evolvDSO

Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks

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Advanced Tools and Methodologies for Forecasting, Operational Scheduling and Grid Optimisation

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Executive Summary

This deliverable contains the detailed description of the tools which support the business processes described in D2.1 [1] and perform the most innovative functionalities described in the form of System Use Cases (SUC) in D2.2 [2]. Based on the functional and non-functional requirements associated to System Use Cases and on the guidelines reported in the DoW, a list of 10 tools in 4 domains has been defined.

This document covers four tools related to the Operational Planning domain (i.e. maximum 72 hours ahead), considering the short-term to real-time timeframe. For each tool both methodologies and algorithms are described, as well as functional specifications. Furthermore, a simple test case is presented in order to show the actual capabilities of the tool. The complete test cases evaluation and results are presented in D3.4**.**

Based on the DoW guidelines, also advanced forecasting tools should have been developed and presented in this document. Anyway, it was decided to put all the efforts in developing advanced scheduling/optimization tools; indeed, given the challenging roles DSOs will undertake in the future, the proposed tools are more innovative compared to advanced forecasting techniques, for which reliable solutions and tools are already available.

Three of the four tools presented in this document are focused on grid optimisation while the fourth addresses the grid management, contingency simulation and operators' training.

State Estimation for LV Networks and *Voltage Control for LV Networks*, although they are two separate tools, used together they can fully tackle the issue of LV network control and optimisation.
State Estimation Tool is an original algorithm capable to predict the state of the system by making use of historical data and a low number of real-time measurements from Smart-Meters. It is based on an artificial intelligence Autoencoders (AE) approach. The overall goal of this tool is to detect in the most accurate way the state of networks where topology is partially unknown (LV networks in most cases), using all the information available.
Voltage Control Tool addresses voltage problems that may occur in grids with high RES penetration.
It is capable to manage all the controllable grid assets in order to provide a close-to-real-time solution to cope with voltage deviations in LV grids. Its output is a set of control actions, in the form of set points, which enables a coordinated operation of all the available DERs.

The key features for which these two tools, respectively, can be considered innovative are: (a) the capability to estimate the grid state with poor topology data, (b) fast training of Autoencoders, (c) highly reliable output, for the *State Estimation Tool*; (d) the capability to manage three-phase unbalanced LV grids, (e) taking advantage of the smart meter infrastructure and (f) low-dependence from the observability of the grid (coupled with State Estimator), for the *Voltage Control Tool*.

The *Robust Short-Term Economic Optimization Tool* is an application, based on several algorithms, which fulfils completely the short-term optimization of distribution network; it is capable to detect constraints violations and solve them through the least expensive set of actions. An innovative algorithm, the Merit Order Block, has been developed for techno-economical ranking of all the available controllable resources in the grid.

The innovative features of this tool are the following: (a) multi-temporal optimization of distribution networks with high DRES penetration, (b) techno-economical ranking of levers based on an original Merit Order algorithm, (c) robust optimization functionality, single and multi-step, capable to manage inter-temporal constraints, (d) a modular framework.

The *Network Reliability Tool (Replay)* is a field-oriented application which focuses on the investigation of grid management; its main purpose is to perform a pro-active analysis of grid control actions by the means of an off-line fully operational SCADA platform. Its main goal is to analyse past events and actual real data and re-simulate them for improving grid management policies, as well as new software/hardware technical solutions testing and operators training.

There are four key features for which this application has a concrete impact on the state-of-art: (a) full replicability of SCADA system and real-time management in an off-line status, (b) capability to perform very close to reality tests without using real test grids or dedicated laboratories, (c) estimation of the impact of human operator actions/behaviour on control process, (d) capability to perform both ex-post and predictive analysis.

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1 Introduction

DSOs traditionally focused their attention on two stages: network development and real–time operation. However, the large DRES penetration, together with the evolution of the electrical network, the demand response (DR) and the network management systems, make the DSO look for advanced tools and technologies able, among others, to predict and optimally solve congestions, to provide information regarding network conditions or to increase load and generation controllability, keeping high power quality standards. In fact, a precise detection of a constraint location could help the DSO decide what levers (e.g. storage, Voltage VAr control, demand response, tariff modularity, grid reconfiguration, etc.) should be used and avoided. The development of such tools, together with the resolution of technical and regulatory constraints is ongoing and some DSOs begin to test new smart solutions.
This deliverable focuses on the tools developed to be applied over short term periods (i.e. at most 72 hours ahead). In this timeframe, the main goal is to have accurate network state estimations and perform network optimizations to face the variable behaviour of DRES and loads.
Given that the evolvDSO Consortium decided to focus on the development of tools mainly for network management purposes, forecast algorithms have not been developed.
The definition of which tool to develop was based on the Use Cases (UCs) WP2 activities. In the operational planning domain, four System Use Cases (SUCs) are included in the Business Use Case”Optimise network operations until market gate closure based on a schedule (in operational planning)”, see Table 1.

Domain	Business Use Case	System Use Cases	Tool	Responsible Partner
Operational Planning	Optimise network operations until market gate closure based on a schedule (in operational planning)	Solve network constraints using optimisation levers based on a merit order	State Estimation for LV Networks	INESC TEC
			Voltage Control for LV Network	INESC TEC
		Identify and solve network constraints for a given zone and an optimization application period in operational planning	Robust Short-Term Economic Optimization Tool for Operational Planning	INPG, RSE and VITO
		Simulate contingency analysis in operational planning (asset unavailability analysis)	Network Reliability	ENEL

Table 1 – Relationship among Use Cases and tools in the operational planning domain

1.1 Innovative Contributions

State Estimation for LV Networks

In the ambit of distribution state estimation, several techniques have been proposed for appropriately characterising distribution systems [3]. Most of these techniques are able to deal with the very particular characteristics of distribution systems (e.g. extremely large number of nodes and branches, unbalanced loads, large number of dispersed generation). A few are even suited to be used in smart distribution grids. But no existing techniques can be applied to networks where the topology and parameters are partially or completely unknown, which can be the case in some Low Voltage (LV) distribution systems.

This report presents an original algorithm developed by INESC TEC (formerly INESC Porto) that is able to accurately predict the state of the system by making use of historical data and a relative low number of measurements recorded in real-time. The referred data may be composed of several distinct electrical quantities and may be acquired by several telemetry equipment dispersed among the grid, such as Remote Terminal Units (RTU), Phasor Measurement Units (PMU), Intelligent Electronic Devices (IED) and Smart Meters (SM). Therefore, it is assumed that the proposed Distribution State Estimator (DSE) is capable of dealing with the following two main aspects:

- **i)** networks where their topology and technical parameters are partially or completely unknown;
- **ii)** full exploitation of all the sensorial information available, i.e. both real-time and historical data.

In the state estimation area, Artificial Neural Networks (ANN) have often been oriented to perform other functions associated with a DSE such as topological analysis, observability analysis, bad data detection, etc. Obtaining a state estimation solution and evaluating its quality is thus usually not its main goal. For instance, in [6], the authors use ANN to recompose missing information in SCADA systems, while the identification of topology errors is proposed in [7]. An example of generation of pseudo-measurements by the exploitation of ANN capabilities can be found [8]. In [9], an ANN-based hybrid state estimator is proposed for determining the state of the system in the presence of conventional asynchronous as well as synchronous PMU measurements. Therefore, the referred studies have not been developed taking into account both requirements specified in **i)** and **ii)**.
“Pure” state estimation algorithms addressing these two requirements were only covered by two recent works in the literature [10] and [11]. In [10] the authors tackle both issues **i)** and **ii)** through the use of Autoencoders (AE), which have been trained with a resilient back-propagation algorithm and then apply a meta-heuristic procedure for finding system state variables. A similar methodology was used in [11] but applied to the problem of three-phase state estimation in unbalanced distribution grids, both in MV and LV networks.
Moreover, in contrast to the DSE tool proposed in [10] and [11], the proposed state estimation tool uses a completely different concept for training AE – the concept of Extreme Learning Machine Autoencoder (ELM-AE). Basically, it consists of the application of ELM techniques [12] to properly train an AE which is used as the “brain” of the proposed DSE tool. The

advantages of this concept were already proved in several areas with very promising results, but have never been tested in the state estimation area [13]. From the point of view of the evolvDSO project, the expectations are the development of an approach that tackles the same issues as the one presented in [10] and [11], but making use of ELM techniques to enhance estimation accuracy as well as to reduce the training and running times of the DSE.

Voltage Control for LV Networks

It is the task of the Distribution System Operator (DSO) to guarantee the quality of supply to all customers, in terms of adequate voltage levels, i.e. ensuring that voltage values are within certain pre-specified limits [14]. However, with the widespread proliferation of Distributed Generation (DG) the status quo has changed considerably, since distribution grids have now become active networks with multiple power injections and bidirectional energy flows. In addition, the variability of some DG units based on Renewable Energy Sources (RES), namely solar photovoltaic (PV) generation and wind power, has also a significant impact on distribution network operation. One of the most relevant effects of this is the so-called voltage rise effect [15]. In this context, traditional voltage regulation methods are not adequate.

The voltage rise effect is especially relevant in Low Voltage (LV) distribution grids given the low X/R ratio of the power lines used and the lack of simultaneity between load consumption and RES-based generation (namely solar PV). In some cases, high voltage profiles in LV distribution grids with significant integration of energy from RES may lead to overvoltage tripping of microgeneration units, which limits the possibility of increasing the amount of DG that can be safely integrated in distribution grids. Therefore, it is necessary to develop efficient voltage control schemes in order to overcome these problems, particularly for LV grids.

In order to increase the maximum allowable connection capacity of DG, new strategies that are able to mitigate the voltage rise effect must be used [16]. Essentially, two distinct approaches can be found in the scientific literature: local distributed voltage control and centralized voltage control (active network management) [17], [18].

In this deliverable, an innovative strategy for Voltage Control for LV Networks is proposed by INESC TEC. It takes advantage of the smart grid infrastructure and enables a coordinated operation of the available Distributed Energy Resources (DER) in order to solve voltage problems that may occur, particularly in some extreme situations with high RES integration. The proposed methodology provides a close to real time solution in order to mitigate voltage deviations in LV grids based on a set of rules that is able to manage all the controllable grid assets according to a merit order. The main features of this approach are the possibility of addressing three-phase unbalanced grid operation and the fact that it is not totally dependent on the observability of the LV grid.

Robust Short-Term Economic Optimization Tool

A significant integration of Distributed Renewable Energy Sources (DRES) in the near future may cause severe congestions on distribution networks, most of which have not been designed and constructed with such operating conditions in mind. Several studies have been conducted to determine the maximum amount of DRES different network types can handle. Indeed, the hosting capacity, as it is called, varies greatly from one network to another. It depends on various factors like the architecture of the network and the location of DRES among others. However, over this limit, networks will cease to operate under good conditions, and will create problems with voltages and line over currents.

In order to overcome these problems, several levers – (load and generation flexibilities, grid reconfiguration…) can be exploited in a short-term timescale. This exploitation should be performed through a combined technical and economic optimization to be of value to DSO. Details on these levers can be found subsequently within this document. Most of the current research focuses on "snapshot" based optimization of distribution networks [19]. This means that the network is optimized with DRES and loads for one condition only, not for varying conditions throughout a given time period. While some techniques consider multi-temporal optimization [20] and [21], they either do not consider all the available levers in the network, or do not consider the economics of utilization of these levers. Furthermore, the fact that DRES is intermittent and not dispatchable is considered only in a very few studies [22] and [23].

The Robust Short-Term Economic Optimization Tool for Operational Planning aims to overcome the shortcomings of current research through a multi-temporal optimization of distribution networks with high (and non dispatchable DRES) while considering the technical and economic aspects of the use of flexibility levers and network operation.

Network Reliability Tool – Replay

Today many DSOs manage training of network operators by a direct on-the-job training of the operator, or by the use of network simulator systems. The network simulators are generally an off-line tool where it is possible to simulate particular network conditions but they do not represent the current real-time network condition. Another point is related to the need, to directly test on the field very complex applications related to the network management, because of the impossibility to a have a perfect copy of reality in a lab environment.

Particularly, in Enel different kind of tools that can be used as a simulator are available and an analysis tool based on a commercial platform is also available (*DMS_SchneiderSchenider Electric System*).
In the Enel Laboratory test a specific machine able to reproduce the behaviour of a real MV network connecting to it is also available. This machine is connected to real components in order to analyze the network behaviour changing by the interaction with this components (*RTDS*).

In a context where the DSO passive model is changing to an active one, this new approach introduces a higher complexity in the communication systems as well as in the electric system. The related introduction of new tools and software requires DSOs to perform training in conditions as close as possible to the real network, but it can't be done on the real network to avoid compromising network availability.

The provision of a testing platform of the electric grid represents the benchmark for SCADA system technologies. , A perfect representation of the reality is difficult in test environments. At the same time, no real network in operation could generally be used to test innovative tools for safety reasons.
Some DSOs, as in Enel's case, have full-scale laboratories where it is possible to test the network behaviour by using real network components. These laboratories are used to test innovative tools on specific simulated network. The existing simulators verify the behaviour of a specific component on the network without the need to install in the field the component. The limit of such simulations is related to the possibility of considering real network sections, real network components in the field and a sequence of historic events having occurred on the field.

All these aspects are related to machines and systems, but aspects related to human behaviour must also be analysed and always improved. In particular, some DSOs already have platforms to train control room operators in the network management activities by the use of specific simulators. Generally the existing simulators do not offer the possibility to manage the real-time network with real occurred events and do not give the possibility to analyse the operator performances. The capability to analyse past events (such as criticalities, faults, etc.) and to make predictive analysis are the innovative aspects for the Replay tool. The need for a more complex network management approach, the increase in the requested levels of quality of service, as well as the new efficiency for the activities of the DSO Control room, motivate this new kind of network analysis.

On the basis of the current tools limitations, by reproducing field conditions as well as specific system behaviours, the Replay gives operators, a parallel off-line SCADA system able to simulate the real-time operating network. In this way Replay can be used as a tool for network analysis and an integrated platform to be used for testing new software and applications, . The real-time SCADA integration represents the innovative aspect of this tool with respect to current simulators and laboratory tests

1.2 Structure of the Document

In this deliverable the main characteristics, functional specifications and limits of the tools reported in Table 1 are highlighted. For each tool, the following aspects are described:

- methodology (i.e. the mathematical formulation of the tool);
- functional specifications (i.e. input, output, block diagram, interaction with other methodologies/tools developed within the Project);
- an illustrative example (i.e. description of the tool application on a small test case to highlight the way the algorithm works).

This deliverable is organized as follows: the algorithms developed by INESC for the state estimation and voltage regulation in LV network are described in Chapters 2 and 3, respectively. Chapter 4 analyses the techno-economic optimization tool developed in cooperation by INPG, RSE and VITO. Finally, in Chapter 0, the tool developed by ENEL for network reliability analyses and focused on contingency analysis simulations is presented. Conclusions, application limits and future developments of the tools are collected in Chapter 6.

1.3 Notations, abbreviations and acronyms

AC	Alternate Current
AE	Autoencoder
ANN	Artificial Neural Network
BUC	Business Use Case
CHP	Combined Heat and Power
CIM	Common Information Model
CP	Constraint Programming
CRI	Criticalities Reduction Index
CSV	Comma Separated Value
DB	Data Base
DER	Distributed Energy Resource
DFA	Deterministic Finite Automation
DG	Distributed Generation
DRES	Distributed Renewable Energy Sources
DMS	Distribution Management System
DSE	Distribution State Estimator
DSM	Demand Side Management
DSO	Distributed System Operator
DTC	Distribution Transformer Controller
EEGI	European Electricity Grid Initiative
EEI	Error Estimation Index
ELM-AE	Extreme Learning Machine Auto-Encoder
EMS	Energy Management System
EPSO	Evolutionary Particle Swarm Optimisation
GPRS	General Packet Radio Service
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institution of Electrical and Electronic Engineers
JSON	JavaScript Object Notation
KPI	Key Performance Indicator

LV	Low Voltage
LVC	Low Voltage Control
LNS	Large Neighbourhood Search
MAE	Mean Absolute Error
MAGO	Monitoring and control of Active distribution Grid Operation
MDP	Markov Decision Process
MV	Medium Voltage
NP	Non-deterministic Polynomial-time
OLTC	On-Load Tap Changer
OP	Operational Planning
OPF	Optimal Power Flow
POCS	Projection Onto Convex Sets
PCA	Principal Component Analysis
PMU	Phasor Measurement Unit
PV	PhotoVoltaic
RES	Renewable Energy Source
RETIM	REal Time Interruption Monitoring
RI	Research Institutions
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control And Data Acquisition
SM	Smart Meter
SPRI	SAIDI Potential Reduction Index
SoC	State of Charge
STATCOM	STATic synchronous COMpensator
SUC	System Use Case
SVC	Static VAr Compensator
TAS	Time daily Activity Saved
TCS	Training Cost Saving
TTS	Training Time Saved
TSO	Transmission System Operator
TVR	Transistor Voltage Regulator
UC	Use Case
WP	Work Package

2 State Estimation for LV Networks

The increasing connection of new loads and generation units, as well as the integration of storage devices and electric vehicles into LV networks, will contribute to increase significantly their complexity, resulting in additional challenges to Distribution System Operators (DSO), especially regarding the operational, security and reliability aspects. Thus, DSOs will need more and more reliable information about their networks in order to take the best decisions to operate them in a secure and economic way. In this context, an advanced metering and communication infrastructure, capable of gathering and transmitting data in real-time all over the network, would be expected. However, since monitoring all grid points in real-time will be economically infeasible, a Distribution State Estimator (DSE) module will remain a crucial function in future Distribution Management Systems (DMS).

