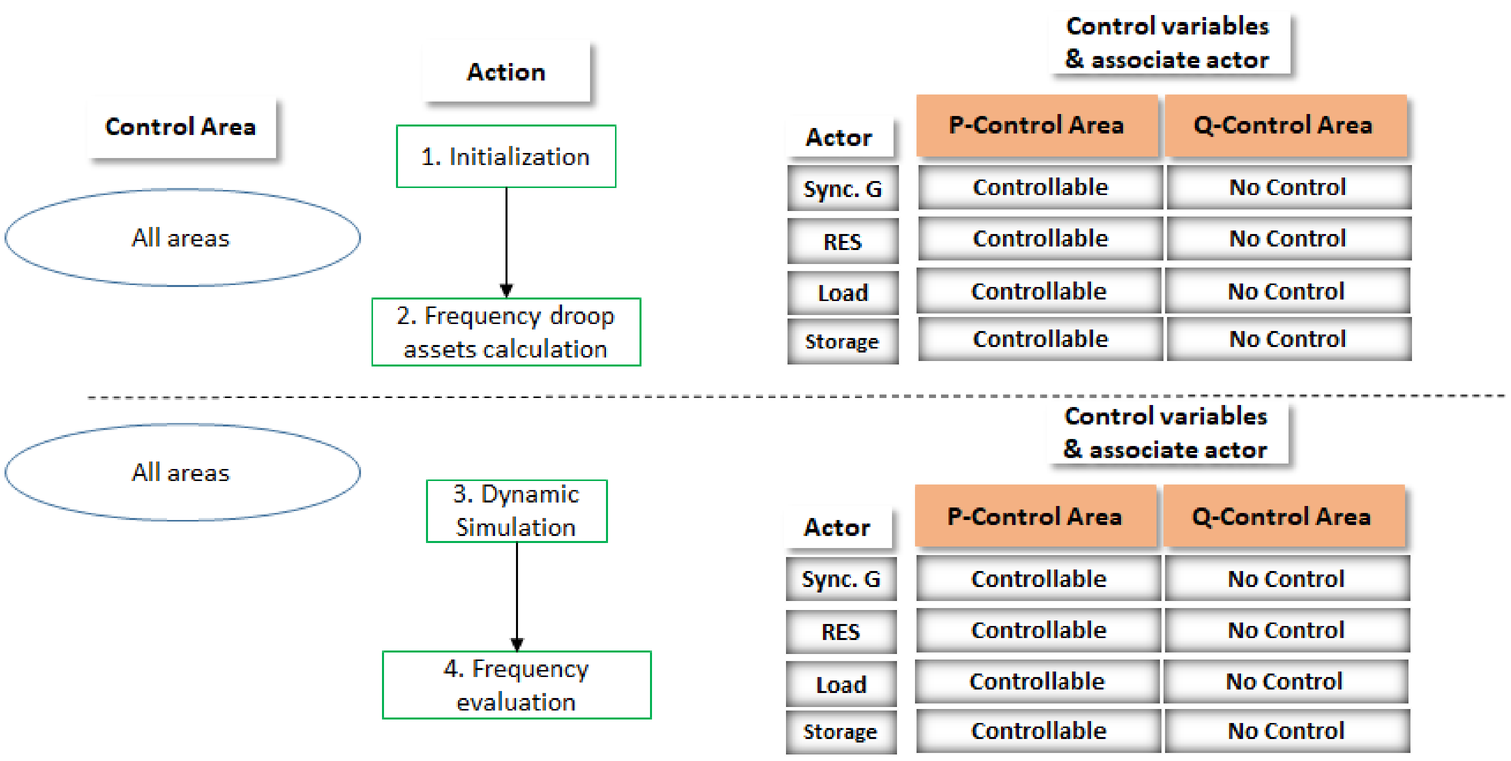
4.1 SC1 - Low inertia systems

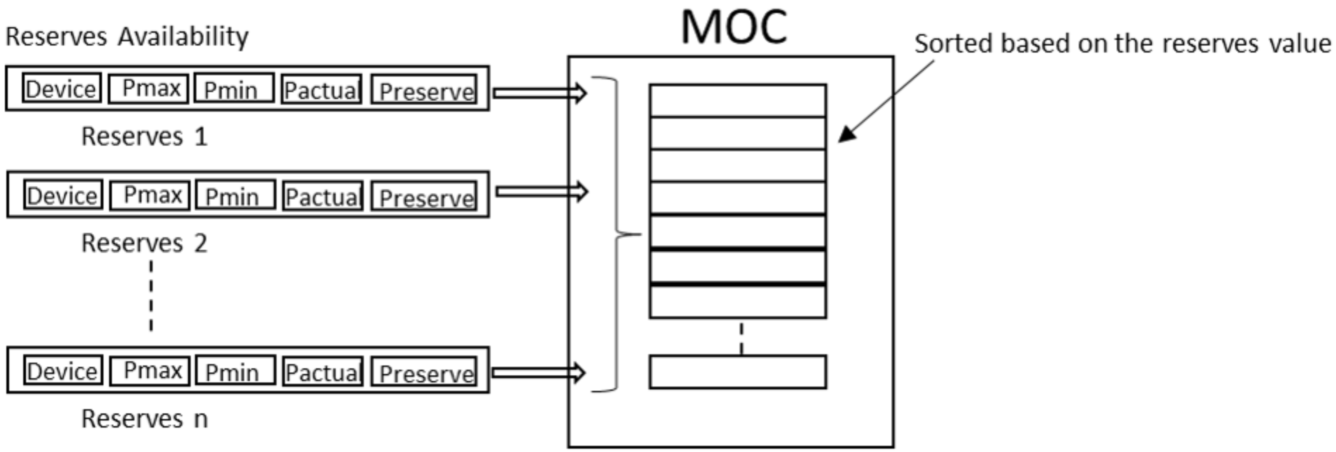
4.1.1 SC properties

ID and Name	SC1: Low inertia systems	
Relevant use case/s	UC4: Fast Frequency Restoration Control UC6: Inertia management	
SC description	**Summary**	
	As the integration rate of RES is predicted to be high in the future power systems, inertia of the system diminishes so rate of change of frequency (RoCoF) and frequency stability can be jeopardized. Fast frequency restoration control and inertia management taking advantage of the capabilities of the distributed energy resources (DER) are employed in order to secure the system stability.	
	Motivation	
	Power systems with low share of synchronous generation, and consequently low total system inertia, are vulnerable to power imbalances. Such systems can experience frequency stability problems, such as high frequency excursions and higher rates of change of frequency. Therefore, the main focus of this showcase is to demonstrate how frequency stability in low inertia systems can be provided through capabilities of other power system objects present in the low inertia grids, such as RES, distributed generation (DG), controllable loads and storage systems. This showcase combines inertia management with fast frequency restoration control. Frequency stability of the first swing in the proposed solution is managed by estimating available and needed inertia for given system conditions, and then utilizing the needed inertia through synthetic inertia and fast frequency response controllers. For further reinforcements, optimal power flow-based frequency restoration is added, which, by using available energy sources, brings the frequency to its nominal value.	
	Objective	
	This SC's objective is to maintain frequency stability in low inertia systems through inertia management and fast frequency restoration.	
	Solution	
	In order to secure stability of the system, inertia management is employed together with the capabilities of emerging technologies to support the frequency through advanced control capabilities of fast frequency control.	

4.1.2 Control functions

4.1.2.1 Control function for Fast Frequency Restoration Control

UC ID 4: Fast Frequency Restoration Control	
Control variables & associate actor/tool & flowchart	
Assumptions	It is assumed that all assets are controllable.
Prerequisites	<u>**Step 1:**</u> • Load flow for initialization; • Frequency Droop calculation for each device.
	<u>**Step 2:**</u> • System Frequency evaluation.

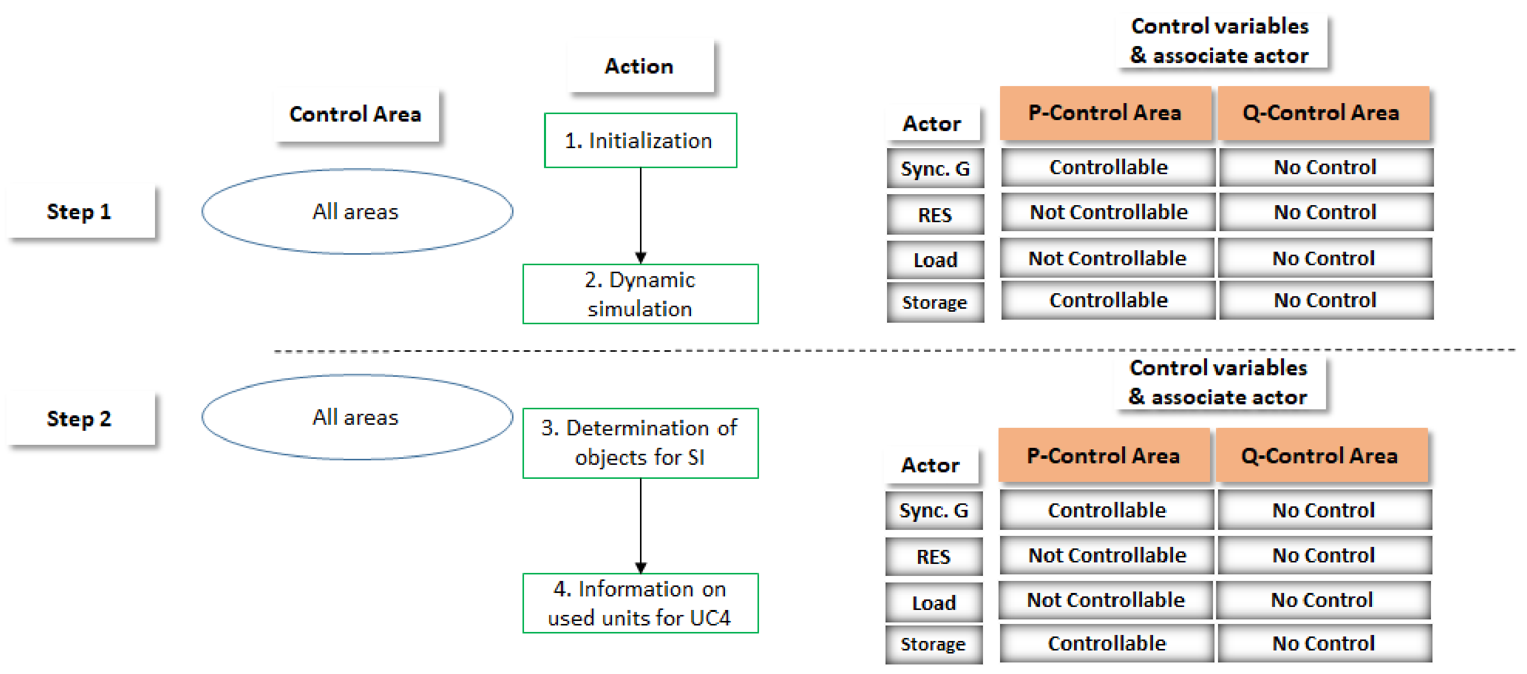
Grid equivalenting	Grid equivalenting in use case 4 is used to represent detailed wind farms models, consisting of several wind turbines, transformers, lines and dynamic models, as a simplified models. The static equivalent consists of a single wind turbine, two transformers and two lines per each wind farm. Impedance of these lines and transformers is calculated in such a way that the wind farm is virtually shifted away from the point of common coupling (PCC), which is needed when it is located deep in the distribution grid. The dynamic equivalent uses models defined by the Western Electricity Coordinating Council (WECC) that mimic the behaviour of detailed models used in the full wind farm model.
Input	<u>**General grid data for all steps:**</u> • Bus data • Branch data • Generator data
	<u>**Step 1:**</u> • Active power for load, RES and storage
	<u>**Step 2:**</u> • Active power for load, RES and storage
Formula	<u>**Step 1:**</u> • For each control area, the total active power-frequency response is evaluated. For each resource in the control area, the active power flexibility is evaluated and stored within a merit order collection list: 

	P_{actual} is the active power provided by resource at time step *i.* $P_{reserve}$ is the active power resource reserve P_{max}-P_{min} at time step *i.* Starting from the total control-area's active power-frequency response and the frequency error threshold set, the device droop slope is calculated per each resource.	
	Step 2: ● The dynamic simulation is performed to evaluate the grid frequency response.	
Simulation environment	PowerFactory, Python	
Simulation type	Semi-dynamic, dynamic	

4.1.2.2 Control function for inertia management

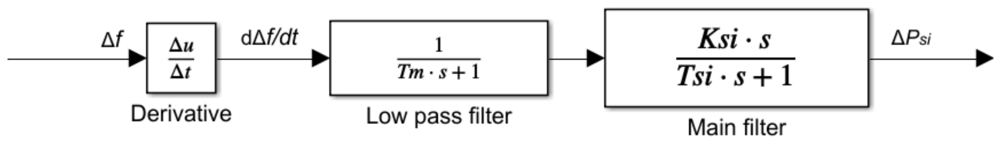
UC ID 6: Inertia management	
Control variables	Active power
Associate actor/tool	Storage units
Assumptions	It is assumed that all storage units are able to provide synthetic inertia.
Prerequisites	Network model should converge for both load flow and dynamic simulation for all time steps. Dynamic models for synchronous generators and storage units should be available and stable for no-event simulation.
Grid equivalenting	Grid equivalenting in use case 6 is used to represent detailed wind farm models, consisting of several wind turbines, transformers, lines and dynamic model, as a simplified model. The static equivalent consists, in this case, of a single wind turbine, two transformers and two lines per each wind farm. Impedance of these lines and transformers is calculated in such a way that the wind farm is virtually shifted away from the point of common coupling (PCC), which is needed when it is located deep in the distribution grid. The dynamic equivalent uses models defined by the Western Electricity Coordinating Council (WECC) that mimic the behaviour of detailed models used in the full wind farm model.
Input	• Actual active power of system objects • Synthetic inertia (SI) model parameters • Apparent power of system objects • Maximum active power of system objects • Synchronous generators inertia

Flowchart



Formula

To provide appropriate response, first the parameters for SI have to be chosen. For each time step the gain (K_{si}) is scaled through weights based on the dynamic simulation output and number of units chosen for SI support. There is no SI support if the RoCoF does not exceed the given maximum value.



$$\int_0^{\tau} y_{SI}(t)dt = \frac{K_{SI}T_{SI}}{T_m - T_{SI}}\left(e^{-\frac{\tau}{T_{SI}}} - 1\right) - \frac{K_{SI}T_m}{T_m - T_{SI}}\left(e^{-\frac{\tau}{T_m}} - 1\right) = \Delta E_{\tau}$$

In UC6 control, system inertia (H_{sys}) is calculated before and after the largest possible trip (of generation, load, etc.) for each time step according to the following formula:

$$H_{sys} = \frac{\sum_{i=1}^{n} H_i S_i}{S_{sys}}$$

Knowing this largest possible trip (ΔP) and post-disturbance system inertia, it is possible to estimate expected RoCoF (df/dt) in the grid:

$$\frac{df}{dt} = \frac{\Delta P f_n}{2H_{sys}S_{sys}}$$

The algorithm selects storage units for synthetic inertia provision taking into consideration two criteria:

1. The active power criterion:

Additional active power for synthetic inertia (P_{SI}) is equal to the sum of available active power from a chosen unit (P_{avai}).

$$P_{SI} = \sum_{i=1}^{n} P_{ava_i}$$

The units are chosen in such a way that the difference between sum of their available active power (P_{avai}) and largest trip (ΔP) is minimum, while preferred solution is that the sum of P_{avai} is equal to or larger than ΔP.

$$\min \left| \sum_{i=1}^{n} P_{ava_i} - \Delta P \right|$$

$$\sum_{i=1}^{n} P_{ava_i} \geq \Delta P$$

where P_{avai} is maximum available active power from a storage unit *i*.

2. The energy criterion:

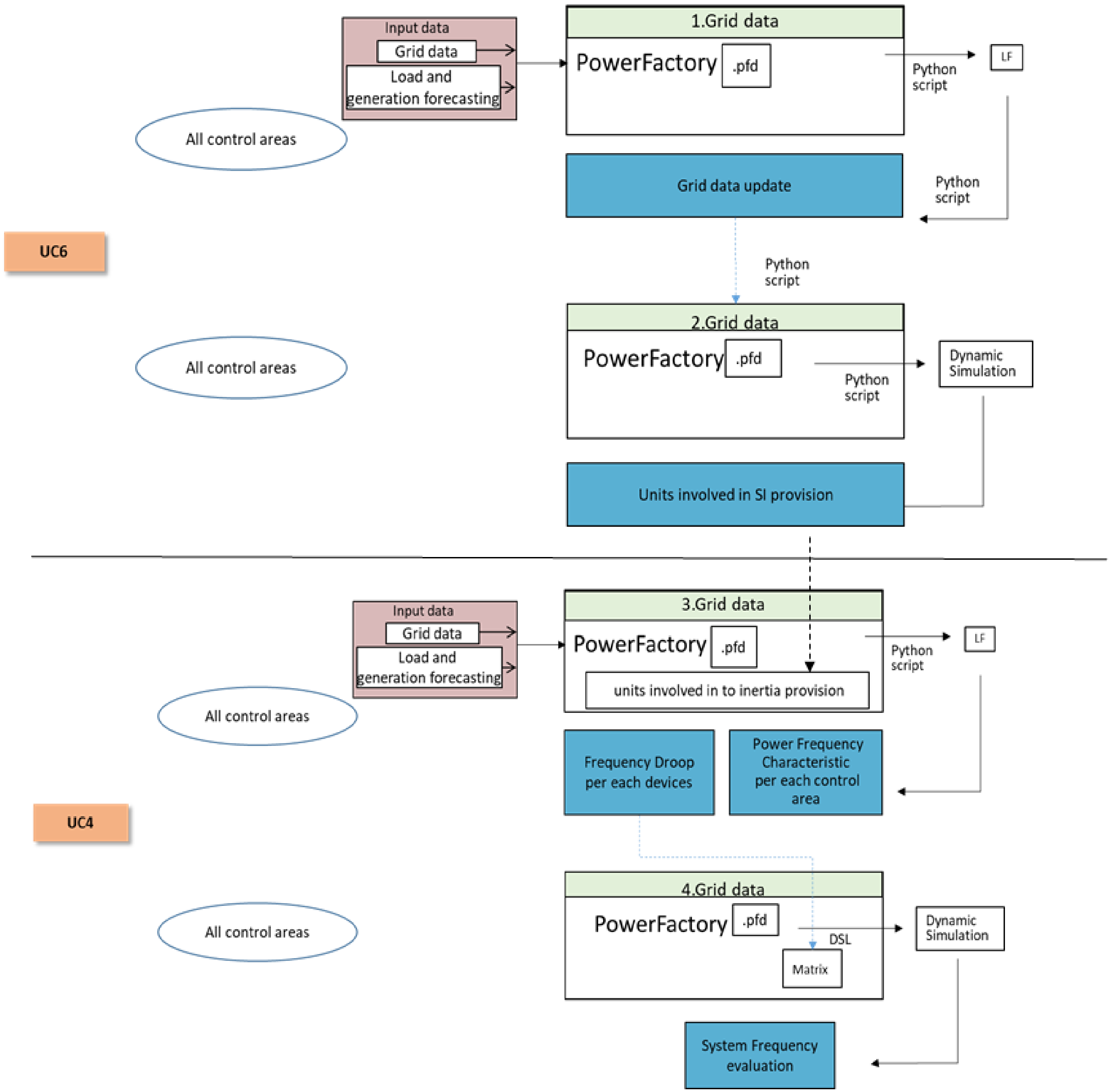
Additional energy for synthetic inertia (E_{SI}) is equal to the sum of available energy from chosen units (E_{avai}).

$$E_{SI} = \sum_{i=1}^{n} E_{ava_i}$$

The units are chosen in such a way that the difference between sum of their available energy (E_{avai}) and largest trip (ΔE) is minimum, while preferred solution is that the sum of E_{avai} is equal to or larger than ΔE_T.

	$$\min \left| \sum_{i=1}^{n} E_{ava_i} - \Delta E_\tau \right|$$ $$\sum_{i=1}^{n} E_{ava_i} \geq \Delta E_\tau$$ where $E_{ava\ i}$ is available energy from a storage unit *i*.
Simulation environment	Python, PowerFactory
Simulation type	Semi-dynamic, dynamic

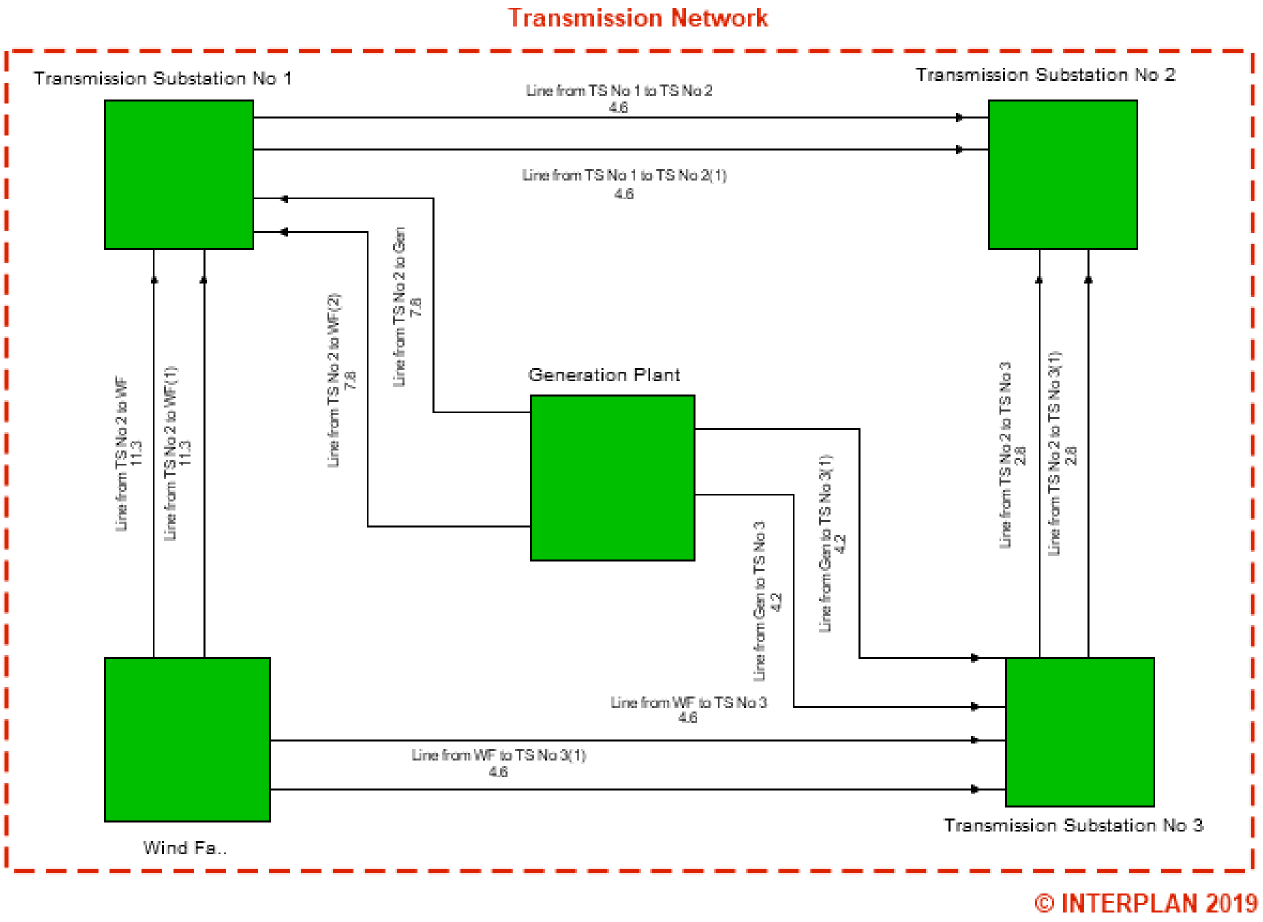
4.1.3 Showcase structure

Sequence diagram	

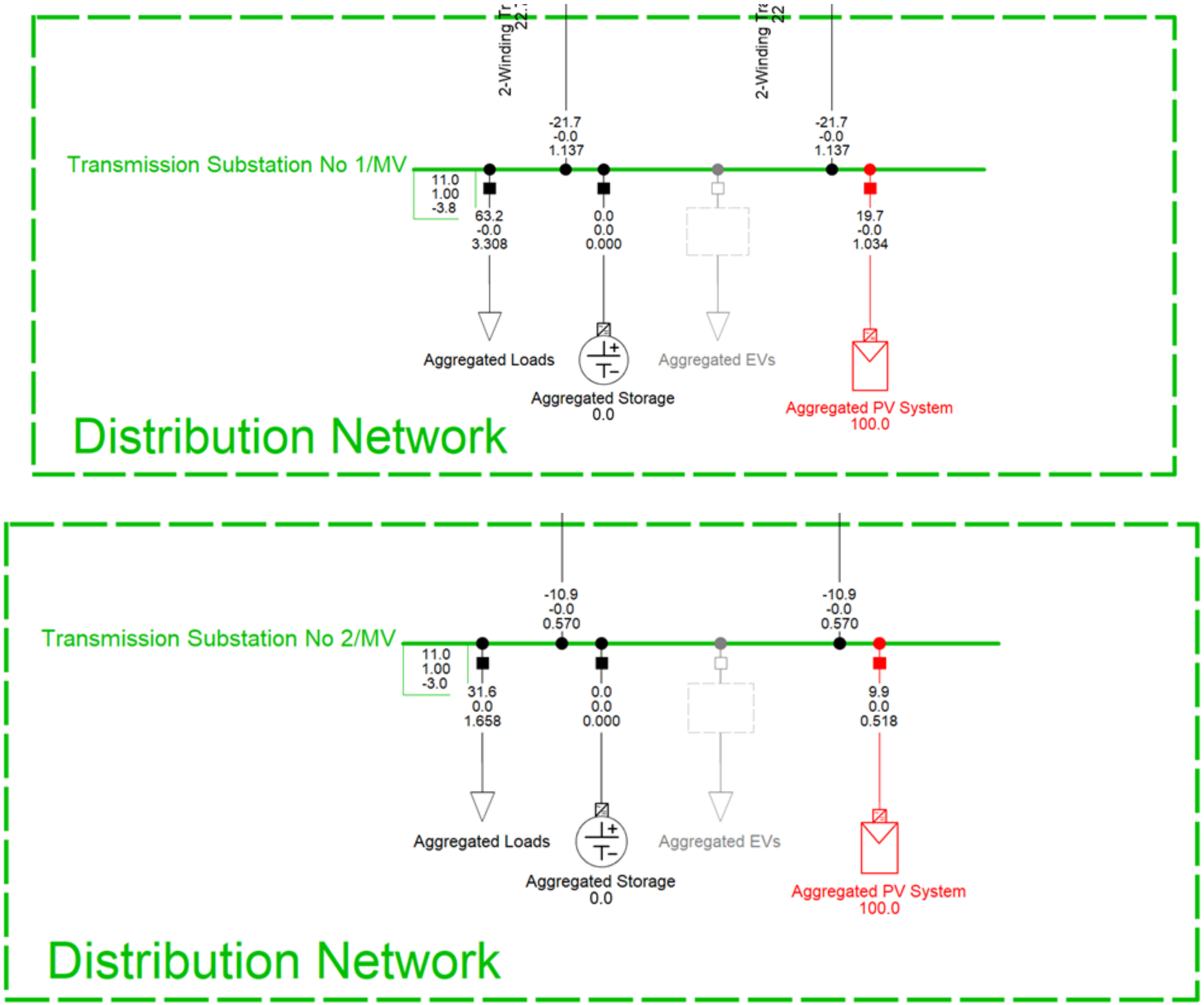
<table>
<tr><td rowspan="5">Detailed description</td><td>Steps</td><td colspan="7">Description</td></tr>
<tr><td>1</td><td colspan="7">The UC6 control function reads internal information from the PowerFactory grid model such as inertia constants, active powers, nominal powers and systems’ kinetic energy. A load flow is performed and grid data are updated.</td></tr>
<tr><td>2</td><td colspan="7">System parameters such as kinetic energy or system inertia as well as system need for additional inertial support is calculated. A choice of power system assets for inertial support is made (active power flexibility/SI provision).</td></tr>
<tr><td>3</td><td colspan="7">Calculate the total power-frequency characteristic for each control area of the power grid under analysis. A static simulation is performed in order to calculate the total power-frequency characteristic per each control area of the power grid under analysis. The input is taken from step 2. Thus, based on the asset’s flexibility information, the frequency droop for each device is calculated. The calculation of the frequency droop for each device is used as input setting for the asset’s dynamic models.</td></tr>
<tr><td>4</td><td colspan="7">Frequency droop per each device is systematized under a matrix with DSL (DIgSILENT Simulation Language). A dynamic simulation of an instability event is performed. This is done in order to locate the instability event in the grid and verify the effectiveness of the devices frequency droop calculated at step one. System frequency is evaluated whereas post-processing is performed offline. The post-processing result is a set of plots and KPIs metrics.</td></tr>
<tr><td rowspan="4">Sequence of actions</td><td>Steps</td><td>UC ID</td><td>Action</td><td>Content</td><td>Input</td><td>Operation</td><td>Output</td><td>Grid Area</td></tr>
<tr><td>1</td><td>6</td><td>Reading of system internal information and calculation of system internal information</td><td>Inherent grid information</td><td>Grid specifications under study</td><td>Python script and load flow</td><td>Inertia constraints, active powers and nominal capacities and systems’ kinetic energy</td><td>TSO&DSO</td></tr>
<tr><td>2</td><td>6</td><td>Flexibility assessment and potential of inertial support</td><td>Storage as flexibility assets are evaluated</td><td>Outputs of step 1</td><td>Static simulation</td><td>Power system assets list</td><td>TSO&DSO</td></tr>
<tr><td>3</td><td>4</td><td>Calculation of system internal information and results of the assets flexibility assessment</td><td>Assets characteris-tics assess-ment</td><td>Grid specifications under study and outputs of step 2</td><td>Python script and load flow</td><td>PF calculation for the grid and each control area and droop calculation for the flexible assets</td><td>TSO&DSO</td></tr>
</table>

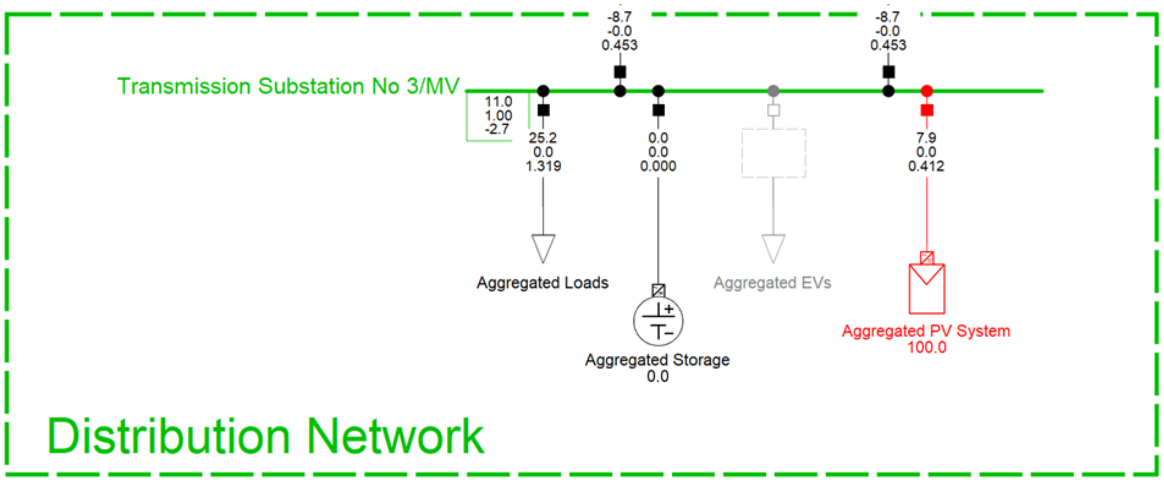
4.1.4 Test Case

System under Test (SuT)	The power system model used to perform the dynamic simulations for showcase 1 is shown in the figures below. The particular system consists of five electrically connected areas and it represents a part of the real grid in Cyprus. This particular grid was selected to highlight the challenge of preserving the frequency stability in a grid with high RES penetration and zero interconnections with other bulk systems. Cyprus grid due to its specifics i.e. isolated and with no interconnections is the most challenging to test the operation of the controllers within this SC.



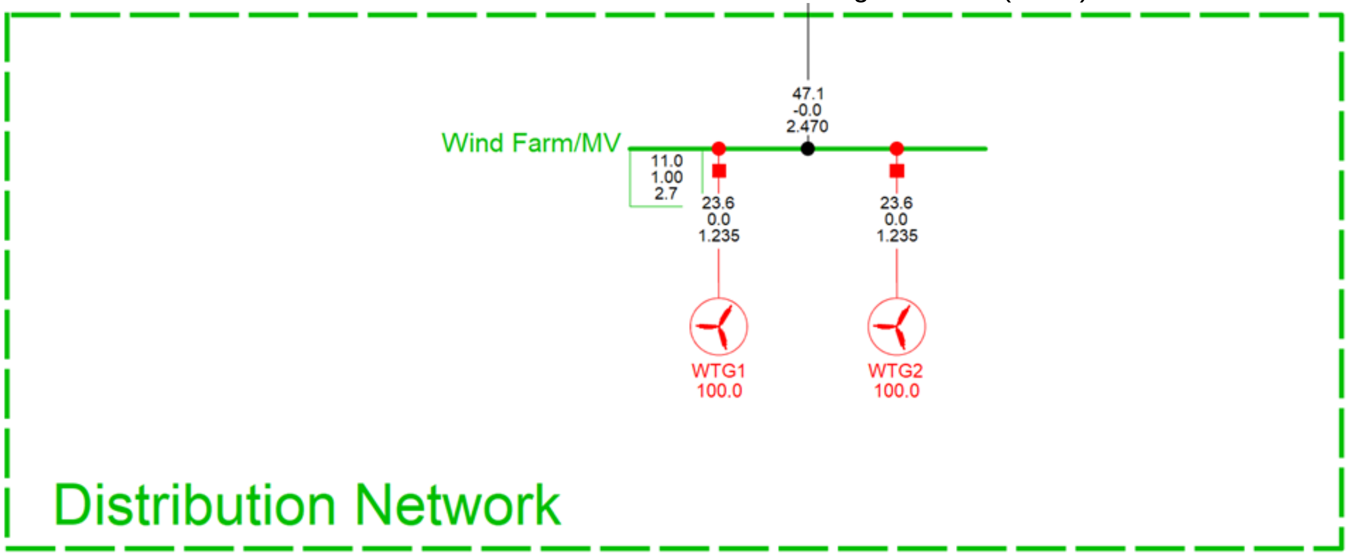
Three transmission substations with same electrical specifications are included. Each substation has two feeders where two HV to MV transformers of 100 MVA respectively serve the distribution side. Each substation serves load as well as PV and battery energy storage systems (BESS) at the MV side (11kV).





Generation Plant area: Two parallel synchronous machines operate at a total of 50 MVA each. The power provided by the generators is produced at the voltage level of 11 kV and delivered into the 132 kV transmission network through two 100 MVA transformers.

Wind farm area: Includes one 16 MVA transformer and two wind turbine generators (WTG).



<table>
<tr><td>Objects under Test (OuT)</td><td colspan="3">

- Static generators - 2 wind turbine generators(23,57 MVA each)
- BESS - 3 aggregated storage systems-(user defined models-90 MVA each, pf=0.8)
- Load - 3 loads (user defined models - 63,10 MW (area1) - 31,65 MW (area2) - 25,2 MW (area3))
- PV systems - 3 aggregated PV systems (user defined models)
- Synchronous generators - 2 x 50 MVA each (Automatic Voltage Regulator Type: EXAC4, Speed Governor Type: TGOV1)

</td></tr>
<tr><td>Scenarios</td><td colspan="3">INTERPLAN-3: Large Scale RES</td></tr>
<tr><td>Input data</td><td colspan="3">

- Generation/demand profiles for all generators (synchronous generators, PVs, wind turbines) and loads are available for a 24 h period.
- Battery energy storage systems (BESS) are assumed to support the system when needed. Time series data: synthetic
- Generation and load forecasting
- Time frame: 24 h
- Time resolution: 15 min.

</td></tr>
<tr><td rowspan="5">KPI under test</td><td>ID</td><td>Name</td><td>Formula</td></tr>
<tr><td>5</td><td>Frequency restoration control effectivity</td><td>$F_{\text{restored}} - F_{\text{nom}} \leq \varepsilon, \varepsilon \to 0$</td></tr>
<tr><td>14</td><td>Level of DG / DRES utilization for ancillary services</td><td>$UAS\% = \frac{E_{AS}}{E_{total}} * 100\ [\%]$

E_{AS} $-$ the energy used for ancillary services $[MWh]$
E_{total} $-$ the total energy produced $[MWh]$</td></tr>
<tr><td>20</td><td>Frequency nadir/zenith</td><td>$max(|f_n - f|)\ [Hz]$

$f_n - nominal\ frequency\ [Hz]$
$f - system\ frequency\ [Hz]$</td></tr>
<tr><td>21</td><td>Rate of Change of Frequency (RoCoF)</td><td>$\frac{df}{dt} = \frac{P_g - P_l}{2H_{sys}}$

$\frac{df}{dt}$ $-$ rate of change of frequency $[Hz/s]$
P_g $-$ generators' active power [pu]</td></tr>
</table>

			P_l − demand active power $[pu]$ H_{sys} − system inertia $[s]$
	25	Indication of stability	this KPI is a boolean value (YES/NO)
	26	Oscillation damping	$\sigma = \ln(\frac{p_1}{p_2})$ p_1, p_2 − max values of two consecutive swings of the signal
	27	Share of RES	$RES\% = \frac{P_{RES}}{P_{total}} * 100\ [\%]$ P_{RES} Active power provided by RES at a given time step $[MW]$ P_{total} Total active power provided by RES and non RES generators at a given time step $[MW]$
Output parameters	Output parameters are: • System frequency • List of units for SI provision • Droops characteristics for devices • P-f characteristic curves for devices Post processing of the outputs will result to the following figures: • Results of dynamic simulations performed for each time step during 24 hours: overfrequency activation, underfrequency protection activation. • Nadir/zenith of frequency (BSC and SC in the same diagram) • RoCoF calculated for each time window (BSC and SC in the same diagram).		

4.1.5 Summary

Summary	The showcase addresses a combination of challenges, which are frequency stability and inertia management that may occur in the presence of high DER penetration level. The proposed integrated control functions (related to UC4 and UC6) allow system operators (DSOs) to solve these operation challenges through planning of unit dispatch under the frequency stability criterion and employing inertia management for assuring transient stability. A system operator (TSO and DSO) that wants to address these operation challenges by using the INTERPLAN tool will be guided by the user manual to select the following planning criteria: • 3.Maximizing share of RES • 6.Assuring transient stability

	• 8.Maximize DG/RES contribution to ancillary services • 9.Assuring frequency stability The simulation functionalities to be employed within the tool is basic load flow along with Stability Analysis Functions. The selected KPIs needed to measure the effectiveness of the control functions are: • 5. Frequency Restoration • 14. DG/RES utilization • 20. Frequency zenith/nadir • 21. RoCoF • 25. Indication of Stability • 26. Oscillation damping • 27. Share of RES The suggested INTERPLAN scenario is INTERPLAN-3: Large Scale RES Regarding the type of grid models to be used, the Cyprus grid has high RES penetration and zero interconnections with other bulk systems to model the frequency stability at the DSO side. The grid equivalenting is required to represent detailed wind farm models, consisting of several wind turbines, transformers, lines and dynamic models, as a simplified model. It has both static equivalent and dynamic equivalent. Once all these steps have been performed, the user is ready to select this showcase control function and perform the simulations through PowerFactory and with the Python scripts. The evaluation phase will follow with reference to the KPI(s) values found in the simulation.

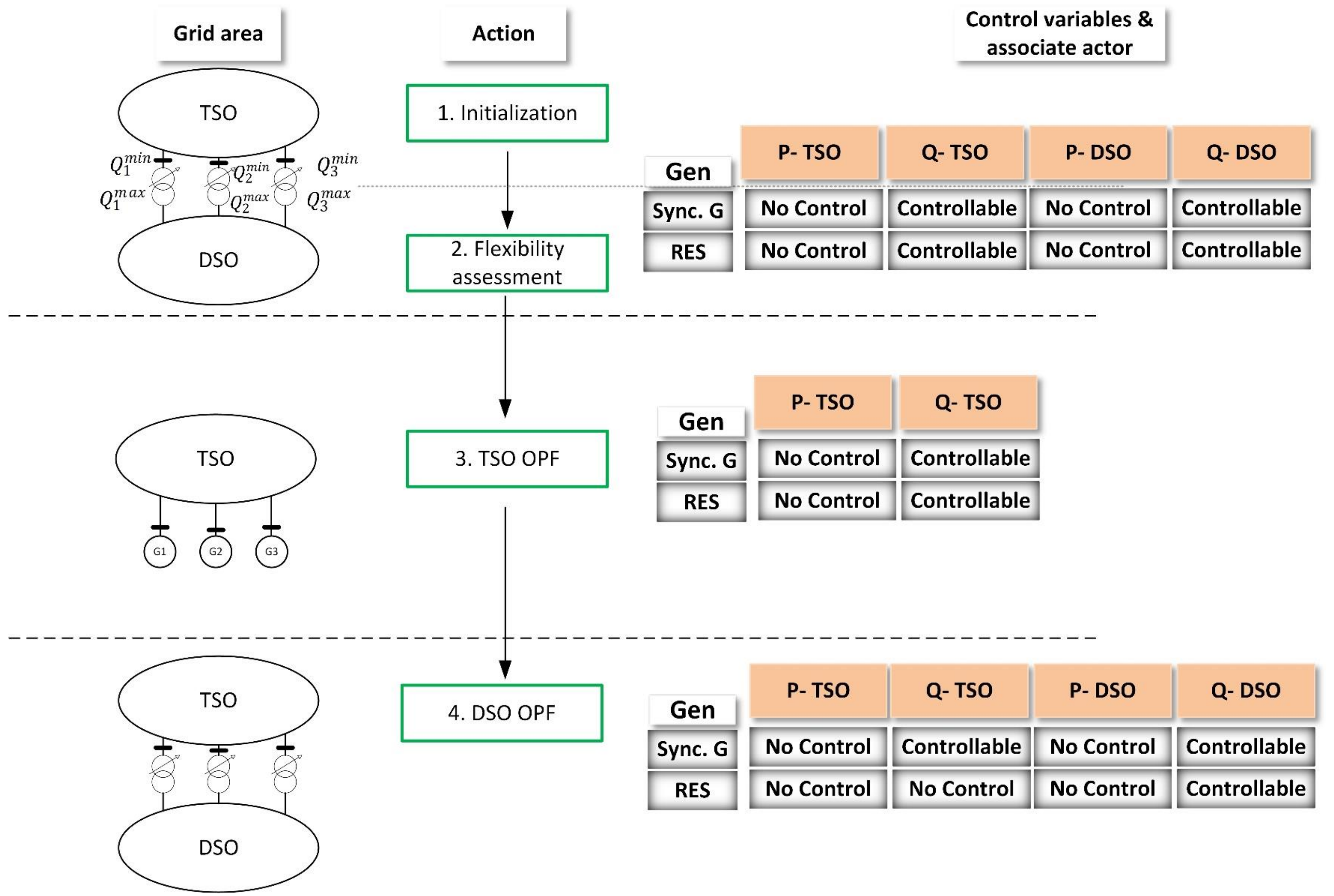
4.2 SC2 - Effective DER operation planning through active and reactive power control

4.2.1 SC properties

ID and Name	SC2: Effective DER operation planning through active and reactive power control	
Relevant UC/s	UC1: Coordinated voltage/reactive power control UC2: Grid congestion management	
SC description	**Summary**	
	Active and reactive power intelligent control for grid congestion management and coordinated TSO-DSO optimization.	
	Motivation	
	The presence of DER can significantly impact the power networks, exposing the system to much higher power fluctuations and compromising the system power quality. Ensuring voltage stability and solving power congestions become even more important issues to deal with when penetration levels of DER increase. Therefore, innovative control schemes have to be considered in the future power systems.	
	Objective	
	The main focus of this showcase is to present a control scheme to improve TSO-DSO coordination both in managing the grid for voltage stability and solving the congestion issues occurring at all voltage levels. By applying a coordinated TSO-DSO optimization methodology, this showcase aims to regulate reactive and active power by using TSO and DSO power assets, including utilization of the DSO flexibilities, to respect TSO optimization objectives and restore the grid in the presence of congestion events.	
	Solution	
	In order to prevent congestion and voltages violations problems in the system, congestion management control with the Coordinated voltage/reactive power control are employed.	

4.2.2 Control functions

4.2.2.1 Control function for coordinated voltage/reactive power control

UC ID 1: Coordinated voltage/reactive power control	
Control variables & associate actor/tool & flowchart	

<table>
<tr>
<td rowspan="4">Prerequisites</td>
<td><u>Step 1:</u>
Load flow for initialization</td>
</tr>
<tr>
<td><u>Step 2:</u>
Reactive power flexibility assessment at the connection points, DSO grid equivalent.</td>
</tr>
<tr>
<td><u>Step 3:</u>
OPF in TSO and fix the reactive power set points in connection point</td>
</tr>
<tr>
<td><u>Step 4:</u>
OPF for optimal distribution of reactive power set points for generators in DSO level to realize set points from step 3</td>
</tr>
<tr>
<td>Grid equivalenting</td>
<td>Grid equivalenting is employed in the third step of UC1 procedure to make a DSO equivalent, because DSO in this step is not under control and just an equivalent generator representing the DSO is sufficient. The equivalent generators are connected to the TSO-DSO connection point and their initial active and reactive power set points are extracted from LF in that node.</td>
</tr>
<tr>
<td>Input</td>
<td><u>General grid data for all steps:</u>
Bus data
<table>
<tr><td>Bus type</td><td>Active power load</td><td>Reactive power load</td><td>Bus area</td><td>Initial Bus voltage magnitude</td><td>Initial bus voltage angle</td><td>Maximum and minimum bus voltage</td><td>Nominal bus voltage</td></tr>
</table>
Branch data
<table>
<tr><td>Branch from which bus</td><td>Branch To which bus</td><td>Branch resistance</td><td>Branch reactance</td><td>Branch conductance</td><td>Branch susceptance</td><td>Branch capacity (max. current carrying capacity)</td><td>Branch type</td><td>Branch tap rate magnitude if it is a transformer</td><td>Branch phase shift angle if it is transformer</td></tr>
</table>
Generator data
<table>
<tr><td>Generator bus number</td><td>Generator type</td><td>Generator operation mode</td><td>Initial active power</td><td>Initial reactive power</td><td>Reactive power boundary</td><td>Voltage in case of operation mode slack or PV</td></tr>
</table>
</td>
</tr>
</table>

	Step 1: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators.
	Step 2: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Active and reactive power for equivalent DSO generators, • Minimum and maximum capable reactive power for DSO-TSO connection points (from step 1).
	Step 3: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Reactive power set point in DSO-TSO connection points (from step 2).
	Step 4: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Reactive power set points for generators in DSO level to fulfill set points at TSO-DSO connection points (from step 3)
Formula	**Step 1:** Initial load flow using complete load flow formulation
	Step 2: **Objective function:** $$\boldsymbol{Q}_{\mathbf{CP}}^{\mathbf{Max}} = max \sum_t \sum_i \sum_j V_i(t) V_j(t) \left[G_{\mathrm{ij}} \sin\left(\theta_i(t) - \theta_j(t)\right) - B_{ij} \cos\left(\theta_i(t) - \theta_j(t)\right)\right]$$ $$\boldsymbol{Q}_{\mathbf{CP}}^{\mathbf{Min}} = min \sum_t \sum_i \sum_j V_i(t) V_j(t) \left[G_{\mathrm{ij}} \sin\left(\theta_i(t) - \theta_j(t)\right) - B_{\mathrm{ij}} \cos\left(\theta_i(t) - \theta_j(t)\right)\right]$$

s.t.

$$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \leq Q_g(t) \leq \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$

$$\frac{P_{\text{ij}}(t)^2 + Q_{\text{ij}}(t)^2}{V_{\text{ij}}(t)^2} \leq I_{\text{ij,max}}^2$$

Where:

- i, j: Index (set) of buses.
- t: Index (set) of time steps.
- g: Index (set) of generators.
- n: Index (set) of connection point.
- CP: Superscripts for connection point.
- SP: Superscripts for set point
- G: Conductance of transmission line
- B: Susceptance of transmission line
- S: Apparent power
- α: Weight/scale factor for objective function
- β: Weight/scale factor for objective function
- P: Active power.
- Q: Reactive power.
- V: Voltage magnitude
- θ: Voltage angle
- I: Electric current

This nomenclature is also applied for formulation of the other steps.

Step 3:

Objective function:

$$\boldsymbol{P}_{\textbf{losses}}: min \sum_t \sum_i \sum_j G_{\text{ij}} \left[V_i(t)^2 + V_j(t)^2 - 2V_i(t)V_j(t)\cos\left(\theta_i(t) - \theta_j(t)\right)\right]$$

	s.t. $$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \le Q_g(t) \le \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$ $$\frac{P_{ij}(t)^2+Q_{ij}(t)^2}{V_{ij}(t)^2} \le I_{ij,max}^2$$
	Step 4: **Objective function:** $$\boldsymbol{P}_{\mathbf{losses}}: min \sum_t \left\{ \sum_i \sum_j G_{ij} \left[V_i(t)^2 + V_j(t)^2 - 2V_i(t)V_j(t)\cos\left(\theta_i(t)-\theta_j(t)\right)\right] + \sum_n \left(Q_{\mathrm{CP}_n}(t) - Q_{\mathrm{sp_n}}(t)\right)^2 \right\}$$ **s.t.** $$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \le Q_g(t) \le \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$ $$\frac{P_{ij}(t)^2+Q_{ij}(t)^2}{V_{\mathrm{ij}}(t)^2} \le I_{\mathrm{ij,max}}^2$$
Simulation environment	PowerFactory, AMPL
Simulation type	Semi-dynamic

4.2.2.2 Control function for grid congestion management

UC ID 2 : Grid Congestion Management	
Control variables	Active power
Associate actor/tool	DG

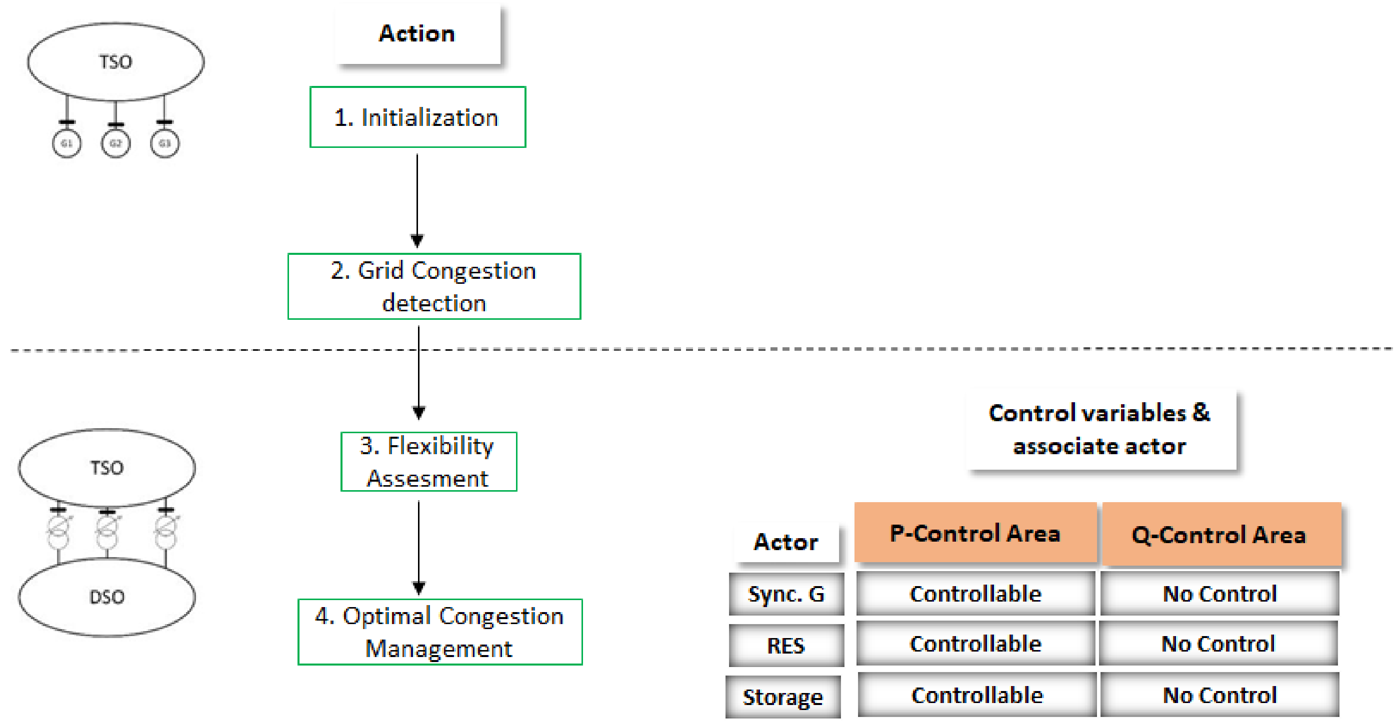
<table>
<tr><td>Assumptions</td><td>It is assumed that all assets are controllable and the n-1 criteria is satisfied</td></tr>
<tr><td>Prerequisites</td><td>

- The grid model under test has to contain both TSO and DSO levels.
- All assets in the grid are controllable

</td></tr>
<tr><td>Grid equivalenting</td><td>No grid equivalenting is used in this UC. Due to its need to preserve the lines information, and considering we assumed that all the assets in the grid are controllable, it is not possible provide a grid equivalent</td></tr>
<tr><td>Input</td><td>The inputs for the control function are:

- The information about the assets flexibility and lines characteristic
- Sensitivities information about each bus bar
- Congested lines information

</td></tr>
<tr><td>Control variables & associate actor/tool & flowchart</td><td>



</td></tr>
</table>

<table>
<tr>
<td rowspan="2">Formula</td>
<td>

<u>Step 1:</u>

Possible congestion problems at TSO level are detected. Per each line at TSO level, the following condition is checked:

$$P_{line_j} < 0.9 * P_{rating_{line_j}}$$

where:

P_{line_j} is the active power that flows through the line *j*;

$P_{rating_{line_j}}$ is the nominal active power of the line *j*;

In case of violation of the above condition, the congestion management process is triggered.

</td>
</tr>
<tr>
<td>

<u>Step 2:</u>

Objective function:

$$f = \min\left(\sum_{i=0}^{N_{busbar}} \left(\Delta P_{busbar_i}^{+} + \Delta P_{busbar_i}^{-}\right)\right)$$

where:

$\Delta P_{busbar_i}^{+}$ is the positive active power variation at bus bar *i*;

$\Delta P_{busbar_i}^{-}$ is the negative active power variation at bus bar *i*;

N_{busbar} is the total number of buses.

s.t.

$$I_{rating_{line_j}} - \frac{\sqrt{\left(P_{lo_{linej}} + \frac{\partial P_{line_j}}{\partial P_i} * \Delta P_{busbar_i} + \frac{\partial P_{line_j}}{\partial Q_i} * \Delta Q_{busbar_i}\right)^2 + \left(Q_{lo_{linej}} + \frac{\partial Q_{line_j}}{\partial P_i} * \Delta P_{busbar_i} + \frac{\partial Q_{line_j}}{\partial Q_i} * \Delta Q_{busbar_i}\right)^2}}{\sqrt{3} * \left(U_{lo_{linej}} + U_{N_{line_j}} * \left(\frac{\partial u_{line_j}}{\partial P_i} * \Delta P_{busbar_i} + \frac{\partial u_{line_j}}{\partial Q_i} * \Delta Q_{busbar_i}\right)\right)} \geq 0 \ \forall\, i, j$$

where:

$I_{rating_{line_j}}$ is the nominal current value of the line *j*;

$P_{lo_{linej}}$ is the active power initial condition that flows through the line *j*;

$Q_{lo_{linej}}$ is the reactive power initial condition that flows through the line *j*;

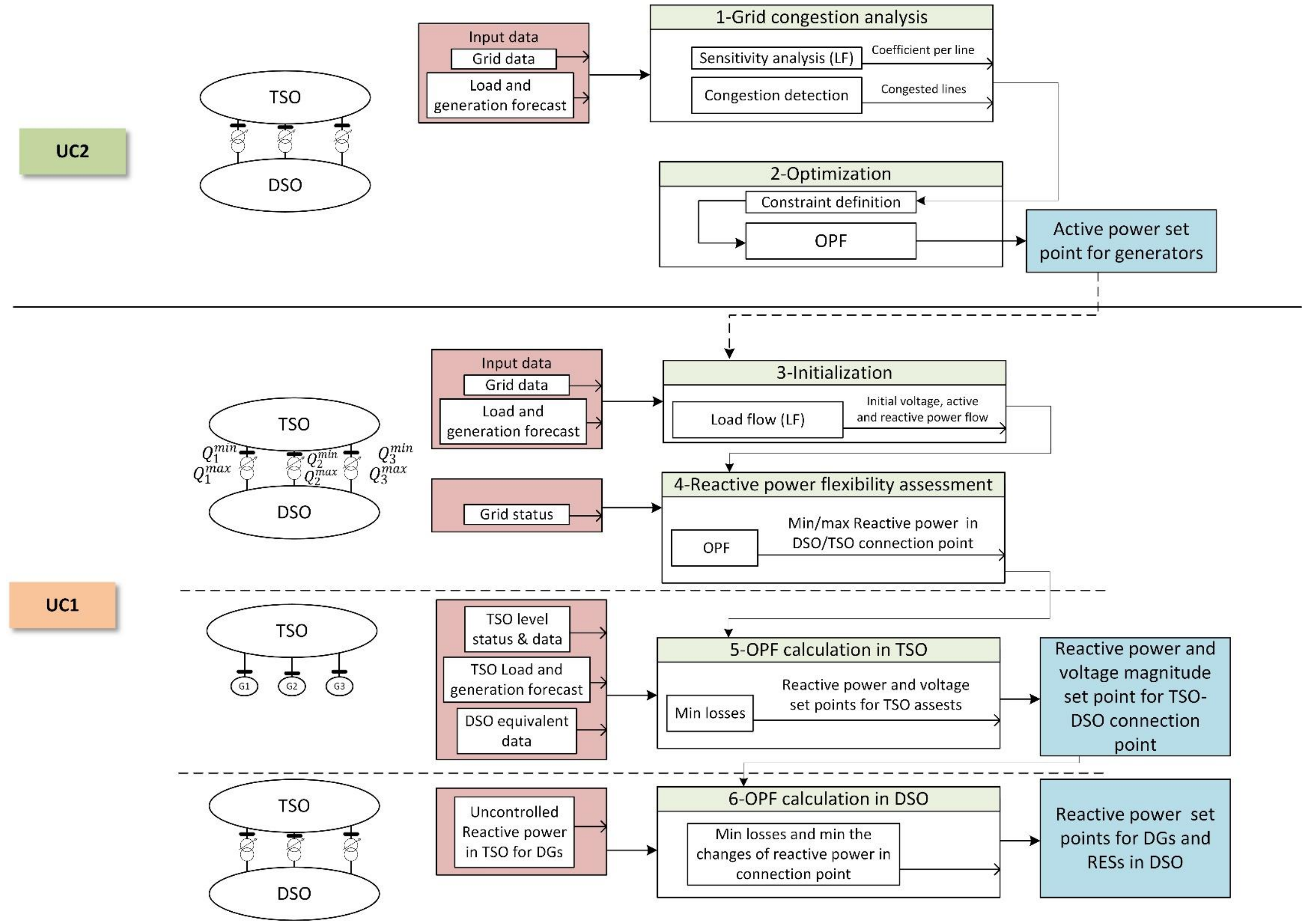
P_{line_j} is the active power that flows through the line *j*;

Q_{line_j} is the active power that flows through the line *j*;

</td>
</tr>
</table>

	$\frac{\partial P_{line_j}}{\partial P_i}$ is the effect on active power of the injection of Δ*P* at bus bar i for the $line_j$. $\frac{\partial P_{line_j}}{\partial Q_i}$ is the effect on active power of the injection of Δ*Q* at bus bar i for the $line_j$. $\frac{\partial Q_{line_j}}{\partial P_i}$ is the effect on reactive power of the injection of Δ*P* at bus bar i for the $line_j$. $\frac{\partial Q_{line_j}}{\partial Q_i}$ is the effect on reactive power of the injection of ΔQ at bus bar i for the $line_j$. $U_{lo_{linej}}$ is the voltage initial condition of the line *j*; $U_{N_{line_j}}$ is the nominal voltage $line_j$ $u_{line_j} = \frac{U_{line_j}}{U_{N_{line_j}}}$ where U_{line_j} is the voltage of the line *j*.
Simulation environment	Python and PowerFactory
Simulation type	Semi-dynamic

4.2.3 Showcase structure

Sequence diagram		
Detailed description	Steps	Description
	1	Possible congestion problems are detected at TSO level. In case problems are detected, the congestion management process is triggered.

<table>
<tr><td rowspan="6"></td><td>2</td><td>The active power flexibility assessment per each resources at both TSO and DSO level is performed. This assessment is essential to know the possible active power variation at each bus bar to solve the congestion problems detected at step 1. Then, a sensitivity analysis is performed to calculate the minimum active power variation at each bus bar to solve the detected grid congestion problems at TSO level.</td></tr>
<tr><td>3</td><td rowspan="2">The reactive power capability is evaluated at each TSO-DSO connection point with an optimization tool. For this, an OPF runs to find the maximum and minimum reactive power that the DSO can exchange with the TSO at each 15 minute interval of a considered. At step 3, first an initialization is performed with running a power flow in order to calculate the initial values for different variables in the grid including voltage magnitude/angle as well as active and reactive power flow. The area of the network that needs to be analysed in this step is both DSO and TSO. Grid data including detailed information about buses, branches, and generators as well as time series for load and generation are required as input data for initialization. Then those data along with grid status information are transferred to the flexibility assessment step (step 4). To evaluate the reactive power capability from DSO to deliver to TSO, reactive power at DSO and TSO should be controlled for RESs and synchronous generators.</td></tr>
<tr><td>4</td></tr>
<tr><td>5</td><td>Finding the possible reactive power provision from DSO to TSO, those data are transferred to the step 5 that is TSO level redispatch via minimizing the grid losses. In this step, TSO level operation is scheduled for the next day based on the given reactive power capability from DSO. Therefore, in this step just the TSO level is analysed and the DSO equivalents are generated as generators in the connection points in a way that the maximum and minimum reactive power for the equivalent generators are set as calculated ones in the previous step. Initial operating active and reactive power for those equivalent generators are also obtained from power flow in the relevant bus. Hence, the reactive power set points for all generators are optimized at TSO in a way that TSO losses is minimized.</td></tr>
<tr><td>6</td><td>Given the reactive power set points from the last step, another OPF is performed in the overall grid The only controlled variables in this step are all generator reactive powers at DSO level and just the RES reactive powers at TSO level. In other words, in the final step, reactive power at DSO is optimized while setting the TSO variables as calculated in the second step. The only exception is synchronous generators' reactive power at TSO level which is supposed to be controllable. Therefore, the optimum reactive power for RES are calculated by minimizing the total grid losses as well as the deviation of reactive power at connection points from what has been calculated in the second stage. It means that in addition to loss minimization, the problem aims to preserve the exchange reactive power in the optimum amount calculated in TSO OPF. This helps to obtain the DSO values independently from TSO level.</td></tr>
</table>

Sequence of actions	Steps	Associate UC ID	Action	Content	Input	Operation	output	Grid area
	1	2	Grid congestion analysis	1-Sensitivity analysis, 2-Congestion detection	• Grid data • Load and generation forecast	Load flow	• Coefficient per line • Congested lines	TSO & DSO
	2	2	Optimization (removing congestion)	• Constraint definition, • Objective function minimization	Outputs from step 1	Optimal power flow	• Active power set points for generators	TSO & DSO
	3	1	Initialization	Set the initial values of assets	• Grid data, • Load and generation forecast, • output from step 2	Load flow	• Initial voltage, active and reactive power flow	TSO & DSO
	4	1	Reactive power flexibility assessment	Definition of reactive power capability from DSO side for TSO grid	• Grid status • Output from step 3.	Optimal power flow	• Reactive power capability in TSO-DSO connection point	TSO & DSO
	5	1	TSO optimization	Loss minimization in TSO grid.	• TSO level status and data • TSO load and generation forecast • DSO equivalent • Output from step 4.	Optimal power flow	• Reactive power and voltage set points for TSO assets	TSO
	6	1	DSO optimization	Loss minimization and trying to keep the reactive power in the set points calculated in the step 5	• Output from step5 • Reactive power set points for TSO DGs and make them uncontrolled	Optimal power flow	• Reactive power and voltage set point for RES and DGs in DSO	DSO

4.2.1 Test case

<table>
<tr><td>System under Test (SuT)</td><td colspan="3">The power system under test is a benchmark grid model based on project SimBench[1] [6]. The SC2 aims to investigate congestions and voltage issues considering both TSO and DSO using the assets at all levels. The selected grid model presents both transmission and distribution levels as well as many distributed resources suitable for the proposed controllers.</td></tr>
<tr><td>Objects under Test (OuT)</td><td colspan="3">• Static Generators (Wind, PVs, Hydro)
• Loads
• Synchronous Generators (Gas, Coal)</td></tr>
<tr><td>Scenario</td><td colspan="3">INTERPLAN-2: Small and Local</td></tr>
<tr><td>Input data</td><td colspan="3">The grid model contains a total of 287 lines, 235 bus bars, 15 transformers, 225 loads, 257 static generators and 5 synchronous machines. The study is performed at the TSO level, which consists of 380kV and 220kV as well as DSO level, which includes 110, 20 and 0.4 kV.
Time Frame: 24h
Time resolution: 15min</td></tr>
<tr><td rowspan="4">KPI under test</td><td>ID</td><td>Name</td><td>Formula</td></tr>
<tr><td>1</td><td>Level of losses in transmission and distribution networks</td><td>$$Percentage\ of\ losses = \frac{\text{Amount of injected energy} - \text{amount of energy delivered to customers}}{\text{Amount of injected energy}} \times 100$$</td></tr>
<tr><td>2</td><td>Congestion detection</td><td>Congestion = If abs(P_{line_i}) > $P_{rating\_line\_i}$ the line i is congested.
P_{line_i} [kW] is the active power that flows troughs the line i
$P_{rating\_line\_i}$ [kW] is the nominal active power of the line i</td></tr>
<tr><td>10</td><td>Voltage Quality</td><td>According to the defined EN 50160 Standards and VDE-AR-N 4120 bus bar voltage magnitudes must comply with following allowed range of variation.
• LV: (±10% of nominal voltage)
• MV: (±5% of nominal voltage)</td></tr>
</table>

[1] Cp. https://simbench.de/de/

			• HV & EHV: (±4-7% of nominal voltage) Voltage deviation indices can be defined to find the frequency or duration that the bus bar voltages violate the allowed voltage range. • Number of voltage excursions exceeded n minutes per year • Percentage of time that the transmission voltage exceeds the permissible limits
	13	Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids	Let *C* be the set of connection points between TSOs and DSOs. Let $q_{c,target}$ (t) [kvar] be the target value for reactive power transmission from DSO to TSO at connection point c and time *t*, as e.g. calculated by grid operation planning. Let $q_c(t)$ be the reactive power actually provided from DSO to TSO at connection point *c* and time *t*. Then the KPI related to reactive power at time *t* is defined as: $\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(q_{c,target}(t)-q_c(t)\right)^2$ The KPI related to voltage is defined as follows. Let $u_{c,target}$ [V] be the nominal value for the line-to-line voltage at connection point *c*, calculated as mean over all phases. Let $u_c(t)$ be the actual line-to-line voltage mean over all phases. Then, the KPI at time *t* is: $\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(u_{c,target}-u_c(t)\right)^2$
	14	Level of DG / DRES utilization for ancillary services	$UAS\% = \frac{E_{AS}}{E_{total}} * 100\ [\%]$ E_{AS} – the energy used for ancillary services $[MWh]$ E_{total} – the total energy produced $[MWh]$
Simulation type	Semi-dynamic		
Output parameters	Active and reactive power set points for generators		

4.2.2 Summary

Summary	This showcase addresses a combination of network operation challenges, which are voltage stability and grid congestion that may occur in the presence of high DER penetration levels. The proposed integrated control functions (related to UC1 and UC2) allow system operators (TSOs and DSOs) to solve these operation challenges through an effective DER operation planning based on active and reactive power intelligent control for grid congestion management and coordinated TSO-DSO optimization. A system operator (TSO and DSO) that wants to address these operation challenges by using the INTERPLAN tool will be guided by the user manual to select the following planning criteria: • 1. Minimizing losses • 3. Maximizing share of RES • 4. Assuring voltage stability • 5. Mitigating grid congestion • 7. Optimize TSO/DSO interaction • 8. Maximize DG / DRES contribution to ancillary services. The simulation functionalities to be used are load flow, load flow sensitivities and optimal power flow, whereas the selected KPIs needed to measure the effectiveness of the control functions are: • 1. Level of losses in transmission and distribution networks • 2. Congestion detection • 10. Voltage Quality: Voltage magnitude variations • 13. Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids • 14. Level of DG / DRES utilization for ancillary services The suggested INTERPLAN scenario is INTERPLAN-2 Small and Local. Regarding the type of grid models to be used, the grid investigated for control is a transmission-distribution grid. Grid equivalenting is required for two reasons: first of all, system operators may not share full details of their own network topology and data with the other operators, and second this will simplify the optimization process at each system operator network. In detail, the TSO network or the DSO network is replaced by proper grid equivalents, which represents the active and reactive power values of the original network. Once performed all these steps, the user is ready to select this showcase control function and perform the simulations through PowerFactory. The evaluation phase will follow with reference to the KPI(s) values found in the simulation.

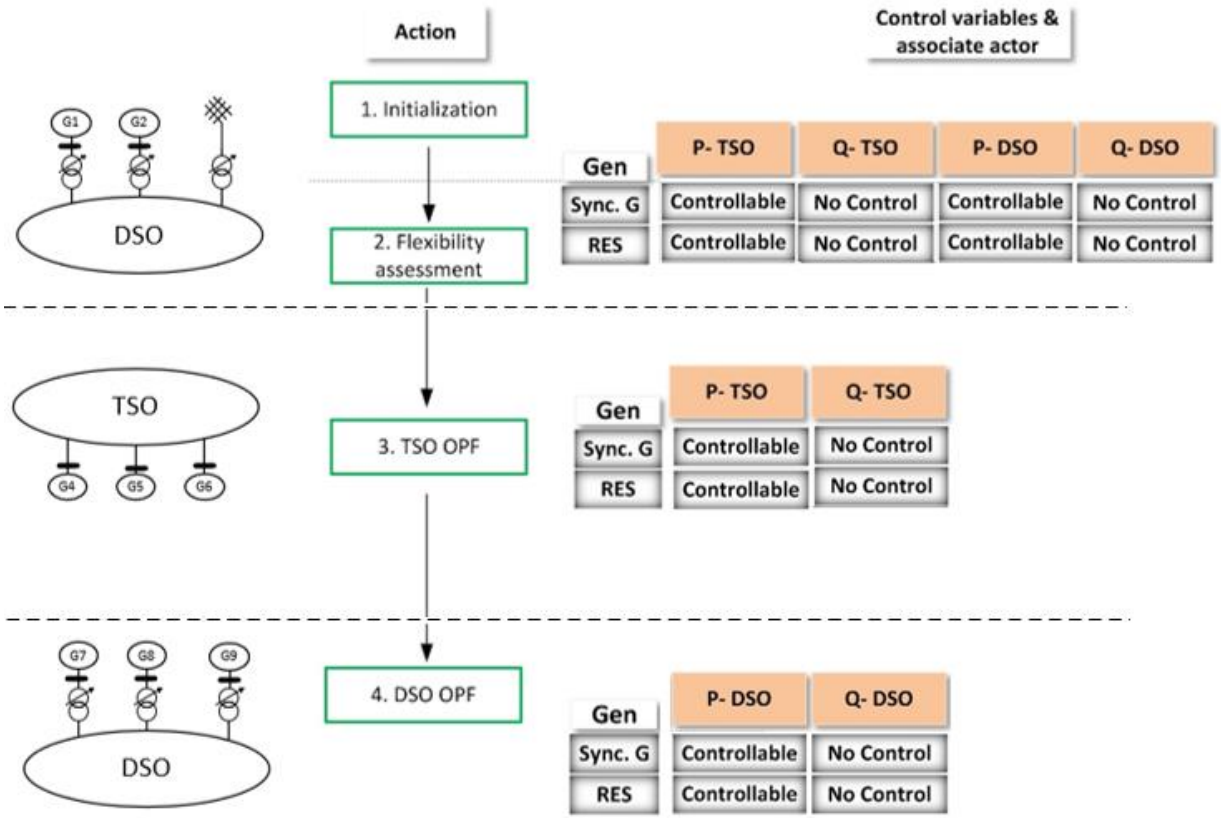
4.3 SC3 - TSO-DSO power flow optimization

4.3.1 SC properties

ID and Name	SC3: TSO-DSO power flow optimization
Relevant UC/s	UC3: Provision of tertiary control reserve based on coordinated TSO-DSO optimal power flow calculations UC5: Power balancing at DSO level
SC description	**Summary**
	Optimisation of tertiary reserve placement in both TSO and DSO levels and energy management in DSO level, with the aim of more efficient operation of the network and decrease of power losses.
	Motivation
	With the rising amount of distributed RES, the grid operation planning has to be adapted to the new conditions. To ensure stable and optimal operation of the network, DSO power management as well as novel TSO-DSO tertiary control are being used in this showcase.
	Objective
	This showcase is to present an optimization strategy for energy flow management between transmission and distribution grid, ensuring the balance within a distribution network on one hand and on the other hand for participation of non-synchronous energy resources in the tertiary reserve market and supporting the TSO in keeping the whole network stable.
	Solution
	The solution is application of optimization strategies which are described in details in • Use case 3: Provision of tertiary control reserve based on coordinated TSO-DSO optimal power flow calculations, and • Use case 5: Power balancing at DSO level

4.3.2 Control functions

4.3.2.1 Control function for provision of tertiary control reserve based on coordinated TSO-DSO optimal power flow calculations

<table>
<tr><th colspan="2">UC3: Provision of tertiary control reserve based on coordinated TSO-DSO optimal power flow calculations</th></tr>
<tr><td>Control variables & associate actor/tool & flowchart</td><td>


<u>Note:</u> In this use cases some of the loads are also considered as controllable in order to represent demand response.
</td></tr>
</table>

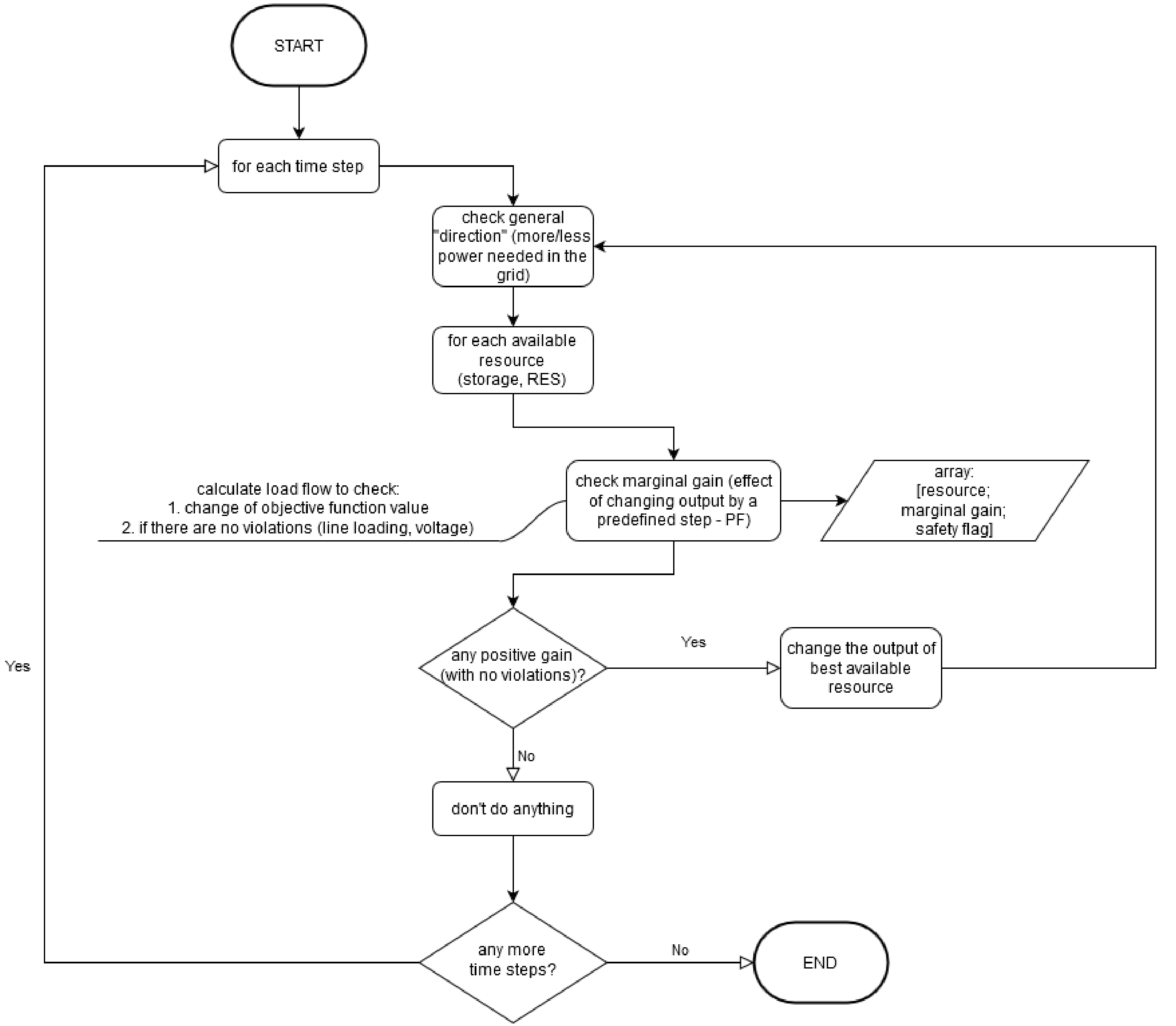
<table>
<tr><td rowspan="3">Prerequisites</td><td><u>Steps 1 and 2:</u>
Load flow for initialization,
TSO grid equivalent.
Active power flexibility assessment in the connection point.</td></tr>
<tr><td><u>Step 3:</u>
Optimisation function for TSO level
DSO grid equivalent.</td></tr>
<tr><td><u>Step 4:</u>
Optimisation function for DSO level
TSO grid equivalent</td></tr>
<tr><td>Grid equivalenting</td><td>At each step of the use case process, either the TSO network or the DSO network is replaced by proper grid equivalents which represent the active and reactive power values of the original network. There are two reasons for implementing this: fist, system operators may not share full details of their own network topology and data with the other operators, and second this will simplify the optimization process at each system operator network.</td></tr>
<tr><td rowspan="4">Input</td><td><u>General grid data for all steps:</u>
Bus data
Branch data
Generator data</td></tr>
<tr><td><u>Steps 1 and 2:</u>
Initial active and reactive power for generators
Active and reactive power for equivalent TSO generators plus slack generator</td></tr>
<tr><td><u>Step 3:</u>
Initial active and reactive power for generators
Active and reactive power for equivalent DSO generators
Minimum and maximum available active power for DSO-TSO connection point (from step 1)</td></tr>
<tr><td><u>Step 4:</u>
Initial active and reactive power for generators
Active power set points in DSO-TSO connection point (from step 2)</td></tr>
</table>

Formula	**<u>Step 2:</u>** **Objective function:** $$P_{\mathrm{PCC}}^{\max} = max \sum_{i}^{M} \sum_{k}^{N} V_i V_k (G_{ik} \cos\theta_{ik} + B_{ik} \sin\theta_{ik})$$ $$P_{\mathrm{PCC}}^{\min} = min \sum_{i}^{M} \sum_{k}^{N} V_i V_k (G_{ik} \cos\theta_{ik} + B_{ik} \sin\theta_{ik})$$ **s.t.** $$P_{\mathrm{gen}}^{\min} <= P_{\mathrm{gen}} <= P_{\mathrm{gen}}^{\max}$$ Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling P_{gen}: Active power generated by a generator V_i : Voltage magnitude at bus i G_{ik}: Real part of admittance matrix B_{ik}: Imaginary part of admittance matrix *M*: Total number of points of common coupling between TSO and DSO *N*: Total number of buses in the network under analysis
	<u>Step 3:</u> **Objective function:** $$P_{\mathrm{Losses}}^{\min} = \min \left(\sum_{x}^{G} P_{\mathrm{gen}} - \sum_{y}^{L} P_{\mathrm{load}}\right)$$ **s.t.** $$P_{\mathrm{PCC}}^{min} <= P_{\mathrm{PCC}} <= P_{\mathrm{PCC}}^{\max}$$ $$P_{\mathrm{gen}}^{\min} <= P_{\mathrm{gen}} <= P_{\mathrm{gen}}^{\max}$$

	Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling P_{gen}: Active power generated by a generator P_{load}: Active power consumed by a load P_{Losses}: Active power losses in the network under analysis *G*: Total number of generators in the network under analysis *L*: Total number of aggregated loads in the network under analysis
	Step 4: **Objective function:** $$P_{\mathrm{Losses}}^{\mathrm{min}} = \min\left(\sum_{x}^{G} P_{gen} - \sum_{y}^{L} P_{load}\right)$$ **s.t.** $$P_{\mathrm{PCC}} = P_{\mathrm{PCC}}^{\mathrm{step\ 2}}$$ $$P_{\mathrm{gen}}^{\mathrm{min}} <= P_{\mathrm{gen}} <= P_{\mathrm{gen}}^{\mathrm{max}}$$ Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling $P_{\mathrm{PCC}}^{\mathrm{step\ 2}}$: The identified P_{PCC} in step 2 optimisation P_{gen}: Active power generated by a generator P_{load}: Active power consumed by a load P_{Losses}: Active power losses in the network under analysis *G*: total number of generators in the network under analysis *L*: total number of aggregated loads in the network under analysis
Simulation environment	Python, PowerFactory
Simulation type	Semi-dynamic

4.3.2.2 Control function for power balancing at DSO level

UC ID 5 : Power balancing at DSO level	
Control variables	Active power
Associate actor/tool	DG and storage devices in DSO grid
Assumptions	• Flexible sources (DG including RES, storage) are available and controllable by the DSO • Forecast data for intermittent RES is available • Load and generation profiles (including forecasted profiles) are available for each relevant network bus
Prerequisites	• Grid model includes both TSO and DSO grids • The relevant DSO grid is radial • There are no grid congestion or voltage profile issues (i.e. overloads, voltage limit violations) in the observable grid before the start of the UC
Grid equivalenting	Grid equivalents are used for each TSO/DSO connection point and represent active and reactive power flow from/to TSO grid, as seen from the HV voltage side of the transformer. This simple representation of TSO grid is used since UC5 optimisation is performed only at the DSO level.
Input	• List of time steps for which the use case should be performed (as UC3 operates partly on the same resources and has higher priority in SC3, the time steps where UC3 performed any changes are excluded from UC5 operation). • Time series data for all relevant resources and other objects

Flowchart	START for each time step check general "direction" (more/less power needed in the grid) for each available resource (storage, RES) calculate load flow to check: 1. change of objective function value 2. if there are no violations (line loading, voltage) check marginal gain (effect of changing output by a predefined step - PF) array: [resource; marginal gain; safety flag] any positive gain (with no violations)? Yes change the output of best available resource No don't do anything any more time steps? Yes No END

<table>
<tr><td>Formula</td><td>
The objective function used for calculating marginal gain for each resource s in time step t is defined as follows:

$$F(s,t) = \sum_{i=0}^{n} (W_i(s,t) * a_{W_i})$$

where:
$W_i(s,t)$ - single criterion used for objective function (see below);
a_{W_i} - weight factor for W_i criterion (see below).