A DSE provides to the DSO a complete and reliable view of their networks in real-time ([24] and [25]) and, at the same time, its solution can be used as an input for other power system related modules (e.g., analysis modules, control modules, etc.). Unlike transmission networks, the application of conventional state estimation techniques to distribution grids, namely at LV level, is not suitable since the complete knowledge of the networks' technical parameters and topology are less reliable or even unknown. This issue becomes more relevant considering the high number of nodes and branches of distribution grids and its low automation level, resulting in a large number of new real-time measurements required to guarantee system observability.

In the view of the above, a DSE capable of dealing with the partial or complete absence of knowledge of the networks' parameters and topology, as well as taking advantage of advanced metering infrastructure, is essential. In this sense, a DSE algorithm based on artificial intelligence concepts developed by INESC TEC is presented.

2.1 Relation with System Use Case

Figure 1 depicts the main steps of the SUC "Solve network constraints using optimization levers based on a merit order". For this tool, and for the LV control tool described in section 3, the SUC is applied to the LV network. The first step consists in gathering all data from the DMS/SCADA database regarding the LV network, including measurements from a subset of smart meters with real-time communication and available flexibility in the LV network (e.g., non-firm connection contracts, demand response, storage).

In the second step, the state estimation tool for the LV network is used for identifying network constraints (e.g. overvoltages, overcurrents, etc.) when the system is not fully observable i.e. in a scenario where only a set of smart meters have real-time measurements of active power and voltage. This is the case for several LV networks and this state estimation tool can be used in conjunction with the voltage control tool described in section 3 (and step 3). The LV control tool aims at identifying and sending set-points to the levers located in this voltage level.

Finally, control set-points are sent to the different resources located in the LV network and stored in the DMS/SCADA database.

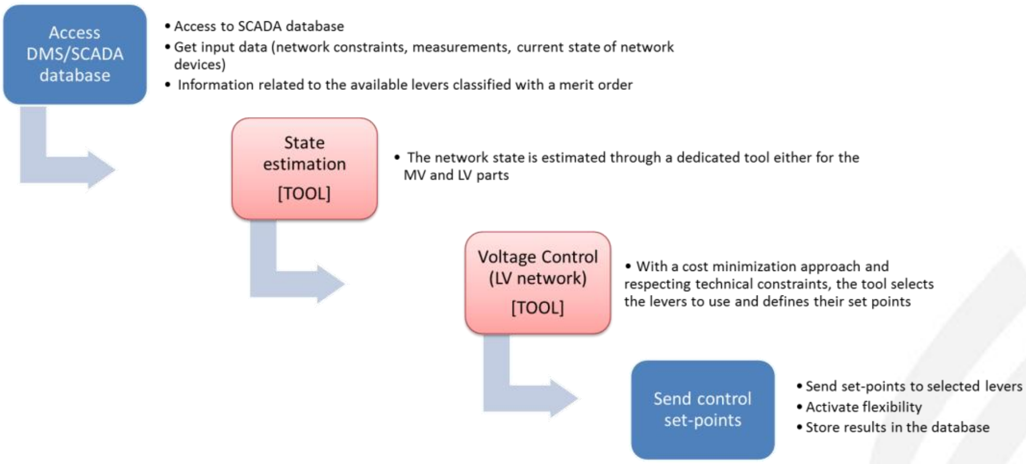


Figure 1 – Relation between system use case steps and the LV state estimation tool.

The LV state estimation and voltage control tools are the two core functions when this SUC is applied to the LV network. The state estimation tool can be used for two purposes: (a) assisting the LV control when the network is not fully observable (i.e., a power flow calculation cannot be performed) by detecting violation of voltage limits in nodes without real-time voltage measurements; (b) correcting erroneous data collected from smart meters. The match between WP2 non-functional requirements and LV state estimation tool is presented in ANNEX V – Match between Tools and WP2 Requirements.

2.2 Methodology and Algorithms Description

The DSE proposed for LV networks is a real-time function designed to provide a voltage solution in terms of voltage magnitudes (state variables). In addition to that, system state variables as well as variable, active and/or reactive power injections at customers' premise may be estimated, if desired. As mentioned before, it is based on the use of artificial intelligence and relies on a specific type of artificial neural networks – the Autoencoders (AE). Moreover, the present work exploits the concept of Extreme Learning Machine Autoencoder (ELM-AE), which applies ELM techniques [12] to properly train an AE. The trained AE can be seen as the "brain" of the presented DSE algorithm and its solution can be used as an input for other power system related modules (e.g., analysis modules, control modules, etc.).

The estimation of voltage phase angles is not performed due to the fact that the capability to measure such variables is not expected from the majority of metering devices foreseen to be deployed in LV grids. It is thus not possible to create a historical database containing such variables and, consequently, the proposed DSE will not be capable of estimating it. Furthermore, taking only voltage magnitudes into account may be enough for the functionalities expected to be used at this voltage level.

The major benefit of the proposed DSE algorithm, when compared to the traditional state estimation techniques (e.g., Weighted Least Squares algorithm), relies on the fact that information about some network parameters (branch technical characteristics namely) and topology are not required to achieve a state estimation solution.

Another difference between the proposed DSE and the traditional state estimation algorithms is related to the guarantee of observability. While for the traditional techniques, a given area/network can become unobservable (e.g. if measurements do not exist in two connected buses and their adjacent branches), the same does not happen for the proposed DSE. As it does not involve any mathematical equations related to power flow, the concept of observability can be defined in a much wider manner. Independently of the system under analysis, the minimum requirements for running the proposed DSE and providing the correspondent solution are, at least, historical data for a period of a few days regarding the variables to be estimated and one measurement being transmitted in real-time. Naturally, although the DSE can run, its accuracy may be compromised when a reduced number of telemetry data is considered – higher redundancy on the set of real-time measurements and a larger historical data set available will increase the state estimation accuracy. Thus, the existence of observability problems related with the execution of the proposed DSE algorithm is not expected.

It is also important to state that when a measurement that was previously available in real-time becomes no longer available following some event that may have occurred, the proposed DSE algorithm overcomes this limitation by turning this measurement into variables that will be estimated (to the detriment of results accuracy).
In general, the methodology presented in this work comprises of three main processes:

1. Building a synchronised historical data set;
2. Training the AE (ELM-AE);
3. Building the DSE model.

These processes are described in detail in the following sections.

2.2.1 The Autoencoder Concept

Auto-associative neural networks or Autoencoders (AE) are feed-forward neural networks that are built to mirror the input space *S* in their output. Obviously, this implies that the size of its output layer is always the same as the size of its input layer – this is the main difference between an AE and a traditional neural network. The typical architecture of an AE is a simple neural network with a smaller single hidden layer – Figure 2. This simple architecture is frequently adopted because networks with more hidden layers have proved to be difficult to train [26], although they might provide better accuracy.

There is no *a priori* indication of an adequate hidden layer reduction rate (measured as the ratio between the number of neurons in the smallest hidden layer and the number of neurons in the input/output layer) to be adopted. The decision on the reduction rate is dictated in present-day practice by trial and error and by the characteristics of the problem.

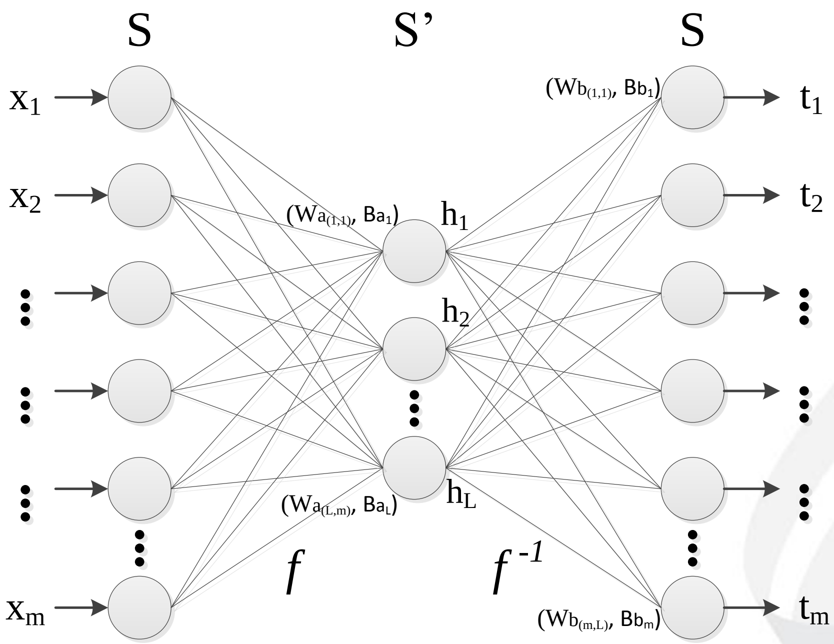


Figure 2 – Architecture of an Autoencoder with a single hidden layer

With adequate training, an AE learns the data set pattern and stores in its weights information about the training data manifold. The training process of an AE is conducted to display an output equal to its input. This is achieved by projecting the input data onto a different space *S'* (in the hidden layer) and then by re-projecting it back to the original space *S*.

In other words, the first half of the AE approximates the function f that encodes the input space S to the space compressed S'. For an input space composed by an m-dimensional input vector x_i (i = 1, 2, ..., m), the output values of the hidden neurons form a L-vector given by:

$$h_p = f_a\left(W_{a_{(L,m)}} x_i + B_{a_L}\right), i = 1, 2, ..., m \text{ and } p = 1, ..., L \tag{1}$$

where W_a is the input-to-hidden $L \times m$ weight matrix and B_a is the hidden neurons L-vector of biases. f_a represents the hidden neurons activation function.

Then, the second half approximates the inverse function f^{-1} that projects back the set of values in the space S' to the original space S. This mapping happens through a similar transformation and the output values form again an m-vector given by:

$$y_i = f_b\left(W_{b_{(m,L)}} h_p + B_{b_m}\right), i = 1, 2, ..., m \text{ and } p = 1, ..., L \tag{2}$$

where W_b is the hidden-to-output $m \times L$ weight matrix and B_b is the output neurons m-vector of biases. f_b represents the output neurons activation function. For a historical database with N training samples, the optimal weight matrices W_a, W_b and bias vectors B_a, B_b can be found by minimising the error between inputs and outputs during the training procedure.

More details about mathematical formulation can be found in [27].

Once the AE is trained, if an incomplete pattern is presented, the missing components may be replaced by random values producing in general a significant mismatch between input and output. Typically three different approaches can be followed in order to find the missing values on the way to minimise that error (convergence is reached). The approach called Projection Onto Convex Sets (POCS) [28] consists, basically, in iteratively reintroducing the output value in the input so that it will converge to a value that minimises the input-output error (Figure 3). This convergence method uses alternating linear projections on the input and output spaces to converge to the assumed missing values. The two other approaches are based on an optimisation algorithm in order to discover the values that should be introduced in the missing components so that the input-output error becomes minimised. In the unconstrained search, the convergence is controlled only by the error on the missing signals (Figure 4), whereas in the constrained search it is controlled by the error on all the outputs of the AE (Figure 5). Any of these optimisation procedures may be used, but according to some related works in the state estimation area [6] and [7], the constrained search appears to the most suitable method to search for a missing signal.

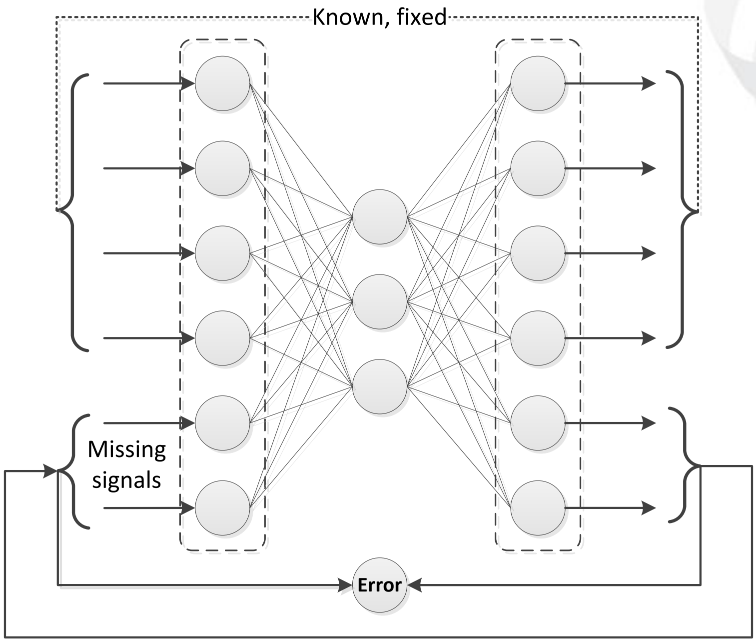


Figure 3 – Illustration of the POCS algorithm

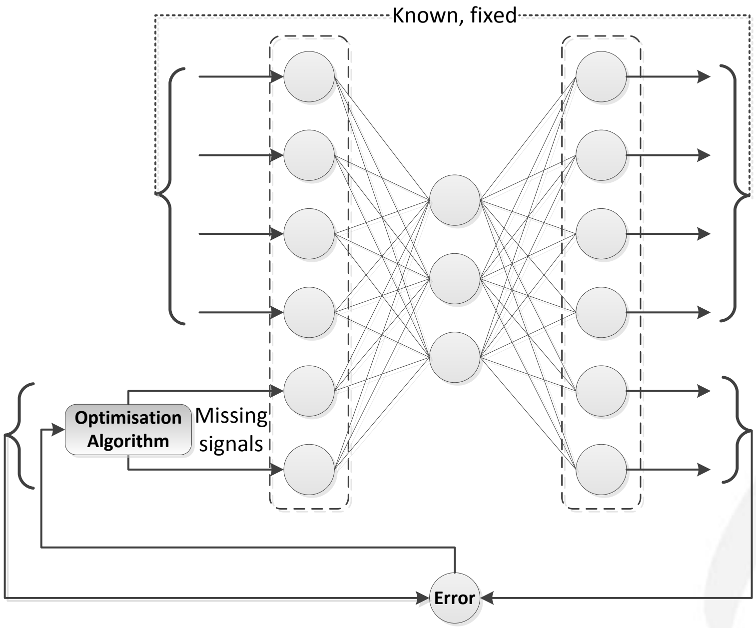


Figure 4 – Illustration of the unconstrained algorithm

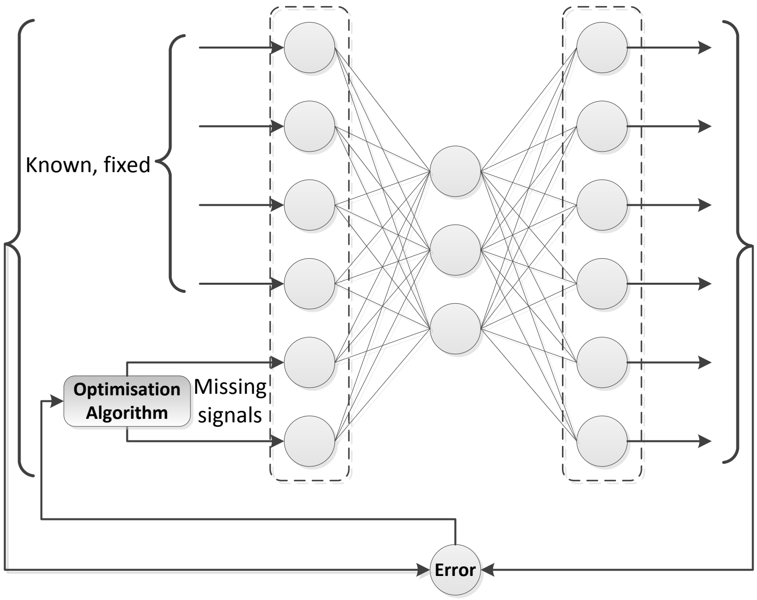


Figure 5 – Illustration of the constrained algorithm

An AE with one hidden layer and linear activation functions performs the same basic information compression from space *S* to space *S'* as a Principal Component Analysis (PCA) [29]. With nonlinear activation functions and multiple layers, an AE charts the input space on a non-linear manifold in such a way that an approximate reconstruction is possible with less error [30]. Plus, PCA does not easily show how to do the inverse reconstruction, which is straightforward with AE. AE with thousands of inputs have been proposed for data or image compression, using the signals available in the hidden layer which maps the input to a reduced dimension space. Reconstruction is then performed using the second half of the AE

[31]. A different application area in which AE are frequently employed is related with the reconstruction of missing sensor signals [28] and [34]. Their application in the power systems area is however confined to a few works. In [6], one can find the proposal of offline trained AE for recomposing missing information in the SCADA of Energy/Distribution Management Systems (EMS/DMS). In [7], a model for breaker status identification and power system topology estimation is presented and in [35], a concept of transformer fault diagnosis is proposed, both applications using AE. More recently, in two different works [10] and [11], the AE are used as “the brain” of a DSE algorithm. Particularly in [11], AE are applied to the problem of three-phase state estimation in unbalanced distribution grids, both in Medium Voltage (MV) and LV networks.