<table>
<tr><th>Criterion</th><th>Calculation method</th><th>Weight factor</th></tr>
<tr><td>TSO/DSO transformer loading</td><td>$1 - \text{loading } [pu]$</td><td>0,5 / 0,35*</td></tr>
<tr><td>Power losses in DSO grid</td><td>$1 - \frac{\text{losses after change of resource output}}{\text{losses before change of resource output}}$</td><td>0,15</td></tr>
<tr><td>RES curtailment</td><td>$\frac{\text{total RES power after change of resource output}}{\text{total RES power before change of resource output}}$</td><td>0,35 / 0,5*</td></tr>
</table>

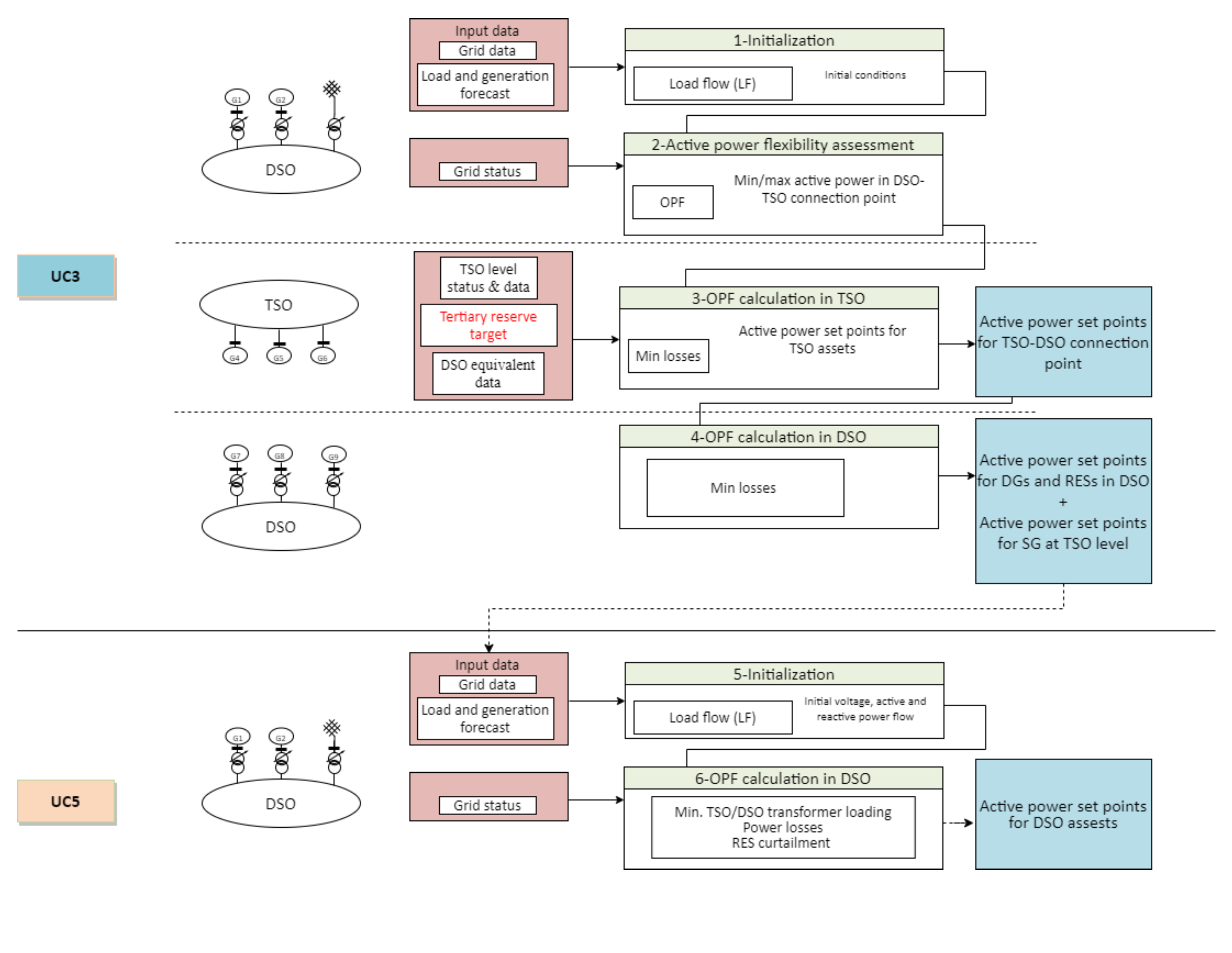
* weight factor values for transformer loading and RES curtailments criteria are variable depending on transformer loading value: when it’s close to 1 p.u., the weight for this criterion is higher.

The constraints checked after testing the effect of the output change for each relevant resource are:

1. Loading of all lines in the relevant DSO grid (check for overloadings)
2. Voltage levels at all terminals in the relevant DSO grid (check for limit violations)
</td></tr>
<tr><td>Simulation environment</td><td>Python and PowerFactory</td></tr>
<tr><td>Simulation type</td><td>Semi-dynamic</td></tr>
</table>

4.3.3 Showcase structure

Sequence diagram



<table>
<tr><td rowspan="7">Detailed description</td><td>Steps</td><td colspan="7">Description</td></tr>
<tr><td>1</td><td colspan="7">In step1, a power flow is performed to collect the initial values of the network parameters.</td></tr>
<tr><td>2</td><td colspan="7">Then, the DSO, having a simple grid equivalent from transmission network, runs an optimisation which is aimed to identify the active power flexibility it can provide to the transmission network in case of demand for provision of tertiary reserve for frequency control. In this step the maximum and minimum available active powers at TSO-DSO connection points are identified.</td></tr>
<tr><td>3</td><td colspan="7">In this step, the TSO gathers the information of flexibility from DSO level and with regards to the required tertiary reserve, runs an optimization in its own network while using a DSO grid equivalent. The optimization is aimed to satisfy the tertiary reserve from the renewable sources available at the DSO network as well as minimizing the losses at TSO level. At the end of this step the active power values for the connection points between TSO and DSO are defined as set points in addition to the active power set points for the generator units at TSO level.</td></tr>
<tr><td>4</td><td colspan="7">In this step, the DSO will run another optimisation while the active power values for TSO-DSO connection points are fixed and the TSO grid is considered using a proper grid equivalent. The aim of this optimization is to minimise the losses at the DSO network with the defined constraints of active power exchange with the TSO level. At the end of this step, the active power set points for the remaining controllable units in the networks meaning generators and controllable loads at DSO level are defined.</td></tr>
<tr><td>5</td><td colspan="7">After receiving data on active power set points for generators and controllable loads at DSO level from UC3, a load flow is performed to evaluate the network operation point.</td></tr>
<tr><td>6</td><td colspan="7">In this step, the algorithm iteratively checks for all available resources how changing their output active power will effect chosen grid performance criteria (TSO/DSO transformer loading, grid losses in DSO grid, RES generation level). If the change is positive, the algorithm checks whether this caused any violations in the grid. At the end of the iterative process, the active power set points for the controllable units at DSO level are defined.</td></tr>
<tr><td rowspan="2">Sequence of actions</td><td>Steps</td><td>Associate UC ID</td><td>Action</td><td>Content</td><td>Input</td><td>Operation</td><td>output</td><td>Grid area</td></tr>
<tr><td>1</td><td>3</td><td>Initialization</td><td>Set the initial values of assets</td><td>• Grid data,
• Load and generation forecast</td><td>Load flow</td><td>• Initial voltage, active and reactive power flow</td><td>Full network (TSO and DSO levels)</td></tr>
</table>

	2	3	Active power flexibility assessment	Definition of active power flexibility from DSO side for TSO grid	• Grid initial condition	Optimal power flow	• Active power flexibility in the TSO-DSO point of common coupling	Equivalent TSO, DSO
	3	3	TSO optimization	Loss minimization in TSO grid	• TSO network conditions • TSO load and generation forecast • DSO equivalent • Output from step 2	Optimal power flow	• Active power set points for TSO-DSO points of common coupling • Active power set points for generators at TSO level	TSO, Equivalent DSO
	4	3	DSO optimization	Loss minimization considering the fixed values for active power exchange at TSO-DSO point of common coupling defined in step 3	• Output from step 5 • fixed values for active power exchange at TSO-DSO point of common coupling defined in step 3	Optimal power flow	• Active power set points for generators and controllable loads at DSO level	Equivalent TSO, DSO
	5	5	Initialization	Determination of grid operation point	• Grid data, • Load and generation forecast, • output from step 4	Load flow	• Initial voltage, active and reactive power flow	DSO, Equivalent TSO

	6	5	DSO optimization	DSO/TSO transformer loading minimization, considering grid losses and RES curtailment, as well as constraints from UC5	• Output from step 5	Optimal power flow	• Active power set points for DSO assets	DSO, Equivalent TSO

4.3.4 Test Case

System under Test (SuT)	The power system under testing is a benchmark grid model based on project SimBench [6], with radial DSO network. The grid model contains a total of 287 lines, 235 bus bars, 15 transformers, 225 loads, 262 static generators and 5 synchronous machines. The study is performed at TSO level, which consists of 380kV and 220kV as well as DSO level which includes 110, 20 and 0.4 kV. This grid was selected as it contains both TSO and DSO grids which are needed by UC3 and UC5. Moreover, UC5 has been designed for a radial grid which is provided by the selected grid model.		
Objects under Test (OuT)	• Static Generators (RES, storage) • Synchronous Generators • Controllable loads		
Scenario	INTERPLAN-2: Small and local		
Input data	The input data consists of generation and consumption profiles of all units in the networks within a time frame of 24 hours and resolution of 15 minutes.		
KPI under test	**ID**	**Name**	**Formula**
	1	Level of losses in transmission and distribution networks	$P_{\text{losses}} = \frac{\text{amount of injected energy} - \text{amount of energydelivered to customers}}{\text{amount of injected energy}} * 100\ [\%]$
	7	Power losses	$P_{\text{losses}} = \sum_{i}^{Nline} \lvert I \rvert_i^2 r_i\ [kW]$ $I_i -$ magnitude of current flow in line i $[A]$

			$r_i -$ resistance of line i $[\Omega]$
	14	Level of DG / DRES utilization for ancillary services	$UAS\% = \frac{E_{AS}}{E_{total}} * 100\ [\%]$ E_{AS} – the energy used for ancillary services $[MWh]$ E_{total} – the total energy produced $[MWh]$
	16	Transformer loading	$Loading\% = \frac{\text{power at transformer primary winding}}{\text{transformer nominal power}} * 100\ [\%]$
	17	RES curtailment	$Curtailment\% = 100 - \frac{\text{energy supplied by RES to the grid}}{\text{RES available energy}} * 100\ [\%]$
	22	Quadratic deviation from global active power exchange target	Let $p_{target}(t)$ be the global active power production target at time t. Let G be the set of generators producing active power, and $p_g(t)$ be the active power generated by generator g at a given time t. Then, the KPI at this time is: $\left(p_{\text{target}}(t) - \sum_{g \in G} p_g(t)\right)^2$
	23	Mean quadratic deviation from active power targets at TSO/DSO connection points	$\frac{1}{\lvert C \rvert} \sum_{c \epsilon C} (P_{c,\text{target}}(t) - P_c(t))^2$
	27	Share of RES	$RES\% = \frac{P_{RES}}{P_{total}} * 100\ [\%]$ P_{RES} – Active power provided by RES at a given time step [MW] P_{total} – Total active power provided by RES and non-RES generators at a given time step [MW]
Simulation type	Semi-dynamic		
Output parameters	Active power of generators, transformer losses and loading, line losses and loading, terminals voltage		

4.3.5 Summary

Summary	This showcase addresses a combination of network operation challenges, which are provision of appropriate tertiary reserve and energy management on DSO level in the presence of high DER penetration levels. The proposed integrated control functions (related to UC3 and UC5) allow system operators (TSOs and DSOs) to solve these operation challenges through an effective DER and storage operation planning based on active power control. A system operator (TSO and/or DSO) that wants to address these operation challenges by using the INTERPLAN tool will be guided by the User Manual to select the following planning criteria: • 1. Minimizing losses, • 3. Maximizing share of RES, • 7. Optimize TSO/DSO interaction, • 8. Maximize DG / DRES contribution to ancillary services, • 9. Assuring frequency stability. The simulation functionalities to be used are load flow and optimal power flow, whereas the selected KPIs needed to measure the effectiveness of the control functions are: • 1. Level of losses in transmission and distribution networks, • 7. Power losses, • 14. Level of DG / DRES utilization for ancillary services, • 16. Transformer loading, • 17. RES curtailment, • 22. Quadratic deviation from global active power exchange target, • 23. Mean quadratic deviations from active power targets at TSO/DSO connection points, • 27. Share of RES. The suggested INTERPLAN scenario is INTERPLAN-2 Small and Local. Regarding the type of grid models to be used, the grid investigated for control is a transmission-distribution grid. Grid equivalenting is required for two reasons: first of all, system operators may not share full details of their own network topology and data with the other operators, and second this will simplify the optimization process at each system operator network. In detail, the TSO network or the DSO network is replaced by proper grid equivalents which represents the active and reactive power values of the original network. Once all these steps are performed, the user is ready to select this showcase control function and perform the simulations through PowerFactory. The evaluation phase will follow with reference to the KPI(s) values found in the simulation.

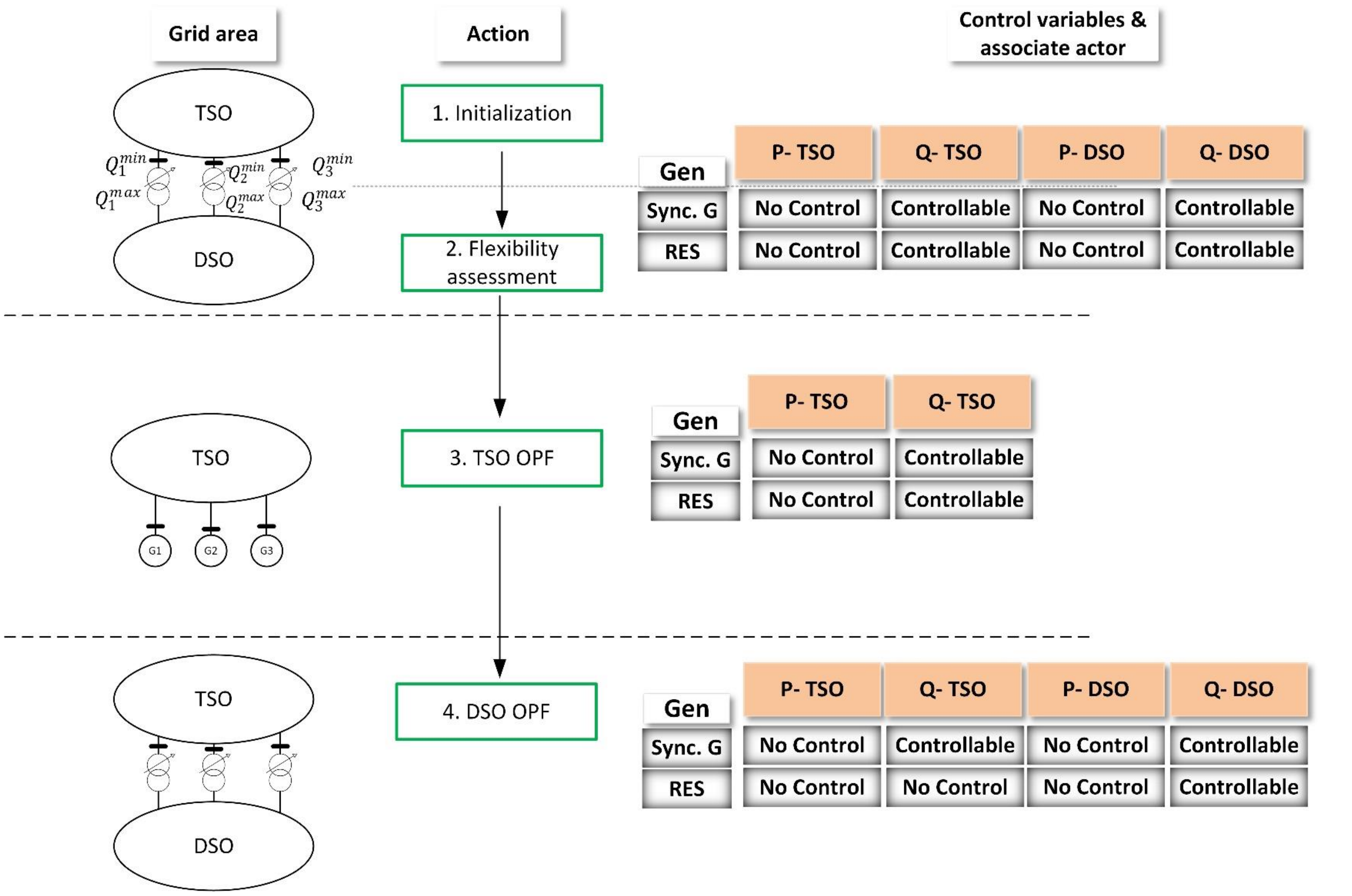
4.4 SC4 - TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles

4.4.1 SC properties

ID and Name	SC4: TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles.
Relevant UC/s	UC1: Coordinated voltage/reactive power control UC3: Provision of tertiary control reserve based on coordinated TSO-DSO active power optimization
SC description	**Summary**
	Optimisation of active and reactive power flow in both TSO and DSO levels with the aim of efficient operation of the network ensuring high power quality and decrease of power losses
	Motivation
	The presence of renewable energy resources can significantly impact the power networks, exposing the system to much higher power fluctuations and compromising the system power quality. Ensuring high power quality through measures like voltage control and frequency control are even more challenging issues to deal with in presence of higher shares of such fluctuating sources. Therefore, innovative control schemes have to be considered in operation of the future power systems.
	Objective
	The objective of this showcase is to present an optimization strategy for parallel control of active and reactive power at transmission and distribution grids, for maintaining the voltage quality at both network levels on one hand and on the other hand for participation in the tertiary reserve market and supporting the TSO in keeping the whole network stable. The control strategy must ensure an optimization of both active and reactive power of all available resources with no conflict in set points, considering the constraints.
	Solution
	The solution is application of optimisation strategies which are described in details in use case 1: Coordinated voltage/reactive power control and UC3: Provision of tertiary control reserve based on coordinated TSO-DSO active power optimization.

4.4.2 Control functions

4.4.2.1 Control function for coordinated voltage/reactive power control

UC 1: Coordinated voltage/reactive power control	
Control variables & associate actor/tool & flowchart	

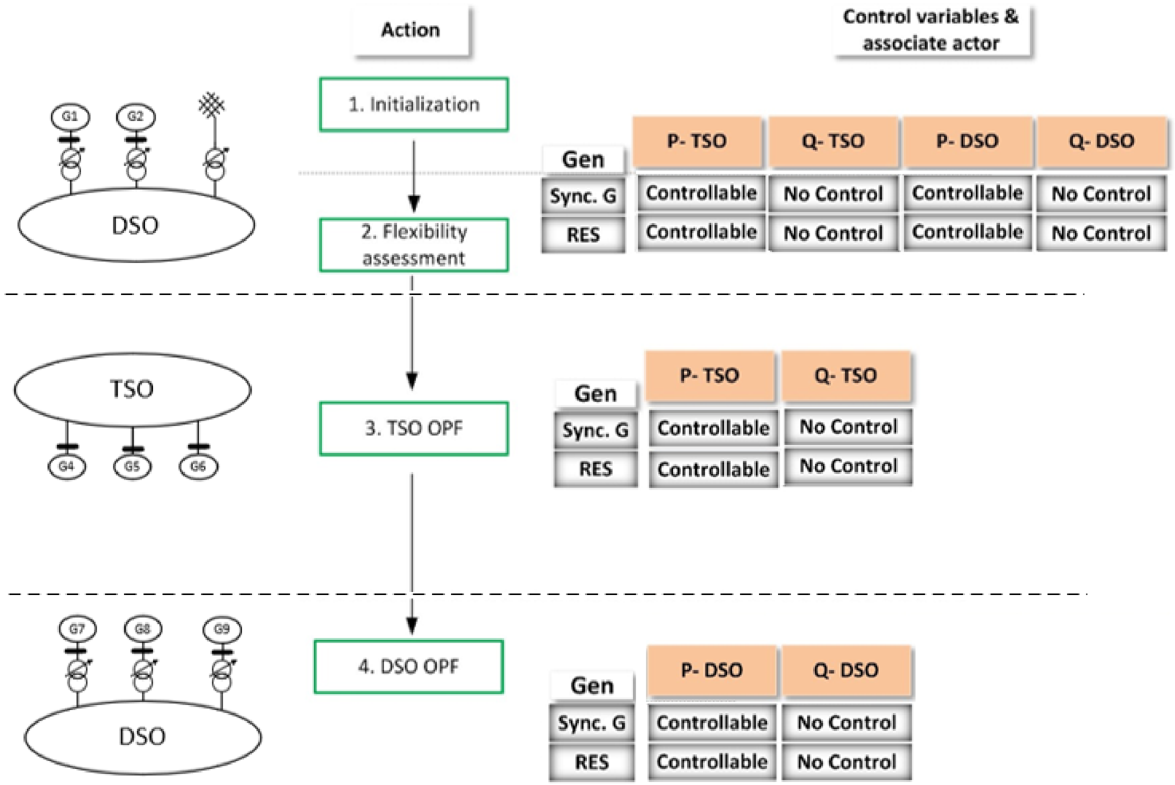
<table>
<tr><td>Prerequisites</td><td><u>Step 1:</u>
Load flow for initialization</td></tr>
<tr><td></td><td><u>Step 2:</u>
Reactive power flexibility assessment at the connection points, DSO grid equivalent</td></tr>
<tr><td></td><td><u>Step 3:</u>
OPF in TSO and fix the reactive power set points in connection point</td></tr>
<tr><td></td><td><u>Step 4:</u>
OPF for optimal distribution of reactive power set points for generators in DSO level to realize set points from step 3</td></tr>
<tr><td>Grid equivalenting</td><td>Grid equivalenting is employed in the third step of the UC1 procedure in terms of a DSO equivalent, because the DSO in this step is not under control and just equivalent generators representing the DSO are sufficient. The equivalent generators are connected to TSO-DSO connection points and their initial active and reactive power set points are extracted from LF results at that node.</td></tr>
<tr><td>Input</td><td><u>General grid data for all steps:</u>
Bus data
<table>
<tr><td>Bus type</td><td>Active power load</td><td>Reactive power load</td><td>Bus area</td><td>Initial Bus voltage magnitude</td><td>Initial bus voltage angle</td><td>Maximum and minimum bus voltage</td><td>Nominal bus voltage</td></tr>
</table>
Branch data
<table>
<tr><td>Branch from which bus</td><td>Branch To which bus</td><td>Branch resistance</td><td>Branch reactance</td><td>Branch conductance</td><td>Branch susceptance</td><td>Branch capacity (max. current carrying capacity)</td><td>Branch type</td><td>Branch tap rate magnitude if it is a transformer</td><td>Branch phase shift angle if it is transformer</td></tr>
</table>
Generator data
<table>
<tr><td>Generator bus number</td><td>Generator type</td><td>Generator operation mode</td><td>Initial active power</td><td>Initial reactive power</td><td>Reactive power boundary</td><td>Voltage in case of operation mode slack or PV</td></tr>
</table>
</td></tr>
</table>

	Step 1: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators.
	Step 2: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Active and reactive power for equivalent DSO generators, • Minimum and maximum capable reactive power for DSO-TSO connection points (from step 1).
	Step 3: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Reactive power set point in DSO-TSO connection points (from step 2).
	Step 4: • Voltage magnitude and angle initialization for buses and generators, • Initial active and reactive power for generators, • Reactive power set points for generators in DSO level to fulfill set points at TSO-DSO connection points (from step 3)
Formula	Note: Within these optimisations, all decision variables including bus indexes and time are optimized in a way that this objective is going to reach. This means that all variables at buses and all time steps are involved to achieve this goal. When those variables are being decided to minimize overall grid losses, they consequently cause reduction of the grid losses at each time step. Briefly, the only way to minimize the grid losses over entire time steps is to reduce the grid losses at each time steps. Therefore, the overall grid losses are minimized and the results for each time step is extracted. **Step 1:** Initial load flow using complete load flow formulation
	Step 2: **Objective function:** $$\boldsymbol{Q}_{\mathbf{CP}}^{\mathbf{Max}} = max \sum_{t} \sum_{i} \sum_{j} V_i(t) V_j(t) \left[G_{\mathrm{ij}} \sin\left(\theta_i(t) - \theta_j(t)\right) - B_{ij} \cos\left(\theta_i(t) - \theta_j(t)\right) \right]$$ $$\boldsymbol{Q}_{\mathbf{CP}}^{\mathbf{Min}} = min \sum_{t} \sum_{i} \sum_{j} V_i(t) V_j(t) \left[G_{\mathrm{ij}} \sin\left(\theta_i(t) - \theta_j(t)\right) - B_{\mathrm{ij}} \cos\left(\theta_i(t) - \theta_j(t)\right) \right]$$

	s.t. $$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \leq Q_g(t) \leq \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$ $$\frac{P_{\mathrm{ij}}(t)^2 + Q_{\mathrm{ij}}(t)^2}{V_{\mathrm{ij}}(t)^2} \leq I_{\mathrm{ij,max}}^2$$ Where: i, j: Index (set) of buses t: Index (set) of time steps g: Index (set) of generators n: Index (set) of connection point CP: Superscripts for connection point SP: Superscripts for set point G: Conductance of transmission line B: Susceptance of transmission line S: Apparent power α: Weight/scale factor for objective function β: Weight/scale factor for objective function P: Active power Q: Reactive power V: Voltage magnitude θ: Voltage angle I: Electric current This nomenclature can be applied for formulation of other steps.
	Step 3: **Objective function:** $$\boldsymbol{P}_{\mathbf{losses}}: min \sum_t \sum_i \sum_j G_{\mathrm{ij}} \left[V_i(t)^2 + V_j(t)^2 - 2V_i(t)V_j(t)\cos\left(\theta_i(t) - \theta_j(t)\right)\right]$$

	s.t. $$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \leq Q_g(t) \leq \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$ $$\frac{P_{ij}(t)^2 + Q_{ij}(t)^2}{V_{ij}(t)^2} \leq I_{ij,max}^2$$
	<u>Step 4:</u> **Objective function:** $$\boldsymbol{P}_{\mathbf{losses}}: min \sum_t \left\{ \sum_i \sum_j G_{ij} \left[V_i(t)^2 + V_j(t)^2 - 2V_i(t)V_j(t)\cos\left(\theta_i(t) - \theta_j(t)\right)\right] + \sum_n \left(Q_{\mathrm{CP}_n}(t) - Q_{\mathrm{sp_n}}(t)\right)^2 \right\}$$ **s.t.** $$-\sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2} \leq Q_g(t) \leq \sqrt{1-\left(\frac{P_g(t)}{S_g}\right)^2}$$ $$\frac{P_{ij}(t)^2 + Q_{ij}(t)^2}{V_{\mathrm{ij}}(t)^2} \leq I_{\mathrm{ij,max}}^2$$
Simulation environment	PowerFactory, AMPL
Simulation type	Semi-dynamic

4.4.2.2 Control function for provision of tertiary control reserve based on coordinated TSO-DSO active power optimisation

<table>
<tr><th colspan="2">UC ID 3: Provision of tertiary control reserve based on coordinated TSO-DSO active power optimisation</th></tr>
<tr><td>Control variables</td><td>

Note: In this use cases some of the loads are also considered as controllable in order to represent demand response.</td></tr>
<tr><td>Prerequisites</td><td><u>Steps 1 and 2:</u>
Load flow for initialization
TSO grid equivalent
Active power flexibility assessment in the connection point</td></tr>
</table>

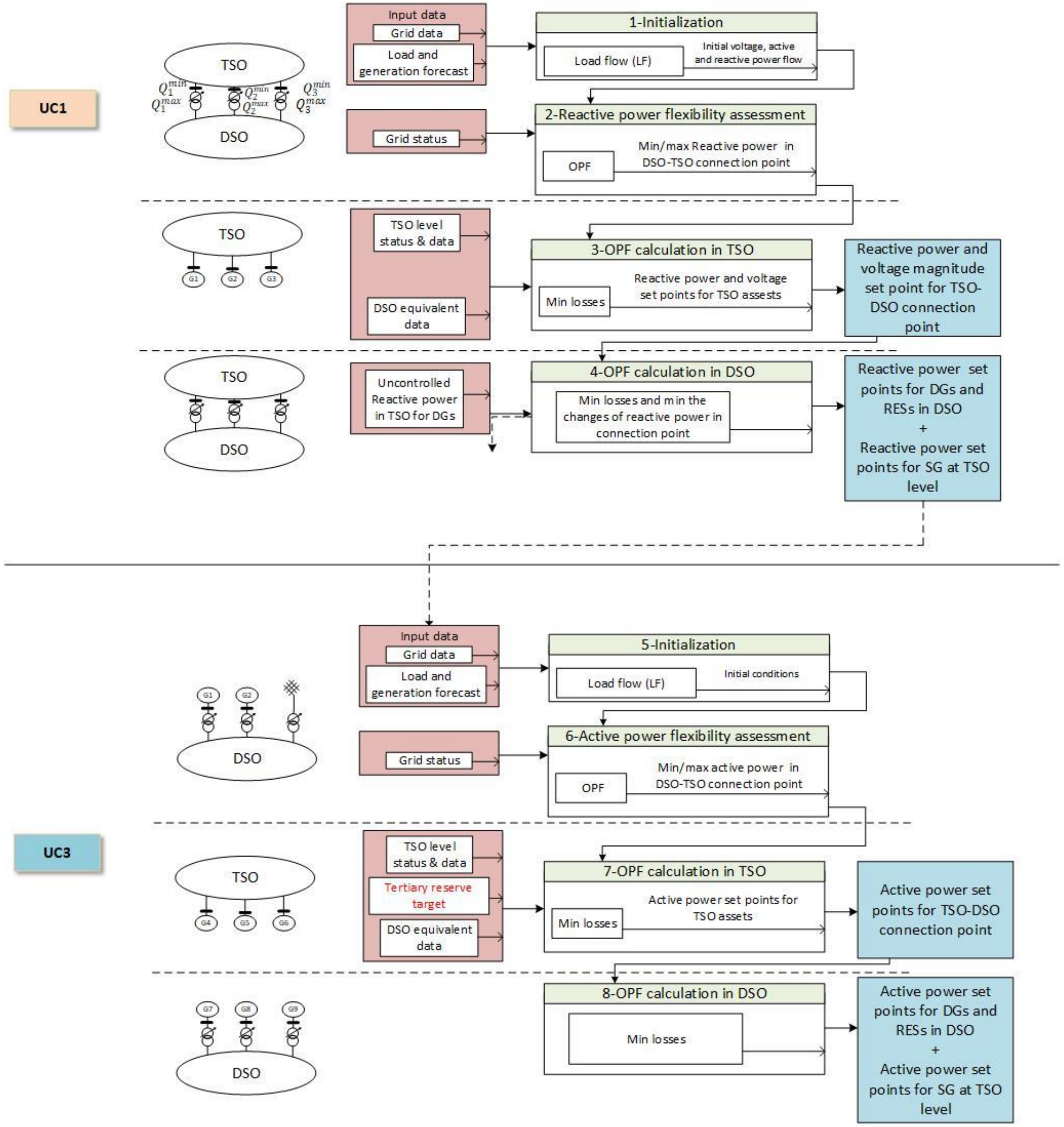
	Step 3: • Optimisation function for TSO level • DSO grid equivalent.
	Step 4: • Optimisation function for DSO level • TSO grid equivalent
Grid equivalenting	At each step of the use case process, either the TSO network or the DSO network is replaced by proper grid equivalents which represent the active and reactive power values of the original network. There are two reasons for implementing this: fist, system operators may not share full details of their own network topology and data with the other operators, and second this will simplify the optimization process at each system operator network.
Input	**General grid data for all steps:** • Bus data • Branch data • Generator data
	Steps 1 and 2: • Initial active and reactive power for generators. • active and reactive power for equivalent TSO generators plus slack generator
	Step 3: • Initial active and reactive power for generators • active and reactive power for equivalent DSO generators • Minimum and maximum available active power for DSO-TSO connection point (from step 1)
	Step 4: • Initial active and reactive power for generators • Active power set points in DSO-TSO connection point (from step 2)
Formula	**Step 2:** **Objective function:** $P_{\mathrm{PCC}}^{\max}(t):\ max \sum_{i}^{M} \sum_{k}^{N} V_i(t) V_k(t)\ (G_{ik} \cos\theta_{ik}(t) + B_{ik} \sin\theta_{ik}(t))$

	$$P_{\text{PCC}}^{\min}(t):\ min\sum_{i}^{M}\sum_{k}^{N}V_i(t)V_k(t)\ (G_{ik}\cos\theta_{ik}(t)+B_{ik}\sin\theta_{ik}(t))$$ Note: The optimization is done for a fixed point of time (t). **s.t.** $$P_{\text{gen}}^{\min}(t)\ <=\ P_{gen}(t)\ <=\ P_{\text{gen}}^{\max}(t)$$ The reactive power set points for controllable units are considered as fixed values. Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling P_{gen}: Active power generated by a generator V_i : Voltage magnitude at bus i G_{ik}: Real part of admittance matrix B_{ik}: Imaginary part of admittance matrix θ_{ik}: Voltage angle difference t: Index of time steps. The range of t is 96 time steps (each 15 minutes in 24 hours) *M*: Total number of points of common coupling between TSO and DSO *N*: Total number of buses in the network under analysis
	<u>Step 3:</u> **Objective function:** $$P_{\text{Losses}}^{\min}(t)=\ min\ (\sum_{x}^{G}P_{\text{gen}}(t)-\sum_{y}^{L}P_{\text{load}}(t))$$ Note: The optimization is done for a fixed point of time (t). **s.t.** $$P_{\text{PCC}}^{\min}(t)<=P_{\text{PCC}}(t)\ <=\ P_{\text{PCC}}^{\max}(t)$$

	$$P_{\mathrm{gen}}^{\mathrm{min}}(t) <= P_{\mathrm{gen}}(t) <= P_{\mathrm{gen}}^{\mathrm{max}}(\mathrm{t})$$ The reactive power set points for controllable units are considered as fixed values. Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling P_{gen}: Active power generated by a generator P_{load}: Active power consumed by a load P_{Losses}: Active power losses in the network under analysis t: Index of time steps. The range of t is 96 time steps (each 15 minutes in 24 hours). G: Total number of generators in the network under analysis L: Total number of aggregated loads in the network under analysis
	Step 4: **Objective function**: $$P_{\mathrm{Losses}}^{\mathrm{min}}(t) = min\left(\sum_{x}^{G} P_{\mathrm{gen}}(t) - \sum_{y}^{L} P_{\mathrm{load}}(t)\right)$$ Note: The optimization is done for a fixed point of time (t). **s.t.** $$P_{\mathrm{PCC}}(t) = P_{\mathrm{PCC}}^{\mathrm{step\ 2}}(\mathrm{t})$$ $$P_{\mathrm{gen}}^{\mathrm{min}}(t) <= P_{gen}(t) <= P_{\mathrm{gen}}^{\mathrm{max}}(\mathrm{t})$$ The reactive power set points for controllable units are considered as fixed values. Obviously all power flow constraints for all units and parameters are considered. Where: P_{PCC}: Active power injected at point of common coupling $P_{\mathrm{PCC}}^{\mathrm{step\ 2}}$: The identified P_{PCC} in step 2 optimisation P_{gen}: Active power generated by a generator P_{load}: Active power consumed by a load

	P_{Losses}: Active power losses in the network under analysis t: Index of time steps. The range of t is 96 time steps (each 15 minutes in 24 hours). G: Total number of generators in the network under analysis L: Total number of aggregated loads in the network under analysis
Simulation environment	Python, PowerFactory
Simulation type	Semi-dynamic

4.4.3 Showcase structure

Sequence diagram	

 |

<table>
<tr><td rowspan="9">Detailed description</td><td>Steps</td><td>Description</td></tr>
<tr><td>1</td><td rowspan="2">The reactive power capability is evaluated at each TSO-DSO connection point with an optimization tool. An OPF is executed to find the maximum and minimum reactive power that the DSO can exchange with the TSO at each 15 minutes in a day. At step 1, first an initialization is performed by running a power flow in order to calculate the initial values for different variables in the grid, including voltage magnitude/angle as well as active and reactive power flow. The area of the network that needs to be analysed in this step is both DSO and TSO. Grid data including detailed information about buses, branches, and generators as well as time series for load and generation are required as input data for initialization. Then those data along with grid status information are transferred to the flexibility assessment in step 2. To evaluate the reactive power capability from DSO to deliver to the TSO, reactive power at DSO and TSO should be controlled for RESs and synchronous generators.</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td><td>Finding the possible reactive power provision from DSO to TSO, this data is transferred to step 3 which is TSO level redispatch via minimizing the grid losses. In this step, the TSO level operation is scheduled for the next day based on the given reactive power capability from the DSO. Therefore, in this step just the TSO level is analysed and the DSO is represented by equivalents, namely generators in the connection points, in a way that the maximum and minimum reactive power for the equivalent generators are set like the calculated ones in the previous step. Initial operating active and reactive power for those equivalent generators are also obtained from the power flow results at the relevant bus. Hence, the reactive power set points for all generators are optimized at the TSO in a way that TSO losses are minimized.</td></tr>
<tr><td>4</td><td>Given the reactive power set points from the last step, another OPF is performed in the overall grid in a way that the only variables under control are all generator reactive powers at the DSO level and the reactive power of RES at the TSO level. In other words, in the final step, reactive power at the DSO is optimized while setting the TSO variables as calculated in the second step. The only exception is synchronous generator reactive power at TSO level which is supposed to be controllable. Therefore, the optimum reactive power for RESs is calculated by minimizing the total grid losses as well as the deviation of reactive power at connection points from what has been calculated in the second stage. This means that in addition to loss minimization, the calculation aims to preserve the exchanged reactive power at the optimum amount calculated by the TSO OPF. This helps to obtain the DSO values independent from the TSO level.</td></tr>
<tr><td>5</td><td rowspan="2">After UC1 is terminated, the assigned reactive power set points are transferred to UC3. Considering these values, a power flow is performed to collect the initial values of the network parameters. Then, the DSO, using a simple grid equivalent from transmission network, runs an optimisation which is aimed to identify the active power flexibility it can provide to the transmission network in case of demand for provision of tertiary reserve for frequency control. In this step the maximum and minimum available active power for points of common coupling are identified.</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td><td>In this step, the TSO gathers the information of flexibility from DSO level and with regards to the required</td></tr>
</table>