2.2.2 Building the Historical Data Set

In future LV grids, synchronised measurements gathered by telemetry equipment, such as Smart Meters (SM) located at customers’ place and/or other telemetry equipment dispersed among the grid, will be stored and transmitted periodically (for instance, daily) into a database of the DMS. The stored measurements can then be used as the historical data set of the proposed DSE.

An effective state estimation through the use of AE inevitably requires a large historical database. This database needs to contain data about the variables that will be passed to the AE during its training stage (both for the missing signals and for the measurements that will be available in real-time). Additionally, all data must be temporally synchronised and in sufficient number for each time instant/operating point, otherwise the AE will not learn effectively the patterns/correlations between the electrical variables of a given network.

There is no rule of thumb regarding the quantity of data that the historical data set should contain. However, it is experimentally known that too few or too much data will lead to an inaccurate AE. A trial and error approach can be followed to identify the optimal quantity of data in the historical database to be passed to the AE whenever a large amount of historical data is available. Of course, if the data records are scarce (for example, less than a week) all data should be considered.

2.2.3 Training the Autoencoder (ELM-AE)

2.2.3.1 Historical Data Set Standardisation

After defining the historical data set, a standardisation procedure is run with the goal of pre-processing the input and output training data set. In this scale adjustment process, the range of the input and output values is adjusted to a normalised interval of [-1, 1]. This procedure increases the performance and efficiency of the AE training since it allows a better adjustment of the input variables to the range of the activation function and allows the AE to be less affected by the different ranges of the variables present in the training data set.

There are three main methods to standardise the data: Z-Score method, Decimal Scaling method and Min-Max method. The last one is the best standardisation procedure when the minimum and maximum values of the data set are known. Therefore, this is the method applied here to perform the standardisation (3) since the minimum and maximum values of the variables that compose the input vectors can be easily obtained when looking to the historical database.

$$y' = \frac{y - \min_a}{\max_a - \min_a} \times (\max_A - \min_A) + \min_A \tag{3}$$

where:

y'	Standardised value for the considered variable;
y	Variable value in the "original" representation interval;
$\min_a$	Minimum value of the "original" range of values;
$\max_a$	Maximum value of the "original" range of values;
$\min_A$	Minimum value of the standardised range of values (-1);
$\max_A$	Maximum value of the standardised range of values (1).

2.2.3.2 Training Algorithm

Regarding the training algorithm, unlike conventional AE that usually apply back-propagation based algorithms for training purposes, an ELM technique is employed here to train the AE. Compared to the traditional gradient-descent based algorithms, particularly back-propagation, ELM [12] is a relatively recent computational intelligence technique that has been applied in different problems (e.g., regression, binary and multiclass classifications) with very promising results, both in terms of accuracy and computational performance [36]. Differently from the traditional training techniques, ELM is a non-iterative learning algorithm that only computes the weights vector between the hidden layer and the output layer, while the input weights matrix and the hidden layer biases vector are randomly generated (using for instance a uniform distribution) without tuning and independently from the input data [12] and [39]. Thus, as these weights and biases do not require to be tuned and can stay fixed, the output weights can be analytically calculated by solving a linear system of equations using the least-squares method. This is the essence of ELM techniques, contrary to the common understanding of learning. It has been shown that a single-layer neural network trained with ELM algorithm can maintain its universal approximation capability, even considering that the input weights and hidden layer biases remain fixed after having been randomly generated [39]. Furthermore, and in contrast to the commonly used back-propagation learning algorithm which only minimises the training error (without considering the magnitude of the weights), ELM minimises not only the training error but also the norm of the output weights. According to the neural network theory [42], the minimum norm output weights produces better generalisation performance. ELM also offers some advantages such as fast learning speed, minimal human intervene and ease of implementation [43].

Mathematically, the concept of an ELM-AE is quite similar to the traditional ELM presented next. The input data is mapped from the m-dimensional input space to L-dimensional hidden layer feature space and the network output is given by:

$$f_L(x) = \sum_{i=1}^{L} \beta_i h_i(x) = \mathbf{h}(x)\boldsymbol{\beta} \tag{4}$$

where $\boldsymbol{\beta} = [\beta_1, \ldots, \beta_L]^T$ is the output weight matrix between the hidden nodes and the output nodes, $\mathbf{h}(\mathbf{x}) = [h_1(\mathbf{x}), \ldots, h_L(\mathbf{x})]$ are the hidden node outputs with respect to the input $\mathbf{x}$ and $h_i(\mathbf{x})$ is the output of the i-th hidden node. Given N training samples $\{(\mathbf{x}_i, \mathbf{t}_i)\}_{i=1}^{N}$, where the input data is $\mathbf{x}_i = [x_1, \ldots, x_m]^T$ and the target is $\mathbf{t}_i = [t_1, \ldots, t_m]^T$, the learning problem to be resolved can be compactly formulated as:

$$\mathbf{H}\boldsymbol{\beta} = \mathbf{T} \tag{5}$$

where $\mathbf{T} = [\mathbf{t}_1, \ldots, \mathbf{t}_N]^T$ consists of the target matrix and $\mathbf{H} = [\mathbf{h}^T(\mathbf{x}_1), \ldots, \mathbf{h}^T(\mathbf{x}_N)]^T$ is the hidden layer output matrix. The i-th column of $\mathbf{H}$ is the i-th hidden node output with respect to inputs $\mathbf{x}_1, \ldots, \mathbf{x}_N$. The training procedure is equivalent to finding a least-squares solution $\hat{\boldsymbol{\beta}}$ of the linear system defined in (5) as:

$$\left\| \mathbf{H}\hat{\boldsymbol{\beta}} - \mathbf{T} \right\| = \min_{\beta} \left\| \mathbf{H}\boldsymbol{\beta} - \mathbf{T} \right\| \tag{6}$$

If the number N of training samples is equal to the number L of hidden nodes, matrix $\mathbf{H}$ is square and invertible and the neural network can approximate these training samples with zero error [43]. In such case:

$$\begin{gathered} \hat{\boldsymbol{\beta}} = \mathbf{H}^{-1}\mathbf{T} \\ \boldsymbol{\beta}^T \boldsymbol{\beta} = \mathbf{I} \end{gathered} \tag{7}$$

However, the number N of training samples is usually different from the number L of hidden nodes. In this case, $\mathbf{H}$ is a non-square matrix and the smallest norm least-squares solution of the linear system defined in (5) can be calculated by:

$$\hat{\boldsymbol{\beta}} = \mathbf{H}^{\dagger}\mathbf{T} \tag{8}$$

where $\mathbf{H}^{\dagger}$ represents the Moore-Penrose generalised inverse of matrix $\mathbf{H}$ [44] and [45] and $\hat{\boldsymbol{\beta}}$ is the vector of optimal output weights that minimise the training error.

To make the solution more robust and improve the generalisation performance [46], a regularisation term can be added [47]:

$$\boldsymbol{\beta} = \left(\frac{\mathbf{I}}{C} + \mathbf{H}^T\mathbf{H}\right)^{-1}\mathbf{H}^T\mathbf{T} \tag{9}$$

$$\boldsymbol{\beta} = \mathbf{H}^T\left(\frac{\mathbf{I}}{C} + \mathbf{H}\mathbf{H}^T\right)^{-1}\mathbf{T} \tag{10}$$

where $\mathbf{I}$ is the identity matrix and C is a scale parameter. The choice between (9) or (10) depends on the dimension of the training data set N and on the dimension of the feature space L. Both expressions can be used no matter the size of N and L, but computational costs are usually more reduced when using (9) for the cases where $N >> L$ and (10) for the cases where the training data set is relatively small [47].

Basically, there are two main differences between the ELM-AE and the traditional ELM. The first one is that in an ELM-AE the target output $\mathbf{t}$ is the same as the input $\mathbf{x}$ (as previously mentioned, an AE is trained to display an output equal to its input). The second one is that the input weights and the hidden nodes biases of an ELM-AE are made orthogonal after being randomly generated. Orthogonalisation of these randomly generated parameters tends to improve the ELM-AE's generalisation performance. As shown in [48], the orthogonal random weights and biases of the hidden nodes (that project the input data to a L-dimensional space) can be calculated as:

$$\begin{aligned} \mathbf{h} &= g(\mathbf{w}\cdot\mathbf{x}+\mathbf{b}) \\ \mathbf{b}^T\mathbf{b} &= 1 \end{aligned} \tag{11}$$

where $\mathbf{w} = [\mathbf{w}_1,\ldots,\mathbf{w}_L]$ are the orthogonal random input weights, $\mathbf{b} = [b_1,\ldots,b_L]$ are the orthogonal random hidden layer biases and $g(.)$ is the activation function of the hidden nodes. Depending on the relation between the number m of input nodes and the number L of hidden nodes, orthogonality of input weights matrix may or may not be complete, being verified in (11) as follows: when the number of input nodes is larger than the number of hidden nodes ($m > L$), $\mathbf{w}^T\mathbf{w} = \mathbf{I}$ is true; when the number of input nodes is smaller than the number of hidden nodes ($m < L$), $\mathbf{w}\mathbf{w}^T = \mathbf{I}$ is true; finally, when the number of input nodes coincides with the number of hidden nodes ($m = L$), $\mathbf{w}^T\mathbf{w} = \mathbf{w}\mathbf{w}^T = \mathbf{I}$ is true.

2.2.3.3 Activation Function and Hidden Nodes Number Definition

Besides the training algorithm selection, two other parameters need to be defined to successfully complete the training stage: the activation function and the number of the hidden nodes. The activation function can be modelled by different types of mathematical functions, such as the sine, the sigmoid or the radial basis function. For the specific problem under analysis, a symmetric sigmoid has generally shown to be the most appropriate activation function for the hidden nodes [10] and [11] due to its analytic benefits, leading to a better AE performance. Therefore, in the studies performed, a symmetric sigmoid was adopted as the activation function for the hidden layer. This activation function is illustrated in equation (12).

$$\begin{cases} g(\upsilon) = \dfrac{1}{1+e^{(-a\upsilon)}} \\ -1 \leq g(\upsilon) \leq 1 \end{cases} \tag{12}$$

where:

- $g(\upsilon)$ Output of the respective neuron;
- υ Sum of all inputs (affected by the respective weights) plus the corresponding bias of the respective neuron;
- a Slope parameter of the sigmoid function (constant).

Regarding the output nodes, a linear function was selected as activation function.

In relation to the number of hidden nodes, as it was denoted at the beginning of the current section, there is no *a priori* indication of an adequate number of hidden nodes to be adopted. Nevertheless, for the type of problem under study, a hidden layer smaller than the input/output layer is usually adopted [6], [7], [10], [11] and [35]. In order to properly define the number of hidden nodes, experimental tests should be carried out.

2.2.4 Distribution State Estimator Model

The proposed DSE model is depicted in Figure 6. As it can be seen, an AE with only a single hidden layer (smaller than the input/output layer) was adopted. In accordance with the beginning of the current section, a constrained search approach was used to find the missing signals, i.e. in our case the voltage magnitude values. As also stated before, any other electrical variable can be included if desired. The only mandatory requirement is the existence of historical data related to them (e.g., active/reactive power quantities).

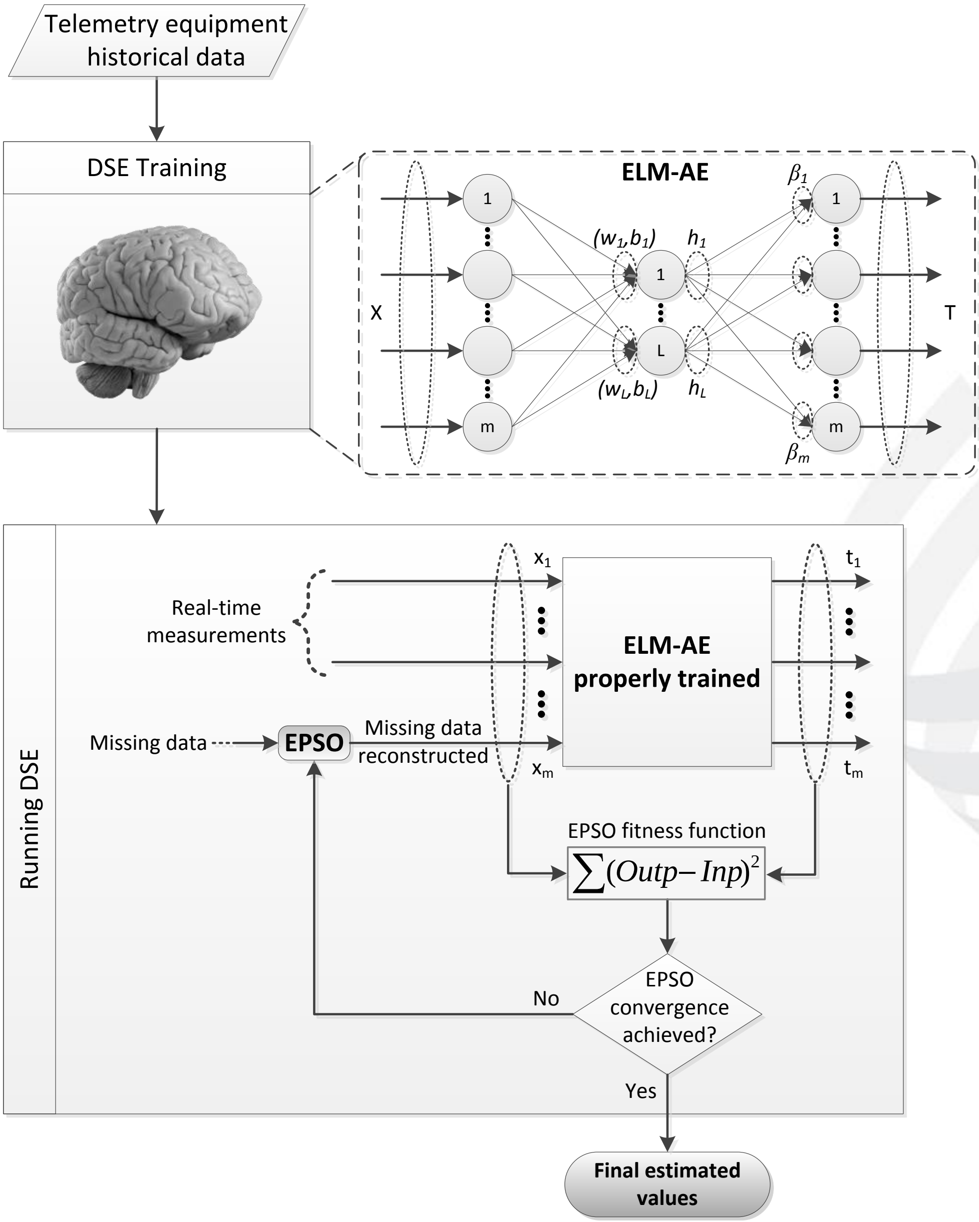


Figure 6 – Scheme of the proposed DSE algorithm

After having an AE properly trained, the measurements available in real-time are used as inputs for the AE in order to guide the optimisation algorithm to the system state estimation achievement. The meta-heuristic selected to reconstruct the missing signals was an Evolutionary Particle Swarm Optimisation (EPSO) which has been successfully applied in several problems in the power systems area [49]. The fitness function of the EPSO was defined to minimise the square error between all the inputs (x_i) and outputs (t_i) of the AE. It is given by:

$$\varphi(\varepsilon) = \sum_{i=1}^{m} (x_i - t_i)^2 \qquad (13)$$

The number and the type of variables to be estimated will depend on their availability on the historical data set as well as on the amount and type of measurements being telemetered in real-time. It should be noted that the proposed DSE algorithm is able to deal with either single-phase or three-phase data (gathered per phase) depending on the variables existing in the historical data set used in the training procedure.

It is important to mention that, in order to have an effective prediction of the system state for a given operating point, the measurements of all the electrical quantities existing in the historical database as well as the ones being transmitted in real-time should be temporally synchronised. Moreover, whenever the quantity or type of measurements present in the input data set is changed, a new training process must be performed. However, as it was referred before, if a measurement that was previously available in real-time suddenly becomes non-available, the proposed DSE algorithm will proceed to its estimation.

The proposed DSE algorithm is evaluated by estimating the state of the network presented in Section 2.5 for distinct real-time telemetry scenarios.

2.3 Operational Key Performance Indicators

The most relevant key performance indicators (KPIs) for this tool are operational KPIs for accuracy and performance, which are:

- Accuracy of active and reactive branch power flow: these KPIs are defined by choosing a power flow solution quantity of interest (e.g. active branch power flow) and defining a norm-like calculation on the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution). Larger KPIs values indicate worse performance.
- Accuracy of active and reactive bus power injections: these KPIs are defined by choosing a power flow solution quantity of interest (e.g. active bus power injection) and defining a norm-like calculation on the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution). Larger KPIs values indicate worse performance.
- Accuracy of voltage: this KPI is defined by choosing the power flow solution for the voltage magnitudes and using a norm metric that captures the effect of calculation, doing the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution).
- Error Estimation Index (EEI): this KPI is defined by the difference between the "true" values (derived from the power flow solution) and the "estimated" values (derived from the state estimation solution), for all quantities measured.
- Ability to accurately discern measurements: these KPIs determine the ability of the state estimator to accurately discern active and reactive power flow and injection measurements. They are defined by choosing a power flow solution quantity of interest (e.g. active branch power flow) and defining a norm-like calculation on the relative difference between the "true" value (derived from the power flow solution),

the “estimated” value (derived from the state estimation solution) and the “measured” value (derived from measuring devices or forecasting tools). For a good estimation, the estimate of each flow/injection will lie closer to the true than the measured value and the entire metric will be less than one.

The operational KPIs for accuracy and performance described can be quantified by evaluating these measures for different scenarios of measurements affected by random errors, comparing with a free errors base scenario. For all these KPIs, it is desired that estimated quantities be as close as possible to their true values. More details can be found in ANNEX I – Operational KPIs (State Estimation for LV Networks).

2.4 Functional Specification

In this section the main functions related to the proposed DSE methodology are presented. Before proceeding to its description, we present the relevant inputs for the DSE module as well as its outputs, whose file format should be in general csv-Format.

The relevant inputs for the DSE algorithm are presented below:

- Network topology data (optional) - IEEE Common Data Format;
- Load and generation data – if possible, information about its connection phase and bus;
- Synchronised historical data of:
  - secondary substation: voltage magnitude, active power flows and reactive power flows (optional) in the transformer and/or in all LV feeders;
  - telemetry devices in LV network: voltage magnitude, active power and reactive power (optional) consumed and generated (when available).
- Synchronised real-time data of:
  - the electrical quantities available at the secondary substation level;
  - voltage magnitude, active power and reactive power (optional) consumed and generated (when available) gathered from each telemetry device in the LV network with real-time communication capability (subset of smart meters).

The referred data should be gathered in time steps of 30 minutes, 15 minutes or less (either instantaneous or average values per phase, preferentially, for at least 4 months period, ideal 1 year). It is important to state that, if a state estimation solution per phase is required, the measurements available on the historical data set as well as the ones being telemetered in real-time must also be per phase, otherwise such state estimation is not possible.

The outputs of the DSE module are:

- Voltage magnitudes in all phases, and neutral wire (LV Network) if useful, at each network bus;
- Power injections per phase in each network bus (optional);
- Estimation errors;
- Error code if not successful in estimating.

Once again, if a state estimation solution per phase is required, the measurements available on the historical data set as well as the ones being telemetered in real-time must also be per phase, otherwise such state estimation is not possible.

The proposed DSE has three main functional blocks that are indispensable to its execution, which are:

- Pre-processing analysis;
- Training procedure;
- Real-time estimation procedure.

2.4.1 Pre-processing Analysis

Pre-processing of the input data consists of the definition of the quantity of historical data that will be telemetered in real-time as well as those that will be estimated, in order to build the AE architecture. This function should be run initially and for each significant change in the measurements set (those available in real-time and/or those that will be estimated).

There is also a topological analysis sub-function, which consists in fixing the topology of the network, not in the sense of knowing all the branches connections between buses, but in order to know which buses belong to each feeder or, at least, to the correspondent secondary substation (at a minimum). The full knowledge of the network topology, as was mentioned before, would be unfeasible for the large majority of the networks (due to the lack of information in this kind of networks) and it is not required by the tool, which is one of the main advantages of the proposed methodology.

This topological analysis sub-function is done by cross-checking the information related to the network topology with the measurements, which is very important since changes in topological configuration usually imply either running a new training procedure (for the new configuration) or the selection of an appropriate AE specific to the new configuration (if an AE trained with historical data related to that topological configuration exists).

Another sub-function is related to the observability analysis. This functionality selects a set of data so that the network under analysis is observable. The concept of observability for the proposed DSE was already defined in Section 2.2. As it was stated in that section, the minimum requirements for running the proposed DSE and providing the correspondent solution are, at least and independently of the system under analysis, historical data for a period of a few days regarding the variables to be estimated and one measurement available in real-time. A more adequate sizing of the historical data set available and the number of real-time measurements can be fixed using parameters, based on network under analysis and the type of customers.

2.4.2 Training Procedure

In order to properly train an AE, it requires a historical database containing data about all the variables, both the ones that will be available in real-time and the ones whose estimation is intended. It should be noted that all data must be temporally synchronised and in sufficient number for every instant/operating point, otherwise the AE will not learn effectively the patterns/correlations between the electrical variables of a given network.
According to the number and the location of the telemetry devices with real-time communication capability, the most appropriate type of AE should be selected (global for the whole network, per feeder and/or per phase). Then, accordingly with that, one should set the most appropriate training parameters (activation functions and number of hidden layer neurons) as well as defining the state variables to be estimated and the measurements that will be available in real-time.

Based on the aforementioned information, the training procedure is performed through an ELM technique. The output of this process is an ELM-AE appropriately trained for a given network topological configuration and for the historical data used. The flowchart presented in Figure 7 shows the main steps required to properly train an ELM-AE.

In Section 2.2, the training procedure is described in more detail.

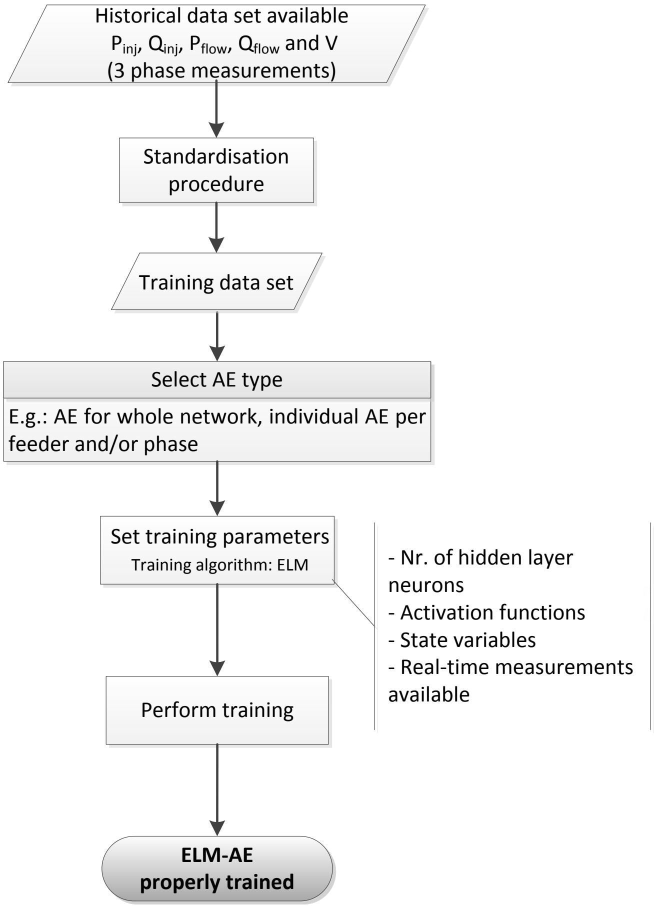


Figure 7 – Flowchart of the overall process used to train the ELM-AE

It is important to state that, if the historical database includes data of different network topologies, one ELM-AE per topology should be trained.

Other aspects to be taken into account when applying the proposed tool to solve the state estimation problem are summarised in Figure 8. This figure shows the type of data to be used when networks' technical parameters are (or not) known, as well as how to proceed when are verified changes in networks' topology and the connection of new clients. Aspects related with the lack of instants in the historical database, the suddenly unavailability of the expected real-time telemetry data and seasonal patterns are also addressed.

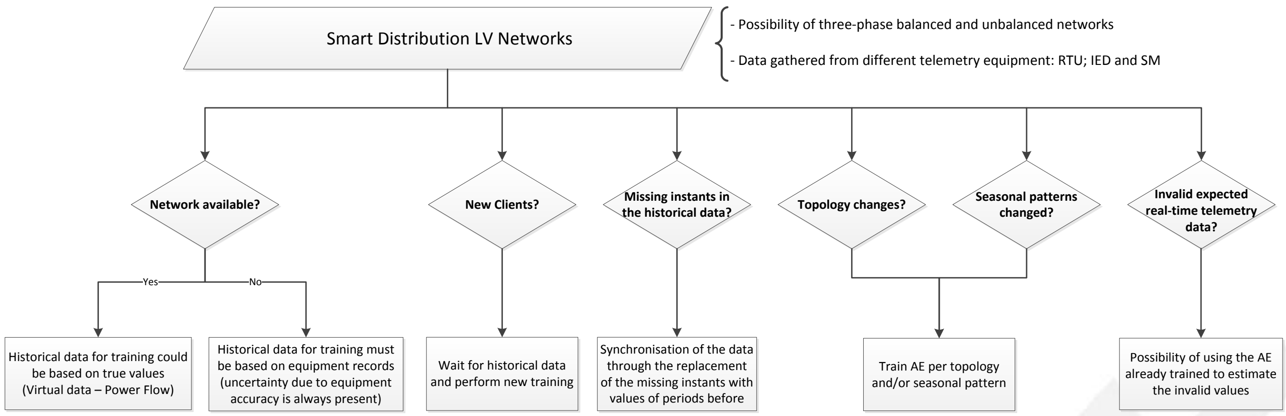


Figure 8 – Aspects to be taken into account

2.4.3 Real-time Estimation Procedure

Figure 9 presents the main steps involved in the estimation of the system state variables. After having the ELM-AE properly trained, the measurements available in real-time are used as its inputs for guiding the optimisation algorithm to the system state estimation achievement. In the context of this state estimation problem, the state variables to be estimated are the voltage magnitude values and the active power and reactive power (optional) injections (if desired). An EPSO algorithm is the optimisation algorithm selected to estimate the system state variables. This is achieved by minimising the square error between all the inputs and outputs of the ELM-AE.

More details about the DSE execution can be found in Section 2.2.

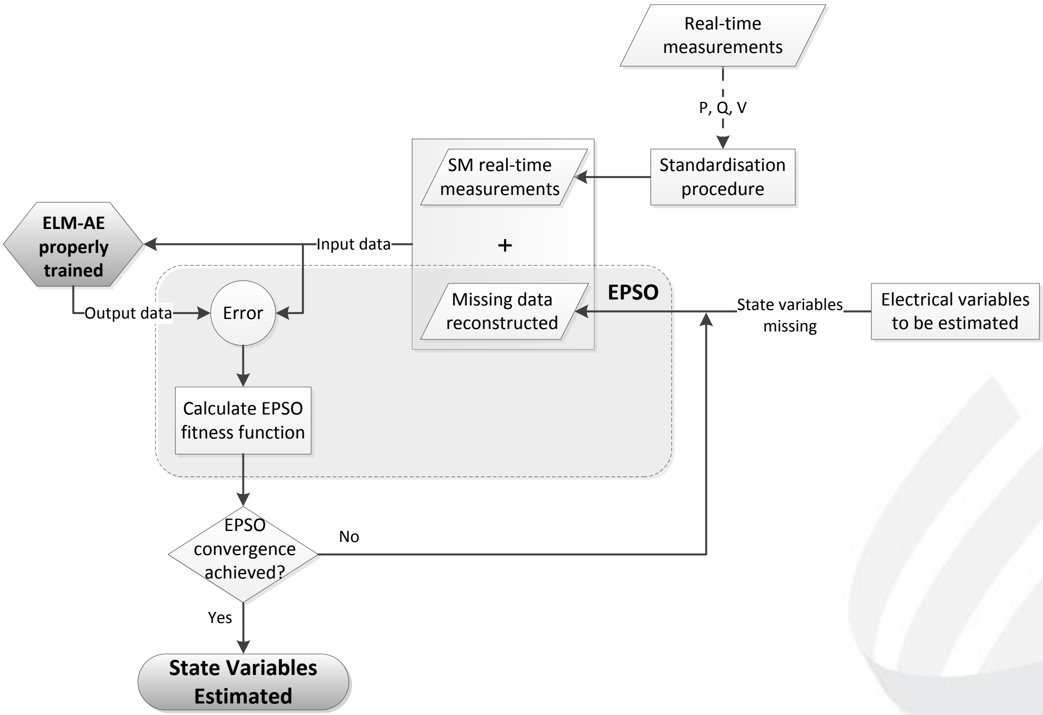


Figure 9 – Flowchart of the overall process used to estimate the system state variables

2.5 Illustrative Example

2.5.1 Description

The proposed DSE methodology was tested in a small typical Portuguese LV network (Figure 10) where the MV/LV secondary substation – which it is connected to, is equipped with one transformer with a rated power of 100 kVA. The grid contains 57 customers with contracted powers that vary in a range between 3.45 to 6.9 kVA for single-phase consumers and 6.9 to 13.8 kVA for three-phase consumers.

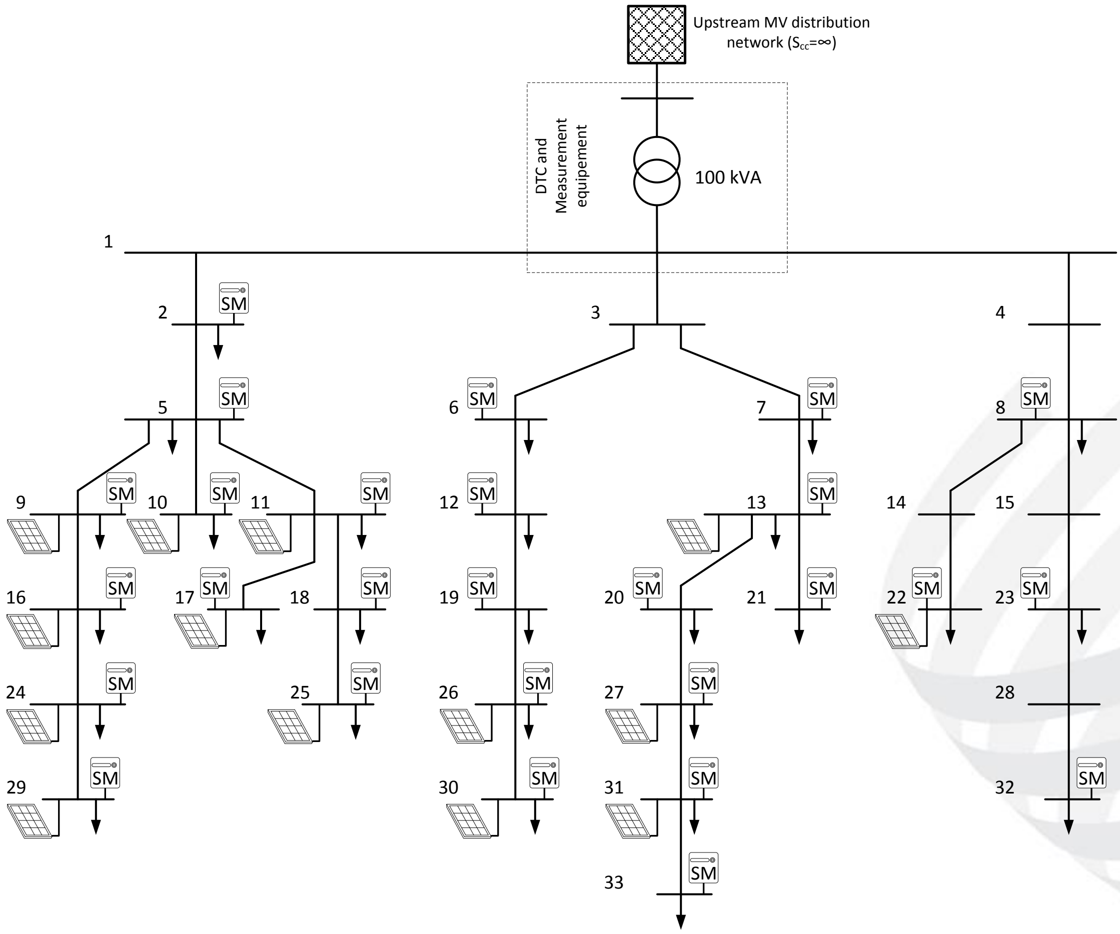


Figure 10 – Typical Portuguese LV network of 100 kVA considered

Table 2 shows the existing customers and its distribution among the grid nodes. Since a significant amount of single-phase customers (loads) is present, load is not distributed equally among phases, generating imbalances between them – in some points of the network, load imbalances are quite notorious. Even so, the load is almost balanced at the MV/LV substation level. The network has a total of 33 nodes and a peak load of 53.3 kW, recorded for the summer season.