<table>
<tr><td rowspan="2"></td><td></td><td colspan="7">tertiary reserve, runs an optimization in its own network while using a DSO grid equivalent. The optimization is aimed to satisfy the tertiary reserve from the renewable sources available at the DSO network as well as minimising the losses at TSO level. At the end of this step, the active power values for the connection points between TSO and DSO are defined as set points in addition to the active power set points for the generator units at TSO level.</td></tr>
<tr><td>8</td><td colspan="7">In this step, the DSO runs another optimisation while the active power values for TSO-DSO connection points are fixed. The TSO grid is replaced by a proper grid equivalent for this step. The aim of the optimization is to minimise the losses at the DSO network with the defined constraints of active power exchange with the TSO level. At the end of this step, the active power set points for the remaining controllable units in the network, meaning generators and controllable loads at DSO level, are defined.</td></tr>
<tr><td rowspan="4">Sequence of actions</td><td>Steps</td><td>Associate UC ID</td><td>Action</td><td>Content</td><td>Input</td><td>Operation</td><td>output</td><td>Grid area</td></tr>
<tr><td>1</td><td>1</td><td>Initialization</td><td>Set the initial values of assets</td><td>• Grid data,
• Load and generation forecast</td><td>Load flow</td><td>• Initial voltage, active and reactive power flow</td><td>TSO & DSO</td></tr>
<tr><td>2</td><td>1</td><td>Reactive power flexibility assessment</td><td>Definition of reactive power capability from DSO side for TSO grid</td><td>• Grid status
• Output from step 1</td><td>Optimal power flow</td><td>• Reactive power capability in TSO-DSO connection point</td><td>TSO & DSO</td></tr>
<tr><td>3</td><td>1</td><td>TSO optimization</td><td>Provision of required tertiary reserve as much as possible from DSO level with the aim of loss minimization in TSO grid</td><td>• TSO level status and data
• Required tertiary reserve
• TSO load and generation forecast
• DSO equivalent
• Output from step 2</td><td>Optimal power flow</td><td>• Reactive power and voltage set points for TSO assets</td><td>TSO, Equiva-lent DSO</td></tr>
</table>

	4	1	DSO optimization	Loss minimization and trying to keep the reactive power in the set points calculated in the step 5	• Output from step 3 • Reactive power set points for TSO DG and make them uncontrolled	Optimal power flow	• Reactive power and voltage set point for RES and DGs in DSO	Full network (TSO, DSO)
	5	3	Initialization	Set the initial values of assets	• Grid data, • Load and generation forecast	Load flow	• Initial voltage, active and reactive power flow	Full network (TSO and DSO levels)
	6	3	Active power flexibility assessment	Definition of active power flexibility from DSO side for TSO grid	• Grid initial condition	Optimal power flow	• Active power flexibility in the TSO-DSO point of common coupling	Equiva-lent TSO, DSO
	7	3	TSO optimization	Loss minimization in TSO grid.	• TSO network conditions • TSO load and generation forecast • DSO equivalent • Output from steps 2 to 6	Optimal power flow	• Active power set points for TSO-DSO points of common coupling • Active power set points for generators at TSO level	TSO, Equi-valent DSO

	8	3	DSO optimization	Loss minimization considering the fixed values for active power exchange at TSO-DSO point of common coupling defined in step 5	• Output from step 5 • Fixed values for active power exchange at TSO-DSO point of common coupling defined in step 5	Optimal power flow	Active power set points for generators and controllable loads at DSO level	Equiva-lent TSO, DSO

4.4.4 Test case

System under Test (SuT)	The power system under test is a benchmark grid model based on project SimBench [6]. The grid model contains a total of 287 lines, 235 bus bars, 15 transformers, 225 loads, 257 static generators, and 5 synchronous machines. The study is performed at TSO level which consists of 380 kV and 220 kV as well as DSO level which includes 110, 20 and 0.4 kV. This grid was selected as it contains both TSO and DSO grids which are needed by UC3 and UC5. Additionally, the share of static generators is considered high enough to address the selected scenario and prove the functionality of control algorithms in dealing with high share of RES.		
Objects under Test (OuT)	• Static Generators (Renewable based) • Synchronous Generators (Fossil based) • Aggregated loads		
Scenario	INTERPLAN-2 “small and local”		
Input data	The input data consists of generation and consumption profiles of all units in the networks within a time frame of 24 hours and resolution of 15 minutes.		
KPIs under test	**ID**	**Name**	**Formula**
	1	Level of losses in transmission and distribution networks	$\text{Percentage of losses} = \frac{\text{Amount of injected energy} - \text{amount of energy delivered to customers}}{\text{Amount of injected energy}} \times 100$
	10	Voltage Quality	According to the defined EN 50160 Standards and VDE-AR-N 4120, bus bar voltage magnitudes must comply with following allowed range of variation. • LV: (±10% of nominal voltage)

			• MV: (±5% of nominal voltage) • HV & EHV: (±4-7% of nominal voltage) Voltage deviation indices can be defined to find the frequency or duration that the bus bar voltages violate the allowed voltage range. • Number of voltage excursions exceeded n minutes per year • Percentage of time that the transmission voltage exceeds the permissible limits
	13	Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids	Let *C* be the set of connection points between TSOs and DSOs. Let $q_{c,target}(t)$ [kvar] be the target value for reactive power transmission from DSO to TSO at connection point c and time *t*, as e.g. calculated by grid operation planning. Let $q_c(t)$ be the reactive power actually provided from DSO to TSO at connection point *c* and time *t*. Then the KPI related to reactive power at time *t* is defined as: $$\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(q_{\mathrm{c,target}}(t)-q_c(t)\right)^2$$ The KPI related to voltage is defined as follows. Let $u_{c,target}$ [V] be the nominal value for the line-to-line voltage at connection point *c*, calculated as mean over all phases. Let $u_c(t)$ be the actual line-to-line voltage mean over all phases. Then, the KPI at time *t* is: $$\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(u_{\mathrm{c,target}}-u_c(t)\right)^2$$
	14	Level of DG / DRES utilization for ancillary services	$$\mathrm{UAS\%}=\frac{\mathrm{E_{AS}}}{\mathrm{E_{total}}}*100\ [\%]$$ E_{AS} – the energy used for ancillary services $[MWh]$ E_{total} – the total energy produced $[MWh]$
	22	Quadratic deviation from global active power exchange target	Let $p_{target}(t)$ be the global active power production target at time t. Let G be the set of generators producing active power, and $p_g(t)$ be the active power generated by generator g at a given time t. Then, the KPI at this time is: $$\left(p_{\mathrm{target}}(t)-\sum_{g\in G}p_g(t)\right)^2$$

	23	Mean quadratic deviations from active power targets at TSO/DSO connection points	Let C be the set of connection points between TSOs and DSOs. Let $p_{c,target}$ (t) [kW] be the target value for active power transmission from DSO to TSO at connection point c and time t, as e.g. calculated by grid operation planning. Let p_c(t) be the active power actually provided from DSO to TSO at connection point c and time t. Then the KPI related to active power at time t is defined as: $$\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(p_{\mathrm{c,target}}(t)-p_c(t)\right)^2$$
	24	Reactive energy provided by RES and DG	Let G be the set of RES and DG generators producing reactive power, and q_g(t) be the reactive power generated by generator g at a given time t. Then, the KPI during the time interval *t1*..*t2* is: $$\sum_{g\in G}\sum_{t=t1}^{t2}\lvert q_g(t)\rvert$$ [kvarh]
	27	Share of RES	$$RES\% = \frac{P_{\mathrm{RES}}}{P_{\mathrm{total}}} * 100 \text{ [\%]}$$ P_{RES} = Active power provided by RES at a given time step [MW] P_{total} = Total active power provided by RES and non-RES generators at a given time step [MW]
Simulation type	Semi-dynamic		
Output parameters	Active and reactive power set points for generators, Active power set points for controllable loads.		

4.4.5 Summary

Summary	This showcase addresses a combination of network operation challenges, which are voltage stability and provision of tertiary reserve to ensure frequency stability in an optimum way. The proposed integrated control functions (related to UC1 and UC3) allow system operators (TSOs and DSOs) to solve these operation challenges through an effective DER operation planning based on active and reactive power intelligent control and coordinated TSO-DSO optimization. A system operator (TSO and DSO) that wants to address these operation challenges by using the INTERPLAN tool will be guided by the user manual to select the following planning criteria: • 1. Minimizing losses • 3. Maximizing share of RES • 4. Assuring voltage stability • 7. Optimize TSO/DSO interaction • 8. Maximize DG / DRES contribution to ancillary services • 9. Assuring frequency stability The simulation functionalities to be used are load flow, optimal power flow. The selected KPIs needed to measure the effectiveness of the control functions are: • 1. Level of losses in transmission and distribution networks • 10. Voltage quality • 13. Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids • 14. Level of DG / DRES utilization for ancillary services • 22. Quadratic deviation from global active power exchange target • 23. Mean quadratic deviations from active power targets at TSO/DSO connection points • 24. Reactive energy provided by RES and DG • 27. Share of RES. The suggested INTERPLAN scenario is INTERPLAN-2 Small and Local. Regarding the type of grid models to be used, the grid investigated for control is a transmission-distribution grid. Grid equivalenting is required for two reasons: first of all, system operators may not share full details of their own network topology and data with the other operators, and second this will simplify the optimization process at each system operator network. In detail, the TSO network or the DSO network is replaced by proper grid equivalents which represent the active and reactive power values of the original network. Once all these steps are performed, the user is ready to select this showcase control function and perform the simulations through Python and PowerFactory. The evaluation phase will follow with reference to the KPI(s) values found in the simulation.

4.5 SC5 - Optimal energy interruption management

4.5.1 SC properties

ID and Name	SC5: Optimal energy interruption management	
Relevant use case/s	UC7: Optimal generation and load scheduling for energy interruption management Sub UC7.1: Load flow for the identification of credible contingency list and sensitivity analysis for prioritizing resources Sub UC7.4: Optimal energy interruption management in the presence of a contingency event	
SC description	**Summary**	
	Minimizing the energy interruption in the presence of a contingency event by re-scheduling the generators and controlling interruptible loads	
	Motivation	
	The climate change impacts and unforeseen events have revitalized the importance of energy interruption planning. The grid of the future should be able to make smart choices by redispatching of available generation capacity and control of interruptible loads to ensure reliable supply to critical loads and minimize the total energy interrupted.	
	Objective	
	The showcase demonstrates a tool that performs optimal energy interruption scheduling and generator dispatch while minimizing the total energy interrupted in the network. Grid congestion resulting from a contingency is an important consideration. The critical lines and buses are identified, and the sensitivity analysis is performed to prioritize resources that reduce the likelihood of grid congestion and voltage constraint violation.	
	Solution	
	Applying UC7 ‘optimal generation and load scheduling for energy interruption management’ with two sub use cases including UC 7.1 ‘Load flow for the identification of credible contingency list and sensitivity analysis for prioritizing resources’ and UC 7.4 ‘optimal energy interruption management in the presence of a contingency event ‘. The UC 7.1 acts as base showcase that identifies a set of credible contingencies and use sensitivity analysis to prioritize load flexibility that leads to congestion minimization. It configures inputs for the showcase control function. The energy interruption is minimized in the presence of a contingency event by re-scheduling the generators and controlling interruptible loads in UC 7.4. For a given time step, a load flow is performed and contingencies that can occur in transmission or distribution system	

	are enlisted. They are either specified by a TSO/DSO or can be listed based on peak loaded lines/transformers or the terminals having peak voltage levels. One of the contingencies is activated and load flow is performed. Afterwards, sensitivity analysis is performed towards the heavily loaded line/transformer or bus that could result in a network operational constraint violation. This information is used to prioritize resources that can effectively meet the demand and to prevent the network constraint violation.

4.5.2 Control functions

4.5.2.1 Control function for optimal generation and load scheduling for energy interruption management

To develop the control functions for this part, two sub use cases including UC7.1 'Load flow for the identification of credible contingency list and sensitivity analysis for prioritizing resources' and UC 7.4 'optimal energy interruption management in the presence of a contingency event' are used in which the former has no control action and the later implements the control functions.

4.5.2.1.1 Information for the identification of credible contingency list and sensitivity analysis for prioritizing resources

UC 7.1: Load flow for the identification of credible contingency list and sensitivity analysis for prioritizing resources	
Control variables	No control action is performed in this UC. The contingency identification process and sensitivity analysis prepares the network for UC 7.4.
Associate actor/tool	• The load flow of HV and MV levels is used to prepare the pre-contingency state of the network. • Load flow analysis is used to identify critical contingencies. • Sensitivity analysis is used to prioritize load flexibility for each contingency.
Assumptions	• It is assumed that all flexible loads can be communicated to reduce their active power. • The synthetic cost variable can have different scaling factors that may influence the impact on generator dispatch that has also associated costs. An elaborate mechanism of prioritizing load flexibility is not explored in this study.
Prerequisites	• The network size should at least have 10 terminals (buses). • The grid model must contain a transmission system and distribution system. • Reliability data from lines, loads and transformers will be required. • Load flow for initialization. • The model should have controllable generators and interruptible loads at MV and HV levels.

- The detailed feeder models of some of the LV feeders are not required unless there is significant flexibility in those feeders that can be remotely activated. Therefore, the equivalent of such low voltage networks have been obtained and respective profiles for the equivalent load have been identified and associated.
- The time tariffs of load flexibility in terms of nature of loads (residential, commercial or industrial) are identified.
- Generator costs related to dispatch are specified.

Grid equivalenting

The grid model under test has detailed urban and rural feeder models and number of equivalent feeder models representing typical urban and rural distribution networks. In this use case the detailed grid models for some low-voltage feeders are not needed for the cases in which contingency in MV or neighbouring LV feeder is considered. Therefore, for such feeders, an network equivalent is required. It is used to reduce the simulation calculation effort and also when detailed data or information about the grid are not available.

Input

General grid data for all steps:

Bus data

Bus type	Active power load	Reactive power load	Initial Bus voltage magnitude	Initial bus voltage angle	Maximum and minimum bus voltage	Nominal bus voltage

Branch data

Branch from which bus	Branch To which bus	Branch resistance	Branch impedance	Branch capacity	Branch type	Branch rate of power if it includes transformer	Branch tap changer number if it includes transformer

Generator data

Generator bus number	Generator type	Generator operation mode	Initial active power	Initial reactive power	Reactive power boundary	Active power boundary	Initial voltage magnitude and angle

In addition:

- Penalty costs EUR/MWh
- Fixed costs EUR/h

Reliability parameters

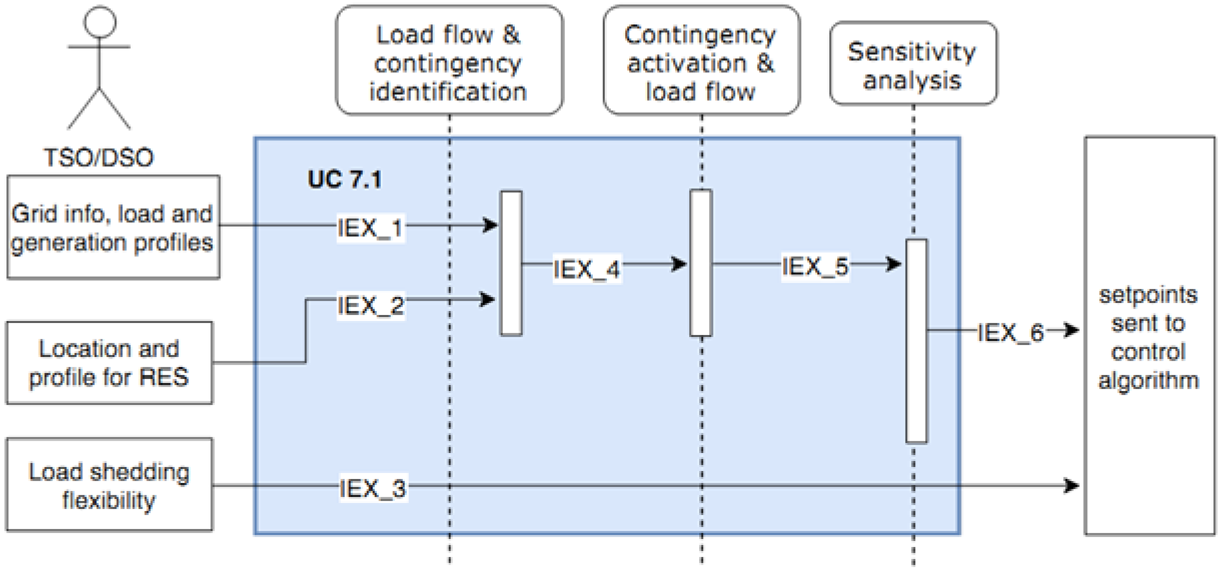
Reliability model parameters		Failure rate	Additional failure rate per connection	Repair time
		$\lambda[1/a]$	$\lambda[1/a]$	$d[h]$
Bus bar failure	11 kV	0.001	0.001	2
	33 kV	0.001	0.001	2
	230 kV	0.22	0.22	10
		$\lambda[1/a * km]$	$\lambda[1/a]$	$d[h]$
Line failure	11 kV	0.065	-	5
	33 kV	0.046	-	8
	230 kV	0.02	-	10
		$\lambda[1/a]$	$\lambda[1/a]$	$d[h]$
Transformer failure	11kV/0.4kV	0.015	-	200
	138kV/33kV	0.01	-	15
	230kV/138kV	0.02	-	768

Time tariffs for loads flexibility whether loads are industrial, residential or commercial.

Load flexibility is identified as one of the candidate schemes

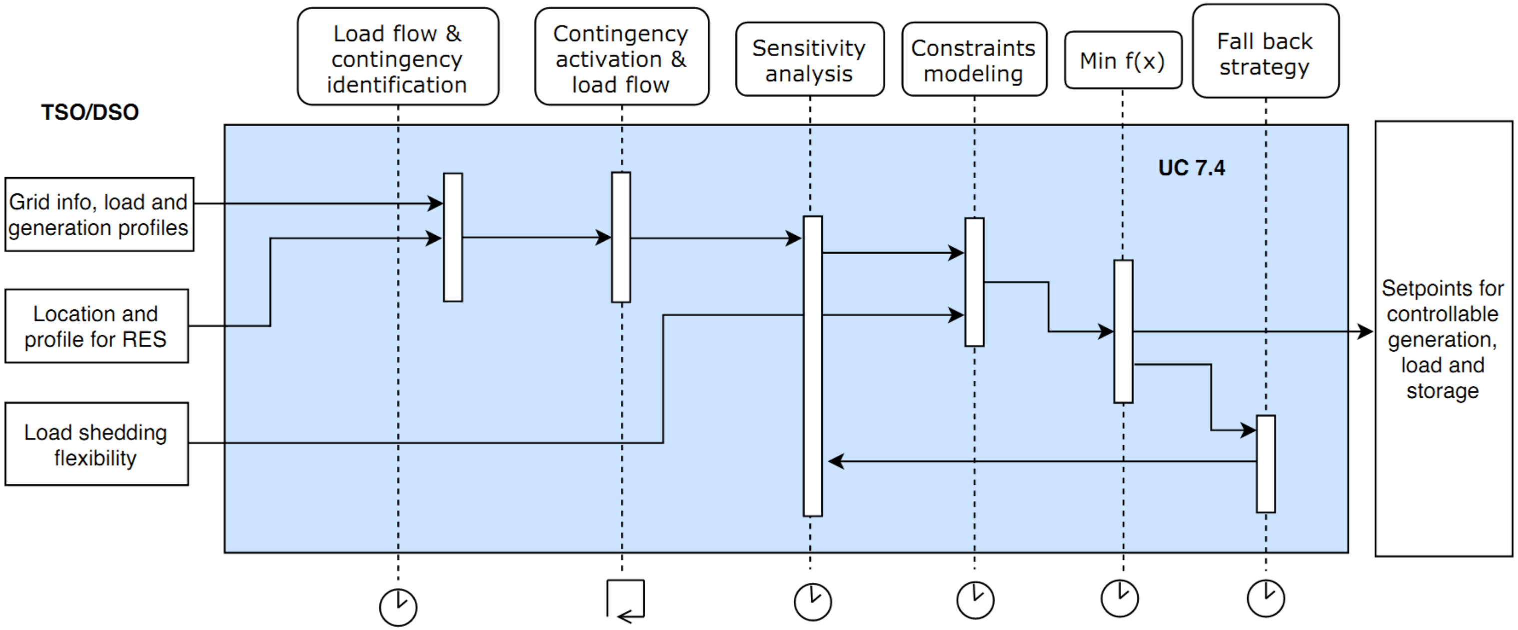
scenario	House Hold	Commercial	Industrial
base scenario	0 - 40 %	0 - 30 %	0 - 40 %
Scenario 1	0 - 50%	0 - 50%	0 - 50%
Scenario 2	0 - 70%	0 - 60%	0 - 60%
Scenario 3	0 - 100%	0 - 70%	0 - 70%

load shedding flexibility scenarios

Flowchart	
Formula	No control action is performed
Simulation environment	PowerFactory, Python
Simulation type	Semi-dynamic simulation

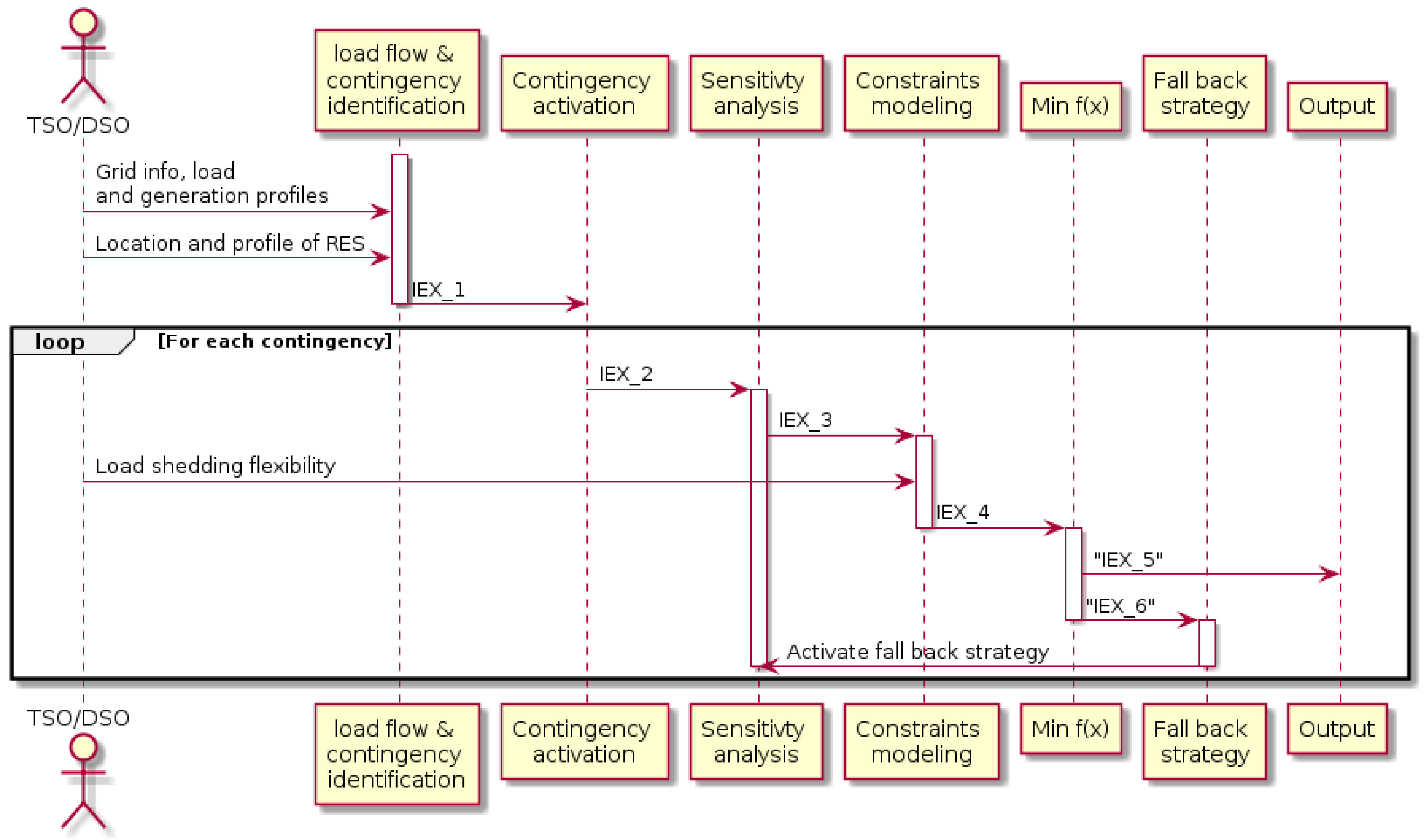
4.5.2.1.2 Control function for optimal energy interruption management in the presence of a contingency event

UC7.4: Optimal energy interruption management in the presence of a contingency event	
Control variables	The control variables are new set points for loads that can be reduced as well as new active/reactive power set points for dispatchable generators.
Associate actor/tool	Optimal power flow for load interruption and generator redispatch.
Assumptions	It is assumed that if a contingency creates an island in the network and if there is local generation sufficient for meeting the load in the island then the generator possesses sufficient grid forming capability and capacity to supply energy to loads. The contingency activation does not result in a load flow failure.
Prerequisites	The contingency list has been created as output of UC 7.1. Secondly, the additional costs related to the objective of grid congestion minimization have been associated with the load flexibility.
Grid equivalenting	The grid model under test has detailed urban and rural feeder models and a number of equivalent feeder models representing typical urban and rural distribution networks. In this use case the detailed grid models for some low-voltage feeders are not needed for the cases in which contingency in MV or neighbouring LV feeder is considered. Therefore, for such feeders, a network equivalent is required. It is used to reduce the simulation calculation effort and also when detailed data or information about the grid are not available.
Input	The inputs to the UC 7.4 are the outputs of UC 7.1.

Flowchart	 For each contingency, the following steps are performed: 1. Reliability analysis is performed using a reliability assessment tool with two cases after a contingency from the contingency list is activated. One case is without any control action, and in the second case the selected control function is activated. 2. The contingency is manually activated and OPF is performed in PowerFactory with objective of “minimization of load shedding” with generator actor power dispatch activated. 3. The impacted loads and generator set points are changed to reflect the post-optimization scenario. 4. In case the contingency activation creates an island and if there is local generation, then the terminal connected to the largest generator becomes the slack node. In case there is more than one generator then the terminal connected to largest generator becomes the slack node. 5. Reliability analysis is performed for the new scenario and reliability-related KPIs are saved for the contingency case.

Formula	The optimal energy interruption problem is formulated using Newton-Lagrange method which corresponds to the minimization of the Lagrange function given as: $$L(\vec{x}, \vec{s}, \vec{\lambda}) = f(\vec{x}) - \mu \sum_i log(s_i) + \lambda^{\vec{T}} [g(\vec{x}) + h(\vec{x}) + \vec{s}] \quad (1)$$ where $\vec{x}$ is the state vector at the i^{th} bus, (P^i, Q^i, v^i, $\boldsymbol{\theta}^i$). $g(\vec{x}) = 0$. load flow equations $h(\vec{x}) \leq 0$. Inequality constraints, e.g., $\upsilon^i \leq 1.1$ p.u. (2) Rest of the variables includes: $\vec{s}$ is the slack variable for each inequality constraint, where $\vec{s} \geq 0$ such that $h(\vec{x}) + \vec{s} = 0$, $\vec{\lambda}$ as Lagrangian multiplier and μ is the multiplier for logarithmic function of $\vec{s}$ as a penalty factor. The objective function, $f(\vec{x})$ is given as: $$f(\vec{x}) = W_L \sum_{j=1}^{N_L} C_{LS}^j \left\|P_{LS}^j\right\| + W_G \sum_{k=1}^{N_G} C_{GD}^k \left\|P_{GD}^k\right\| \quad (3)$$ here, C_{LS}^j and C_{GD}^k are the cost factor of load curtailed and generator redispatch, W_L and W_G are the weighing factors of loads and generators, and N_L and N_G are the number of loads that can be shed and the number of generators that can be redispatched. The variables P_{LS} and P_{GD} represent the load shedding and generator redispatch flexibility.
Simulation environment	PowerFactory, Python
Simulation type	Semi dynamic simulation

4.5.3 Showcase structure

Sequence diagram		
Detailed description	Steps	Description The showcase has two conceptual levels: contingency identification (load flow analysis, identification of critical lines, generators and loads) and energy interruption planning (activating the contingency in the grid, performing sensitivity analysis, modelling the constraints, optimization). In case the optimization fails, then the fall-back strategy is activated, and the process is repeated until the dispatch signals for the generators and interrupt able loads are identified. Following is the description of the individual actions.

<table>
<tr><td rowspan="6"></td><td>1</td><td colspan="7"><u>Load flow and contingency identification</u>
The user can be a TSO or a DSO who provides the grid information (network model) and load & generation forecasts. This action performs the load flow to calculate the status of the grid. This information is used to identify the critical contingencies in the grid; the user (TSO/DSO) can also specify them. A list of credible contingencies is sent to next stage.</td></tr>
<tr><td>2</td><td colspan="7"><u>Sensitivity analysis</u>
Here, the sensitivity of the critical lines and buses is calculated with respect to the buses having dispatchable generators and interruptible loads for the selected contingency. The sensitivity information is used to define the penalty cost terms that assigns less penalty costs to the terminals whose control action can influence the grid constraint violation more.
This information is communicated to the next stage of constraints modelling.</td></tr>
<tr><td>3</td><td colspan="7"><u>Constraints modelling</u>
This action prepares the matrices for the constraints for the optimization process. The mathematical model of the problem is sent to the optimizer.</td></tr>
<tr><td>4</td><td colspan="7"><u>Min f(x): objective function minimization</u>
At this stage, the optimization problem is solved with constraints enabled in the network. The optimization results are load and generator set points.</td></tr>
<tr><td>5</td><td colspan="7"><u>Fall back strategy</u>
If the optimization process is either unable to meet the demand due to lack of generation or there is a grid constraint violation, then the fall back or pre-defined backup strategy is selected. That could include allowing more load to be interrupted.</td></tr>
<tr><td>6</td><td colspan="7"><u>Output signal</u>
In this step, the control signals from the optimizer are received and send to the respective generators and loads.</td></tr>
<tr><td rowspan="2">Sequence of actions</td><td>Steps</td><td>Associate UC ID</td><td>Action</td><td>Content</td><td>Input</td><td>Operation</td><td>output</td><td>Grid area</td></tr>
<tr><td>1</td><td>7.1</td><td>Grid information, load and generation profile information</td><td>PowerFactory grid model is created with reliability and load flexibility data configured.</td><td>• TSO/DSO</td><td>Network configu-ration</td><td>• Network model</td><td>Complete grid</td></tr>
</table>

	2	7.1	Load flow analysis	PF balanced quasi-dynamic simulation performing load flow at each 15-minute step for the yearly data.	• Network model, criteria for contin-gency identify-cation	Load flow	• Set of nodes and lines that are candidate contingen-cies	Complete grid
	3	7.4	Contingen-cy activation	The node, line or transformer contingency is activated by making corresponding object out of service	• Contin-gency list	Object parameter change	• Network model with contingency activated	Complete grid
	4	7.4	Sensitivity analysis	It performs the sensitivity analysis from the node connected to generator or flexible load to the most vulnerable line or node after the contingency event	• Contin-gency is activated	Sensitivity analysis	• A list of sensitivity parameters that are used to adjust the auxiliary costs for prioritizing resources	Complete grid
	5	7.4	Reliability indices calculations	PF reliability assessment tool is used with contingency object specified to calculate reliability indices	• Configured grid from step 3	Reliability calcula-tion	• Reliability parameters calculate that are noted as without controls	Complete grid
	6	7.4	Optimiza-tion activation	The OPF is run with the objective of minimizing load shedding and with the active power dispatch of generators enabled	• Contin-gency is activated	OPF	• New set points for controllable loads and generators	Complete grid

	7	7.4	Fall-back strategy	In case OPF fails, then load flexibility is re-defined. Afterwards step 5 is repeated	• OPF failure	Load flexibility changed	• New load shedding flexibility	Complete grid
	8	7.4	Reliability indices calculations	PF reliability assessment tool is used to calculate reliability indices	• The new set points for loads and generators are updated in the network	Reliability calcula-tion	• Reliability parameters calculate that are noted as with controls	Complete grid

4.5.4 Test case

System under Test (SuT)	The system under test is a synthetic grid including HV, MV and LV sections. The network represents typical urban and rural networks at MV and LV levels and is based on the statistics of a large set of real distribution grid models from four European countries. The synthetic grid consists two MV feeders: one for urban and one for rural network, and 34 LV feeders. Among them, 10 LV feeders are modeled in detail while the rest of LV networks are represented by equivalent models. SC5 aims to investigate how to optimally dispatch generators and interruptible loads after the contingency situation. The grid model allows to define contingency events at both MV and LV levels. It provides a suitable platform to evaluate the impact of contingency events on the grid and how optimal activation of flexibility can bring the system within operational constraints. The impact is evaluated on the reliability metrics that require comprehensive data about reliability in LV and MV grids. Moreover, the impact of network equivalence on the results is also studied.
Objects under Test (OuT)	Terminals, generators set points, flexible load, lines
Scenario	INTERPLAN_2 Small and Local
Input data	The synthetic network used in this showcase consists of 34 LV feeders connected to two MV feeders (rural and urban).

Feeder name	No. of PVs	No. of generators	No. of lines	No. of loads	No. of terminals	No. of transformers
MV Rural	0	4	39	6	61	22
MV Urban	0	4	15	0	25	10
LV urban 5	14	0	21	19	21	0
LV urban 1	20	0	28	25	28	0
LV urban 2	14	0	22	19	22	0
LV urban 3	20	0	30	26	30	0
LV urban 4	24	0	34	31	34	0
LV rural 1	12	0	26	16	26	0
LV rural 2	10	0	22	14	22	0
LV rural 3	12	0	30	17.0	30	0
LV rural 4	16	0	34	22	34	0
LV rural 5	0	0	2	1	2	0

Information about the LV grids is given as follows. Some of the LV grids are equivalented.

	No. of PVs	No. of generators	No. of lines	No. of loads	No. of terminals	No. of transformers
Rural LV 14	1	0	105	103	105	0
Rural LV 15	2	0	108	110	108	0
Rural LV 4	2	0	137	139	137	0
Rural LV 20	1	0	114	114	113	0
Rural LV 21	2	0	110	116	108	0
Rural LV 10	1	0	77	104	77	0
Rural LV 11	0	0	96	103	95	0
Rural LV 12	0	0	88	103	86	0
Rural LV 3	1	0	152	144	151	0
Rural LV 5	1	0	137	123	135	0
Rural LV 6	1	0	114	111	112	0
Rural LV 8	0	0	109	103	109	0
Rural LV 9	6	0	79	100	79	0
Rural LV 1	1	0	169	144	164	0
Rural LV 16	4	0	83	109	83	0
Rural LV 17	3	0	118	113	118	0
Rural LV 18	2	0	121	117	121	0
Urban LV 3	4	0	683	213	676	0
Urban LV 5	2	0	390	193	388	0
Urban LV 7	4	0	457	200	451	0
Urban LV 9	0	0	438	173	437	0
Urban LV 1	1	0	98	113	96	0

No. of static generators connected to MV grid

Name	Nominal power (MW)
Biomass 1	1.2
Biomass 2	0.2
DG1_Coal-fired combustion turbine	0.25
DG2_Natural gas combustion turbine	0.4
DG3_Coal gasification combined-cycle (IG	1.2
DG4_Natural gas combined-cycle	0.2
DG5_Hydroelectric	0.5
DG6_Hydroelectric	0.65
Wind Farm 1	3.2
Wind Farm 2	1.4

No. of Bus bars	346
No. of Lines	311
No. of Loads	273
No. of 2-w Trfs.	34
No. of 3-w Trfs.	2

During execution of UC 7.4, each contingency is activated and corresponding date and time is set.

KPI under test

ID	Name	Formula
3	SAIDI (System Average Interruption Duration Index)	$SAIDI = \frac{sum\ of\ all\ customer\ interruption\ duratios}{total\ number\ of\ customers\ served}$
7	Power losses	$P_{\text{losses}} = \sum_{i}^{Nline} \lvert I \rvert_i^2 * r_i\ [kW]$ I_i − magnitude of current flow in line i $[A]$ r_i − resistance of line i $[\Omega]$

	8	AENS & ENS (Average Energy not Supplied & Energy not Supplied)	$AENS = ENS/\sum C_i$ $ENS = \sum LPENS_i$ $LPENS_i$: Load Point i Energy Not Supplied $C_{i:}$: Customer *i* $ACIT$: Average Customer Interruption Time
	9	IEAR(Interrupted Energy Assessment Rate)	$EAR = \frac{EIC}{ENS}$ in $ / kWh EIC: Expected Interruption Cost, in units of [M$/y], is the total expected interruption cost ENS: Energy Not Supplied, in units of [MWh/a], is the total amount of energy on average not delivered to the system loads
	18	SAIFI (System Average Interruption Frequency Index)	$SAIFI = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$
	24	Reactive energy provided by RES and DG	During this showcase the reactive power provided by DGs connected to MV grid are recorded.
	27	Share of RES	Maximum share of RES as hosting capacity is calculated for the feeder in which contingency occurs and is calculated for UC 7.3 only. This KPI is not calculated for the showcase.
Output parameters	Active power set points for the generators and for flexible loads		

4.5.5 Summary

Summary	This showcase addresses the operational challenges arising due to contingency events in the grid that are related to voltage limits, line and transformer loading constraints. Although contingency studies are routinely performed in the power grid, post-contingency situations are diverse and will require frequent re-assessment in terms of network reliability due to high penetration of DER in the system. In addition, weather dependent events also increase volatility of the grid and require advance network planning. In such situations, the flexibility offered by DER and interruptible loads can be used to recover the system to operational condition after the contingency. Therefore, SC5 provides a suitable platform for the grid operator to plan the flexibility in the grid. If the dispatchable DERs are available in the MV grid, they can be dispatched by the algorithm. Following planning criteria can be selected by the operator using INTERPLAN tool: • 1. Minimizing losses • 2. Minimizing the cost • 4. Assuring voltage stability • 8. Maximize DG / DRES contribution to ancillary services • 10. Minimizing energy interruptions The simulation functionalities used are load flow, sensitivity analysis, reliability calculation and optimal power flow. The KPIs used to measure the effectiveness of the control are: • 3. System average interruption duration index • 7. Power losses • 8. Average energy not supplied • 9. Interrupted energy assessment rate • 18. System average interruption frequency index • 24. Reactive power provided by DGs • 27. Share of RES The suggested INTERPLAN scenario is INTERPLAN-2 Small and Local. The grid model used is a synthetic grid with number of LV grids modeled as equivalents. This is necessary as the contingency analysis requires the consideration of large number of credible contingencies against which flexibility resources need to be planned. In such situations, grid simplifications reduce the problem complexity. This is particularly important, as the SC5 will be needed frequently by the grid operator within the tool. The equivalent LV feeders should provide the equivalent impedance, active and reactive power, and equivalent reliability parameters. Once network equivalence is performed, the user is ready to select the showcase function and performs simulations through PowerFactory. The evaluation phase will follow with reference to KPI results from the simulation studies.

5. Proof-of-concept for showcase 3

This proof of concept describes every step of the INTERPLAN tool procedure in an example, from a perspective of an identified user (a DSO) who is interested in analyzing its own network using showcase 3 simulation functionalities. The overview of these steps is presented in Figure 6.

Figure 6: The procedure of the INTERPLAN tool

With regards to SC3 simulation functionality, the user is interested in more efficient and stable operation of the distribution network while respecting specific operation planning criteria. These planning criteria, their corresponding KPIs and other steps of the INTERPLAN tool are fully described in the following.