Client Number	Location Bus	Contracted Power (kVA)	Microgeneration Installed Capacity (kVA)	Client Number	Location Bus	Contracted Power (kVA)	Microgeneration Installed Capacity (kVA)
1	2	3.45	0	30	20	3.45	0
2	2	3.45	0	31	21	3.45	0
3	5	3.45	0	32	21	3.45	0
4	6	1.15	0	33	22	6.9	3.45
5	7	3.45	0	34	22	3.45	0
6	7	3.45	0	35	22	3.45	0
7	7	3.45	0	36	22	3.45	0
8	8	3.45	0	37	23	3.45	0

Client Number	Location Bus	Contracted Power (kVA)	Microgeneration Installed Capacity (kVA)	Client Number	Location Bus	Contracted Power (kVA)	Microgeneration Installed Capacity (kVA)
9	8	3.45	0	38	24	3.45	0
10	8	3.45	0	39	24	17.25	5.75
11	9	6.9	3.45	40	24	17.25	5.75
12	9	3.45	0	41	24	17.25	5.75
13	9	3.45	0	42	24	3.45	0
14	10	3.45	0	43	25	3.45	0
15	10	13.8	5.75	44	25	13.8	5.75
16	11	3.45	0	45	26	13.8	5.75
17	11	6.9	3.45	46	27	6.9	3.45
18	12	3.45	0	47	27	3.45	0
19	12	3.45	0	48	27	3.45	0
20	13	6.9	3.45	49	29	3.45	0
21	13	3.45	0	50	29	3.45	0
22	13	3.45	0	51	29	6.9	3.45
23	16	6.9	3.45	52	29	3.45	0
24	17	13.8	5.75	53	30	13.8	5.75
25	18	3.45	0	54	31	6.9	3.45
26	18	3.45	0	55	32	3.45	0
27	19	3.45	0	56	32	3.45	0
28	19	3.45	0	57	33	3.45	0
29	20	3.45	0				

Table 2 – Consumers and microgeneration distribution

Regarding the data related to the load, the only data available for this network was an average aggregated load diagram at the secondary substation level. In order to represent consumers with different behaviours, distinct load diagrams were generated from the referred average aggregated load diagram for each customer. To this end, a Gaussian distribution with a mean value equal to the aggregated load diagram and a standard deviation of 8% was used.

In this study, the consumers' load was aggregated at the corresponding connection node and its distribution per phase was assumed to be perfectly balanced. Nevertheless, as this process is performed after using each individual consumer power value for a given time instant, the different consumers' load patterns are still reflected by the equivalent load. There are two main reasons for this simplification. Firstly, by assuming balanced loads, single-phase power flows can be run instead of three-phase power flows. Secondly, the assumption made does not compromise in any way the quality of the state estimation results through the use of AE.

Several microgeneration units (photovoltaic panels), both three-phase and single-phase, were added and randomly distributed through the network clients, totalising ≈74% of the secondary substation transformer capacity (ca. 74 kVA). Each microgeneration unit represents 50% of the contracted power of the correspondent consumer. In order to represent different days (e.g. sunny, cloudy, rainy, etc.) and consequently different power generations, 5 different real profiles obtained from a real meteorological station [52] were randomly distributed by the existing units according to their probability of occurrence in a typical Portuguese summer.

As there was no historical data for the network considered in the present study, single-phase power flows were run to generate it, according to the aforementioned information, for a period of 4 months (summer season) in time steps of 15 minutes (11040 samples for training purposes and 672 samples for the DSE evaluation).

In order to emulate a smart grid environment, some additional features and equipment were assumed to exist in the network considered. It was assumed that the MV/LV substation holds a Distribution Transformer Controller (DTC, which has, among other functions, the SM information concentrator function – like an head-end server) as well as the associated measurement equipment with the capability of monitoring in real-time the following variables: active and reactive power flows in the transformer and in all LV feeders and voltage magnitude at the medium and low voltage sides of the transformer. For the purpose of this study, the term "real-time" is used in the sense of measuring the variables in a short period of time, around 15 minutes.

It was also considered that each consumer has a SM to monitor his consumption and communicate it to the DTC (for instance, daily) for billing purposes. The customers that own a microgeneration unit have an additional SM for measuring its power production. As happens in some real smart grid test sites, not all SM are capable of transmitting data in real-time due to communication infrastructure restrictions. Only some, which use, for instance, *General Packet Radio Service* (GPRS) technology, have that capability. It was assumed that their active (P) and reactive (Q) power and voltage magnitude (V) measurements are synchronised. Phase angles were assumed not to be measured as the majority of SM foreseen to be deployed in LV grids do not have such capability.

Taking into account the referred assumptions, and in order to evaluate the proposed DSE methodology, three different scenarios were defined. In each scenario, the number of SM (located at customers' premise) with capabilities of transmitting measurements of the mentioned electrical variables in real-time (SM_r) was assumed to be different.

In scenario 1, no SM_r were considered. Only real-time measurements from equipment existing in the substation were assumed to exist in the network.

Scenario 2 is more optimistic. In this scenario, SM_r placed at the customers located on the 5 farthest nodes from the substation were assumed (electrical distances were taken in consideration).

In Scenario 3, SM_r were continuously added to scenario 2 to the network buses where the voltage magnitude estimated error was greater than the defined threshold of 2% until the overall inaccuracy remains below that limit.

In Table 3 it is summarised, for each scenario, the number of real-time measurements existing in the network (gathered from the metering equipment available in the network), the total number of variables to be estimated, as well as its computation (m/n factor) that gives the relation between these two quantities (expressed in percentage). In the same table, the SM_r bus location is shown for each scenario in accordance to Figure 10.

Scenario	Number of real-time measurements (m)	Number of variables to be estimated (n)	m/n (%)	Location of SM (bus)
1	8	64	12.5	DTC
2	23	59	39.0	DTC-25-29-30-32-33
3	29	57	50.9	DTC-17-22-25-29-30-32-33

Table 3 – Real-time measurements and location of SMr in each scenario

It is important to state that, since the amount and type of measurements present in the input data set vary in each scenario (measurements available in real-time and variables to be estimated), it was necessary to train three different ELM-AE, one for each scenario, since the number of its input nodes is equal to the number of measurements present in the input data set.

2.5.2 Results

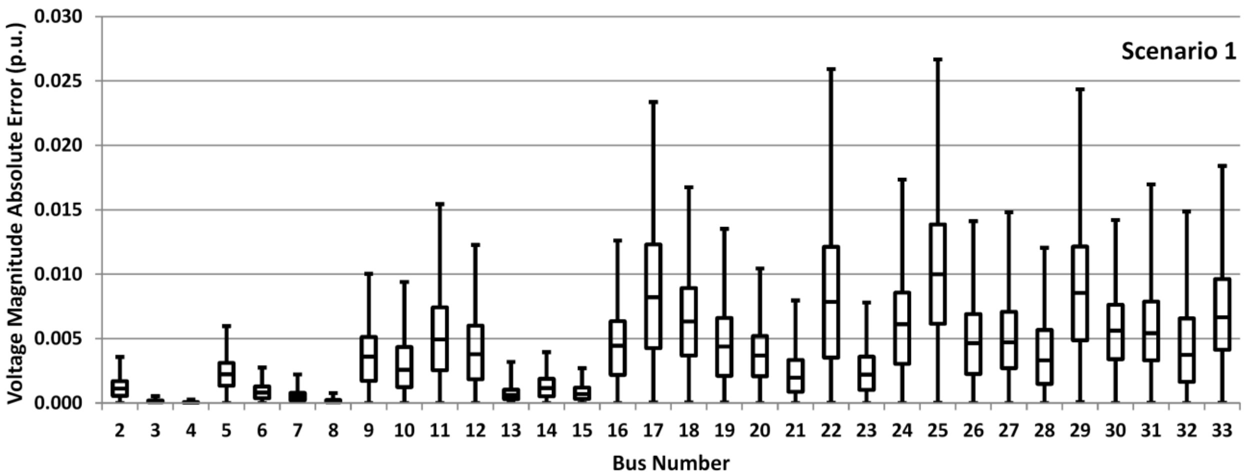
The results obtained for the proposed DSE methodology are presented next. All the simulations were performed on a computer with an Intel Core i7-2600, 3.40 GHz CPU and 8 GB of RAM. In results presented, the bus voltage magnitude was considered as the state variable to be estimated.

For each created telemetry scenario, one week (last seven days from the historical database) was used as the test set to evaluate the proposed methodology. In all the performed simulations, an ELM-AE with one hidden layer was used. The number of hidden nodes assumed in each scenario is presented in Table 4; a hidden layer reduction rate (measured as the ratio between the number of hidden nodes and the number of input/output nodes) of 0.6 was considered. As mentioned before, a symmetric sigmoid function was adopted as the activation function for the hidden nodes, whereas a linear function was selected for the output nodes. Regarding the input weights and hidden layer biases, they were generated through a uniform distribution between the normalisation range [-1, 1]. In what concerns the EPSO algorithm, the convergence criterion adopted was a fixed number of 200 iterations.

In Figure 11, the boxplots depict the voltage magnitude absolute error in all the network buses not being monitored in real-time. The absolute error was calculated between the real values (generated through power flows) and the estimated values obtained with the proposed DSE model. As it was expected, the estimation accuracy is improved when more real-time measurements are available. Regarding to Figure 12, where the distribution of the voltage magnitude absolute error is shown in scenario 1, it is clear that the worst estimation occurs for buses that have both loads and microgeneration (e.g., buses 22, 25 and 29), which was expected due to the higher variability of the power injected in these buses.

Observing Figure 11 for scenario 3 (Table 3), it can be seen that only 7 SM_r (besides the telemetry equipment existing in the substation) were required to achieve the goal of a maximum voltage magnitude inaccuracy of 2%. Furthermore, with this number of SM_r, the maximum voltage magnitude inaccuracy verified in this scenario was slightly greater than 1% in only one bus (bus number 10), showing the good performance of the proposed DSE algorithm.
Taking into account the results shown in Figure 11 and the way as the number of SM_r was defined in scenario 3, if the base for its creation was scenario 1 instead of scenario 2, we would expect that a lesser number of SM with such capabilities was required for maintaining the voltage magnitude absolute error below the 2% threshold limit in all buses. Moreover, continuing to observe Figure 11, but specifically to the one related to scenario 1, it is possible to state that only 4 SM_r (besides the telemetry equipment existing in the substation) would be required to fulfil with the maximum voltage magnitude absolute error requirement. After a careful results analysis, it was verified that the occurrence probability of a maximum absolute error greater than 2% was always lower than 0.43%. This value reveals, once more, the good performance achieved by the DSE presented here.

Considering what was said in the previous paragraph, the importance of the location of metering devices with the capability of transmitting data in real-time becomes obvious. Methodologies to find the most suitable locations for these devices should be investigated since this kind of approaches could enable a smaller state estimation error while using the same number of real-time telemetry devices, resulting in a more cost-effective solution.



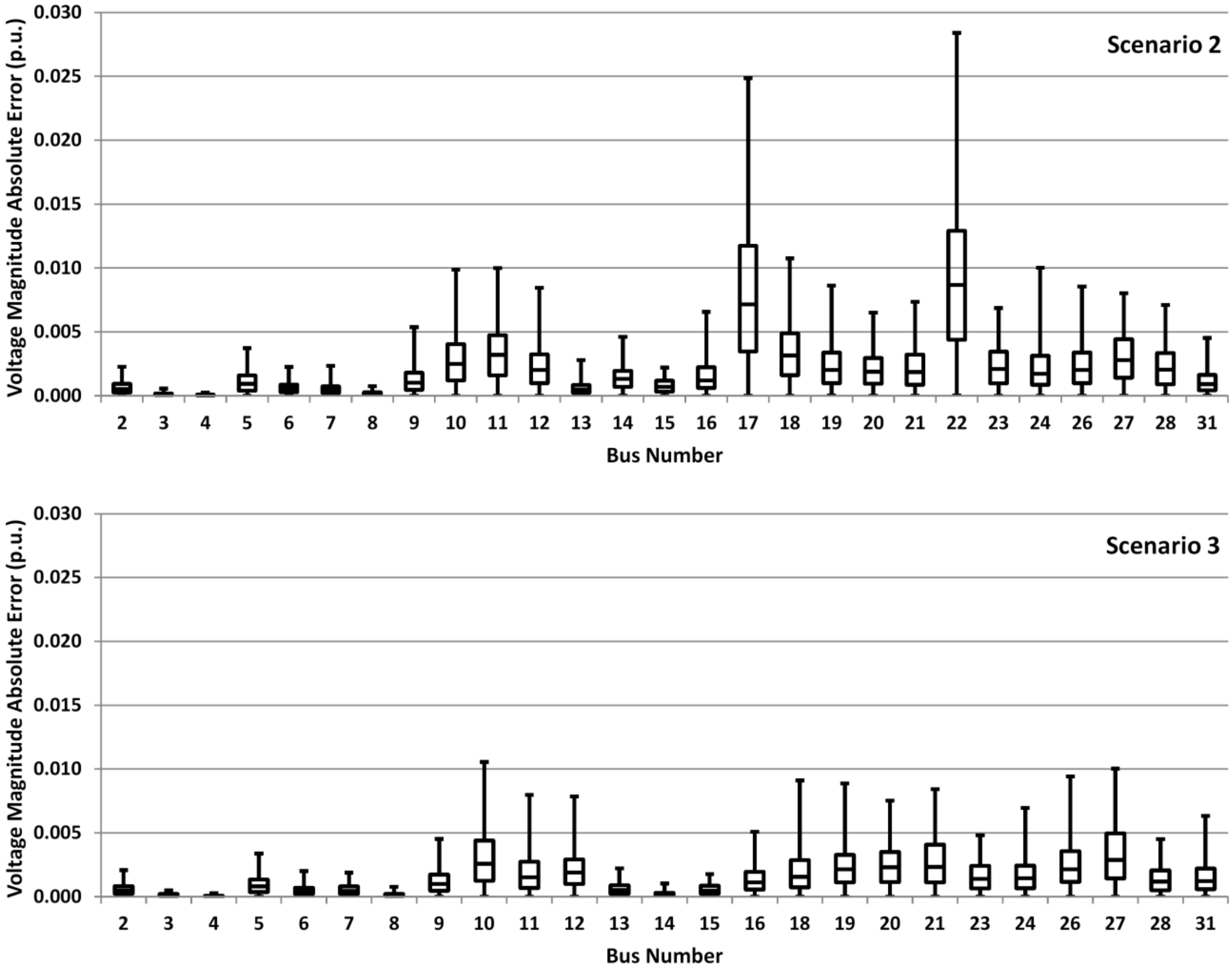


Figure 11 – Voltage magnitude absolute error for all network buses (not being real-time monitored) in scenarios 1, 2 and 3

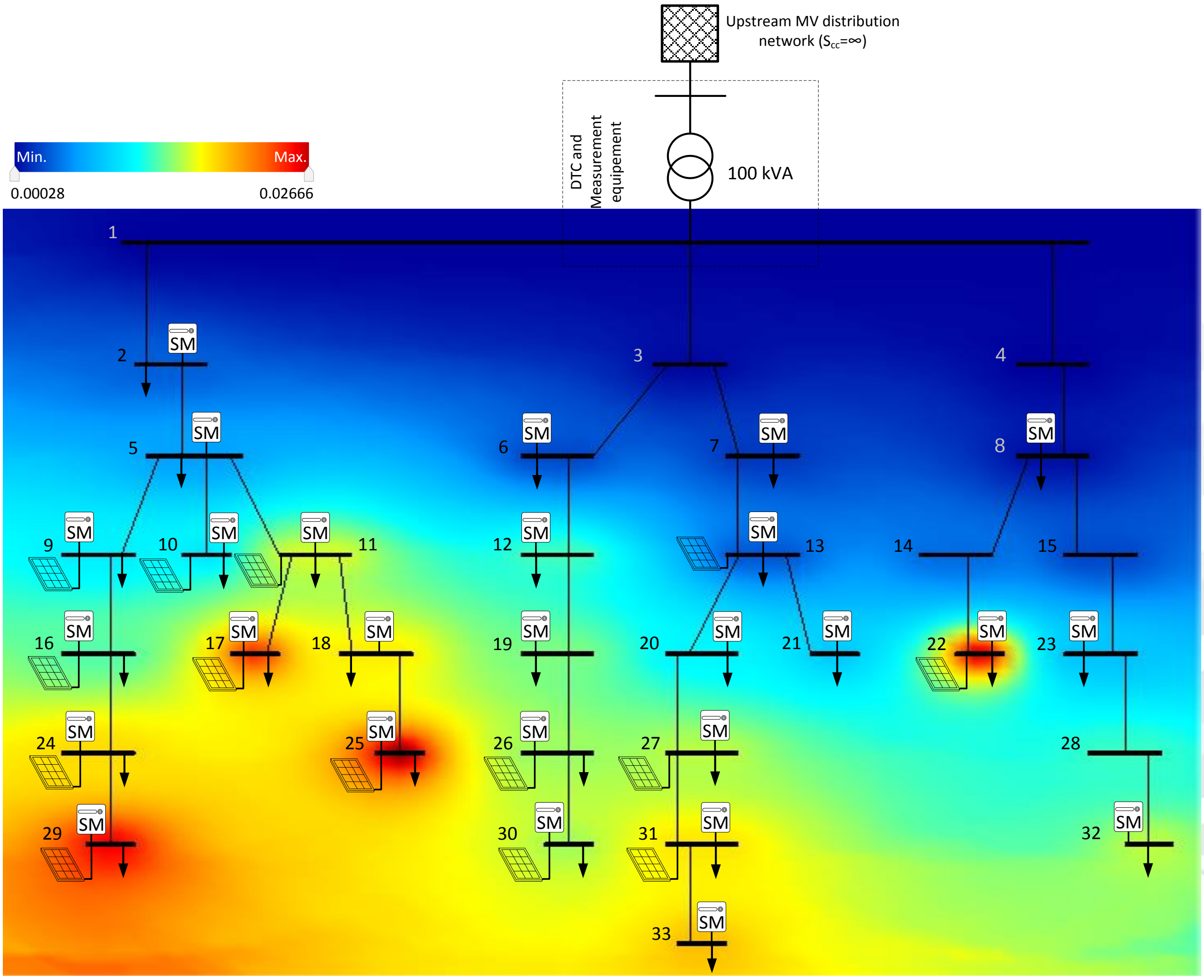


Figure 12 – Distribution of voltage magnitude absolute error in scenario 1

Comparing Figure 12 with Figure 13, a general improvement in the state estimation solution is clearly seen when more measurements are available in real-time. Furthermore, a reduction of the estimation error is evident in the buses close to the ones where SM_r are installed.