START: Planning Criteria

Before stage 1, the user must define one single planning criterion or a group/subgroup of planning criteria, which need to be analyzed.

0. Selection of planning criteria
At the start, the list of operation planning criteria for the power network is presented to the user. 1. Minimizing losses. 2. Minimizing cost. 3. Maximizing share of RES. 4. Assuring voltage stability. 5. Mitigating grid congestion. 6. Assuring transient stability. 7. Optimize TSO/DSO interaction. 8. Maximize DG/RES contribution to ancillary services. 9. Assuring frequency stability. 10. Minimizing energy interruptions. This proof of concept is described from the perspective of a distribution system operator (DSO), who is in this example the primary user of the tool and is interested in minimizing the grid losses in parallel to increasing the share of RES based generation in his network and providing ancillary services whenever possible. It is assumed that the TSO is using the tool too, in order to gain support from the DSO in satisfying the need for tertiary reserve. Based on this, the DSO selects the planning criteria numbers 1, 3, 7 and 8.

STAGE1: Simulation functionalities, KPIs and Future Grid scenarios

In this stage, the user identifies the simulation functionalities, KPIs and future grid scenarios, which are needed for the analysis.

1.1 Identification of simulation functionalities
Considering the selected planning criteria in the previous step and the integrated reference in the tool (Table 6 of deliverable D5.2), the tool suggests SC3[2] as a potential solution, which is consisting of LF and OPF simulation functionalities. The tool then proceeds to the next step.
1.2 Selection of Key Performance Indicators
After identifying planning criteria and proper simulation functionalities, a list of KPIs which can be covered by the selected functionality (according to Table 6 of deliverable D5.2) is presented to the user (DSO): 1. Level of losses in transmission and distribution networks. 2. Power losses. 3. Level of DG/DRES utilization for ancillary services. 4. Transformer loading. 5. RES curtailment. 6. Quadratic deviation from global active power exchange target. 7. Mean quadratic deviations from active power targets at each connection point between TSO and DSO grids. 8. Share of RES. The DSO is interested in calculating the level of ancillary services, RES curtailment and share of RES in the whole generation. Therefore, the DSO selects KPIs number 3, 4, 5 and 8.
1.3 Future grid scenario selection
In this step, according to the selection of planning criteria, the tool suggests INTERPLAN scenario 2 “Small and Local” (according to Table 6 in D5.2) as a possible scenario for investigation among the four INTERPLAN scenarios (described in D3.2). During the selection, the detailed description of the scenario such as the total demand, share of DER technologies in the installed capacity and generation will be visible to the user to guide the selection also according to the grid structure the user is interested to analyze. Based on the grid structure and the suggestion provided by the tool, the user selects the suggested scenario INTERPLAN2: Small and local. The user also selects the target year i.e. 2050.

[2] SC3: TSO-DSO interface active power flow optimization. This showcase is to present an optimization strategy for energy flow management between transmission and distribution grid, ensuring the balance within a distribution network on one hand and on the other hand for participation of non-synchronous energy resources in the tertiary reserve market and supporting the TSO in keeping the whole network stable.

STAGE2: Grid model selection/ preparation

When starting stage 2, the user has already selected the planning criteria, simulation functionalities, the KPIs and the future scenario in stage 1. Steps of stage 2 are described in the tables below.

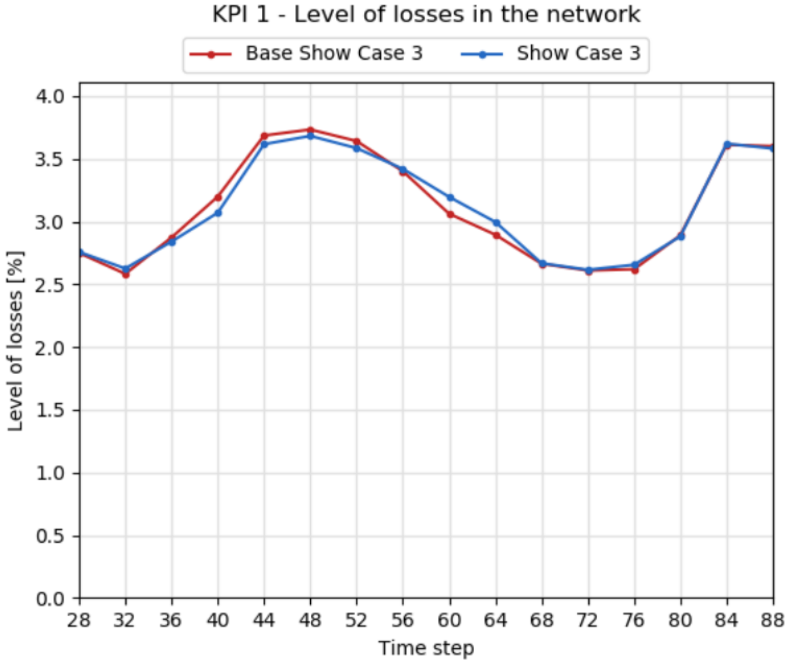
2.1 Grid type selection
In this step, the user can select among three types of grids with regards to the analysis: • Transmission grid only; • Distribution grid only; • Transmission and distribution grids. Since for performing an analysis with SC3 objectives the full grid model is required, the user selects the third option.
2.2 Grid model selection
In this step, a default list of grid models (benchmark models), with all of their characteristics, is presented to the user. In this case, the user is interested in performing analysis on its own network, which is represented by the SimBench based north-eastern Germany benchmark network model [6] in this example. The network model is loaded into the tool. It is worth mentioning that the whole procedure of loading and analysis of the full grid models is confidential and in case, there are several users (in this example, the DSO and TSO), the tool analysis may be done through co-simulation methods such that no confidential data is exchanged among the users.
2.3 Identification of need for Grid equivalent
In this step, the tool guides the user to understand if a grid equivalent model is required or not. These requirements are use case and showcase oriented and are shown in Table 8 of D5.2. According to this reference table, basic grid equivalents are needed for SC3 application. In fact, in order to perform the study through the selected functionalities, grid equivalents for both transmission and distribution networks are required. The reason is to simplify the calculations and avoid time-consuming simulations on complex grid models.
2.4 Application of grid equivalents (if required)
In this step, as the need for grid equivalents is identified, the primary user - DSO, and the TSO as the other user of the tool, need to either provide the proper equivalent models of their own grids to the tool or select a proper methodology provided by the tool considering the requirements and corresponding KPIs of the SC to generate the equivalent models. In this example, it is assumed that the users load these equivalents into the tool.
2.5 Adaptation of selected scenario
In this step, the INTERPLAN scenario chosen in the previous stage of the tool is adapted to the grid model through the scenario adaptation procedure.
2.6 Preparation of time series
In this step, the user sets the time frame and time step interval for the simulation phase of stage 3. Having the adapted grid model, the tool is able to generate suitable time series data for the analysis. Nevertheless, the user in this case loads its own time series data to the tool. The time series data in a presented example consists of 96 time steps within a day (15-minute time interval). It is assumed that once in every 4 steps during time steps 28 to 88 (once an hour between 7:00 am to 10:00 pm) a tertiary control reserve is requested by the TSO.

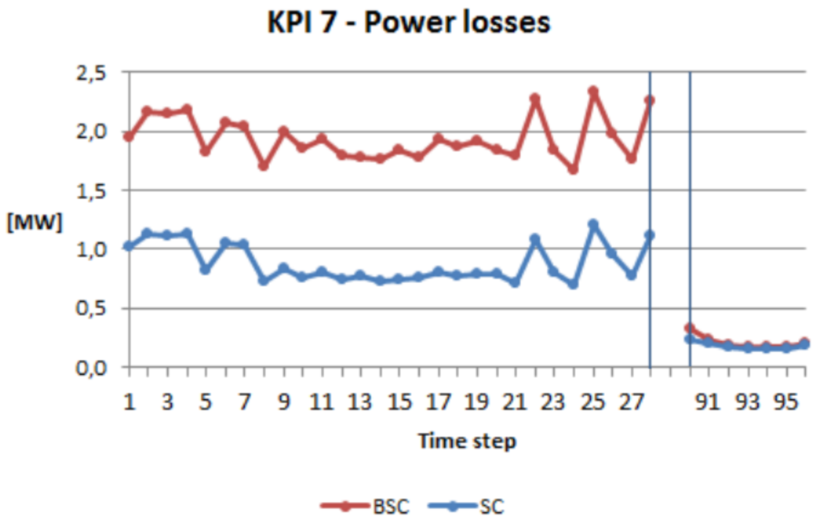
2.7 Grid model preparation (assignment of the time series data)
In this step, the tool incorporates the time series data from step 2.6 and prepares necessary grid models (full DSO network model with TSO equivalent model and full TSO network model with DSO equivalent model). Prepared grid models are already adapted to the chosen scenario (step 2.5).

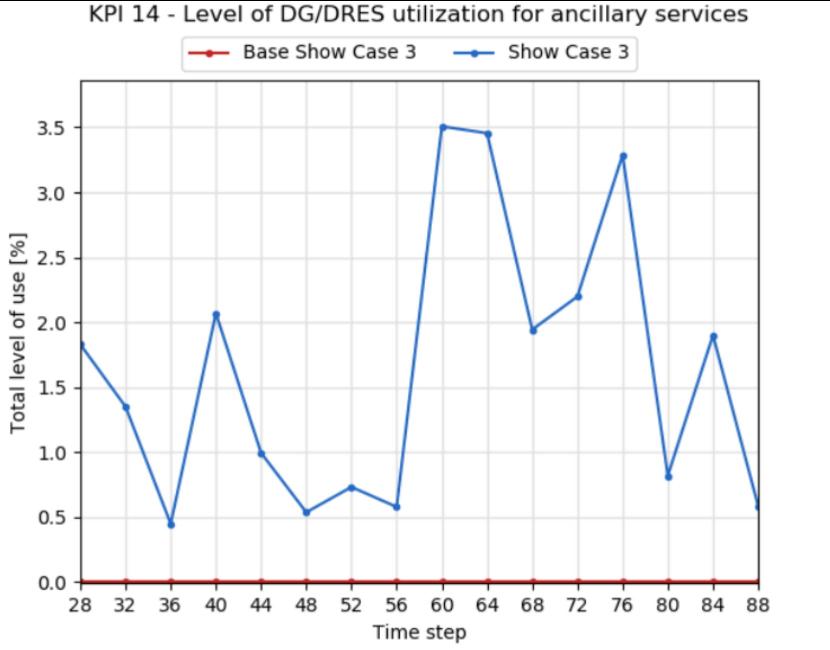
STAGE3: Simulation and Evaluation

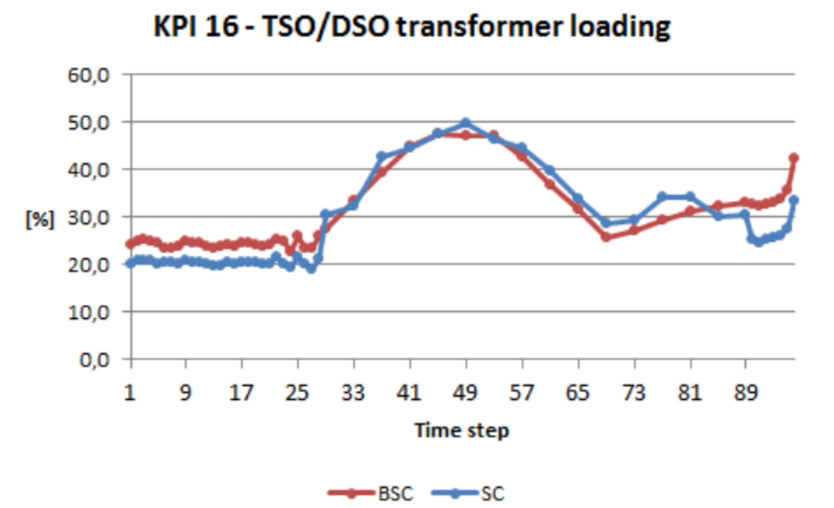
3.0 Reference case selection and simulation
This step is included for giving the possibility to the user to create his own reference case, allowing to compare the results obtained by selecting one of the INTERPLAN solutions. This choice requires that the user performs the simulations in consistence with the selections done in the previous stages 1 and 2. The DSO as the primary user selects BSC3 as the reference case, where no control functions are implemented.
3.1 Solution selection
In this step, the user selects one of the INTERPLAN solutions enabled. In fact, based on the selections done in the previous stages, only some (at least one) of the INTERPLAN solutions are enabled for this selection. The INTERPLAN solutions are intended as the control functions embedded within INTERPLAN use cases and showcases. Therefore, in this example the DSO selects the only enabled solution, which is SC3.
3.2 Solution simulation
At this step, the python-based toolbox interfaces with PowerFactory for the simulation phase. In detail, the user can enter here either from step 3.0 or from step 3.1. In this latter case, the python script related to the control function embedded within the INTERPLAN solution selected at step 3.1 is called in PowerFactory for simulation. The tool performs the simulation(s) of the selected in the previous steps solution. In this step control functions are active.

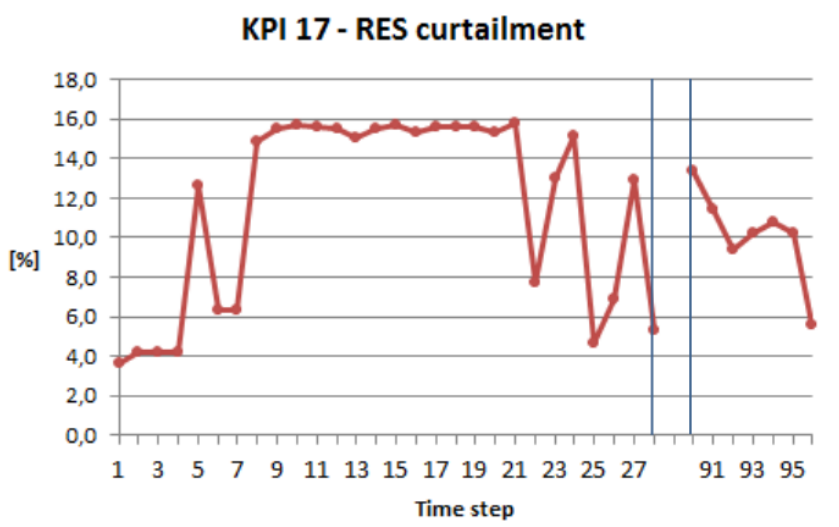
3.3 Evaluation phase through Key performance indicators

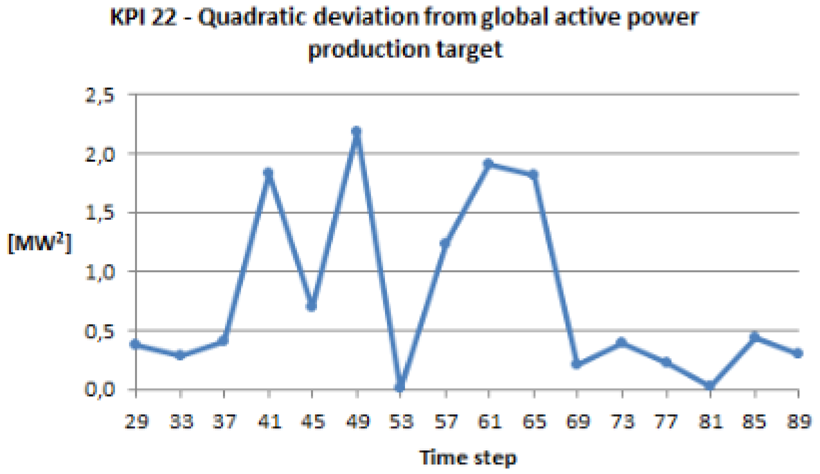


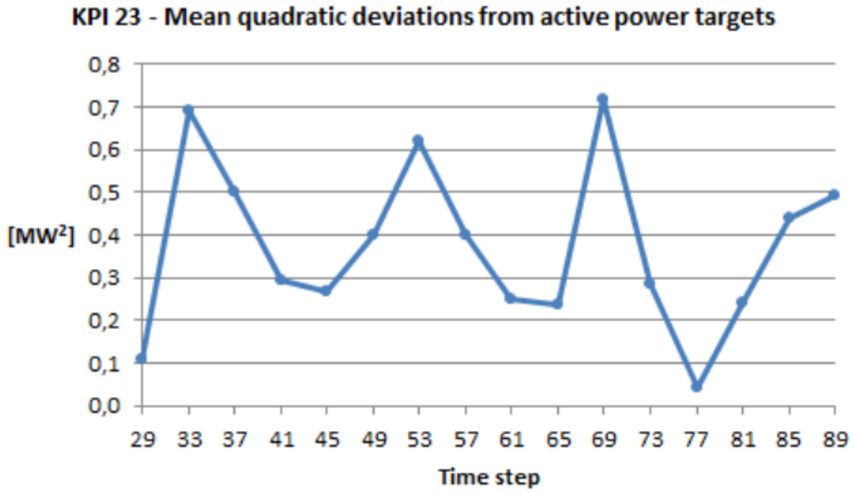


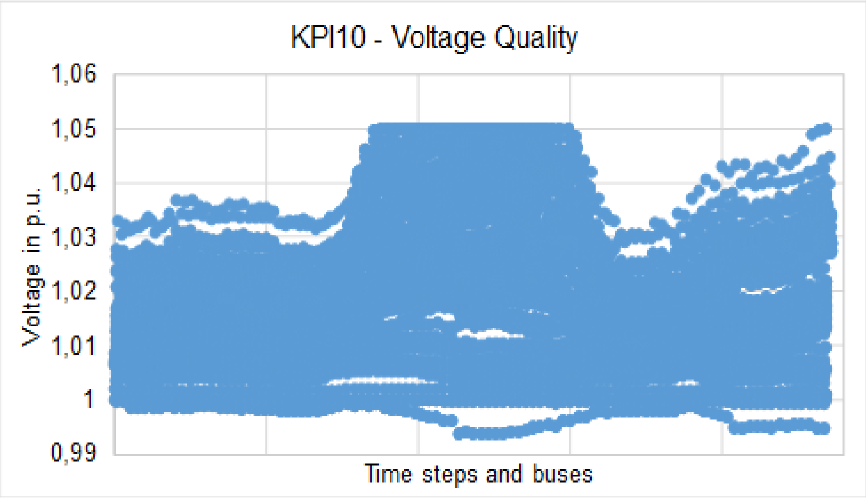

KPI 14 - Level of DG/DRES utilization for ancillary services
Base Show Case 3
Show Case 3
Total level of use [%]
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
28 32 36 40 44 48 52 56 60 64 68 72 76 80 84 88
Time step


KPI 16 - TSO/DSO transformer loading
[%]
0,0
10,0
20,0
30,0
40,0
50,0
60,0
1 9 17 25 33 41 49 57 65 73 81 89
Time step
BSC
SC


KPI 17 - RES curtailment
[%]
0,0
2,0
4,0
6,0
8,0
10,0
12,0
14,0
16,0
18,0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 91 93 95
Time step







<u>KPI 1:</u> Considering the presented comparison plot, it can be seen that in several time steps the level of losses in the presence of SC3 tertiary control functions are lower than BSC3, where no control functions were applied and no tertiary reserve requested by the TSO. Nevertheless, there are some time steps in which power losses in the SC are equal to the BSC or even higher. The reason is related to the requested tertiary reserve from the TSO. When the requested tertiary reserve is a relatively high positive value (more generation is required), the total power flowing within the grid will be higher consequently and this leads to higher losses. In fact, this should not mean the control functions are increasing the losses knowing the fact that the total power flow is

higher due to the requested tertiary reserve. Even in these cases, the control functions are reducing the losses in comparison to the case of non-optimized provision of tertiary reserve.

Note: the values of this KPI for base SC3 are updated considering the corresponding values presented in D5.2. In the new values the contribution of external grids (slack bus bars) is excluded from the calculation, since their role is not of interest for power losses calculations.

KPI 7: Comparison of values presented in the graph clearly indicates that the controller function is successful in significantly reducing the total active power losses in the distribution grid, especially in the first part of the simulation, when the power losses are higher. The reduction is this period is about 50-60%, while during later hours, when the losses are much lower, the reduction is within a 5-30% range.

KPI 14: Comparing the values of this KPI in SC3 and its corresponding BSC, it is obvious that SC3 control functions were successful in involving the available controllable units in providing tertiary reserve.

KPI 16: Controller function operation has succeeded in lowering the transformer loading by 10 to 25% of its pre-controller value during the part of simulation performed by UC5. In case of UC3, minimizing the transformer power flow is not a primary objective, therefore in part of simulation performed by this controller, the post-controller values of transformer loading are lower than pre-controller values for some time steps and higher for others.

KPI 17: Because the optimization function of UC5 controller includes contradictory objectives, in order to maximize its value i.e. achieve other controller objectives, a certain amount of RES energy had to be curtailed in every simulated time step. The percentage of available RES power which was curtailed fell in the 4-16% value range. As in the BSC no controller is operating in order to achieve any optimization goals, no RES power had to be curtailed and therefore the value of KPI 17 is always equal to 0.

KPI 22 & 23: These two KPIs present the success level of the optimization algorithm. It can be seen that the KPI 22 values vary between 0 to 2.2 MW^2. KPI 23 also indicates the mean quadratic deviation, which is in the maximum case about 0.72 MW^2. These deviations can be easily compensated by available synchronous/ static generators at TSO level. Nevertheless, this error can be reduced by improving the optimization algorithms

KPI 27: Comparing the KPI 27 values of the BSC3 and SC3, it can be concluded that the control functions are able to maintain the total share of RES in generation or even to increase in few time steps. This strongly depends on the magnitude and type (increase / decrease in the generation) of the requested tertiary reserve. In several time steps, the requested tertiary control is negative and the RES need to decrease their generation. Even in these cases the share of RES is maintained which proves that optimization algorithm are successful to some extent in increasing the share of RES while responding to the other major goals, which are providing the tertiary reserve and minimising the active power losses.The objectives of SC3 pose a significant degree of optimization function issues. As some of the individual criteria (i.e. objectives) are contradictory, e.g. reducing the power flow between DSO and TSO grids, involving the DG/ DRES in contributing in ancillary services as well as decreasing the amount of power losses in the grid can be effectively achieved by curtailing a certain percentage of generation. As the simulated test case is implementing the “small and local” scenario, the majority of available generation, particularly in the distribution grid, is renewable and therefore any power curtailments involve curtailing RES generation, minimizing of which is itself an optimization objective. Therefore, the main optimization function has to be constructed considering different - and variable - weights for individual objectives.

The values of relevant KPIs, presented in the above subsections, indicate that despite this, the system performance as characterized by predefined parameters was overall improved by the operation of controllers and the assumed optimization goals were achieved. Therefore the tool procedure stops.

6. Showcases simulation results

In this chapter, the results of KPIs calculations for all show cases (SCs) with the developed control functions from chapter 4 are presented. The calculated KPIs in this section are compared with those obtained in D5.2 “Operation planning and semi-dynamic simulation of grid equivalents” [4] for base show cases (BSCs) not including any controls. Based on the KPIs, it is evaluated how successfully each SC meets the relative planning criteria.

Accordingly, this chapter is organized based on the results of KPIs for each showcase as follows:

1- SC1: Low inertia systems
    - KPI 14 - Level of DG / DRES utilization for ancillary services
    - KPI 20 - Frequency nadir/zenith
    - KPI 21 - Rate of Change of Frequency (RoCoF)
    - KPI 25 - Indication of Stability
    - KPI 27 - Share of RES

2- SC2: Effective DER operation planning through active and reactive power control
    - KPI 1 - Level of losses in transmission and distribution networks
    - KPI 2 - Congestion detection
    - KPI 10 - Voltage Quality
    - KPI 13 - Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids
    - KPI 14 - Level of DG / DRES utilization for ancillary services

3- SC3: TSO-DSO power flow optimization
    - KPI 1 - Level of losses in transmission and distribution networks
    - KPI 7 - Power losses
    - KPI 14 - Level of DG / DRES utilization for ancillary services
    - KPI 16 - Transformer loading
    - KPI 17 - RES curtailment
    - KPI 22 - Quadratic deviation from global active power exchange target
    - KPI 23 - Mean quadratic deviations from active power targets at TSO/DSO connection points
    - KPI 27 - Share of RES

4- SC4: TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles.
    - KPI 1 - Level of losses in transmission and distribution networks
    - KPI 10 - Voltage Quality
    - KPI 13 - Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids
    - KPI 14 - Level of DG / DRES utilization for ancillary services
    - KPI 22 - Quadratic deviation from global active power exchange target
    - KPI 23 - Mean quadratic deviations from active power targets at TSO/DSO connection points
    - KPI 24 - Reactive energy provided by RES and DG
    - KPI 27 - Share of RES

5- SC5: Optimal energy interruption management
    - KPI 3 - SAIDI (System Average Interruption Duration Index)
    - KPI 8 - AENS & ENS (Average Energy not Supplied & Energy not Supplied)

- KPI 9 - IEAR(Interrupted Energy Assessment Rate)
- KPI 24 - Reactive energy provided by RES and DG

For each KPI, five parts are described to show the goals, numerical results, and relevant discussions as follows:

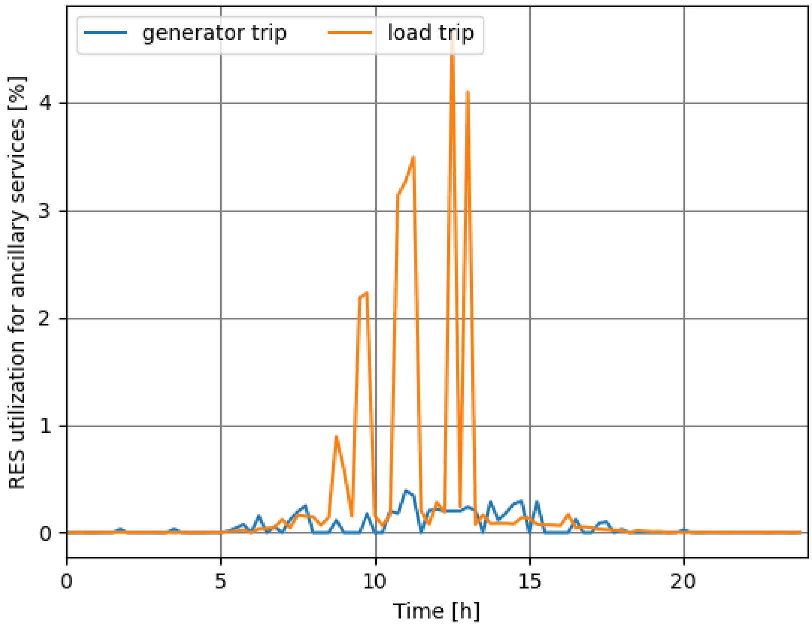
- ➢ Description: The intention of the KPI and its connection with planning criteria are outlined.
- ➢ Formula: The predefined formula in chapter 4 is shown together with any complementary information as modifications or additional information. This complementary information is defined based on the requirement of the showcase while simulating.
- ➢ Numerical results: The numerical results of the KPI calculations are depicted in this section in the format of graph, table or other information.
- ➢ Discussion: A detailed discussion regarding the results is given in this section. All the necessary details about the simulation, which effect the result, are outlined. The interpretation of the numerical output of KPIs including any phenomenon, or issues within the time steps are discussed.
- ➢ Comparison with BSC: The KPIs that are calculated for the SC after employment of control functions are compared with the one obtained in the BSC. During this comparison, the advantages of applying the developed control function are presented.

At the end of each section (SC), the results are summarized to present the achievements of each SC simulation, the effectiveness of SCs to meet the planning criteria, and the suitability of them for the INTERPLAN tool.

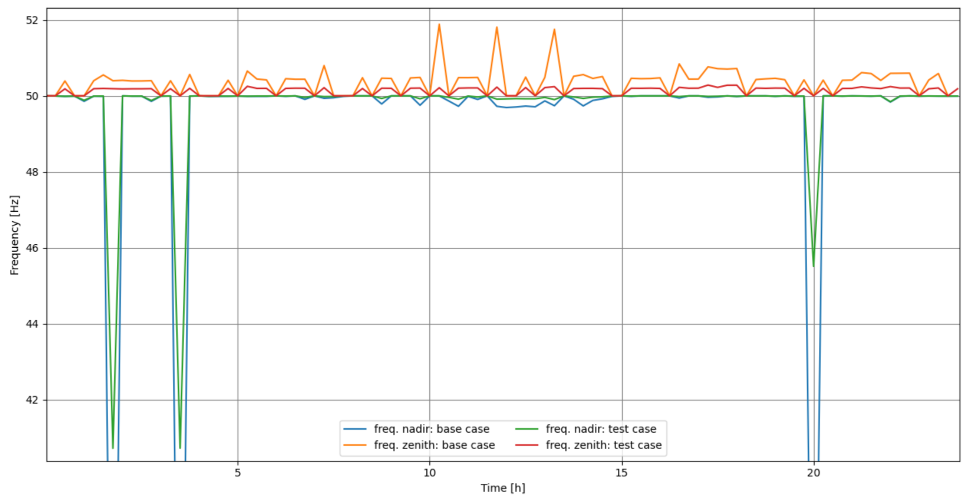
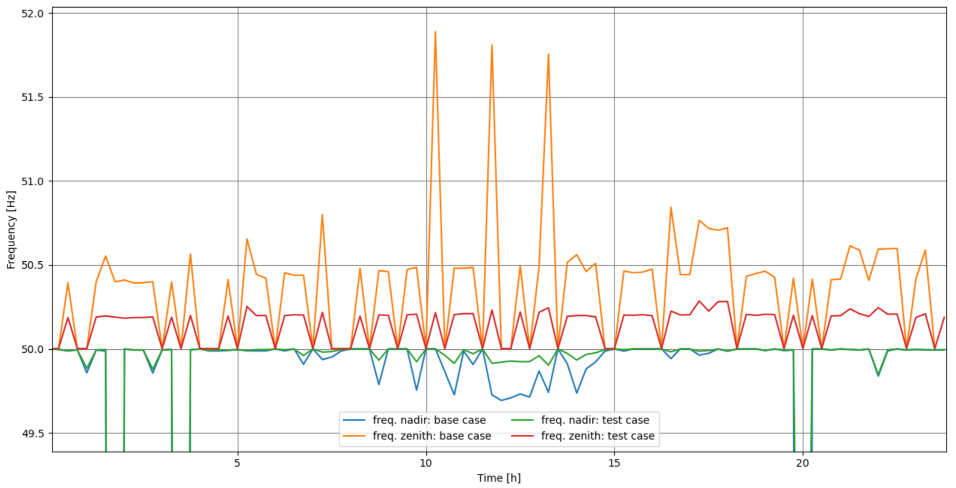
6.1 SC1 results – Low inertia systems

In the following tables, the showcase 1 results are presented. The KPIs have been selected to illustrate the effectiveness of the proposed control and it's influence on the system's frequency stability.
The involved use cases have been applied in series (UC6->UC4) for each of the 96 time steps in the 24h time.

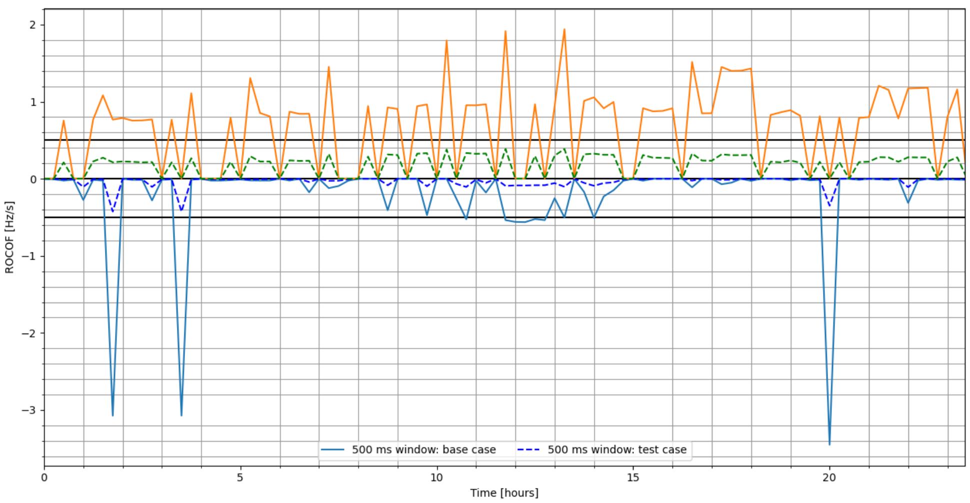
6.1.1 KPI 14 - Level of DG/DRES utilization for ancillary services

Description	The purpose of this KPI is to measure the utilization of DER for ancillary services (UAS). It is expressed as a ratio between the energy used for ancillary services and the total energy produced.
Formula	$$\mathrm{UAS\%} = \frac{E_{\mathrm{AS}}}{E_{\mathrm{total}}} \times 100\ [\%]$$ E_{AS} - the energy used for ancillary services [MWh] E_{total} - the total energy produced [MWh]
Numerical results	
Discussion	As UC6 utilizes only storage, the values in the graph above show the RES utilization by UC4. The utilization depends on the type and location of the trip, as well as on the level of instability that results from it. Since the type of RES used in UC4 for frequency support is PV, the largest RES utilization is observed during the day (around noon) and reaches circa 4,5% at maximum for the case in which a load has been tripped in the grid. For cases when generator trips (blue line on the graph), the KPI is below 0.5%, which means that RES contribution in those cases was small compared to contributions from other sources (e.g. storages or synchronous generators).
Comparison with BSC1	In BSC there was no DG/DRES utilization.

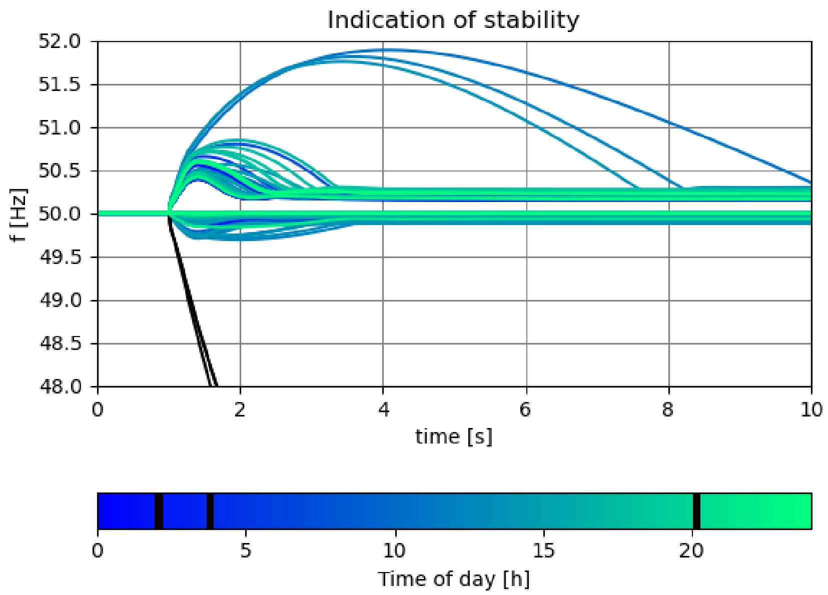
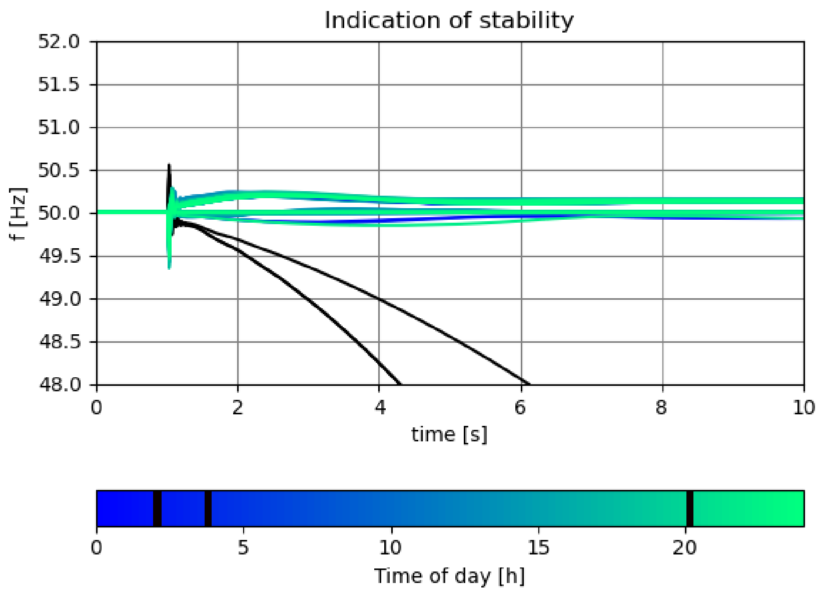
6.1.2 KPI 20 - Frequency nadir/zenith

Description	Maximum drop/rise in frequency after a disturbance in a power system. Over- and under-frequency is dangerous for system secure operation as it can trigger protections and lead to load/generation disconnections.
Formula	$max(\lvert f_n - f \rvert)$ [Hz] f_n - nominal frequency [Hz] f - system frequency [Hz]
Numerical results	 
Discussion	Figure shows comparison of frequency minimum and maximum values after a generator/load trip for BSC and SC. The three most severe cases (f<48 Hz) are the synchronous generator trips. In those cases, the system was unsuccessful in bringing the frequency back to safe operational values due to lack of frequency support from UC4 (as synchronous generators are not within defined control areas). In the rest of cases (where the trip occurred in one of the control areas) the SC1 has helped with reducing frequency nadir/zenith.
Comparison with BSC1	See above.

6.1.3 KPI 21 - Rate of Change of Frequency (RoCoF)

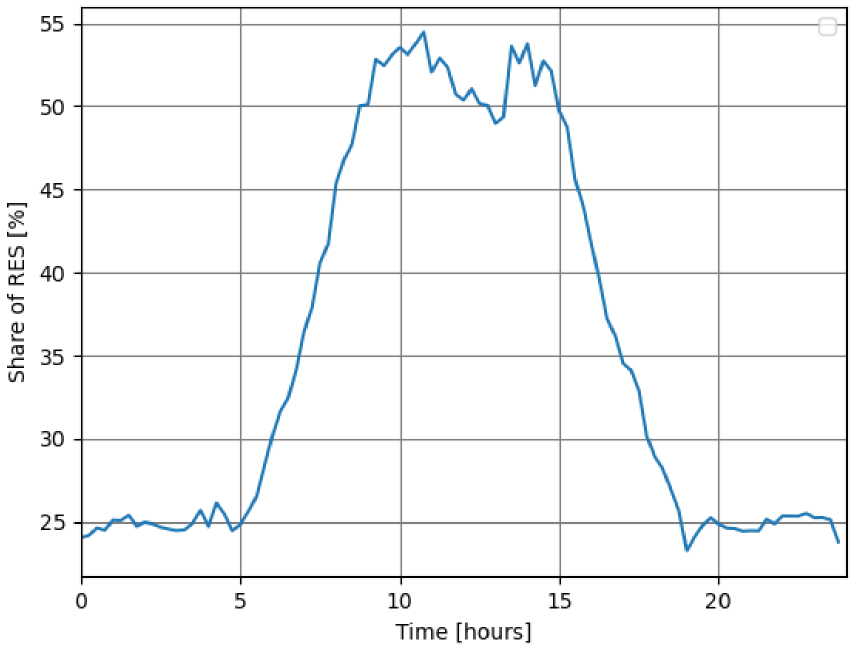
Description	The initial rate of change of frequency (RoCoF) after a disturbance is important for power system stability. If change in frequency is too fast, primary control does not have enough time to start acting which could lead to tripping of generating units, therefore increasing power imbalance in the grid. As high RoCoF can have severe consequences, it is crucial to keep its value low.
Formula	$$\frac{df}{dt} = \frac{P_g - P_l}{2H_{sys}}$$ $\frac{df}{dt}$ - rate of change of frequency [Hz/s] P_g - generators' active power [p.u.] P_l - demand active power [p.u.] H_{sys} - system inertia [s]
Numerical results	
Discussion	It can be seen that RoCoF values in the base showcase in several cases are outside the defined acceptable interval ($\pm$0.5 Hz/s, marked with black lines). After applying SC1 control, RoCoF has been reduced and brought back to acceptable values.
Comparison with BSC1	See above.