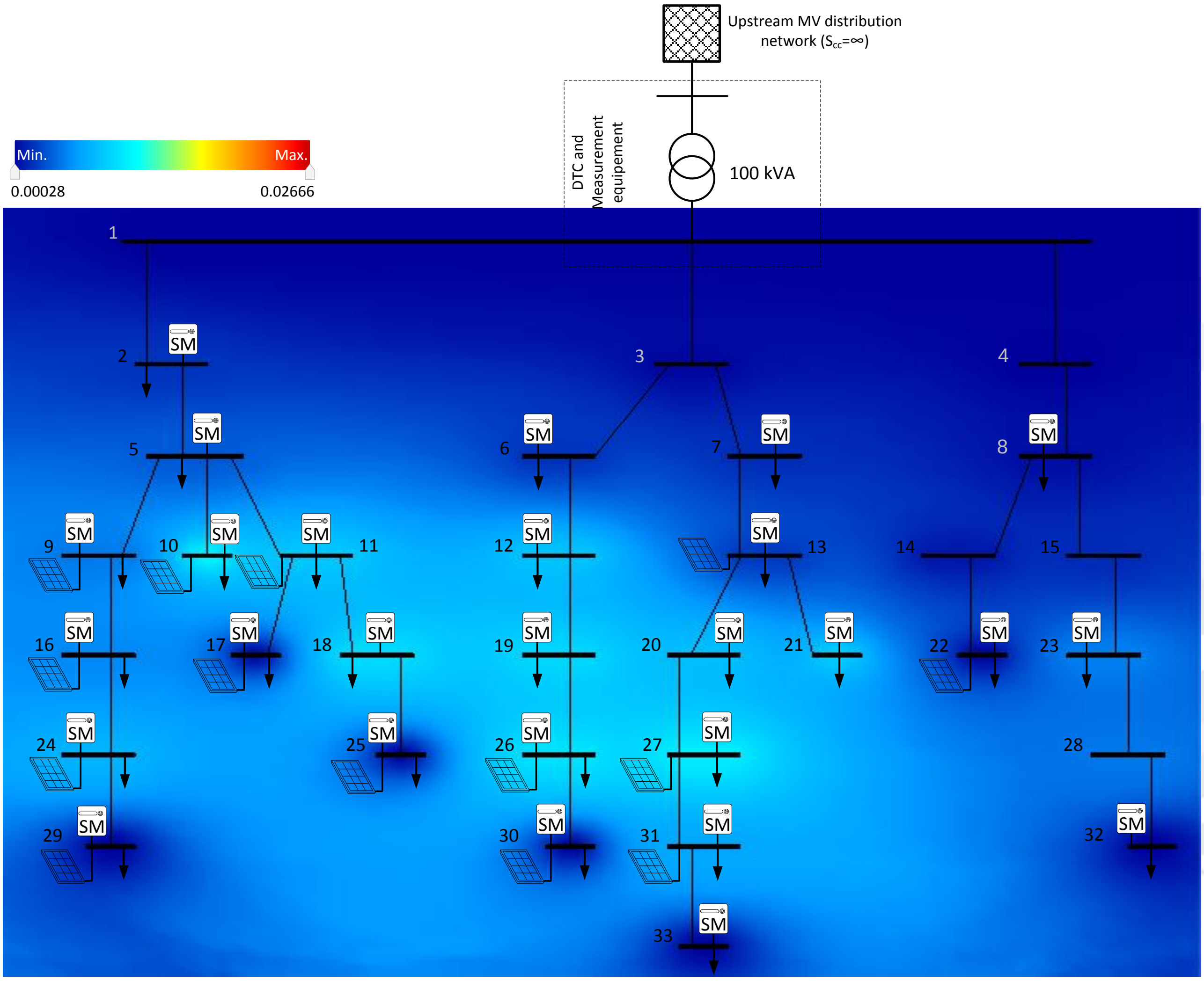


Figure 13 – Distribution of voltage magnitude absolute error in scenario 3

The accuracy of the AE performance was also evaluated using the mean absolute error (MAE), given by:

$$MAE = \frac{1}{n}\sum_{i=1}^{m}|x_i - t_i| \tag{14}$$

where:

n Number of evaluation samples;
x_i Real values (generated through power flows);
t_i Estimated values (obtained with the proposed DSE model).

Table 4 summarises the MAE and the maximum absolute error (Max.) for the considered evaluation set. It is possible to see that the presented results are in accordance with what was said before – the estimation accuracy is improved when more measurements are available in real-time. This is more noticeable for MAE results, for which reductions of about 50% between scenarios 1 and 2 and between scenarios 2 and 3 are verified.

Scenario	Magnitude (p.u.)		No of hidden
	MAE	Max.	nodes
1	0.0039	0.0267	43
2	0.0021	0.0284	49
3	0.0013	0.0106	52

Table 4 – Voltage accuracy

Another parameter to take into account to evaluate the proposed DSE methodology is the computational time. The training procedure is very fast and also much faster than conventional training algorithms. Although the training procedure is expected to be done offline, this can be an advantage especially when there is a large amount of historical data to be dealt with. Regarding the estimation time, the proposed DSE takes less than one second to perform the state estimation for the network considered in the present study, which makes it suitable for real-time applications.

In general, the obtained results give good indications about the possibility of having a good state estimation even in poorly characterised networks. Nevertheless, a real historical database should be used in order to make a final validation of these results.

3 Voltage Control for LV Networks

In this chapter, the approach for voltage control in Low Voltage (LV) grids developed by INESC TEC is presented. The main objective is to ensure that voltage profiles remain within admissible limits by taking advantage of the controllable resources and equipment that may be available in the LV grid.

3.1 Relation with System Use Case

This tool stems from the SUC "Identify and solve network constraints for a given zone and an optimization application period in operational planning", aiming to solve network violations by providing a list of commands to act on the relevant resources and related set points. The main steps of this SUC were previously presented in section 2.1. The proposed LV control tool can be applied to LV network with known and unknown topology/electrical characteristics. The match between WP2 non-functional requirements and LV voltage control tool is presented in Annex V.

3.2 Methodology and Algorithms Description

The proposed methodology for voltage control in LV grids (LVC) is based on a set of rules and actions that follow a merit order of the grid's controllable resources in order to fulfil the macro objective of the Distribution System Operator (DSO) of minimizing its operation costs (*i.e.* use control actions with less impact in terms of financial compensations to the affected customers).

The selected control actions are prioritized according to the previously stated macro objective, *i.e.* minimizing the operation costs. The available grid assets that have been considered are the following:

- Energy storage systems;
- MV/LV secondary substation transformers with OLTC capability;
- Microgeneration units;
- Flexible loads under Demand Side Management (DSM) actions.

Regarding the storage systems, these may be owned by the DSO and installed at the MV/LV secondary substation level or scattered throughout the LV grid in order to locally support voltage; alternatively storage devices owned by LV customers may be available to support grid operation as a service to be provided to the DSO following some type of remuneration scheme.

Concerning the OLTC transformers, these are typically DSO owned resources that may be used for voltage control purposes but that do not require any payment for being utilized. Their maintenance costs should however be considered since the number of tap changing actions impacts the frequency of equipment maintenance and renewal.

Microgeneration units or flexible loads owned by LV customers may also be used. In this case, it is assumed that the flexibility of the customer (either for generation or load) must be secured through some type of bilateral contract between the client and the DSO or through a market mechanism for ancillary services provision by means of an aggregator agent. In the case of microgeneration units, the existence of non-firm contracts (for instance, subject to limitation in case of technical problems in the grid) may also be considered.

According to the methodology that was developed, the resources are sorted according to their cost operation. Then, for each type of controllable grid asset, the most suitable control action is determined by taking into account a set of decision factors prioritizing between the resources which are the best suited to solve a specific voltage violation. The most relevant decision factors used are the following:

- Proximity to overvoltage location;
- Flexibility of operation;
- Impact in mitigating the voltage deviation.

The main obstacle to an efficient voltage control strategy in LV grids has to do with the fact that these grids can be poorly characterized both in terms of topology and electrical characteristics of the lines or cables. In some cases, the only information available is the knowledge of which loads are connected to which MV/LV distribution transformer, without data regarding the lines, type and length.

Therefore, the proposed methodology is adaptive since it is capable of solving voltage problems taking advantage of the available distributed resources in two distinct situations:

- **Full knowledge of the LV grid**: Topology and access to smart metering devices and possibility of running a three-phase unbalanced power flow routine.
- **Limited knowledge of the LV grid**: Unknown topology; access only to smart meter readings, customer connection phases? and geographic coordinates of customers.

As previously explained, the control methodology proposed is based on a set of rules that aims at managing the grid assets in a prioritized manner in order to mitigate potential technical problems that may arise in distribution operation. The degree of efficiency of this control module is related to the quality of the information available regarding the current state of the grid. The State Estimation for LV Networks described in the previous section is a valuable tool in this respect since it allows obtaining a complete characterization of the grid's state even when only some real-time measurements are available (i.e. smart meter reading with GPRS at some grid nodes).

With the updated measurements of the state of the grid, it is possible to run a three-phase unbalanced power flow, in case there is full knowledge of the grid topology and characteristics, otherwise the control actions management system is run. In both cases, the results of the voltage control algorithm will be set-points to the available DER or other voltage control equipment such as MV/LV transformers with OLTC capability.

These two modes of operation are described in the following sub-sections.

3.2.1 Full Knowledge of the LV Grid

When full knowledge of the LV grid (including topology, characteristics of lines/transformers) is available, there is sufficient information to run a three-phase unbalanced power flow.

The algorithm for the centralized control scheme includes power flow routine used for three-phase, four-wire radial distribution networks, where the neutral wire and the ground are explicitly represented. It uses a general power flow algorithm based on backward-forward technique, which is extremely fast to reach convergence. It must be noted that this method was designed for radial distribution networks, although it may be adapted for weakly meshed networks. The power flow algorithm that was implemented is described in detail in [53].

This information is complemented by the most recent data available of the power injections in the different network nodes and the collected historical data. They are used to provide an approximate view of the state of the grid in quasi-real time, *i.e.* a snapshot of the LV system.

The voltage control algorithm may run periodically following each update of the grid's condition (*i.e.* cycle of measurement of the main quantities such as power injections at each node) or after receiving a voltage alarm from a smart meter. Whenever a violation is detected, a suitable solution for controlling voltage profiles is determined by testing several possible solutions iteratively and then identifying which resources need to be actuated in order to solve the voltage violation. This mechanism is referred to as the Smart Power Flow.

3.2.2 Limited Knowledge of the LV Grid

With limited information and without the possibility of running a three-phase unbalanced power flow, the algorithm uses the State Estimation for LV Networks tool to assess the impact of the control actions to be applied to the controllable assets, according to the priority rules previously established, until the voltage deviation is corrected.

In this case, apart from the availability of smart meter readings, the minimum information required is the geographical position of each unit (load, μG unit or storage device) as well as the phase to which it is connected.

In this case, when there is a voltage violation, an alarm is generated (originating from the smart meter, for instance) where the voltage violation is identified and its location is determined. Then, the proposed control actions management system is used and successive control actions are applied to the controllable assets until the voltage deviation is corrected, according to the priority rules previously established.

3.3 Operational Key Performance Indicators

An operational KPI was defined in order to evaluate the performance of the LVC tool, which corresponds to the "Reduction of Technical Losses". The objective of this KPI is to measure the reduction of energy losses in the grid, due to an increase of RES integration as a result of the LVC tool. In order to calculate this KPI, the difference in magnitude of technical losses with and without the use of the LVC tool is determined. The complete description of this KPI can be found in Annex II.

It must be stressed that other EEGI KPIs will also be used to assess the performance of the LVC tool. More information can be found in ANNEX II – Operational KPIs (Voltage Control for LV Networks).

3.4 Functional Specification

As previously explained, the LVC tool aims at ensuring near to real time voltage control in Low Voltage (LV) networks by using available grid assets that may be managed for voltage control purposes. These assets include not only DSO owned assets possibly present in the grid such as storage devices or On-Load Tap Changing (OLTC) transformers at the MV/LV secondary substation, but also Distributed Energy Resources (DER) owned by customers such as Distributed Generation (DG) units, small storage systems and flexible loads.

The proposed approach uses a merit order to select the most suitable grid asset(s) to be mobilized. This merit order uses the expected costs of each possible control action in order to sort the available grid assets in regards to the main objective, i.e. minimizing the overall cost of operation. The output of the tool is a set of control actions for the DER and the other voltage control devices present in the LV network.

In Figure 14, a high level diagram of this management module is presented, with emphasis on the input and output data and on the relevant external systems.

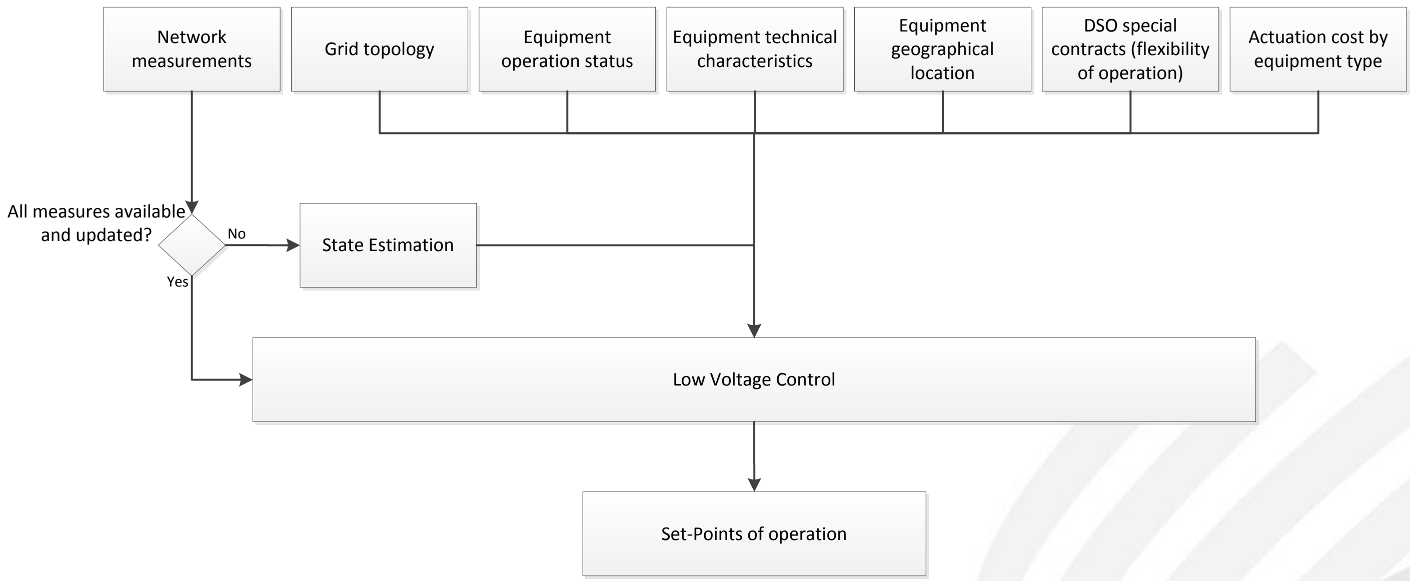


Figure 14 – General Diagram of the Voltage Control for LV Networks Tool

3.4.1 Inputs

The inputs relevant for LVC tool are the following:

- Voltage magnitudes measurements;
- Injected power measurements (active and reactive, if available);
- Geographical location of grid's equipment;
- Grid's equipment current operation status;
- DSO special contracts with consumers and producers;
- Grid topology (if available);
- Technical characteristics of grid's equipment;
- Costs associated with control actions for each equipment.