6.1.4 KPI 25 - Indication of stability

Description	A generic indicator describing whether the system reaches a stable and acceptable equilibrium after a reference incident. The reference incident is dependent on the type of stability analysed: • for frequency stability: trip of the largest infeed or load, • for transient stability: 3-phase to ground fault cleared after the longest allowable time as described in the grid code (e.g. 150 ms), • for voltage stability: any kind of disturbance causing the largest reduction in available reactive power reserves, • for small-signal stability: line trip causing the largest change in modes' shape In case of SC1 the relevant type of stability is frequency stability.
Formula	No calculation needed; this KPI is a Boolean variable (YES/NO)
Numerical results	Base case:  Test case: 

Discussion	Although no calculation is needed and the KPI is a Boolean value, it has been decided to show the graphs with frequency changes, experienced by the system after a generation/load trip in each analysed case. It can be seen that SC1 minimizes frequency deviations seen in the BSC. In three cases, described in table in section 6.1.2, the system remains unstable due to insufficient active power support.
Comparison with BSC1	SC1 minimizes frequency deviations seen in the BSC

6.1.5 KPI 27 - Share of RES

Description	The purpose of this KPI is to measure share of RES in the total generation portfolio.
Formula	$\mathrm{RES\%} = \frac{P_{\mathrm{RES}}}{P_{\mathrm{total}}} \times 100\ [\%]$ P_{RES} - Active power provided by RES at a given time step [MW] P_{total} - Total active power provided by RES and non RES generators at a given time step [MW]
Numerical results	
Discussion	Share of RES in the studied case is between 25% and 55%.
Comparison with BSC1	Share of RES is the same for BSC.

6.1.6 Summary of SC1 on low inertia systems

As part of INTERPLAN tool, SC1 addresses the following operation challenges:

- Maximizing share of RES
- Assuring frequency stability
- Maximize DG/DRES contribution to ancillary services.

Thanks to combination of Fast Frequency Restoration Control and Inertia management, the above-mentioned challenges could be resolved for the network with high RES penetration. To show the proposed solution effectiveness following KPIs have been defined:

- 14 - Level of DG / DRES utilization for ancillary services
- 20 - Frequency nadir/zenith
- 21 - Rate of Change of Frequency (RoCoF)
- 25 - Indication of Stability
- 27 - Share of RES

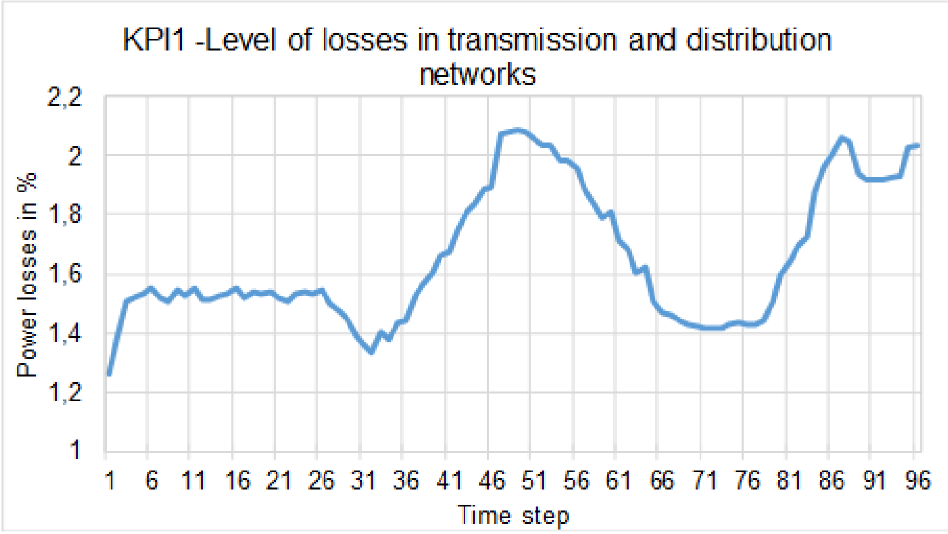
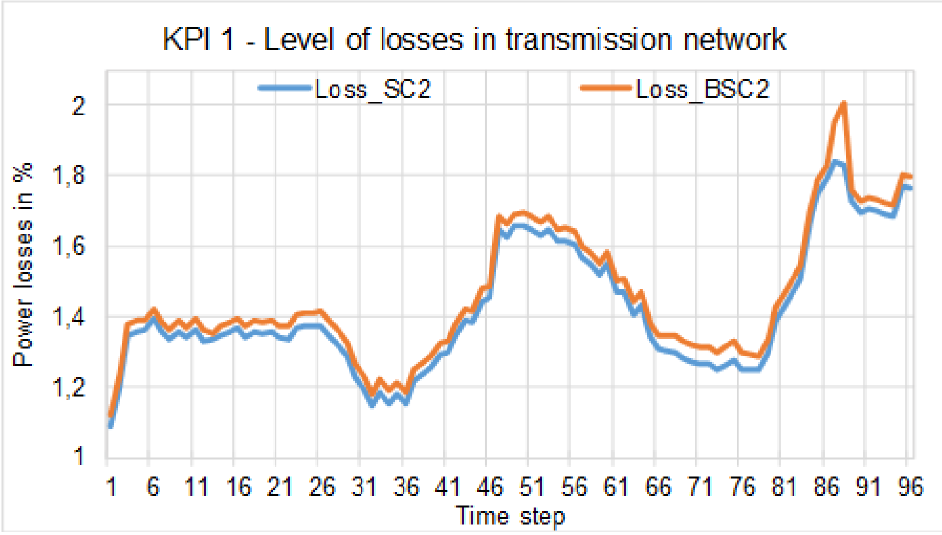
For evaluation purposes two cases have been analyzed: base case in which no additional frequency support was available and test case for which such possibility was added (therefore in the test case not only synchronous generators could provide frequency support but also storage units and RES). It has been shown, in the sub-chapters 5.1.1 - 5.1.5, that in most cases SC1 was able to provide satisfactory frequency support. RoCoF values have been brought to the adequate levels (within predefined range), consequently fulfilling KPI 21, and frequency nadirs/zeniths have been lowered, which was the goal of KPI 20. Additionally, the showcase has used RES for providing ancillary service in form of fast frequency response (UC4) and no RES have been curtailed in the process.

6.2 SC2 results– Effective DER operation planning through active and reactive power control

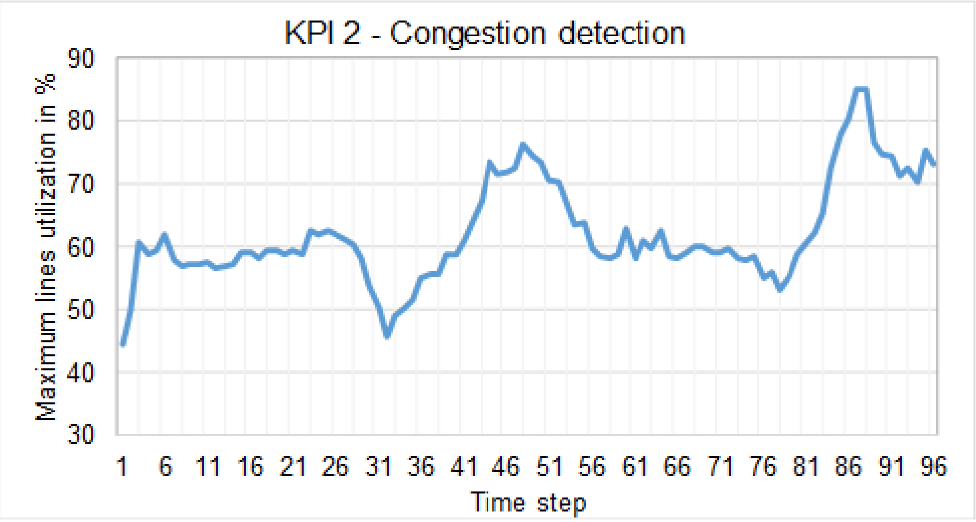
After applying the control functions including active and reactive power of DER, simulation functionalities i.e. OPF and LF are executed on the Simbench-based grid model to meet the predefined SC2 planning criteria i.e. minimize losses, maximize share of RES, assuring voltage stability, mitigating grid congestion, optimize TSO/DSO interaction, and maximize DG/RES contribution to ancillary service. Therefore, KPIs including level of losses in transmission and distribution network, congestion detection, voltage quality, mean quadratic deviations from voltage and reactive power target at TSO/DSO connection point and level of DG/RESs utilization for ancillary services are presented and discussed in this section in order to assess if the SC2 simulation is able to meet these planning criteria.

6.2.1 KPI 1- Level of losses in transmission and distribution networks

Description	This KPI aims to assess if SC2 can meet the planning criterion ”1.minimize losses” (see Figure 5). Therefore, with calculation of level of losses and comparing with BSC2, it can be evaluated if this SC is successful to decrease the power losses.
Formula	$\text{Percentage of losses} = \frac{\text{Amount of injected energy } - \text{amount of energy delivered to the customers}}{\text{Amount of injected energy}} \times 100$ **Complementary information:** The power losses percentage is calculated by following formulation: $P_{\text{loss}}(t) = \frac{\sum_i \sum_j G_{\text{ij}}\left[V_i(t)^2 + V_j(t)^2 - 2V_i(t)V_j(t)\cos\left(\delta_i(t) - \delta_j(t) - \theta_{ij}\right)\right]}{\sum_{g\in \text{G}} P_g(t)}$ Where V_i - voltage magnitude at bus *i* in p.u.; V_j - voltage magnitude at bus *j* in p.u.; δ_i - voltage angle at bus *i* in radian; δ_j - voltage angle at bus *j* in radian; G_{ij} - line conductance between bus *i* and *j*; P_g - active power generation for generator *g*; θ_{ij} - impedance angle of branch between *i* and *j* in radian; *t* - time step; G - all generators;

Numerical results	 
Discussion	This KPI is calculated based on the line-by-line power losses in the network compared with total active power production by all generators at each time step. Performing this approach, it can be quantified how much generated power is lost within the lines. Two results are being extracted in this SC: one for entire network including transmission and distribution levels and another just for the transmission network. As depicted in the first figure, the maximum percentage of power losses in the entire grid is at time step 49 (12:00) with 2.087%. As expected, this happens at peak load time. This value is less at the same time step when looking at just the transmission level power losses with 1.65%. The maximum power losses in the transmission level occur at time step 88 (21:45) with 1.84% when the highest line utilization occurs (see KPI 2 for further information).
Comparison with BSC2	Since power losses were analysed only at transmission level in BSC2, the only way to make the comparison is to extract the same data for SC2; therefore, the second figure as shown in the results for transmission level is helpful. As can be seen in this figure, after performing the optimization with the aim to minimize the power losses in SC2 for transmission level, the time dependent power losses are lower than BSC2 for all time steps. Hence, the SC goad of reducing power losses was fulfilled.

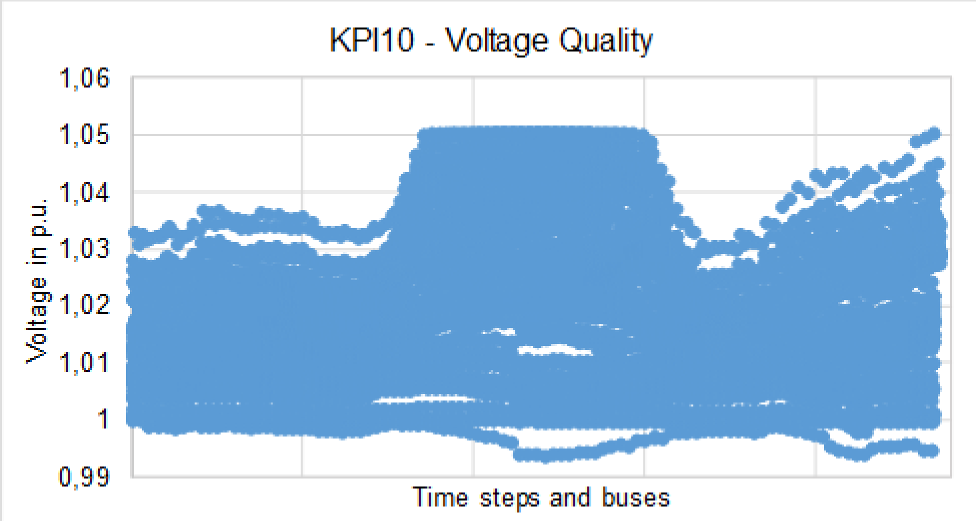
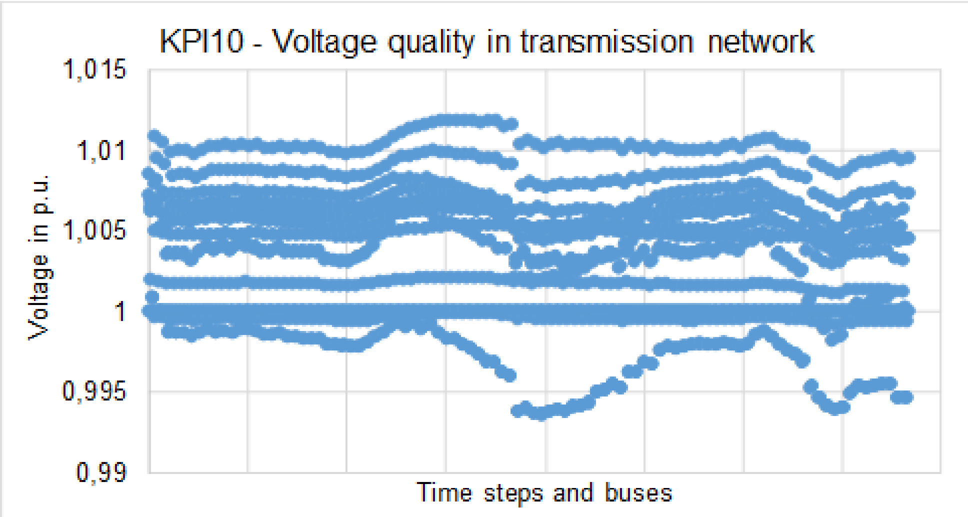
6.2.1 KPI 2 - Congestion detection

Description	This KPI aims to assess if SC2 can meet the planning criterion "5.mitigating grid congestion" (see Figure 5). Therefore, with calculation of electric current of lines and comparing with the maximum acceptable value, it can be evaluated if this SC is successful to reduce load to reach the acceptable level in overloaded lines.
Formula	Congestion = If abs($P_{line\_i} > P_{rating\_line\_i}$) the line *i* is congested P_{line_i} [kW] is the active power that flows troughs the line *i* $P_{rating\_line\_i}$ [kW] is the nominal active power of the line *i* **Complementary information:** To show the results based on above description, the following procedure has been conducted: For each line, the individual utilization is calculated taking into account the actual voltage magnitudes at the bus bars the lines are connected to into account (considering the current value instead of the apparent power value) to obtain the percentage of the line loading. $$max\left(\frac{\sqrt{P_{ij}^2+Q_{ij}^2}}{S_{\text{base}}\cdot V_i},\quad \frac{\sqrt{P_{ji}^2+Q_{ji}^2}}{S_{\text{base}}\cdot V_j}\right)$$ P_{ij} - active power flow of line relating bus i; Q_{ij} - reactive power flow of line relating bus i; V_i - voltage magnitude at bus i in p.u.; S_{base} - Rated apparent power of the line; The maximum line utilization at each time step is selected to show in the following figure.
Numerical results	

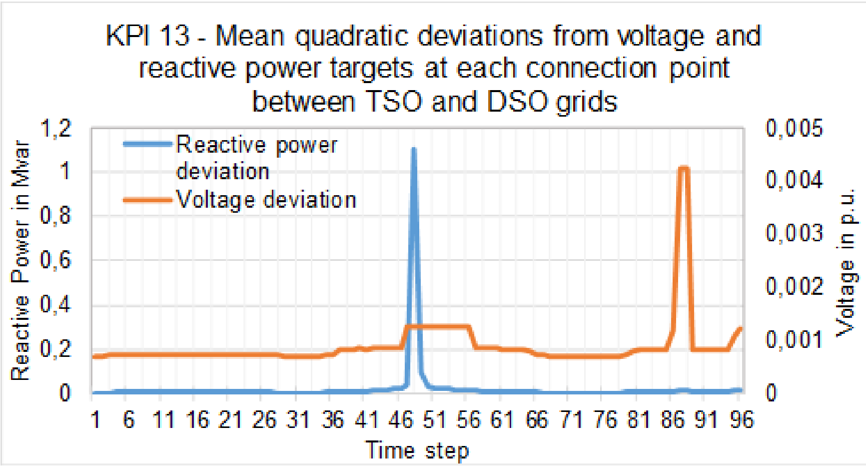
Discussion	It was determined in UC2 that one line at two time steps 87 (21:30) and 88 (21:45) is overloaded (more than 90%) with 90.35% and 94.55%, respectively. Therefore, the congestion management algorithm is employed to lower the load of the congested line to less than 90 percent (85.5% at time step 87 and 85.6% at time step 88) by changing the active power set points of the generators. UC1 is implemented using the new active power set points and all lines are loaded within acceptable range in a way that the maximum line load occurs at time step 88 with 85.4%. This value is a bit lower than UC2 results which is probably because of using apparent power in UC1 to calculate this percentage instead of active power. Note that this calculation has been performed just for three voltage levels 110, 220, and 380 kV.
Comparison with BSC2	Obviously, the detected line congestion in BSC2 is removed in SC2. After SC2 application, no line is overloaded (loading more than 90%) in any of the time steps.

6.2.2 KPI 10 - Voltage Quality

Description	This KPI aims to assess if SC2 can meet the planning criterion ”4.Assuring voltage stability” (see Figure 5). Therefore, with calculation of each bus voltage magnitude and comparing with the admissible values, it can be evaluated if this SC is successful to reach this goal.
Formula	According to the defined EN 50160 standards and VDE-AR-N 4120, bus bar voltage magnitudes must comply with following allowed range of variation. LV: ±10% of nominal voltage MV: ±5% of nominal voltage HV & EHV: ±4-7% of nominal voltage The following voltage deviation indices can be defined to find the frequency or duration that the bus bar voltages violate the allowed voltage range: • Number of voltage excursions exceeded n minutes per year • Percentage of time that the transmission voltage exceeds the permissible limits.

Numerical results	 
Discussion	The voltage magnitudes for both transmission and distribution network including HV, MV, and LV are presented together with the voltage magnitudes just for transmission level buses (220 kV and 380 kV) in two separate figures. The figures show voltage magnitudes for buses at different time steps in blue dots. For all voltage levels, there are 246 buses. As can be seen in the figure, the maximum voltage reaches up to 1.05 p.u., and the minimum hardly reaches down to 0.99 p.u. All voltage magnitudes higher than 1.01 p.u. belong to the distribution level because as the figure shows, there are no values higher than 1.01 p.u. in the transmission network. Therefore, voltages at all levels are kept in the admissible threshold in a way that HV: ±1%, MV, LV: +5% & -1%.
Comparison with BSC2	After comparing voltage quality for the transmission network between SC2 and BSC2, it is concluded that in both cases the bus voltages are kept in acceptable range ±1%. Since there was no analysis for whole network in BSC2, it is not possible to compare the results for distribution network.

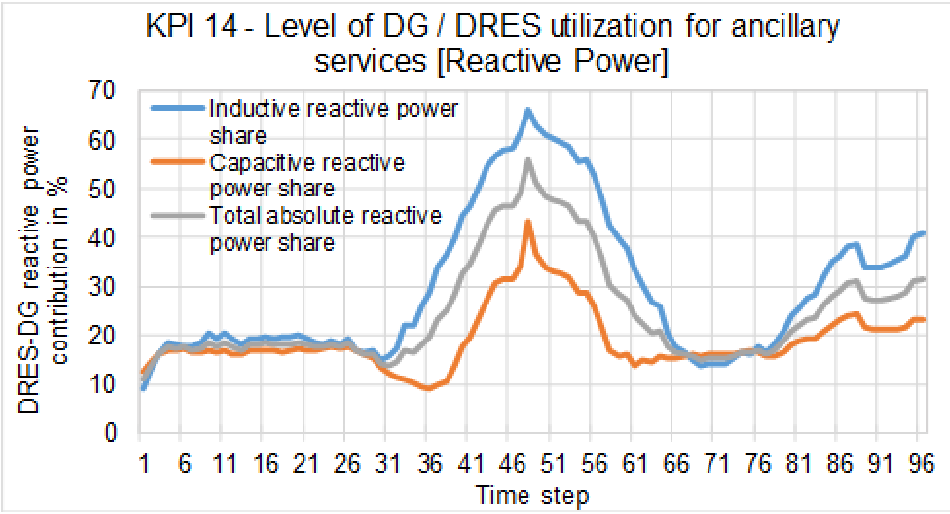
6.2.3 KPI 13 - Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids

Description	This KPI aims to assess if SC2 can meet the planning criterion ”7. Optimize TSO/DSO interaction” (see Figure 5). Therefore, to reach the optimum interaction between TSO and DSO, the reactive power set point and voltage magnitude set point for TSO-DSO connection points defined by the TSO is tried to be kept the same while making the decision about the same set point by the DSO. With calculation of this KPI, it can be evaluated if this SC is successful to keep the set points of connection points within target values.
Formula	Let C be the set of connection points between TSOs and DSOs. Let $q_{c,\text{target}}(t)$ [Mvar] be the target value for reactive power transmission from DSO to TSO at connection point c and time t, as e.g. calculated by grid operation planning. Let $q_c(t)$ be the reactive power actually provided from DSO to TSO at connection point c and time t. Then the KPI related to reactive power at time t is defined as: $\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(q_{c,\text{target}}(t)-q_c(t)\right)^2$ The KPI related to voltage is defined as follows. Let $u_{c,\text{target}}$ [p.u.] be the nominal value for the line-to-line voltage at connection point c, calculated as mean over all phases. Let $u_c(t)$ be the actual line-to-line voltage mean over all phases. Then, the KPI at time t is: $\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(u_{c,\text{target}}(t)-u_c(t)\right)^2$
Numerical Results	

Discussion	Reactive power deviation in connection points, as defined in this KPI, is a part of objective function in UC1 to be minimized. *q* and *u* are the reactive power flow in transformers of TSO-DSO connection points and voltage magnitude at high voltage side of transformers at TSO-DSO connection points, respectively. The target values $q_{c,\text{target}}$ and $u_{c,\text{target}}$ are extracted from the optimization problem that the TSO executes in the second stage of UC1. q_c and u_c are also calculated from the DSO optimization with the goal to minimize the deviation between values and targets. The figure shows that these deviations can be kept close to zero. A peak at time step 48 (11:45 AM) for reactive power can be observed, which is just around 1 Mvar. The reason behind is that this is the peak time and reactive power flow at one out of three connection points has to be a bit bigger than the target.
Comparison with BSC2	In BSC2, due to lack of enough information $q_{c,\text{target}}$ and $u_{c,\text{target}}$ were assumed to be zero and 1, respectively. Therefore, the difference between SC2 and BSC2 results after having the proper target values are significantly high. The minimum value of reactive power deviation in BSC2 was around 13 Mvar while this value in SC2 it is almost zero. Likewise, the minimum value of voltage deviation in BSC2 was 0.008 p.u. while the maximum value in SC2 hardly reaches 0.0045 p.u.

6.2.4 KPI 14 - Level of DG / DRES utilization for ancillary services

Description	This KPI aims to assess if SC2 can meet the planning criteria ”3.Maximize share of RES” and ”8. Maximize DG/RES contribution to ancillary service” (see Figure 5). Therefore, with calculation of this KPI, it can be evaluated if this SC is successful to increase the contribution of RESs for ancillary service provision.
Formula	$\text{UAS\%} = \frac{E_{\text{AS}}}{E_{\text{total}}} \times 100\ [\%] = \frac{\text{scheduled reactive power for DERs}}{\text{total reactive power from DERs} + \text{Syncronous generators}}$ E_{AS} - the energy used for ancillary services [MWh] E_{total} - - the total energy produced [MWh] **Complementary information:** **[Level of <u>reactive power</u> ancillary service provision]** The reactive power ancillary service is divided into three parts to present the share of capacitive, inductive, and absolute total reactive power, separately. To this end, there are two separate fractions: (i) all reactive power data are positive and (ii) all reactive power data are negative as follows: $\text{UAS (Inductive)} = \frac{\text{Inductive scheduled reactive power for DERs}}{\text{total positive reactive power from (DERs} + \text{syncronous generators)}} \times 100$

	$$\text{UAS (Capacitive)} = \frac{\text{Capacitive scheduled reactive power for DERs}}{\text{total negative reactive power from (DERs + syncronous generators)}} \times 100$$ $$\text{UAS (Total absolute)} = \frac{\text{Absolut scheduled reactive power for DERs}}{\text{total absolut reactive power from (DERs + syncronous generators)}} \times 100$$ **[Level of <u>active power</u> ancillary service provision]** The active power for the ancillary services, $P_{i_{\text{optimal\_solution}}}$, is calculated as minimal active power variation at bus bar *i* to solve the detected congestion problems in the grid (i.e., to provide the required ancillary services). Therefore, the level of active power ancillary service provision is defined as follows: $\sum_{i=0}^{N_{\text{bus bar}}} \frac{P_{i_{\text{optimal\_solution}}}}{P_{i_{\text{gen}}}} \times 100$ $N_{\text{bus bar}}$ - total number of buses. $P_{i_{\text{optimal\_solution}}}$ - optimal active power variation at bus bar *i*. $P_{i_{\text{gen}}}$ - total active power provided by generation resources at bus bar *i*.
Numerical results	

Discussion	UC1 aims to just schedule the reactive power set points of generators and active power production of generators are set to the initial values; thus, the level of ancillary service provision by reactive power can be calculated at the end of UC1. Since the reactive power of generators can be absorbed or injected depending on capacitive or inductive nature, three different KPI values named capacitive, inductive, and total absolute are used to present ancillary service provision by reactive power. Note that the difference between final reactive power set points of generators after optimization and initial set points is called scheduled reactive power. The capacitive reactive power is provided by all generators that are scheduled to absorb reactive power at specific time steps, while the inductive reactive power implies injection into the network by the generator. On the other hand, the total absolute reactive power sums up both capacitive and inductive regardless the sign of the values (positive or negative) by the absolute function. This classification is done to show the complete overview of reactive power behaviour after implementation of simulation functionalities (OPF) and control functions (reactive power of DERs) in SC2. As can be seen in the figure (reactive power), inductive reactive power has the highest contribution at most time steps which means that most of the time generators tend to inject reactive power to the network. The maximum contribution of inductive reactive power is at time step 48 (11:45 AM) with 66.02%. The maximum capacitive reactive power occurs at the same time step with 55.7% contribution. This means that 55.7% of the total absorbed reactive power by generators is devoted for flexibility needs of the network. As the active power set points in UC1 are untouched, the ancillary service provision by active power can be calculated by UC2. The UC2 control is triggered when congestion problems are detected at transmission level. The simulation highlighted two congestion issues: at time steps 86 and 87, the line "EHV Line 290" has a loading value of respectively 90.34% (>90%) and 94.55% (>90%). The levels of active power ancillary service provisions are 2.7% and 4.9% respectively. These values allow to solve the congestion problems.
Comparison with BSC2	The ancillary service provision is just scheduled in SC2 because of using simulation functionalities and control functions. Therefore, no comparison can be made here, as there was no ancillary service provision in BSC2.

6.2.5 Summary of SC2 on effective DER operation planning through active and reactive power control

The SC2 aims to make available a tool for the system operators (TSO and DSO) who have to address the following operation challenges:

- Minimizing losses
- Maximizing share of RES
- Assuring voltage stability
- Mitigating grid congestion
- Optimize TSO/DSO interaction
- Maximize DG/DRES contribution to ancillary services

Thanks to a coordinated TSO-DSO optimization and an optimal active/reactive power control of DERs, the proposed control functions solve the above operation challenges ensuring adequate performance levels at the same time. To show the proposed solution effectiveness, the following KPIs have been defined:

- KPI 1 - Level of losses in transmission and distribution networks
- KPI 2 - Congestion detection
- KPI 10 - Voltage Quality
- KPI 13 - Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids
- KPI 14 - Level of DG / DRES utilization for ancillary services

The KPIs have been evaluated considering two showcases. The first one is defined as base showcase with no planning criteria and no controllers for emerging technologies, such as RES, distributed generation (DG), demand response (DR), or storage technologies. The second one is defined as showcase with planning criteria and controllers. The base showcase represents a reference case, with which the results attained by introducing control functions in the grid operation planning are compared.

For both showcases, a SimBench based benchmark grid model with ‘INTERPLAN-2: small and local’ scenario is applied.

Analysing the simulation results, it is evident that the issues highlighted by the BSC2 simulation are effectively solved thanks to the control functions used for the SC2 simulation.

Comparing the level of losses in transmission and distribution networks (KPI 1), the maximum power losses happen at time step 88 (21:45) with 2% for BSC2 and 1.84% for SC2 with a power losses minimization.

The congestion detection (KPI 2) outcomes show the effectiveness of the control function used in SC2 to solve the congestion problem detected in BSC2.

Also, the voltage quality (KPI 10) for transmission network is kept in acceptable range ±1% at all voltage levels.

Regarding the mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids (KPI 13), the minimum value of reactive power deviation in BSC2 is around 13 Mvar while in SC2 it is almost zero. The minimum value of voltage deviation in BSC2 is 0.008 p.u. while the maximum value in SC2 hardly reaches 0.0045 p.u.

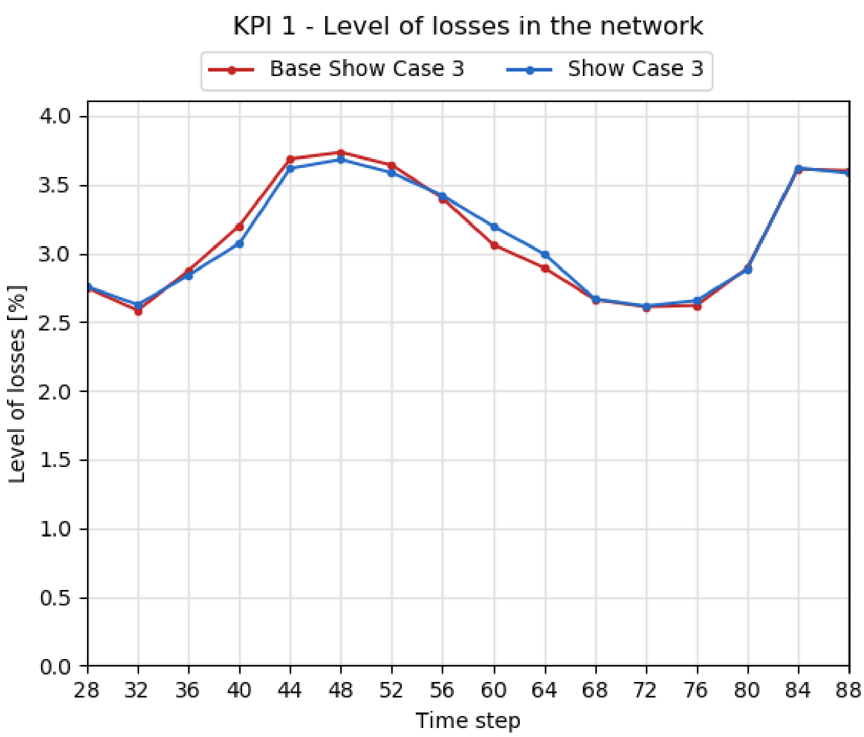
Finally, the level of DG / DRES utilization for ancillary services (KPI 14) is analysed only for the SC2 because of using simulation functionalities and control functions.

The simulation results clearly show the reliability, robustness and effectiveness of the control functions proposed in SC2 to achieve the expected planning criteria.

6.3 SC3 results – TSO-DSO power flow optimization

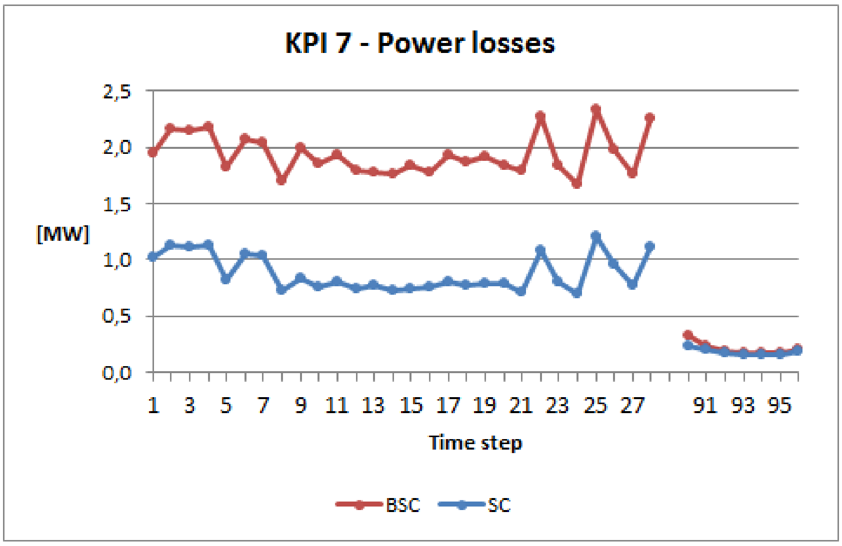
The simulation results for SC3 are presented in this section. As the two use cases included in SC3 operate on disjunct subsets of time steps, the results (KPI values) are presented only for relevant subsets. UC3, the goal of which is to provide tertiary reserve control, is applied to time steps corresponding to full hours between 7:00 and 22:00, i.e. time steps from 29 to 89 (every 4 time steps). UC5, which aims to minimize power exchange between transmission and distribution grids, is considered as being of lower importance than UC3, and therefore is active only for time steps outside the range of UC3 operation. It is thus applied to time steps covering the period before 7:00 and after 22:00 (time steps 1 to 28 and 90 to 96). The presented results and KPI values refer to one single DSO grid within the analyzed model.

6.3.1 KPI 1- Level of losses in transmission and distribution networks

Description	This KPI aims to assess if SC3 can meet the planning criteria ”3.Maximize share of RES” and ”8. Maximize DG/RES contribution to ancillary service” (see Figure 5). Therefore, with calculation of this KPI, it can be evaluated if this SC is successful to increase the contribution of RES to ancillary service provision.
Formula	$P_{\text{losses}} = \frac{\text{amount of injected energy} - \text{amount of energydelivered to customers}}{\text{amount of injected energy}} \times 100\ [\%]$
Numerical results	
Discussion	The level of losses in the full grid including transmission and distribution levels for the SC3 is between 2.5 to 3.7%.

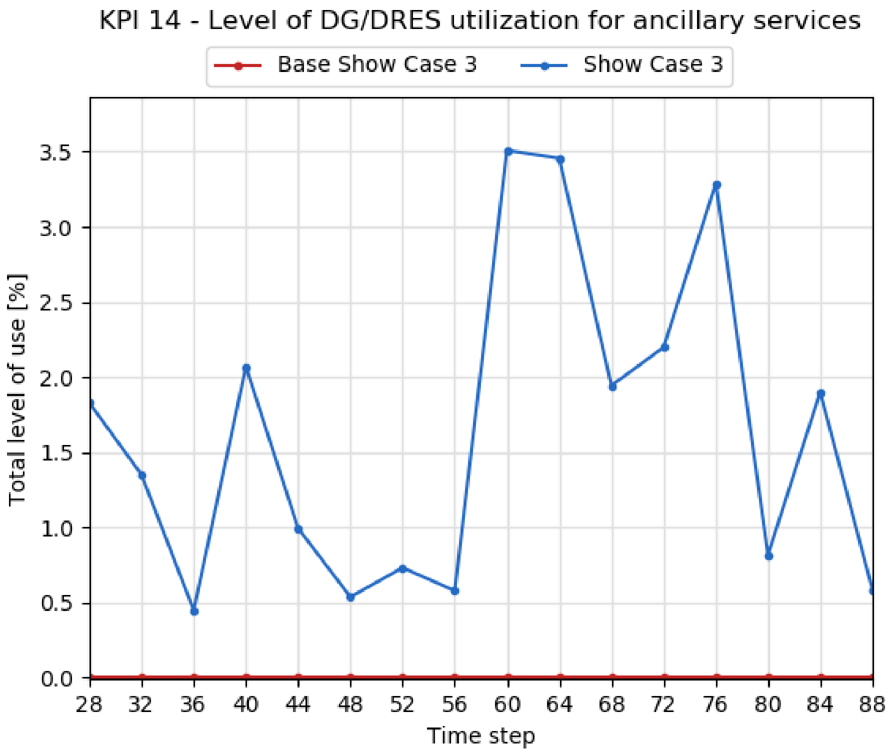
Comparison with BSC3	Considering the presented comparison plot, it can be seen that in several time steps the level of losses in the presence of SC3 tertiary control functions are lower than BSC3, where no control functions were applied and no tertiary reserve was requested by the TSO. Nevertheless, there are some time steps where power losses in the SC are equal to the BSC or even higher. The reason is related to the requested tertiary reserve from the TSO. When the requested tertiary reserve is a relatively high positive value (more generation is required), the total power flowing within the grid will be higher consequently and this leads to higher losses. In fact, this should not mean the control functions are increasing the losses knowing the fact that the total power flow is higher due to the requested tertiary reserve. Even in these cases, the control function is reducing the losses in comparison to the case of non-optimised provision of tertiary reserve. Note: the values of this KPI for base showcase 3 are updated considering the corresponding values presented in D5.2. In the new values, the contribution of external grids (slack bus bars) is excluded from the calculation, since their role is not of interest for power loss calculations.

6.3.2 KPI 7- Power losses

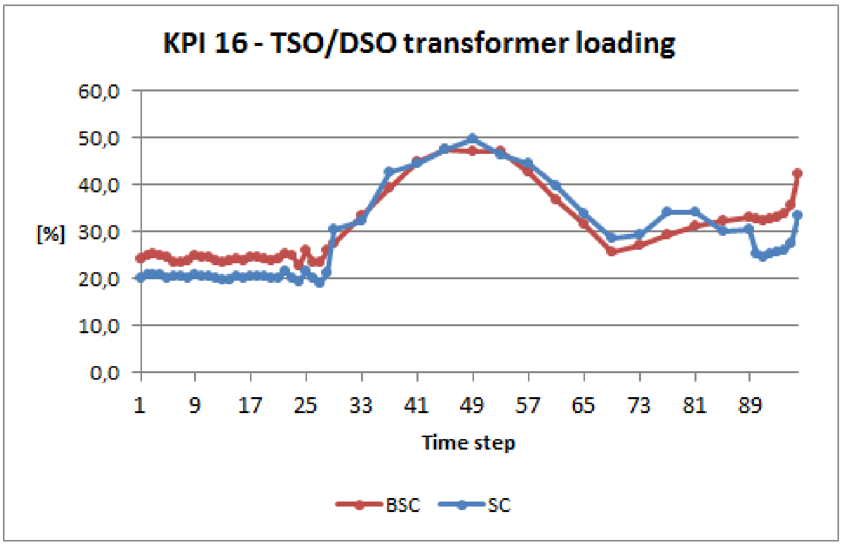
Description	Similarly to KPI 1, this KPI is intended to give a measure of power losses in the grid, in this case only regarding the distribution level and in absolute terms (i.e. in MW of active power losses). It is one of optimization objectives for the UC5 controller function.
Formula	$P_{\text{losses}} = \sum_i^{Nline} \lvert I \rvert_i^2 r_i$ [kW] I_i - magnitude of current flow in line *i* [A] r_i - resistance of line *i* [Ω]
Numerical results	
Discussion	The level of active power losses in the distribution grid for SC3 is usually slightly below 1 MW during the first part of the analyzed time period (before 7:00) and noticeably lower, below 0.5 MW, after 22:00.

Comparison with BSC3	The comparison of values presented in the graph clearly indicates that the controller function is successful in significantly reducing the total active power losses in the distribution grid, especially in the first part of the simulation, when the power losses are higher. The reduction is this period is ca. 50-60%, while during later hours, when the losses are much lower, the reduction is within a 5-30% range.

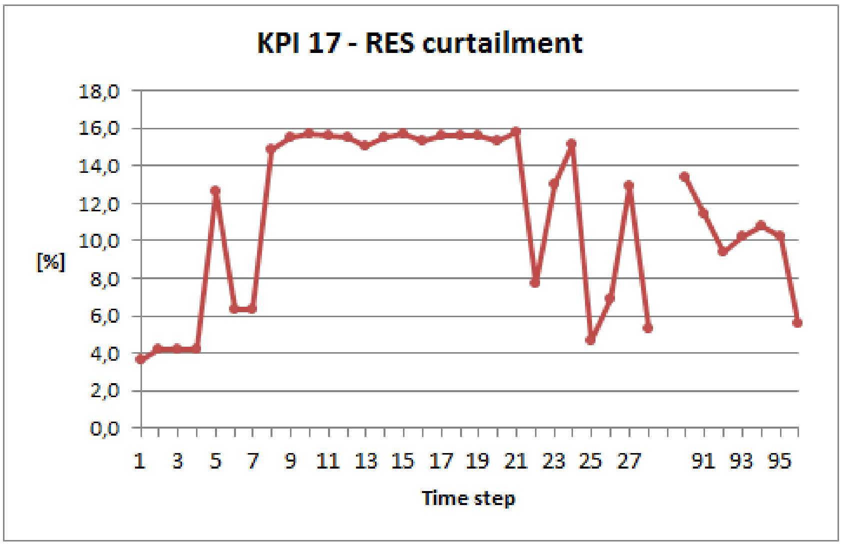
6.3.3 KPI 14- Level of DG / DRES utilization for ancillary services

Description	The purpose of this KPI is to measure the utilization of DER for ancillary services (UAS). It is expressed as a ratio between the energy used for ancillary services and the total energy produced.
Formula	$$\mathrm{UAS\%} = \frac{E_{\mathrm{AS}}}{E_{\mathrm{total}}} \times 100\,[\%]$$ E_{AS} - the energy used for ancillary services [MWh] E_{total} - the total energy produced [MWh]
Numerical results	
Discussion	Depending on the need for tertiary reserve provision in the selected time step, the level of utilization of DG and DRES for ancillary services was variable with a share between 0.4 to 3.5 percent.
Comparison with BSC3	Comparing the values of this KPI in SC3 with the corresponding base showcase, it is obvious that SC3 control functions were successful in involving the available controllable units in providing tertiary reserve.

6.3.4 KPI 16- Transformer loading

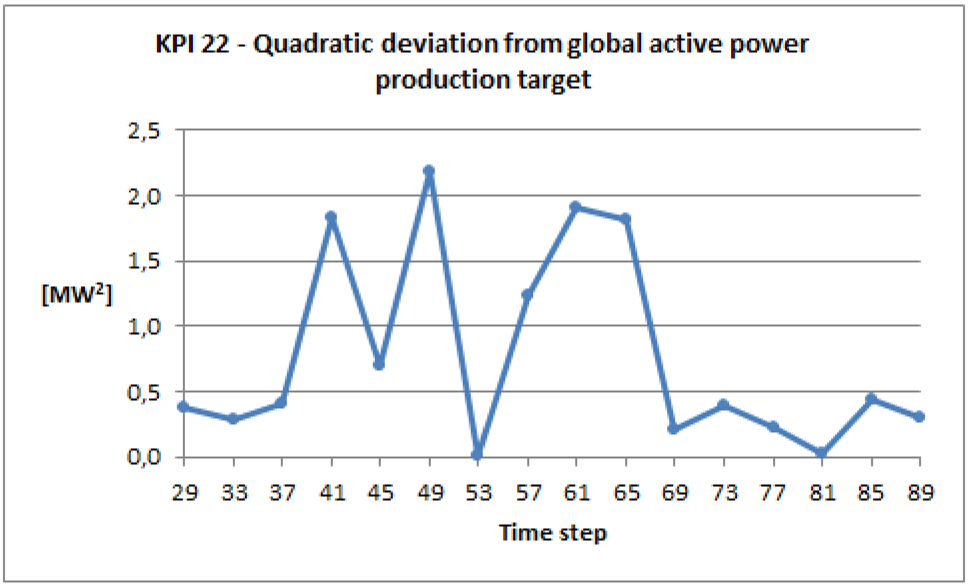
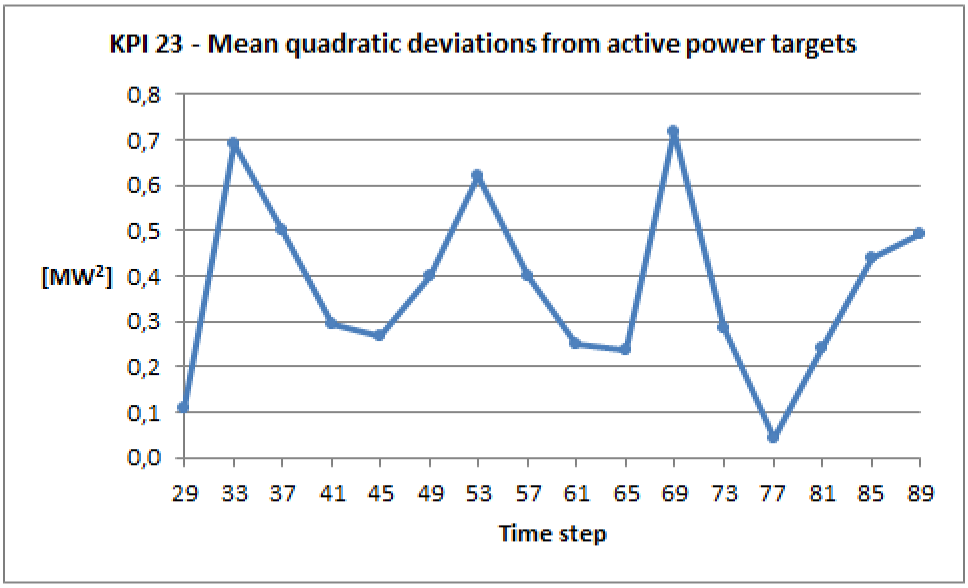
Description	This KPI reflects the value of TSO/DSO transformer loading and is the primary optimization objective of the UC5 controller function, as the main goal of UC5 is to optimize the local usage of energy through minimizing the power exchange between DSO and TSO networks.
Formula	$\text{Loading} = \frac{\text{power at transformer primary winding}}{\text{transformer nominal power}} * 100\ [\%]$
Numerical results	
Discussion	The loading values of the transformer are obviously highly variable due to daily changes in power demand. The lowest loading, approx. 20%, is observed for time steps of the simulation corresponding to night and early morning hours. Peak demand hours correlate with the highest transformer loadings, reaching approx. 50% at time step 49 (corresponding to 12:00).
Comparison with BSC3	The controller function operation has succeeded in lowering the transformer loading by 10 to 25% of its pre-controller value during the part of simulation performed by UC5 (i.e. time steps 1-28 and 90-96). In case of UC3, minimizing the transformer power flow is not a primary objective, therefore in part of simulation performed by this controller, the post-controller values of transformer loading are lower than pre-controller values for some time steps and higher for others.

6.3.5 KPI 17- RES curtailment

Description	The purpose of this KPI is to give an indication of the volume of RES-generated available energy curtailed because of controller actions aiming to meet other goals of optimization. Minimizing RES curtailment is itself one of optimization objectives for UC5.
Formula	$\text{Curtailment} = 100 - \dfrac{\text{energy supplied by RES to the grid}}{\text{RES available energy}} * 100\ [\%]$
Numerical results	
Discussion	Because the optimization function of the UC5 controller includes contradictory objectives, in order to maximize its value i.e. achieve other controller objectives, a certain amount of RES energy had to be curtailed in every simulated time step. The percentage of available RES power which was curtailed fell in the 4-16% value range.
Comparison with BSC3	As in the BSC there is no controller operating in order to achieve any optimization goals, no RES power had to be curtailed and therefore the value of KPI 17 is always equal to 0.

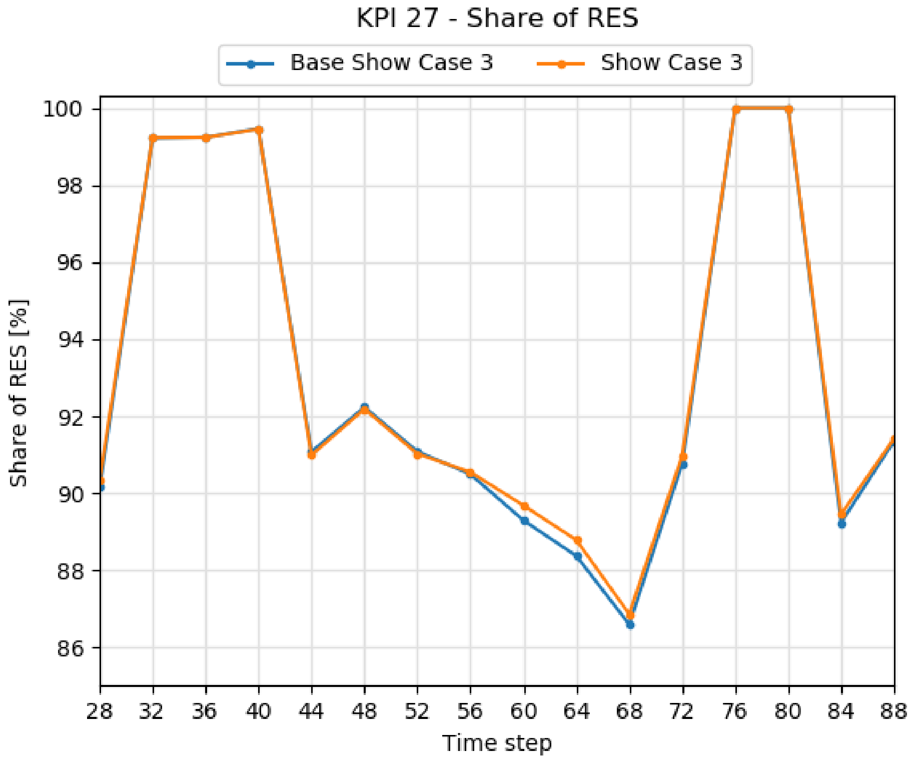
6.3.6 KPI 22- Quadratic deviation from global active power exchange target KPI 23- Mean quadratic deviations from active power targets at TSO/DSO connection points

Description	KPI 22: This KPI calculates the quadratic deviation from global active power production target, which is based on the needed tertiary reserve. Minimizing this KPI is an optimization objective. KPI 23: This KPI calculates the mean quadratic deviations from active power targets (based on the needed tertiary reserve for each connection point) at each connection point between TSO and DSO grids. Minimizing this KPI is an optimization objective.

Formula	KPI 22: Let p_{target} (t) be the global active power production target for tertiary reserve at time *t*. Let G be the set of generators producing active power, and p_g(t) be the active power generated by generator g at a given time *t*. Then, the KPI at this time is: $$\left(p_{\text{target}}(t) - \sum_{g\in G} p_g(t)\right)^2$$ KPI 23: Let C be the set of connection points between TSOs and DSOs. Let $p_{c,\text{target}}$ (t) [kW] be the target value for active power transmission from DSO to TSO at connection point *c* and time *t*, as e.g. calculated by grid operation planning. Let p_c(t) be the active power actually provided from DSO to TSO at connection point *c* and time *t*. Then the KPI related to active power at time t is defined as: $$\frac{1}{\lvert C\rvert}\sum_{c\in C}\left(p_{c,\text{target}}(t) - p_c(t)\right)^2$$
Numerical results	 

Discussion	These two KPIs present the success level of the optimisation algorithm. It can be seen that the KPI 22 values vary between 0 to 2.2 MW². KPI 23 also indicates the mean quadratic deviation, which is in the maximum case about 0.72 MW². These deviations can be easily compensated by available synchronous/ static generators at TSO level. Nevertheless, this error can be reduced by improving the optimisation algorithms.
Comparison with BSC3	These values cannot be calculated for the BSC, since no optimization function was applied and therefore no targeted tertiary reserve or power exchange among TSOs and DSOs is planned.

6.3.7 KPI 27- Share of RES

Description	The purpose of this KPI is to measure share of RES generation in the total generation portfolio.
Formula	$$\mathrm{RES\%} = \frac{P_{\mathrm{RES}}}{P_{\mathrm{total}}} \times 100\ [\%]$$ P_{RES} - Active power provided by RES at a given time step [MW] P_{total} - Total active power provided by RES and non-RES generators at a given time step [MW]
Numerical results	
Discussion	The KPI 27 values for SC3 show that renewable based technologies form a significant share of the generation (above 87%). This is due to the selected grid scenario, “small and local”, in which the local and distributed RES based generators have the major share in total generation as well as the goal of optimisation which is maximising the share of RES in generation.

Comparison with BSC3	Comparing the KPI 27 values of the BSC3 and SC3, it can be concluded that the control functions are able to maintain the total share of RES in generation or even to increase in few time steps. This strongly depends on the magnitude and type (increase / decrease in the generation) of the requested tertiary reserve. In several time steps, the requested tertiary control is negative and the RES need to decrease their generation. Even in these cases the share of RES were maintained which proves that optimization algorithm are successful to some extent in increasing the share of RES while responding to the other major goals, which are providing the tertiary reserve and minimising the active power losses.

6.3.8 Summary of SC3 on TSO-DSO power flow optimization

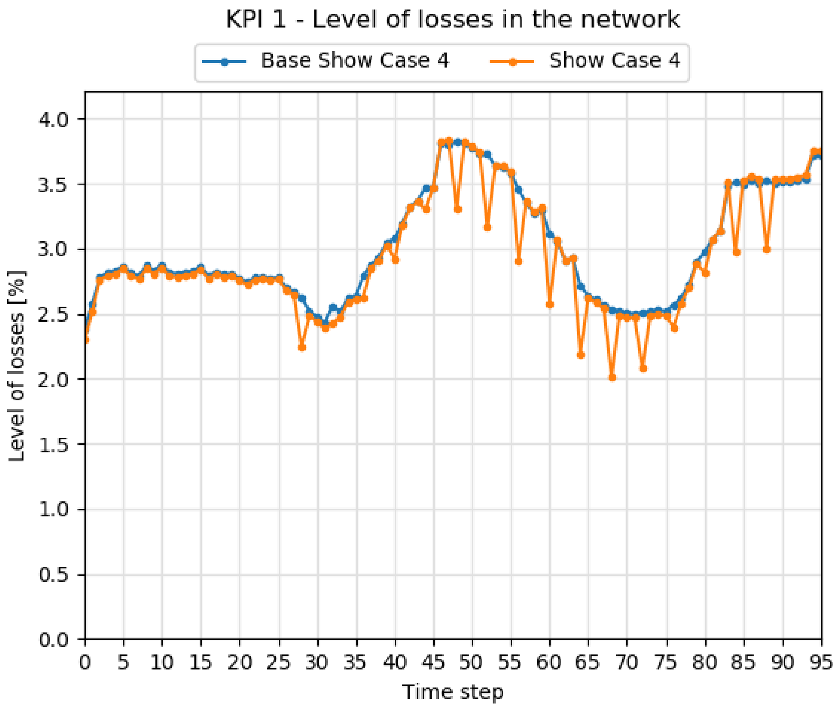
The objectives of SC3 pose a significant degree of optimization function issues, as some of the individual criteria (i.e. objectives) are contradictory, e.g. reducing the power flow between DSO and TSO grids, involving the DG/ DRES in contributing in ancillary services as well as decreasing the amount of power losses in the grid, which can be effectively achieved by curtailing a certain percentage of generation. As the simulated test case is implementing the “small and local” scenario, the majority of available generation, particularly in the distribution grid, is renewable and therefore any power curtailments involve curtailing RES generation, minimizing of which is itself an optimization objective. Therefore, the main optimization function has to be constructed considering different - and variable - weights for individual objectives.
The values of relevant KPIs, presented in the above subsections, indicate that despite this, the system performance as characterized by predefined parameters was overall improved by the operation of controllers and the assumed optimization goals were achieved.

6.4 SC4 results – TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles

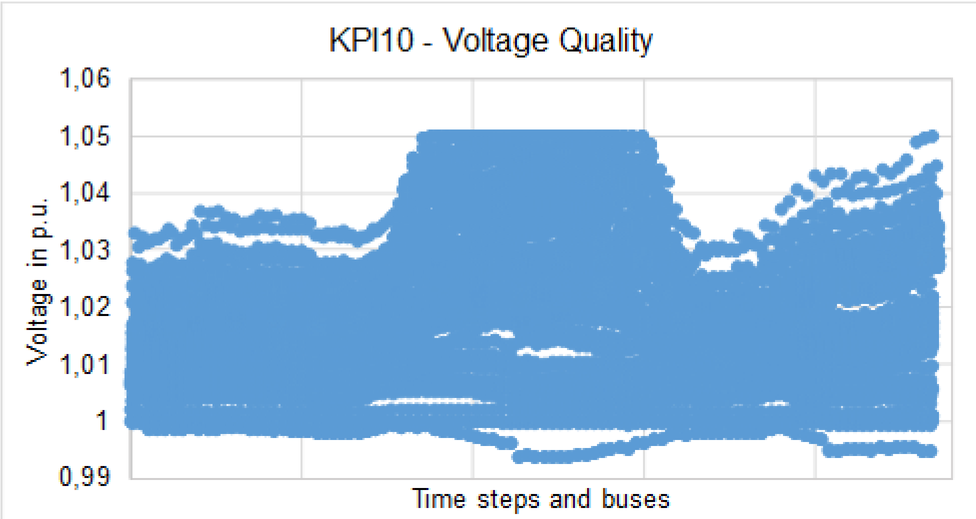
In this subsection, the results of simulating the test case of SC4 are presented. In detail, the control functions of both use cases 1 and 3 are implemented in the same order to the selected grid model, time series and scenario. The set points for the power system units are extracted from the simulation of selected time steps. UC1, which is meant to optimize the reactive power distribution among the controllable units, is applied to all 96 time steps representing a full day (15-minute steps). UC3 is applied to every 4th time step within the range of time steps 22 to 88 where it is assumed that tertiary control contribution is required from the DSO level. In the next steps, the identified KPIs are calculated and the values are analyzed or compared with the corresponding values from BSC simulation, where no control functions were applied. The KPI values, diagrams and analysis are provided below. The selected time steps in the KPI presentation depend on the relevance of the KPI for the involved use cases. In the other words, in case a specific KPI is relevant for both use cases or only UC1, the KPI is presented for the total range of 96 time steps. In case the KPI is only relevant to UC3, only time steps 22 to 88 are presented.

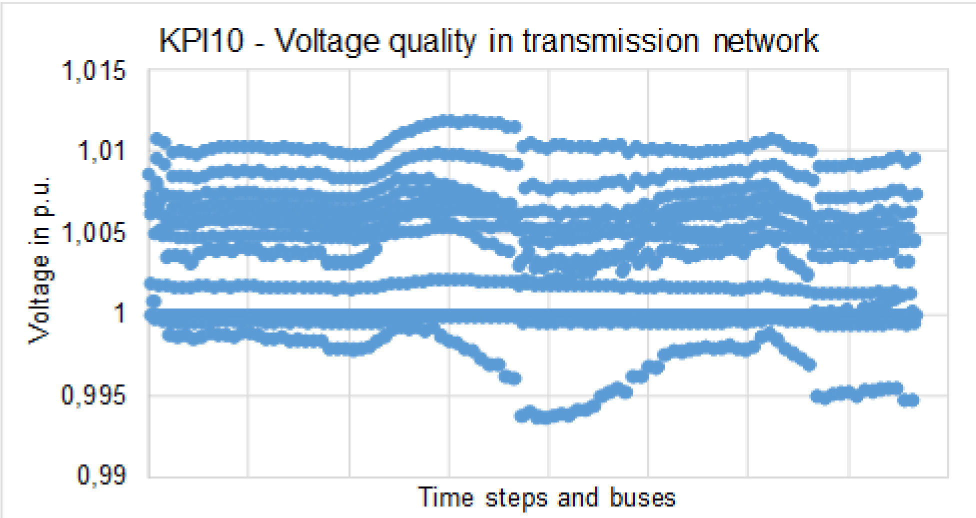
6.4.1 KPI 1 - Level of losses in transmission and distribution networks

Description	The transport of electrical energy through the distribution or transmission network is associated with a certain amount of power losses. Therefore, the amount of power being produced has to be a few percentage points higher than consumption levels. This KPI is meant to present the active power/energy losses in percentage.
Formula	$\text{Percentage of losses} = \frac{\text{Amount of injected energy} - \text{amount of energy delivered to the customers}}{\text{Amount of injected energy}} \times 100$

Numerical results	
Discussion	Based on the presented diagram, the level of losses in the full grid including transmission and distribution levels for the SC4 is within a range of 2% to 3.3%. The variation of power losses in different time steps is due to the changes in the demand and generation. Obliviously in the time steps with higher demand, the power losses in the power system units (mainly lines and transformers) are higher.
Comparison with BSC4	Comparing the values of KPI 1 between showcase and base-showcase (no control functions), it can be concluded that showcase control functions, which are meant to decrease the active power losses, are successful in most of the selected time steps and for the remaining time steps these values are equal or almost in the same range. The reason is that in those selected time steps, other control criteria like voltage control are considered as higher priority than power losses minimisation. Therefore, the control functions kept the power losses at the same level as base showcase corresponding values. Note: the values of this KPI for BSC4 are updated considering the corresponding values presented in D5.2. In the new values the contribution of external grids (slack bus bars) is excluded from the calculation, since their role is not of interest for power losses calculations.

6.4.2 KPI 10- Voltage Quality

<table>
<tr><td>Description</td><td>This KPI aims to assess if SC4 can meet the planning criterion “4. Assuring voltage stability” (see Figure 5). Therefore, with calculation of each bus voltage magnitude and comparing with the admissible values, it can be evaluated if this SC is successful to reach this goal.</td></tr>
<tr><td>Formula</td><td>According to the defined EN 50160 Standards and VDE-AR-N 4120, bus bar voltage magnitudes must comply with following allowed range of variation:
LV: ±10% of nominal voltage
MV: ±5% of nominal voltage
HV & EHV: ±4-7% of nominal voltage
The following voltage deviation indices can be defined to find the frequency or duration that the bus bar voltages violate the allowed voltage range:
• Number of voltage excursions exceeded n minutes per year.
• Percentage of time that the transmission voltage exceeds the permissible limits.</td></tr>
<tr><td>Numerical results</td><td>


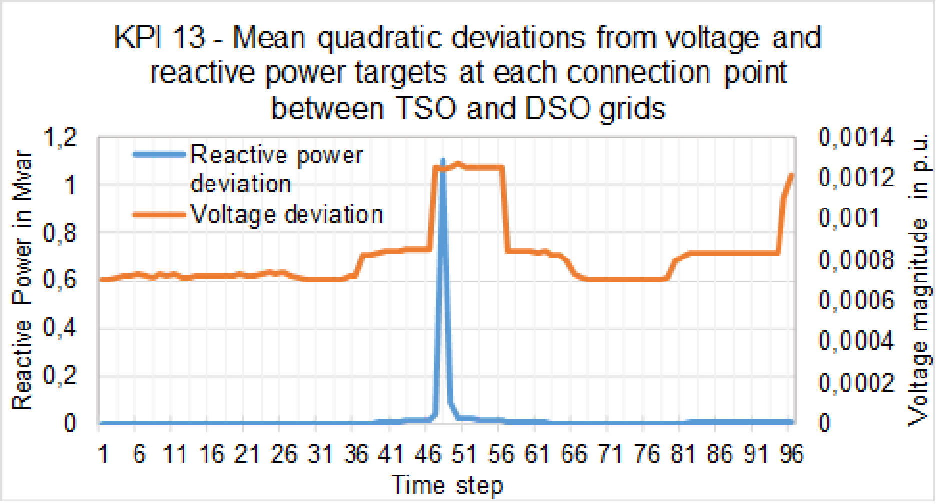


</td></tr>
</table>

Discussion	The values for voltage magnitudes in the transmission network as well as for transmission and distribution network including HV, MV and LV are presented in two separate figures. Here, the voltage magnitude values in p.u. are presented for the different buses at different time steps by blue dots. Overall there are 246 buses in the transmission as well as in the distribution network. The maximum voltage magnitude value reaches 1.05 p.u. and the minimum voltage magnitude value is still above 0.99 p.u. in the whole grid. The voltage magnitude in the transmission network is within the limits of 1.015 p.u. and 0.99 p.u. as the figure shows, so that it can be reasoned that the maximum voltage magnitude values of 1.05 p.u. occur in the distribution network. Therefore, all voltage magnitudes in the different voltage levels are kept within the predefined limits of ±10 % for LV, ±5% for MV and ±4-7% for HV & EHV
Comparison with BSC4	The comparison of the voltage magnitude values for the transmission network in BSC4 and SC4 shows that in both simulations the bus voltage magnitudes are kept within a range of roughly ±1%. Since there was no analysis for the whole network in BSC4, it is not possible to compare the results for the distribution network.

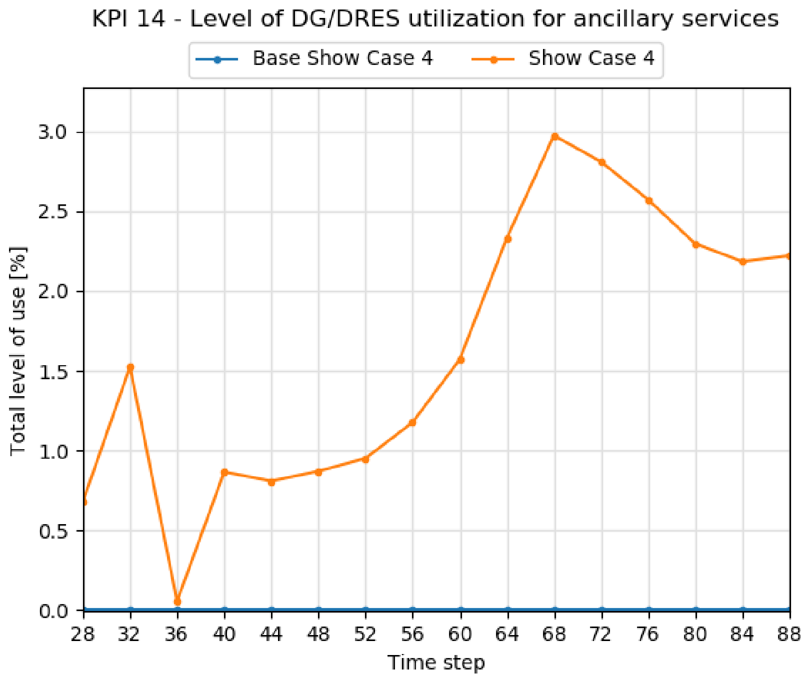
6.4.3 KPI 13- Mean quadratic deviations from voltage and reactive power targets at each connection point between TSO and DSO grids

Description	This KPI aims to assess if SC4 can meet the planning criterion “7. Optimize TSO/DSO interaction” (see Figure 5). Therefore, to reach the optimum interaction between TSO and DSO, the reactive power set point and voltage magnitude set point for TSO-DSO connection points defined by the TSO should be maintained while making the decision about the same set point by DSO. With calculation of this KPI, it can be evaluated if this SC is successful to keep the set points at the connection points within target values.
Formula	Let C be the set of connection points between TSOs and DSOs. Let $q_{c,\text{target}}(t)$ [Mvar] be the target value for reactive power transmission from DSO to TSO at connection point c and time t, as e.g. calculated by grid operation planning. Let $q_c(t)$ be the reactive power actually provided from DSO to TSO at connection point c and time t. Then the KPI related to reactive power at time t is defined as: $$\frac{1}{\lvert C \rvert}\sum_{c\in C}\left(q_{c,\text{target}}(t)-q_c(t)\right)^2$$ The KPI related to voltage is defined as follows. Let $u_{c,\text{target}}$ [p.u.] be the nominal value for the line-to-line voltage at connection point c, calculated as mean over all phases. Let $u_c(t)$ be the actual line-to-line voltage mean over all phases. Then, the KPI at time t is: $$\frac{1}{\lvert C \rvert}\sum_{c\in C}\left(u_{c,\text{target}}(t)-u_c(t)\right)^2$$

Numerical results	
Discussion	The deviation of the reactive power flow at the connection points of TSO and DSO are part of the objective function in UC1 which has to be minimized. Here, q is the reactive power flow at the connection points and u is the voltage magnitude at the high voltage side of the transformers. The target values are extracted from the optimization problem the TSO executes in the second stage of UC1. In the DSO optimization, qc and uc are calculated with the goal to keep the deviation from the target values as small as possible. The figure above shows that the deviations regarding the target values can be kept close to zero. Only for time step 48 (11:45 AM) there is a deviation for the reactive power flow of roughly 1.1 Mvar. The deviations regarding the voltage magnitudes at the TSO-DSO connection points are kept at an acceptable level with a maximum deviation of 0.0012 p.u. at time step 51 (01:00 PM).
Comparison with BSC4	In BSC4 the target values for $q_{c,\text{target}}$ and $u_{c,\text{target}}$ were assumed to be zero respectively one due to a lack of enough information. Therefore, the differences in BSC4 and SC4 results after having proper target values are significantly high. In BSC4 the minimum is around 9 Mvar whereas the deviation in SC4 is roughly 1.1 Mvar. The maximum deviation in in BSC4 is roughly 0.0135 p.u. whereas the maximum voltage deviation is around 0.0012 p.u. in SC4.

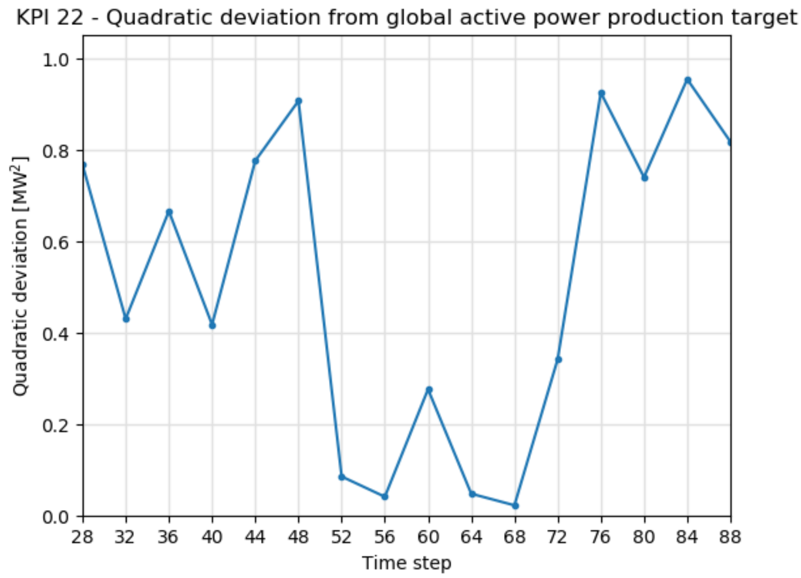
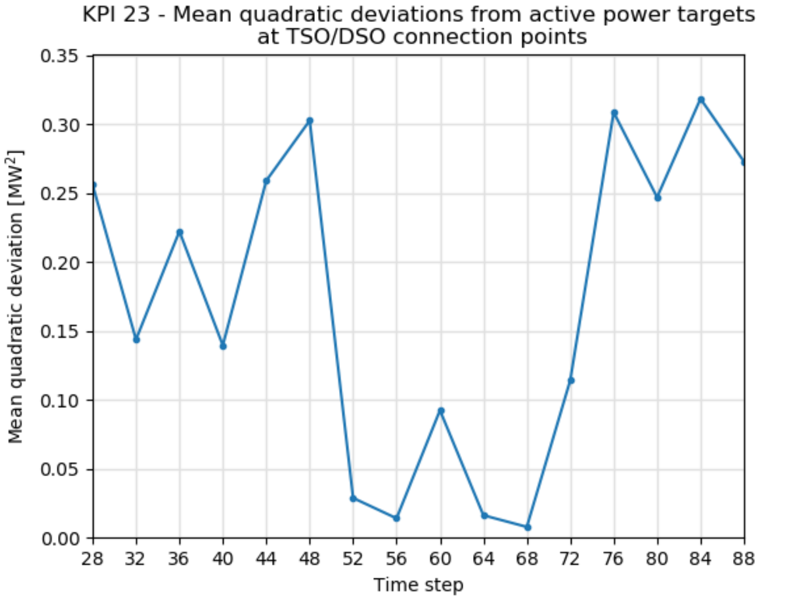
6.4.4 KPI 14 - Level of DG / DRES utilization for ancillary services

Description	The purpose of this KPI is to measure the utilization of DER for ancillary services (UAS). This is expressed as a ratio between the energy used for ancillary services and the total energy produced.
Formula	$$\text{UAS\%} = \frac{E_{\text{AS}}}{E_{\text{total}}} \times 100\ [\%]$$ E_{AS} - the energy used for ancillary services [MWh] E_{total} - the total energy produced [MWh]

Numerical results	
Discussion	This KPI in SC4 represents the total percentage of DG/DRES participation in providing tertiary control reserve to the TSO. Depending on the need for tertiary reserve provision in the selected time step (which depends on the frequency stability control requirements and current conditions of the network), DG and DRES are requested to provide additional/ less active power/ energy. Considering the diagram above, DG/DRES have participated with a total percentage of 0% to 3%.
Comparison with BSC4	Comparing the values of this KPI in SC4 with its corresponding BSC, it is obvious that SC4 control functions were successful in involving the available controllable units in providing tertiary reserve.

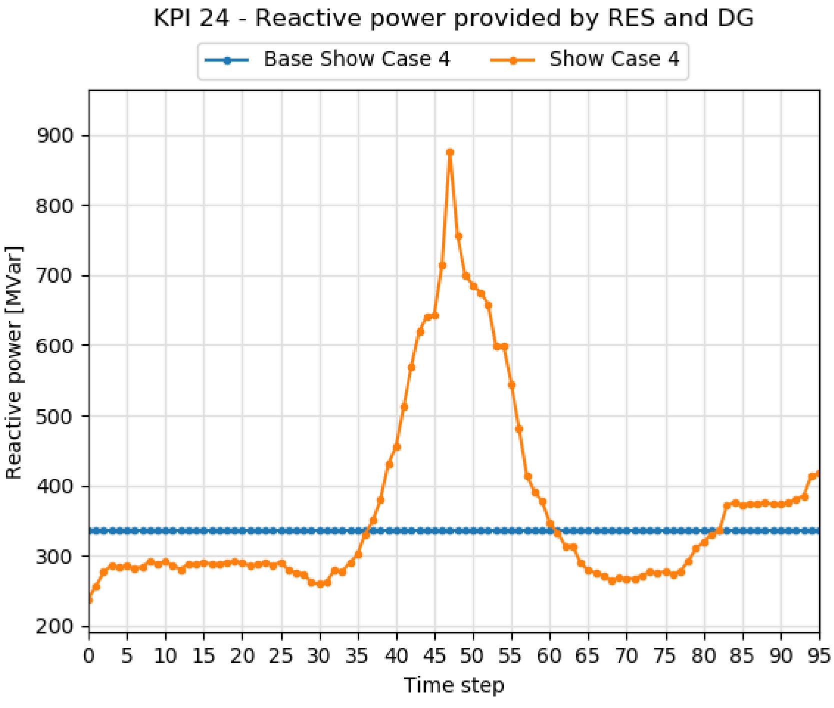
6.4.5 KPI 22 - Quadratic deviation from global active power exchange target KPI 23 - Mean quadratic deviations from active power targets at TSO/DSO connection points

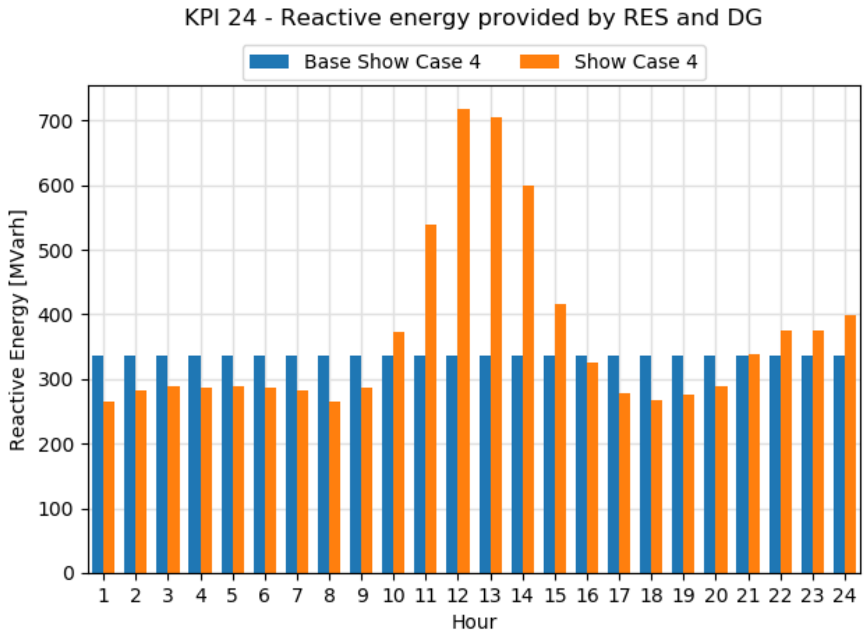
Description	KPI 22: This KPI calculates the quadratic deviation from global active power production target which is based on the needed tertiary reserve. Minimizing this KPI is an optimization objective. KPI 23: This KPI calculates the mean quadratic deviations from active power targets (based on the needed tertiary reserve for each connection point) at each connection point between TSO and DSO grids. Minimizing this KPI is an optimization objective.

Formula	KPI 22: Let p_{target} (t) be the global active power production target for tertiary reserve at time *t*. Let *G* be the set of generators producing active power, and p_g(t) be the active power generated by generator g at a given time *t*. Then, the KPI at this time is: $$\left(p_{\text{target}}(t) - \sum_{g \in G} p_g(t)\right)^2$$ KPI 23: Let C be the set of connection points between TSOs and DSOs. Let $p_{c,target}$ (t) [kW] be the target value for active power transmission from DSO to TSO at connection point *c* and time *t*, as e.g. calculated by grid operation planning. Let p_c(t) be the active power actually provided from DSO to TSO at connection point *c* and time *t*. Then the KPI related to active power at time *t* is defined as: $$\frac{1}{\lvert \mathrm{C} \rvert} \sum_{c \in \mathrm{C}} \left(p_{\text{c,target}}(t) - p_c(t)\right)^2$$
Numerical results	 

Discussion	These two KPIs present the success level of the SC optimisation algorithm. It can be seen that the KPI22 values vary between 0 MW^2 and 0.95 MW^2. The KPI 23 also indicates the mean quadratic deviation, which is in the maximum case about 0.32 MW^2. These deviations can be easily compensated by available synchronous generators at TSO level. Nevertheless, this error can be reduced by improving the optimisation algorithms.
Comparison with BSC4	These values cannot be calculated for the BSC, since no control function was applied and therefore no targeted tertiary reserve or power exchange among TSOs and DSOs is planned.

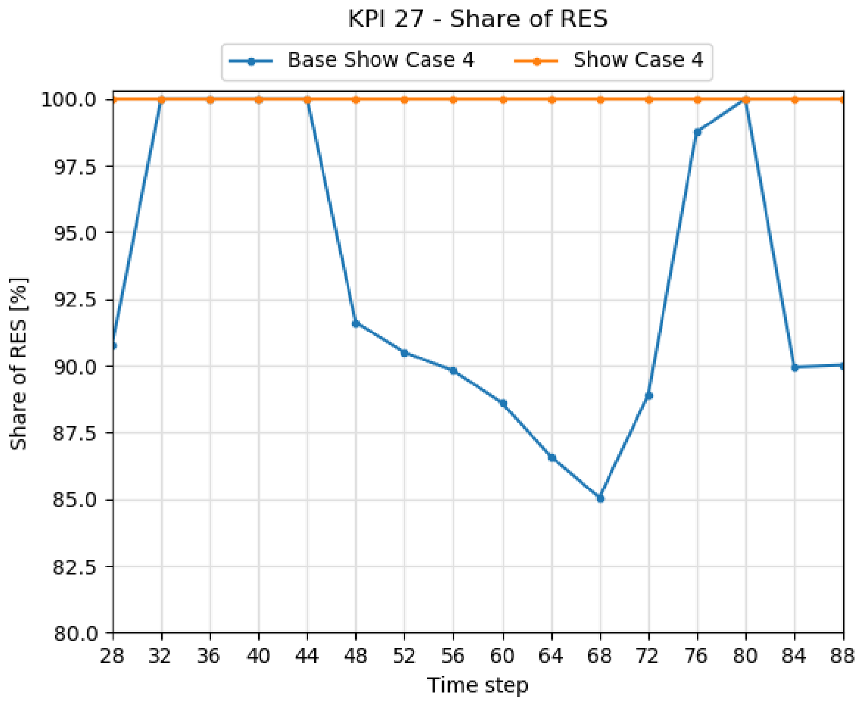
6.4.6 KPI 24 - Reactive energy provided by RES and DG

Description	This KPI aims to assess if SC4 can meet the planning criterion “4. Assuring voltage stability” (see Figure 5). Therefore, with the calculation of the reactive energy provided by RES and DG it can be evaluated if SC4 is successful to reach this goal.
Formula	Let G be the set of RES and DG generators producing reactive power, and $q_g(t)$ be the reactive power generated by generator g at a given time t. Then, the KPI during the time interval $t1..t2$ is: $\sum_{g\in G}\sum_{t=t1}^{t2}\left\|q_g(t)\right\|$ [Mvarh]
Numerical results	

	
Discussion	In the two figures above the reactive power provided by RES and DG for each time step as well as the reactive energy summed up for all 24 hours is shown. It can be seen that especially from 11:00 AM and 02:00 PM the reactive power provided by RES and DG is relatively high compared to the rest of the hours among the day. The maximum reactive energy provided by DG and RES is roughly 720 Mvarh. These amounts of provided reactive power can be derived from the first figure showing the reactive power, that also reaches its maximum at that time. The lowest amount of reactive energy provided by DG and RES is about 264 Mvarh in the first hour of the considered time steps.
Comparison with BSC4	In the figures presented above, it can be seen that in each time step the provided reactive power and energy in the showcase simulation differ from the values derived from the base showcase. As reactive power is one of the flexibilities that is used inside the optimization, the variation of these values is reasonable. These values are used to assure a coordinated voltage/reactive power control between the TSO and the DSO.