3.4.2 Outputs

The outputs of the LVC tool are the following:

- New set points for the grid assets, namely new tap positions for MV/LV OLTC transformers and new points of operation for DER located at the LV level;
- List of equipment operated with restrictions;
- List of nodes where voltage violations have occurred initially.

3.4.3 Functional Model

Two distinct modes of operation are considered: when there is a voltage deviation, an operation mode where the main objective is to manage the voltage deviation and restore the voltage back within admissible limits is run; in case there is no voltage deviation, another mode of operation designed to return to system to its normal state is run, i.e. without any equipment being constrained by previous imposed set-points that may be a result of previous executions of the LVC.

In Figure 15 an overview of the proposed approach is presented highlighting all the alternative paths of the LVC tool, including the use of the two simulation tools previously described:

- Smart Power Flow, which is a tool capable of identifying the best suited solution for a given voltage violation.
- State Estimation as a simulation tool to test the proposed control actions within the LVC.

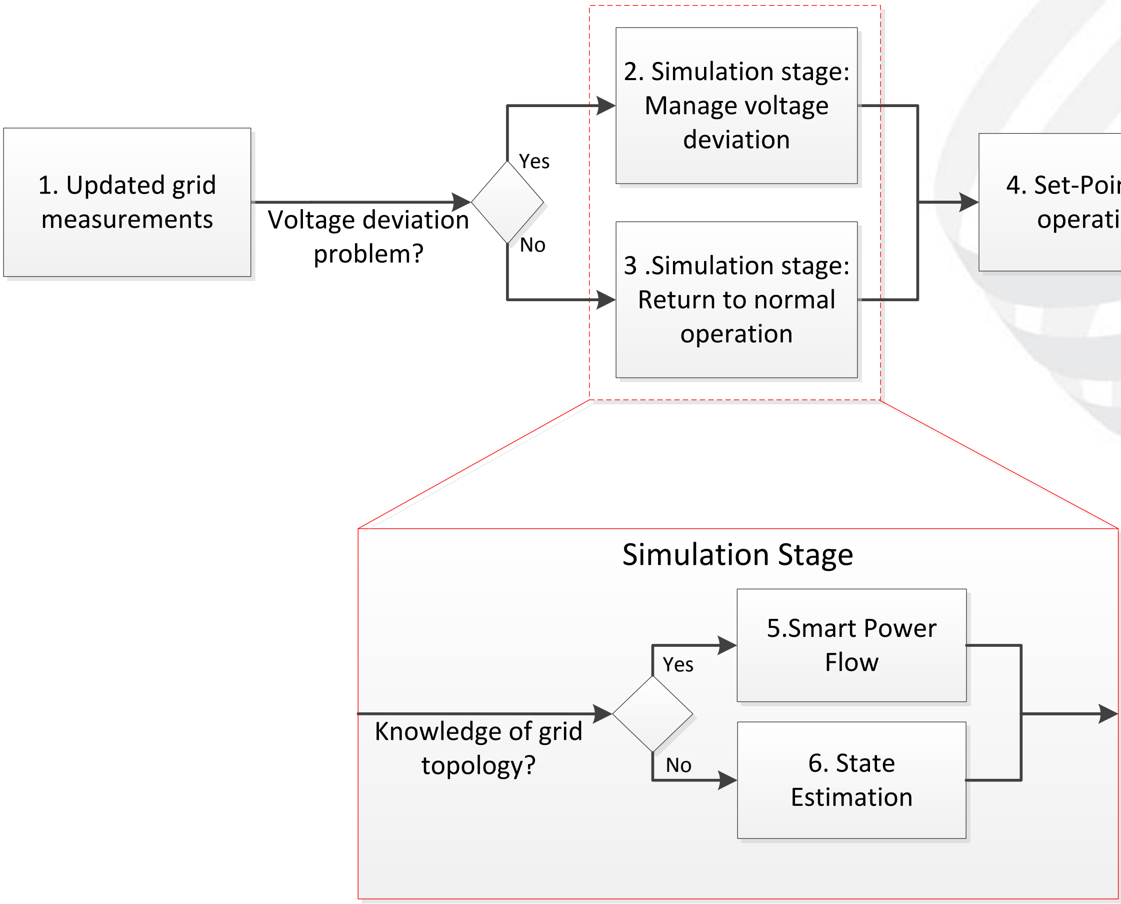


Figure 15 – Overview of Voltage Control in LV Networks Tool

As previously mentioned, this tool is expected to externally interact with the State Estimation for LV Networks tool presented in section 2 in order to assess the current status of the LV grid, being an input to the tool. It may also be used internally, to evaluate the effect of the control actions e.g., test the selected set-points in the case there is limited knowledge of the LV network topology and characteristics.

The implemented methodology is detailed below.

Low Voltage Control (LVC) tool overview

1. Retrieve updated grid measurements

Information related to the state of the grid may be directly relayed by the available smart meters throughout the network. In case some measurements are not updated or some of the smart meters are not available in real time, meaning that these measures cannot be obtained with the required periodicity, the State Estimation for LV Networks is used to obtain the missing measurements.
The State Estimation module provides the complete description of the grid's operation status, namely the voltages magnitudes and injected active power in each node of the grid. Naturally, the precision of the obtained results may vary in accordance with the quality of the input data available, so it is important that the data retrieved is frequently updated.

2. Manage voltage deviation

A voltage deviation situation has been detected from the available input voltage measurements.
Within this process, set-points for the selected equipment will be recursively calculated and tested using the Smart Power Flow or the State Estimation in order to find a combination of actions that is able to solve the voltage deviation problem. This process is explained in more detail in Figure 16 – Detailed action flowchart of the simulation stage.

3. Return to normal operation

This step is only triggered when the grid is operating within the voltage limits and there are grid equipment that are restricted (i.e., with imposed set-points). In this case, the priority is to remove these limitations whenever possible, i.e. when the system can safely operate with the equipment unrestricted.
This process is similar to the step: "2 – Manage voltage deviation". A set-point corresponding to the normal operation state (predefined value) is tested for the current time using the simulation platforms previously mentioned. After the simulation, if the voltage limits are respected throughout the grid, new set-points are sent to the respective equipment. It is possible to modify the equipment default values of operation, for several time windows of a day, which is an input of the LVC tool.

4. Send set-points to DSO controllable equipment

The set-points of operation, determined by either of the two previous steps (2 and 3), are sent to the corresponding grid equipment to manage the voltage deviation or to return the equipment to their normal state of operation. These set-points were selected and tested and should be the best suited solution according to the control methodology proposed.

5. Run the Smart Power Flow (simulation stage)

The smart power flow is used in scenario a) when there is complete information on the grid topology as well as on the electric characteristics of all grid components making it possible to run a three-phase unbalanced power flow. It is defined as a series of power flow calculations (using in this case a forward-backward sweep algorithm) that aims at testing various solutions to mitigate the problem by changing the operating points of the considered equipment in order to determine the most suitable option able to solve a given technical problem, according to the objectives established or manage the limitations previously imposed in the controllable resources. The simulation follows a set of control guidelines to apply in the grid's controllable resources sorted in a merit order of actuation.

6. Run the State Estimation for LV Networks as a simulation tool (simulation stage)

This methodology of control is used in scenario b) when the grid topology is unknown. It uses the State Estimation for LV Networks module as a simulation tool for assessing the impact of the control actions to be imposed to the grid's controllable resources. The method consists in simulating a set of control actions for the controllable resources available following a control action scheme for each grid equipment, which are sorted according to relevant factors in a priority list of actuation. It is a similar approach as the Smart Power Flow (following the same control guidelines) but the results of the simulation are estimated values.

An overview of the simulation stage methodology is presented in the form of an action flowchart in Figure 16 and a detailed description is provided in the next paragraphs. This process is related to the step 2: "Manage voltage deviation" previously described above.

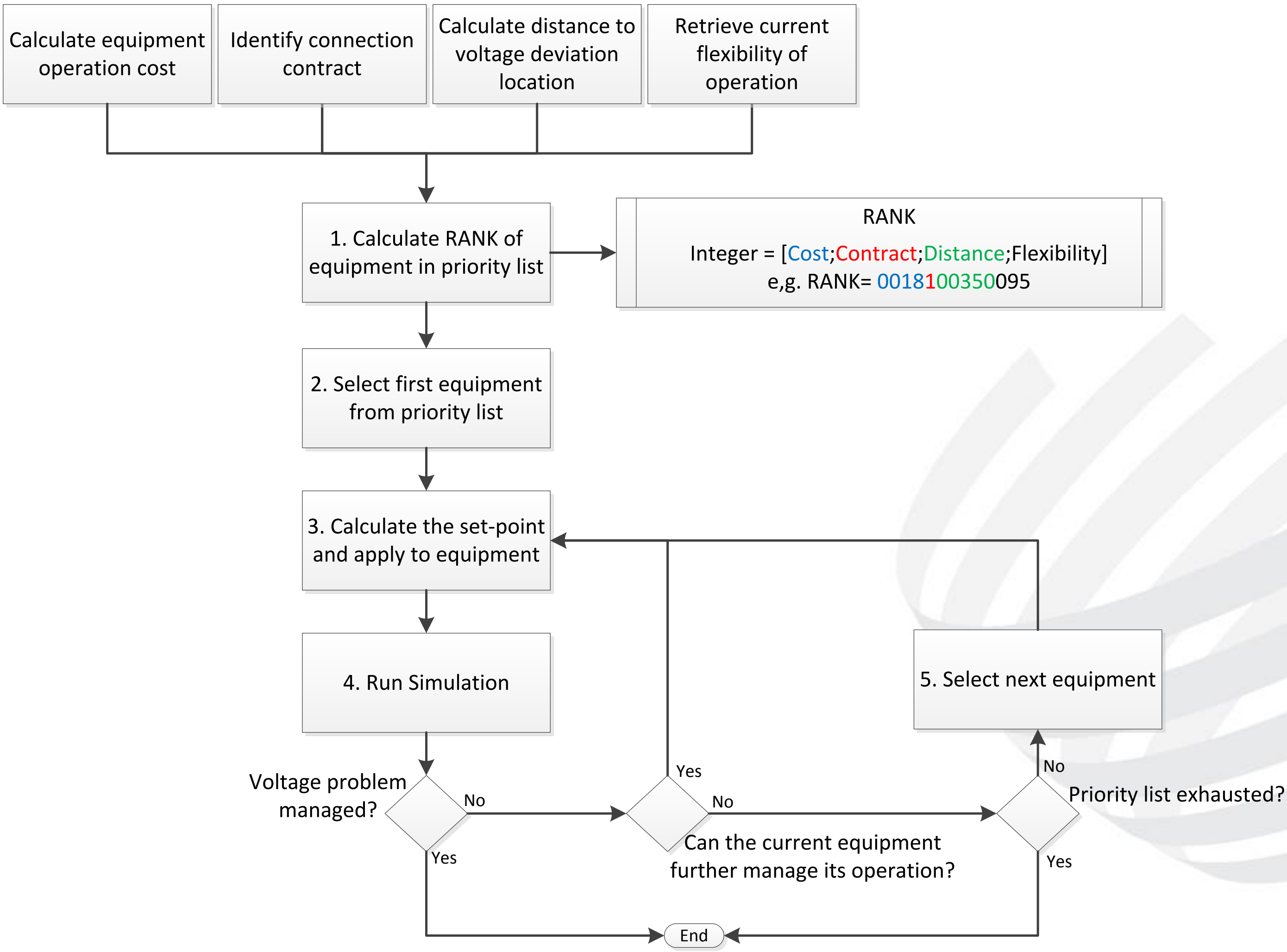


Figure 16 – Detailed action flowchart of the simulation stage.

LVC simulation stage

The simulation system is intended to be used to test possible set-points of operation on grid's controllable resources in order to control a voltage deviation or, in case there is no technical problem, to test the possibility of removing previously imposed power limitations. The proposed methodology in presence of a voltage deviation is detailed below. When the network is operating in normal conditions but when power limitations are imposed, the control algorithm is similar but uses different priorities.

1. Calculate rank of equipment in priority list

It is necessary to sort the available controllable equipment in a priority list of actuation. This merit list will define the first and last equipment to be actuated regarding their given rank. The rank is calculated according to the actuation cost of the equipment, the type of connection contract with the DSO, the distance to the voltage deviation location and the current flexibility of operation, which will result in a final integer (as shown in Figure 16). The list is sorted numerically in increasing order so that the equipment with lower ranks are actuated first. Connection contracts and flexibility of operation are variables coded internally that, given the equipment characteristics, are transposed to a numeric number following the ranking logic implemented (see example in Figure 16).

2. *Select first equipment from priority list*

The first equipment in the merit order of actuation list is selected, it is the best option given the control criteria here established i.e., lowest rank.

3. *Calculate the set-point and apply to equipment*

Regarding the selected equipment the calculated set-point, will take into account the type and characteristics of the equipment in question and the magnitude of the voltage deviation. In order to determine the best suited set-point, some guidelines are considered for each equipment type as follows.

Storage devices

For the case of the storage devices the parameters considered for the control actions are presented in the table below. The values presented reflect the percentage of available power to be reduced/increased, according to the geographical distance and the voltage deviation from a predefined reference value. These tables are specific for each LV network and the percentages and distances considered can be changed by the DSO. The values presented here should be considered only as indicative.

	Distance between asset and voltage deviation location (m)			
Voltage deviation (from 1 p.u.)	d < 100	100 < d < 500	500 < d < 1000	d > 1000
8%	10 %	20 %	30 %	50 %
10%	20 %	30 %	40 %	60 %
12%	40 %	50 %	60 %	80 %
15%	60 %	70 %	80 %	100 %

Table 5 – Parameters for control actions for storage devices

Once the magnitude of the voltage deviation is assessed, a set-point of operation is simulated for the selected grid asset. Regarding the specific case of storage devices, when it is necessary to change their operation mode (from consuming to injecting or vice-versa), the values in the table above will be applied with the same magnitude but with opposite sign. If in the next iteration, the problem persists, a new set-point is calculated and simulated, in this case enabling more power in the chosen storage device.

OLTC transformer

For this resource, a change in the transformer tap is attempted (one step position). After evaluating the effects of this control action, if necessary and feasible, another change in the transformer tap of one position may be attempted (one step). This step may be executed as many times as necessary until the transformer tap reaches one of its limits.

DG units / flexible loads
A similar approach to the one for the storage devices is followed but in this case for DG units or flexible loads. In the table below an example of guideline that could be used for these control actions is presented. It is defined for the case of an overvoltage with the associated power reduction in the DG units as a percentage of the injected power.
As in the case of the storage devices, this table is specific for each LV network and its parameters (distances and percentages) may be changed by the DSO.

	Distance between asset and voltage deviation (m)			
Voltage deviation (from 1 p.u.)	d < 100	100 < d < 500	500 < d < 1000	d > 1000
8%	10 %	20 %	30 %	50 %
10%	20 %	30 %	40 %	60 %
12%	40 %	50 %	60 %	80 %
15%	60 %	70 %	80 %	100 %

Table 6 – Guidelines for control actions for DG units / flexible loads

4. *Run simulation*

In this simulation stage, the impact of each set-point provided by the algorithm is evaluated. As previously explained, the simulation may use either the Smart Power Flow or State Estimation, depending on the level of information available for each specific grid.

5. *Select next equipment available from priority list*

When the current equipment becomes unavailable for further regulation (usually because of operational limits of the device), the next equipment in the priority list will then be selected to manage the problem.

3.5 Illustrative Example

3.5.1 Description

The test network used for evaluating the performance of the algorithm is a three-phase LV network with three main feeders fed by a 100 kVA distribution transformer. A one-line diagram of this network can be seen in Figure 17 with the location and distribution of the consumers, microgeneration units (all were considered to be PV units), storage devices and smart meters (EB). For this network, the full characteristics of the network including the geographical coordinates of all the equipment are available.