6.4.7 KPI 27 - Share of RES

Description	The purpose of this KPI is to measure the share of RES in the total generation portfolio.
Formula	$$\text{RES\%} = \frac{P_{\text{RES}}}{P_{\text{total}}} * 100\ [\%]$$ P_{RES} - Active power provided by RES at a given time step [MW] P_{total} - Total active power provided by RES and non-RES generators at a given time step [MW]

Numerical results	
Discussion	The KPI 27 values for showcase 4 show that the whole active power generation for the time steps where there is a request for tertiary reserve is related to the renewable based technologies. This is due to the selected grid scenario, “small and local”, in which the local and distributed RES based generators have the major share in total generation as well as the goal of optimisation is maximising the share of RES in generation.
Comparison with BSC4	Comparing the values of this KPI in showcase 4 with its corresponding base showcase, it can be seen that there is a significant increase in the share of RES based technologies in most of the time steps where tertiary reserve contribution is requested by the TSO (in the other presented time steps the share of RES was already 100%). Showcase 4 control functions were successful to maximise the share of RES in generation by involving them in the ancillary services.

6.4.8 Summary of SC4 on TSO-DSO coordinated active and reactive power optimization for provision of tertiary reserve and improvement of voltage profiles

SC4 is aimed at optimizing the active and reactive power distribution at both TSO and DSO levels using a coordinated method, which is implemented through control functions of use cases 1 and 3. Use cases 1 and 3 are looking at two more specific goals, which are improving the voltage profile of the grid nodes as well as provision of tertiary reserve by DG and RES at the DSO level. The coordinated optimization and control functions are meant to address the following grid planning criteria:

1. Minimizing losses
3. Maximizing share of RES
7. Optimize TSO/DSO interaction
8. Maximize DG / DRES contribution to ancillary services
9. Assuring frequency stability

In order to evaluate the developed control functions, a grid model consisting of both TSO and DSO levels, which is based on the future EU grid “INTERPLAN-2: small and local” scenario [2] was analyzed two times: Once without any control algorithms (Base showcase 4) and once with the SC4 control functions implemented. The results are evaluated and compared through defined KPIs for this showcase.

Comparing the KPI values of the SC and the BSC, it can be concluded that the showcase control functions are able to:

- reduce power losses at most of the time steps,
- optimize the distribution of reactive power at both TSO and DSO levels,
- increase the share of RES in generation and ancillary services which is in this case provision of tertiary reserve whenever it is required and possible, and
- respect the targeted exchange active power values among TSOs and DSOs within acceptable ranges.

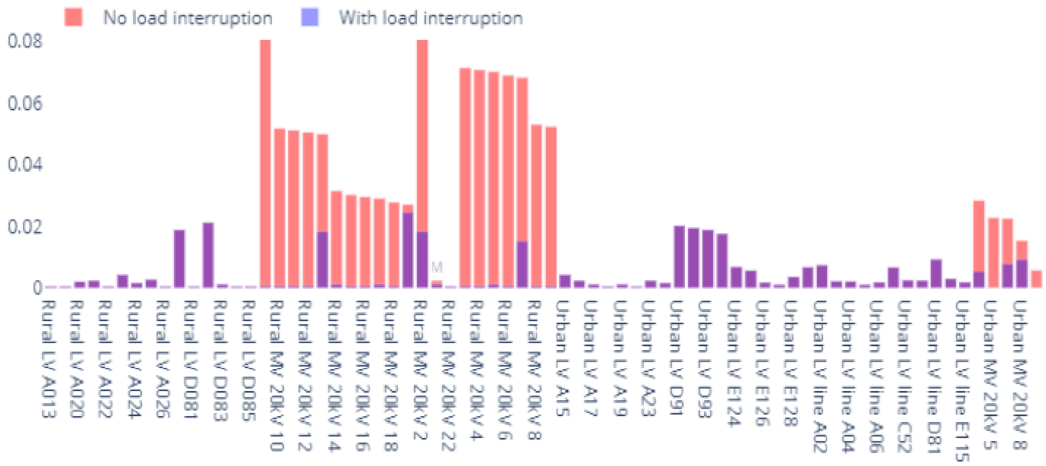
Therefore, the SC4 controllers are able to achieve the optimization goals.

6.5 SC5 results – Optimal energy interruption management

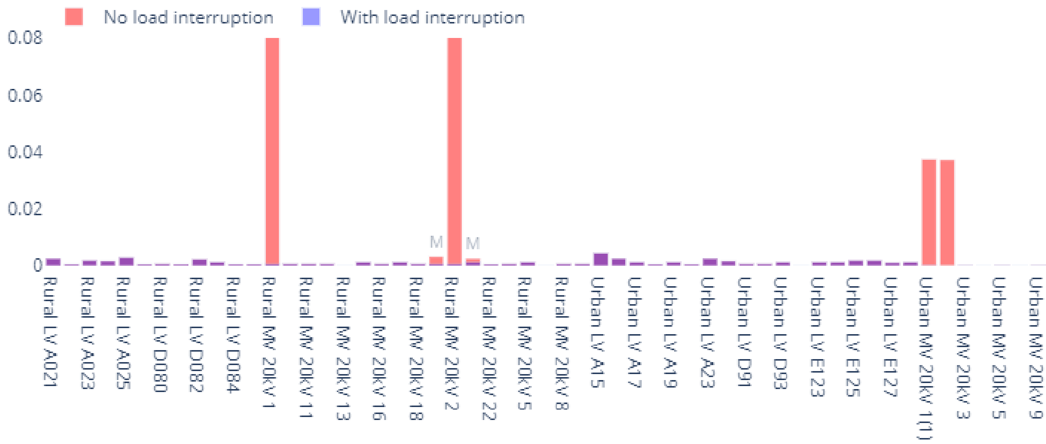
The results show reliability indices for the whole network when contingencies described on the x-axis are active. Please note that reliability indices calculated after energy interruption optimization reflect the rest of the network after load shedding activation.

6.5.1 KPI 3 - SAIDI (System Average Interruption Duration Index)

<table>
<tr><td>Description</td><td>The System Average Interruption Duration Index [h/C/a] is the total duration of interruption for the average customer during the period in the calculation.</td></tr>
<tr><td>Formula</td><td>$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{total number of customers served}}$$</td></tr>
<tr><td>Numerical results</td><td>
Radial configuration



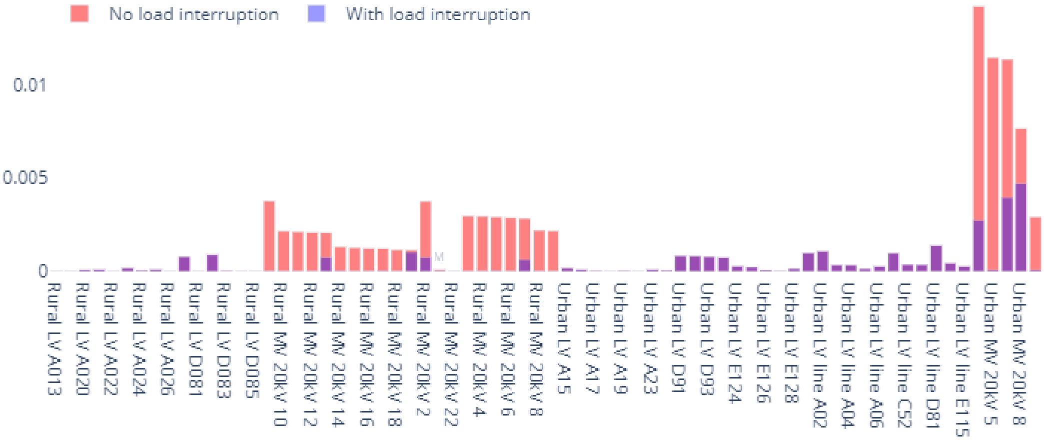
Meshed configuration



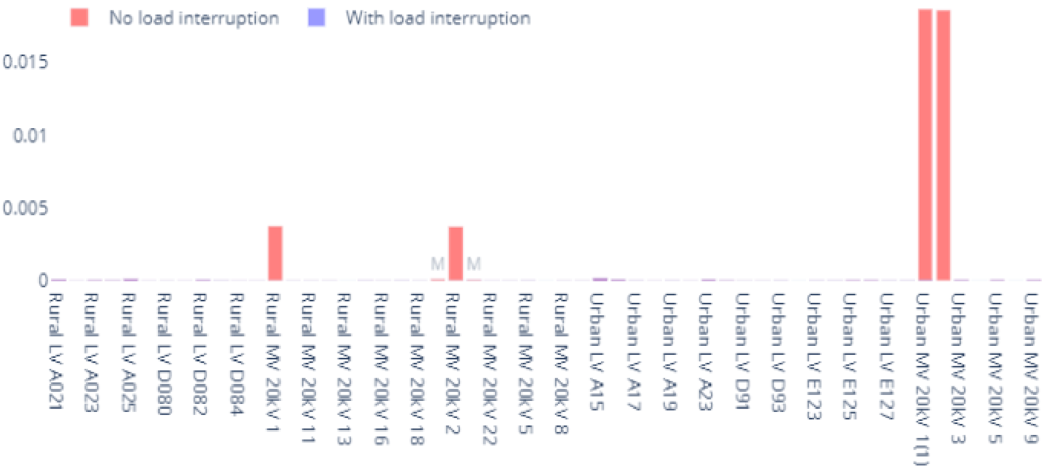
</td></tr>
<tr><td>Discussion</td><td>For both radial and meshed configurations the control actions reduce the levels of SAIDI. The lower levels of SAIDI for meshed configurations are due to alternate source of power after the contingency.</td></tr>
<tr><td>Comparison with BSC5</td><td>On average, the SAIDI value is decreased by 75% for the contingencies in which the control action influences the results.</td></tr>
</table>

6.5.2 KPI 3 - SAIFI (System Average Interruption Frequency Index)

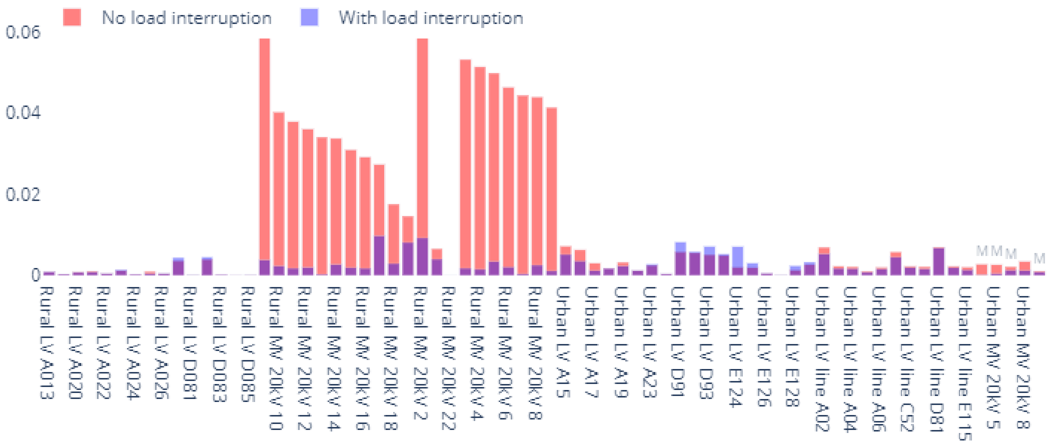
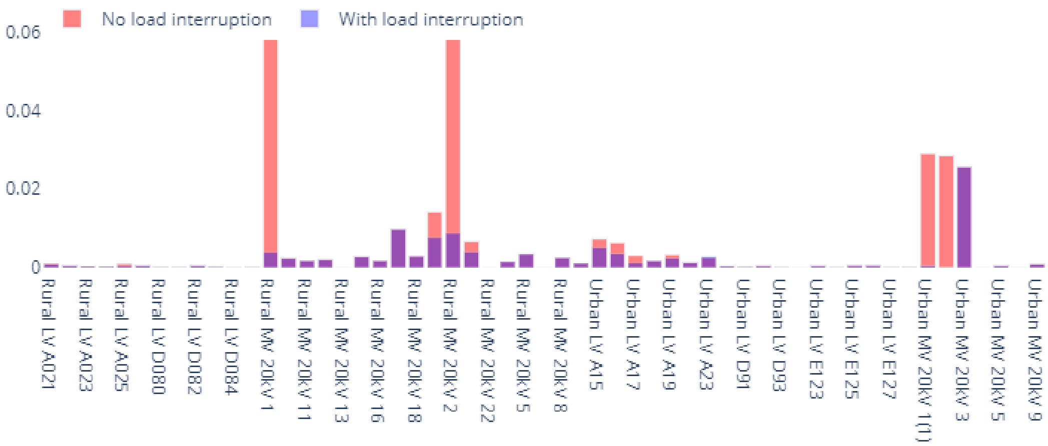
<table>
<tr><td>Description</td><td>The System Average Interruption Frequency Index [1/C/a] is how often the average customer experiences a sustained interruption during the period specified in the calculation.</td></tr>
<tr><td>Formula</td><td>$$\mathrm{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$</td></tr>
<tr><td>Numerical results</td><td>Radial configuration



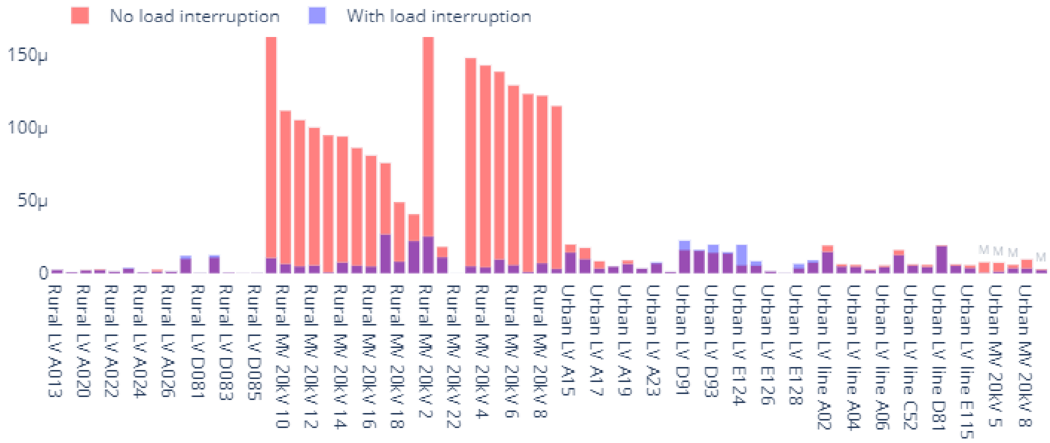
Meshed configuration

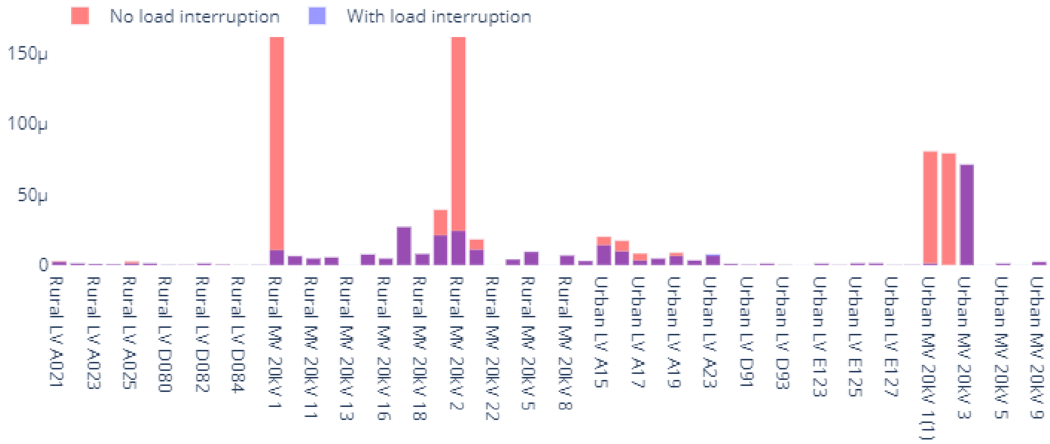

</td></tr>
<tr><td>Discussion</td><td>The control actions reduce the levels of SAIFI for the network considering individual contingencies for both meshed and radial configurations.</td></tr>
<tr><td>Comparison with BSC5</td><td>On average, the SAIFI value is decreased by 72% for the contingencies in which the control action influences the results.</td></tr>
</table>

6.5.3 8 -ENS (Energy Not Supplied)

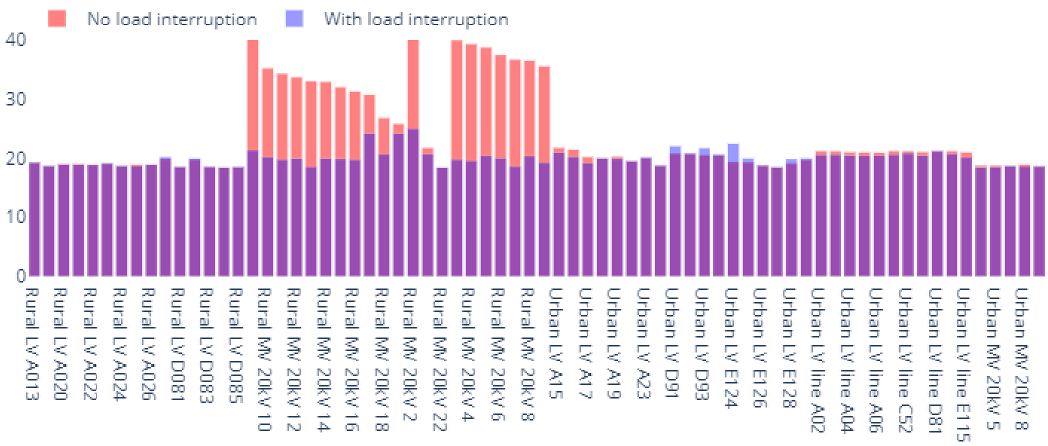
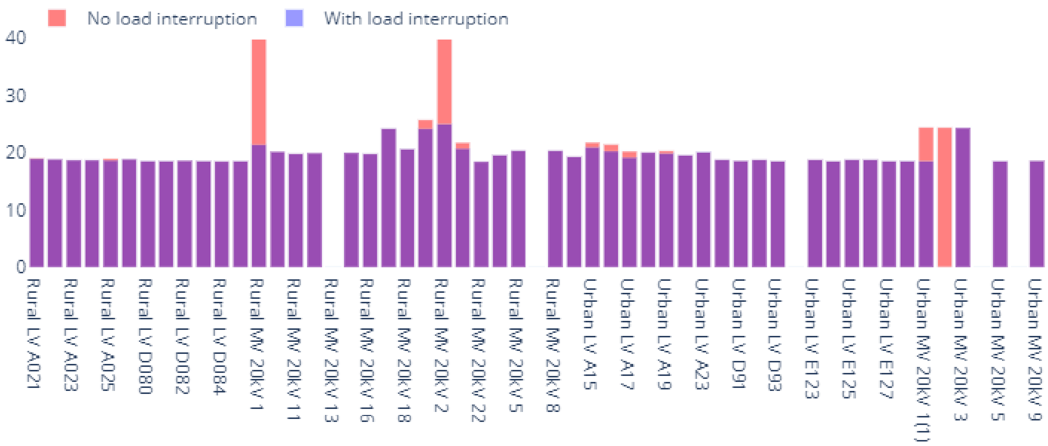
Description	Energy Not Supplied [MWh/a] is the total amount of energy on average not delivered to the system loads.
Formula	$$\text{ENS} = \sum \text{LPENS}_i$$
Numerical results	Radial configuration  Meshed configuration 
Discussion	The control actions reduce the levels of ENS for the network considering individual contingencies for most of cases. However, few cases exist in which ENS is marginally increased for radial configuration.
Comparison with BSC5	Substantial improvement in ENS as compared to BSC results.

6.5.4 8 -AENS (Energy Not Supplied)

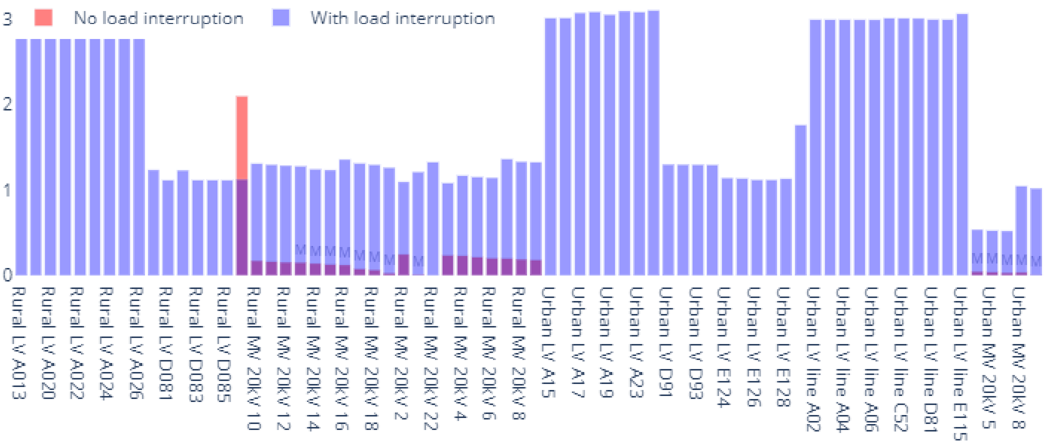
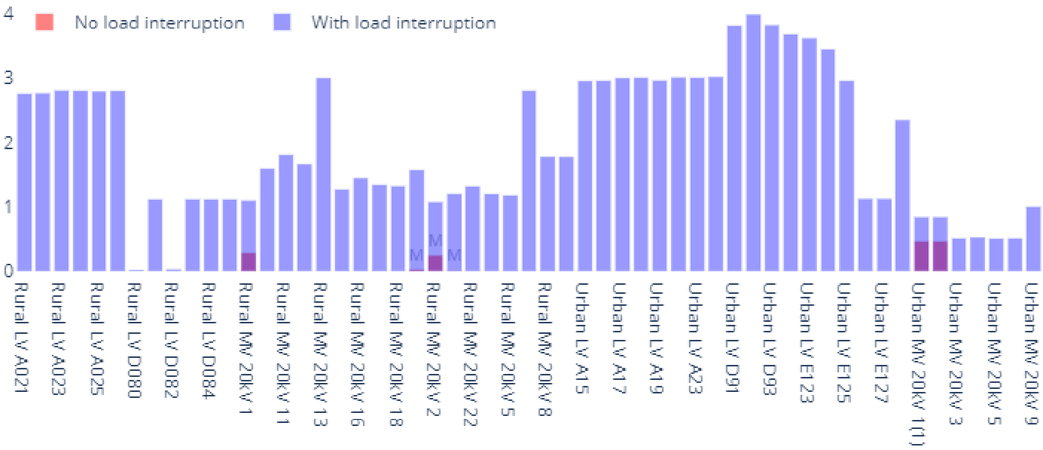
<table>
<tr><td>Description</td><td>Average Energy Not Supplied [MWh/Ca] is the average amount of energy not supplied for all customers.</td></tr>
<tr><td>Formula</td><td>$$\mathrm{AENS} = \mathrm{ENS}/\sum C_i$$
C_i - Number of customers supplied by load point i</td></tr>
<tr><td>Numerical results</td><td>Radial configuration:


Meshed configuration:

</td></tr>
<tr><td>Discussion</td><td>The control actions reduce the levels of AENS for the network considering individual contingencies for most of cases. However, in few cases AENS is marginally increased.</td></tr>
<tr><td>Comparison with BSC5</td><td>The AENS is reduced by 80% as compared to BSC results.</td></tr>
</table>

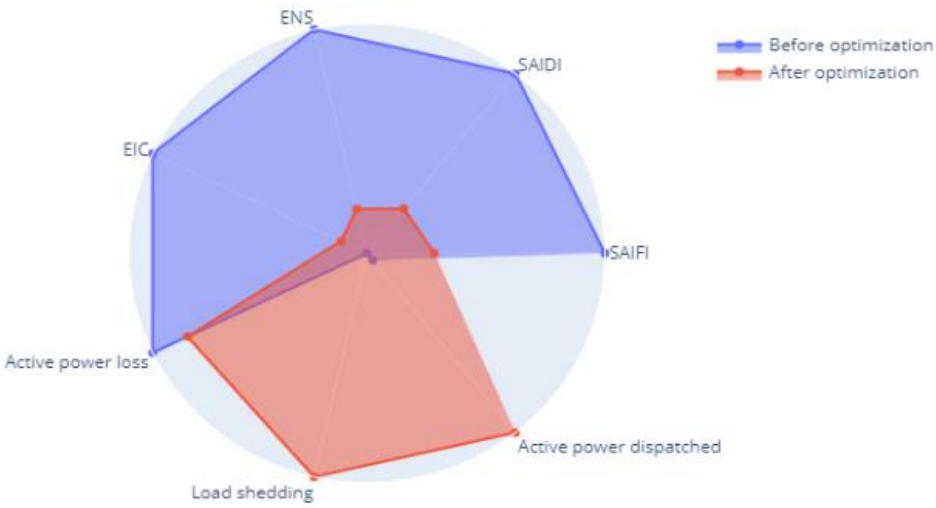
6.5.5 KPI 9 - IEAR (Interrupted Energy Assessment Rate)

Description	Interrupted Energy Assessment Rate [$/kWh] is the total expected interruption cost per not supplied kWh.
Formula	$$\mathrm{IEAr} = \frac{\mathrm{EIC}}{\mathrm{ENS}}$$ EIC - Expected Interruption Cost, in units of [M$/y], is the total expected interruption cost. ENS - Energy Not Supplied, in units of [MWh/a], is the total amount of energy on average not delivered to the system loads.
Numerical results	Radial configuration  Meshed configuration 
Discussion	The control actions reduce the levels of IEAR for some contingencies while for others the value remains the same.
Comparison with BSC5	On average IEAR is reduced for both radial and meshed configurations. However, in most instances it remains constant.

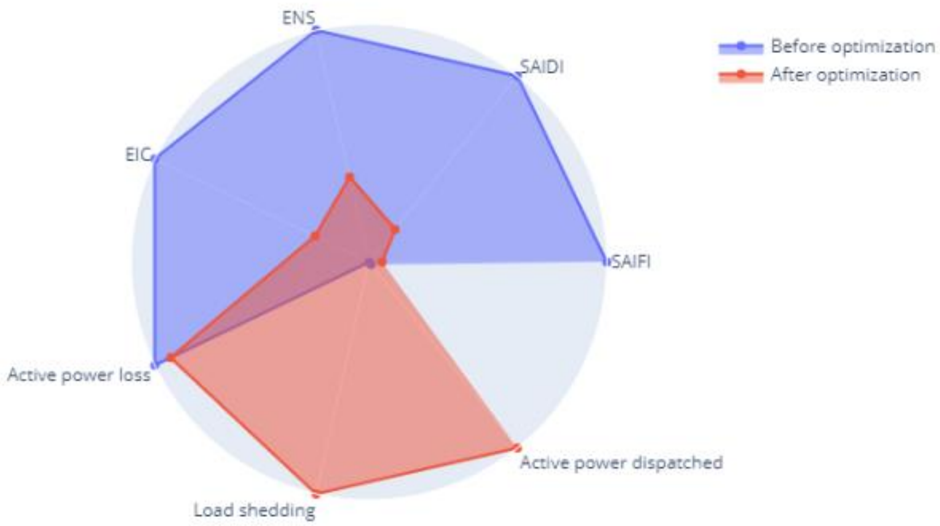
6.5.6 KPI 24 - Active power provided by DG

Description	The KPI calculates total active power dispatched (MW) from DGs for each contingency in order to fulfil the energy demand.
Formula	$P_i = P_{i-dispatch} + \Delta P_i$ [MW] P_i : *is the modified active power of generator i* $P_{i-dispatch}$: *is the initial active power dispatch of generator i* ΔP_i : *is the active power change in generator i*
Numerical results	Radial configuration  Meshed configuration 
Discussion	The contingencies in both radial and meshed configurations results in redispatch of the DGs.
Comparison with BSC5	The active power from DGs is substantially increased for most of the contingencies as compared to "no load interruption" case. This is true for the radial and meshed configurations.

6.5.7 Comparison of KPI’s – Radial

Description	Comparative analysis of multiple KPIs for each contingency before and after applying control strategy in radial configuration.
Numerical results	
Discussion	This is the comparative analysis of multiple KPIs before and after activation of control functions in radial configuration. It can be noticed that reliability indices have reported considerable improvement at the expense of the load shedding and increased dispatch of active power from DGs. The KPIs are averaged over all contingencies and normalized along each axis separately. The radial configuration sees more improvement in reliability indices in comparison with meshed configuration.

6.5.8 Comparison of KPI's – Meshed

Description	Comparative analysis of multiple KPIs for each contingency before and after applying control strategy in meshed configuration.
Numerical results	
Discussion	This is the comparative analysis of multiple KPIs before and after activation of control functions in meshed configuration. It can be noticed that reliability indices have reported considerable improvement at the expense of the load shedding and increased dispatch of active power from DGs. The KPIs are averaged over all contingencies and normalized along each axis separately.

6.5.9 Summary of SC5 on optimal energy interruption management

SC5 addresses the operational challenges arising due to contingency events in the grid that are related to voltage limits, line and transformer loading constraints. Although contingency studies are routinely performed in the power grid, post-contingency situations are diverse and will require frequent re-assessment in terms of network reliability due to high penetration of DER in the system. In addition, weather dependent events also increase volatility of the grid and require advanced network planning. In such situations, the flexibility offered by DER and interruptible loads can be used to recover the system to operational condition after the contingency. Therefore, SC5 provides a suitable platform for the grid operator to plan the flexibility in the grid. If the dispatchable DERs are available in MV grid, they can be dispatched by the algorithm. This algorithm is implemented through control functions of use cases 1 and 4. The optimization and the control functions address the following planning criteria which can be selected by the operator using INTERPLAN tool:

- 1. Minimizing losses
- 2. Minimizing the cost
- 4. Assuring voltage stability
- 8. Maximize DG / DRES contribution to ancillary services
- 10. Minimizing energy interruptions

The simulation functionalities used are load flow, sensitivity analysis, reliability calculation and optimal power flow.

The KPIs used to measure the effectiveness of the control are:

- 3. System average interruption duration index
- 7. Power losses
- 8. Average energy not supplied
- 9. Interrupted energy assessment rate
- 18. System average interruption frequency index
- 24. Active power provided by DGs
- 27. Share of RES

In order to evaluate the developed control functions, a synthetic grid model is used with number of LV grids modeled as equivalents. This is necessary, as the contingency analysis requires the consideration of large number of credible contingencies against which flexibility resources need to be planned. The simulations are based on the future EU grid “INTERPLAN-2: small and local” scenario. The results are evaluated and compared through defined KPIs for this showcase.

Comparing the KPI values of the SC and the BSC (without control functions), it can be concluded that the showcase control functions are able to:

- reduce power losses at most of the contingencies,
- reduce Average Energy Not supplied and the related costs
- reduce System Average Interruption Frequency Index,
- reduce System Average Interruption Duration Index, and
- increase the share of RES in generation

Therefore, the SC5 controllers are able to achieve the optimization goals.

7. Summary

In this deliverable D5.4, the previous actions related to control system logics and development of cluster and interface controllers have been applied to the different showcases and the included controllers presented in D5.3 [1]. A presentation, discussion and comparison of the SC results against the BSC results given by the calculated KPIs has been provided.

The different control functions have been applied to different SCs and the results have been presented by the KPIs. For some of the KPIs the comparison with the BSC was not possible, because in these BSCs the KPIs were not calculated. Nevertheless, the presented results show that the developed control functions are able to fulfill their tasks using the presented methodologies. The planning criteria presented in Figure 5 have been fulfilled by the application of the controllers and grid equivalents if needed in the different SCs.

For SC1, it was shown that in most of the cases (UC4 and UC6 working together) the developed controllers in have been able to provide satisfactory frequency support.

In SC2, the simulation results show that the issues highlighted by BSC2 simulation are effectively solved thanks to the control functions used for the SC2 simulation regarding the level of losses, mitigation of congestions, assuring voltage quality and the mean quadratic deviation for voltage magnitude and reactive power set points.

For SC3, the values of the relevant KPIs show that the system performance as characterized by predefined parameters was overall improved by the operation of controllers and the assumed optimization goals were achieved.

Regarding SC4, the controllers are able to achieve the optimization goals by comparing the KPI values of the SC and the BSC. Here it can be seen, that the power losses are reduced, the distribution of reactive power in TSO and DSO level is optimized, the share of RES in generation and ancillary services is increased and the targeted exchange active power values among TSOs and DSOs are kept within acceptable ranges.

For SC 5, multiple KPIs before and after activation of control functions in radial and meshed configuration show that reliability indices indicate considerable improvement at the expense of load shedding and increased dispatch of active power from DGs.

In addition to the SC results, a proof of concept chapter has been added showing all steps of the tool procedure for SC3 from the perspective of an identified user. The four different stages are:

- Start: Selection of planning criteria
- Stage 1: Simulation functionalities, KPIs and Future Grid scenarios
- Stage 2: Grid model selection/ preparation
- Stage 3: Simulation and Evaluation

All the stages are explained in section 5 in detail for the INTERPLAN tool from the beginning to the end.

8. References

[1] INTERPLAN, “Deliverable D5.3 Control system logics: cluster and interface controllers (first version),” (Public Report), May. 2020.

[2] INTERPLAN, “Deliverable D3.2 INTERPLAN scenarios and use cases,” (Public Report), Oct. 2018.

[3] INTERPLAN, “Deliverable D5.1 INTERPLAN showcases,” (Public Report), Dec. 2018.

[4] INTERPLAN, “Deliverable D5.2 Operation planning and semi-dynamic simulation of grid equivalents,” (Public Report), Nov. 2019.

[5] INTERPLAN, “Deliverable D4.3 Approach for generating grid equivalents for different use cases,” (Public Report), unpublished.

[6] INTERPLAN, “Deliverable D6.3 Operation real-time co-simulation,” chapter 3.2.1 "SimBench based north-eastern Germany network model", confidential report, Dec. 2019.

9. Annex

9.1 List of Figures

9.2 List of Tables

9.3 Glossary of terms and definitions

9.3.1 Definition of project general terms

Term	Definition
Use Case	The specification of a set of actions performed by a system, which yields an observable result that is, typically, of value for one or more actors or other stakeholders of the system.
Sub Use Case	Description of a specific situation a use case is applied to. A Sub Use Case is always attributed to one (main) use case, but one use-case may have multiple sub use cases which detail the main use case in at least one aspect.
Base showcase	Presentation of base use case(s) with no planning criteria and no controllers for emerging technologies, such as RES, DG, demand response or storages in the frame of chosen scenario, simulation type, test model, and time series data. The base showcase allows to analyze the operation challenges of the related use case(s) and improvements achieved through the application of planning criteria with related implementation of controllers in the associated showcase.
Showcase	Presentation of use case(s) in the frame of chosen scenario, simulation type, test model, time series data and planning criteria
Scenario	Definition of a future situation applying to a well-defined time (most often year). A scenario can be fictional or predicted from the present situation. In INTERPLAN, scenarios describe the future situation of the European electric network, typically including grid topology, generation mix, loads and diffusion of EV, RES and storages.
Dynamic Simulation	A simulation experiment which considers the time dependent behaviour of a physical system, looking at events occurring in real-time operation, with a frequency of occurrence of less than one second of real time. The simulation may run faster or slower than real time, and may, despite the fast event frequency, span a total time interval of several hours real-time.
Semi-Dynamic Simulation (also: Quasi-Dynamic Simulation)	A medium- to long-term simulation experiment based on steady-state analysis, considering the state of a physical system at discrete steps of real time through user-defined time step sizes. The real time between the steps is at least one minute.
Grid Cluster	A group of grids and parts of grids with similar characteristics
Grid Equivalent	A simplified network model, which approximately behaves like an associated complex physical network or a group of physical networks. The grid equivalent thus is a representation of the physical network(s), which is typically used for a simulation experiment.
Control function	A set point definition, which is determined based on the goals of each use case. A control function defines the set points of specific elements (e.g. OLTC, DGs, RESs) or some programs (e.g. demand response) calculated by an operation objective in the network.

Interface	A means of transmitting information between two or more controllers or actors. It usually includes a specification about which information is to be transmitted, how this information is represented by data elements, and defines a physical means for transmission of those data elements.
Cluster Controller	A controller to aggregate all control functions signals in a part of the network such as a central controller in a substation.
Interface Controller	A controller, which is intended to be the interface among different cluster controllers in big part of the network and receives information from other cluster controllers. This can facilitate the exchange of commands among the cluster controllers. For instance, the transmission operator can be seen as an interface controller for different clusters residing in several substations.
Local Controller	A controller which is associated with a single specific generator, load or grid asset and which operation does not rely on remotely received information originating from any remote source. i.e. the operation only relies on information available within the local area network of the local controller's installation site.
Co-simulation	A simulation which consists of different parts that form a coupled problem and are modelled and simulated in a distributed manner (cp. Wikipedia). The parts are called "Co-simulation subsystems" and are exchanging data during the simulation. Different models and simulation means can be used in different subsystems. The Co-simulation (in the ideal case) is carried out by running the subsystems, which were individually tested and validated beforehand, in a black-box manner. In INTERPLAN, the data exchange between subsystems is done by the OpSim platform.
Co-simulation subsystem / Co-simulation subcomponents	A part of a Co-simulation which is developed, modelled and validated individually, while at the same time able to be integrated into the Co-simulation platform. In INTERPLAN, a subsystem might represent e.g. a DSO or TSO operation centre, a controller, or even the real physical network model.
Data model	An abstract model that represents a real-world entity, and defines, organizes and standardizes the description of the data elements related with that entity. Since real-world entities are typically consisting of other entities (e.g. an electric grid consists of lines, transformers etc.), a data model typically is hierarchically structured and also allows to define interrelations between entities.
V2G and G2V	Vehicle-to-grid (V2G) describes a system in which *plug-in electric vehicles* communicate with the *power grid* to sell *demand response* services by either returning electricity to the grid or by throttling their charging rate. When an EV is being charged, it's called G2V (Grid to Vehicle).

Allocation	With reference to the grid operation planning phase, it is the process deciding, which are the most suitable resources to commit and dispatch among *n* operating resources for a specific objective and under specific constraints.
Placement and sizing	With reference to the grid planning, it is the process deciding the most proper location (bus) and the size of a resource (active power) for a specific objective and under specific constraints.
Energy Not Supplied	Energy Not Supplied is defined as the amount of energy that would have been supplied to the customer if there had been no interruption.
Energy spillage	Energy spillage is the production (from Solar and Wind) that is unable to be accommodated due to demand being lower than production.

9.3.2 Definition of actors

Term	**Definition**
TSO - Transmission System Operator	Natural or legal person responsible for operating, ensuring the maintenance of the transmission system and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity. The term 'transmission' means the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply.
DSO - Distribution System Operator	A natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity. The term "distribution" means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply.
ESCO	Electricity supply company (sometimes also: Electricity service company). General term for a company which supplies end users with electric energy. An ESCO may offer additional services, e.g. electricity generation, metering or supply with non-electric energy.
Prosumer	Active energy consumer who consumes and produces electricity. Various types of prosumers exist: residential prosumers who produce electricity at home - mainly through rooftop PV, citizen-led energy cooperatives, commercial prosumers whose main business activity is not electricity production, and public institutions.
Generator	A device which produces electricity.
Load	A device which consumes electricity.
Producer	A natural or legal person generating electricity.
Consumer	A natural or legal person consuming electricity.

Distributed Energy Resource (DER)	A source or sink of electric power that is located on the distribution system, any subsystem thereof, or behind a customer meter. DER may include distributed generation, electric storage, electric vehicles and demand response.
Aggregator	Company who grouping distinct agents in a power system (i.e. consumers, producers, prosumers, or any mix thereof) to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s).
Distributed generation (DG) unit	Any source of electric power of limited capacity, directly connected to the power system distribution network. DG can be powered by photovoltaic system, micro-turbines, combustion engines, fuel cells, wind turbines, geothermal, etc.
Flexible Loads	A load which consumption can be influenced in terms of power, time, or total energy consumed while still serving its intended purpose. The influence may be exerted by manual means (e.g. switching the load on or off at arbitrary times) or automatic means (e.g. external control signal).