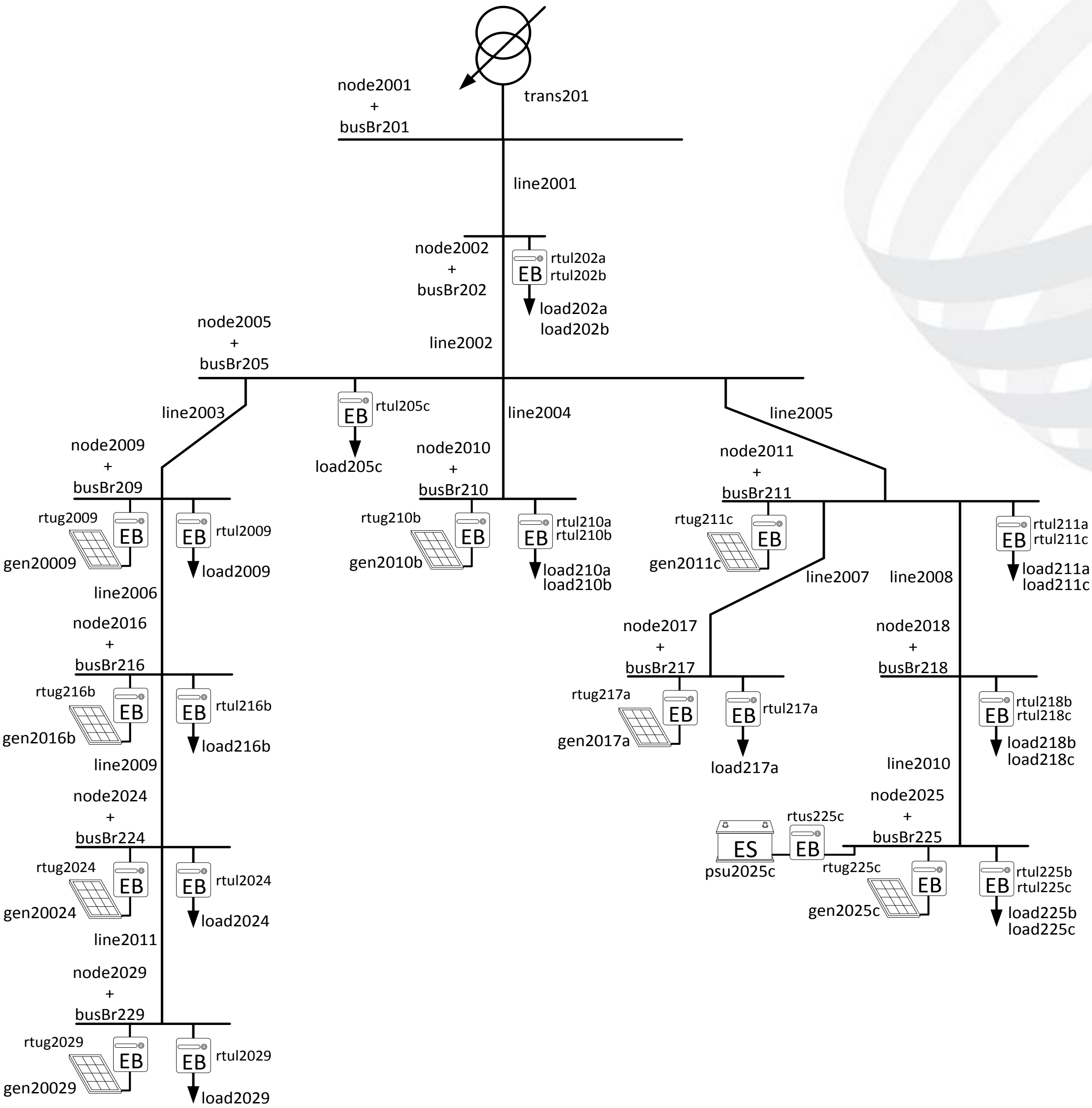


Figure 17 – Test Network

The costs associated with the use of each type of asset considered in this example are presented in the table below. These are only indicative costs which are an approximated value of the cost function for each equipment. The complete description and formulation of the costs associated to each asset will be included in deliverable D3.4.

Type of Equipment	Cost
OLTC	0.043 (€ per tap position change)
PSU	10 (€/MWh)
Load	14.83 (€/MWh)
DG unit	19.8 (€/MWh)

Table 7 – Example of costs for control actions

In order to test and assess the performance of the algorithm proposed for Low Voltage Control, different scenarios for this network were considered. In the next sections, results are presented for a situation where a voltage deviation occurred somewhere in the grid. The tool is used to solve the problem using either the Smart Power Flow or the State Estimation for LV Networks in order to simulate the control actions to be applied and evaluate the results obtained.

Considering scenario a), where a full description of the network is available and all metering devices are equipped with technology that allow real-time relay of the information, meaning that all critical measurements of the network are available, the Smart Power Flow may be executed within the Low Voltage Control tool.

Considering scenario b), only a set of metering devices are assumed to have real-time information transmission capability, which implies that not all measurements of the network are obtained or updated. In this case, the State Estimation for LV Networks tool is used in order to obtain the missing measurements of the network.

The main difference between the two scenarios is the simulation tool that is used within the Low Voltage Control tool to test the different set-points to be applied in the selected equipment.
For both scenarios, a voltage violation situation is detected in the network (in this case an overvoltage in bus bar 25 – busBr225 in Figure 17). This is the baseline scenario for the proposed simulations, since it is a scenario for which the LV grid has a significant amount of generation from the PV installations which lead to higher voltage levels throughout the network. In this particular case, the highest voltage value occurs at bus bar 25, for which the voltage magnitude exceeds the imposed voltage limits.

The Low Voltage Control tool algorithm has default input parameters that may be changed considering user preference, *i.e.* by the DSO. Some examples of these parameters are the selection by type of the equipment to be considered in the algorithm, the voltage limits and the estimation error considered.

For these test cases, a 5% voltage limit variation is considered regarding the nominal voltage, so the voltage limits considered are defined in the interval [218.5; 241.5] V. It must be stressed that, a measurement error associated with the State Estimation for LV Networks tool is added to that limit corresponding to 2% of the nominal voltage (U_n = 230 V) in order to be on the safe side, i.e. ensure that all possible voltage violations are identified by the algorithm. Therefore, admissible voltage values for the LVC tool should be within the interval [223.1; 236.9] V (note that 223.1 = 218.5 + 230 x 2% and 236.9 = 241.5 – 230 x 2%).

3.5.2 Results

Scenario a)

Figure 18 shows the output of the LVC tool. As can be observed, the overvoltage has been detected and the available equipment were identified. The set-points were then determined and tested using the Smart Power Flow until a solution to the problem was found.

```
-------------------------------------- EVOLVDSO -------------------------------------
-------------------------------- LOW VOLTAGE CONTROL --------------------------------
-------------------------------------------------------------------------------------

 :: Overvoltage Detected

   Voltage Value (V): 249.685023
   Problem location: busBr225
   Phase: 3

 :: Merit order of the controllable units

   UNIT ID: trans201
   UNIT ID: psu2025c
   UNIT ID: gen2025c
   UNIT ID: gen2011c
   UNIT ID: gen20029
   UNIT ID: gen20024

 :: Control Action Management System - with Smart Power Flow tool

   *Voltage Problem Managed*

 :: LVC Output

   Operational Set-points:
    Unit ID: psu2025c -> Set-point(kW): 2.000

--------------------------------- LOW VOLTAGE CONTROL ---------------------------------
---------------------------------------- END ------------------------------------------
```

Figure 18 – Output of the Voltage Control in LV Networks Tool for Scenario a) (1)

The procedure that was followed by the tool is described in more detail below in order to show the control methodology.

As previously mentioned, an overvoltage situation has occurred and the highest voltage in the network was identified in bus bar 25 having a corresponding value of 249.68 V, which is above the admissible limit of 236.9 V.

The next step was to identify the available resources located in the same phase of the overvoltage and sort the equipment according to the pre-defined merit order. The resulting list of controllable resources, sorted by merit order of actuation, is as follows:

Order	Unit ID
1	Trans201
2	Psu2025c
3	Gen2025c
4	Gen2011c
5	Gen20029
6	Gen20024

Table 8 – Merit order of the controllable resources (Scenario a)

The first device selected should be the MV/LV transformer (Trans201) however it was assumed that due to not having OLTC capability, or the impossibility of further regulation in this specific moment, this resource is in fact unavailable. The next equipment is then selected, *i.e.* a storage device (Psu2025c). The set-point for this storage device is determined (equivalent to 50% of its nominal power) and then this new operational set-point is tested in order to assess the impact of this control action in the voltage profiles using the Smart Power Flow. In this case, the voltage problem is solved with the determined set-point. In case the problem remained, if the chosen equipment could still be actuated, another set-point would be determined and tested, otherwise another equipment would be selected from the list and the process would continue.

In this example, only one control action was required, as shown in the table below. The final output of the LVC tool is therefore an operation set-point of 2kW (absorbing power from the grid) for storage device Psu2025c. Internally in the LVC algorithm and in the final output (Figure 18, Figure 19 and Figure 20), injected power is treated as a negative value and positive values refer to power consumption. In order to simplify the presentation and ease the understanding of the obtained outputs, the final results are summarized in the tables below, with the essential information and disregarding the signal of the power values.

Steps	Unit ID	Initial Power (kW)	Set-Point (kW)
1	Psu2025c	0	2

Table 9 – Control action defined by the LVC tool (Scenario a)

As can be seen in Table 10, the overvoltage value in bus 25 was brought back to an admissible value following the control action that was applied.

Voltage value (V)	Location	Phase
233.67	Busbar 25 (Busbr225)	c

Table 10 – Voltage after control action of the LVC tool (Scenario a)

Another run of the algorithm was done for the same initial conditions but imposing a full state of charge for the storage device Psu2025c. This means that this resource is now unavailable for mitigating the voltage problem identified as this storage device cannot store more power. The outputs of the LVC tool obtained for this situation are shown in Figure 19.

```
--------------------------------------- EVOLVDSO ---------------------------------------
--------------------------------- LOW VOLTAGE CONTROL ----------------------------------
-----------------------------------------------------------------------------------------

 :: Overvoltage Detected

   Voltage Value (V): 249.685023
   Problem location: busBr225
   Phase: 3

 :: Merit order of the controllable units

   UNIT ID: trans201
   UNIT ID: psu2025c
   UNIT ID: gen2025c
   UNIT ID: gen2011c
   UNIT ID: gen20029
   UNIT ID: gen20024

 :: Control Action Management System - with Smart Power Flow tool

   *Voltage Problem Managed*

 :: LVC Output

   Operational Set-points:
    Unit ID: gen2025c -> Set-point(kW): 0.000
    Unit ID: gen2011c -> Set-point(kW): 0.000

--------------------------------- LOW VOLTAGE CONTROL ----------------------------------
----------------------------------------- END ------------------------------------------
```

Figure 19 – Output of the Voltage Control in LV Networks Tool for Scenario a) (2)

In this case, the sorted list of controllable resources sorted by merit order of actuation is the same as the previous example. The main difference is the selection of the equipment routine within the algorithm that validates the technical and contractual limits of each equipment. If an equipment is not available, the next equipment is selected and the control methodology resumes.

In this case, since it is assumed that the transformer Trans201 does not have OLTC capability and storage device Psu2025c is at full state of charge, the next unit to be selected is microgeneration unit Gen2025c. Since there is an overvoltage problem and this is a generation unit that is not dispatchable, any operational set-point imposed means that there will be curtailment of active power.

In Table 11, the control set-point determined and the results of the iterations using the Smart Power Flow in order to mitigate the overvoltage problem existing at bus 25 are shown.

Steps	Unit ID	Initial Power (kW)	Set-Point (kW)	Power Curtailed (kW)	Voltage (V)
1	Gen2025c	1.61	0.41	1.2	240.57
2	Gen2025c	0.41	0	0.41	237.06
3	Gen2011c	0.96	0	0.96	231.24

Table 11 – Control action defined by the LVC tool (Scenario a) (2)

The first set-point determined to be applied to microgeneration unit Gen2025c, is equivalent to 0.41 kW. As the voltage violation still persists after that control action, another set-point is determined and applied to the same unit, which in this case corresponds to curtailing the total active power provided by that unit.

Since the voltage value is still above the admissible limit, another equipment is selected and a new set-point is calculated for another microgeneration unit (in this case Gen2011c). This control action also curtails all the power provided by microgeneration unit Gen2011c.

After these control actions, the voltage problem is managed and the final output of the algorithm is to curtail microgeneration units Gen2025c and Gen2011c. The final voltage value is shown below.

Voltage value (V)	Location	Phase
231.24	Busbar 25 (Busbr225)	c

Table 12 – Voltage after control action of the LVC tool (Scenario a) (2)

Scenario b)

In this scenario, the same initial conditions are considered (occurrence of an overvoltage in bus 25) and the storage device Psu2025c has a state of charge of 100%. The main difference between the test cases is the simulation tool used. In this case, the State Estimation for LV Networks is used in order to test the operational set-point determined for each equipment.

```
--------------------------------------- EVOLVDSO ---------------------------------------
--------------------------------- LOW VOLTAGE CONTROL ---------------------------------
----------------------------------------------------------------------------------------

 :: Overvoltage Detected

   Voltage Value (V): 249.685023
   Problem location: busBr225
   Phase: 3

 :: Merit order of the controllable units

   UNIT ID: trans201
   UNIT ID: gen2025c
   UNIT ID: gen2011c
   UNIT ID: gen20029
   UNIT ID: gen20024

 :: Control Action Management System - with State Estimation tool

   *Voltage Problem Managed*

 :: LVC Output

   Operational Set-points:
    Unit ID: gen2025c -> Set-point(kW): 0.000
    Unit ID: gen2011c -> Set-point(kW): 0.000
    Unit ID: gen20029 -> Set-point(kW): 0.000

--------------------------------- LOW VOLTAGE CONTROL ---------------------------------
---------------------------------------- END ----------------------------------------
```

Figure 20 – Output of the Voltage Control in LV Networks Tool for Scenario b)

Since the initial conditions are the same for this test case, the overvoltage location and magnitude are the same as in the example in the previous section. The main differences are related with the number of set-points generated for the available assets in order to control the overvoltage.

This list of equipment does not include the storage device Psu2025c unit because there are no historical values of that unit in the network and without historical values the state estimation procedure cannot find a correct correlation with the operational variation of that unit. As a result, the algorithm does not consider that equipment for the merit order of actuation.

Order	Unit ID
1	Trans201
3	Gen2025c
4	Gen2011c
5	Gen20029
6	Gen20024

Table 13 – Merit order of the controllable resources (Scenario b)

For this case, the control actions defined by the LVC tool are presented in Table 14.

Steps	Unit ID	Initial Power (kW)	Set-Point (kW)	Power Curtailed (kW)	Voltage (V)
1	Gen2025c	1.61	0.41	1.2	241.03
2	Gen2025c	0.41	0	0.41	240.18
3	Gen2011c	0.96	0	0.96	240.05
4	Gen20029	0.96	0	0.96	235.10

Table 14 – Control action defined by the LVC tool (Scenario b)

As can be observed, the output of the LVC tool consists of 3 set-points, all of them corresponding to power curtailment of the totality of generation in for microgeneration the units Gen2025c, Gen2011c and Gen20029.

One of the potential weaknesses of the State Estimation tool is directly connected to the quality/quantity of the historical data available. For the LVC tool, high quality data represents an existence of historical variation data of the controllable equipment of the grid; otherwise, when curtailing entirely one generation unit, without having a single historical scenario with these conditions (e.g., photovoltaic generation units at 60% of nominal power and one restricted at 0%) may lead to higher estimation errors.

Observing Table 14, a higher voltage variation for the same control action (same amount of power curtailment) for step 4 in relation to step 3 can be observed, being the equipment in step 3 best suited to manage the voltage deviation (since it is connected electrically closer to the overvoltage location). This can be explained by the fact that the quality of the historical data for the test grid available for these simulations is not good since it does not include an event where unit Gen2011c is disconnected from the grid. Consequently, having higher quality/quantity of historical data will improve substantially the efficiency of the State Estimation process.

In conclusion, from the tests that have been performed, it is clear that the results obtained using the State Estimation for LV Networks are not as good as the ones using the Smart Power Flow, since estimation is not as precise. This is because the estimation error of the State Estimation for LV Networks that is used as a simulation tool has a direct influence on the quantity and quality of the historical data available. Still, the obtained results seem to be robust enough and provide good feedback regarding the definition of possible operation points for the available equipment.

4 Robust Short-Term Economic Optimization Tool for Operational Planning

The System Use Case "Identify and solve network constraints for a given zone and an optimization application period in operational planning" is the scope of the tool described in this section. The time horizon of the algorithm is Operational Planning, which is a maximum 72 hours before the considered period.

The tool has the objective to optimize the network management acting on the resources the DSO can use. Basically, it is made by three modules described in the following sub-sections:

- Identification of violated network constraints;
- Economic analysis of the optimization levers;
- Techno-economic optimization.

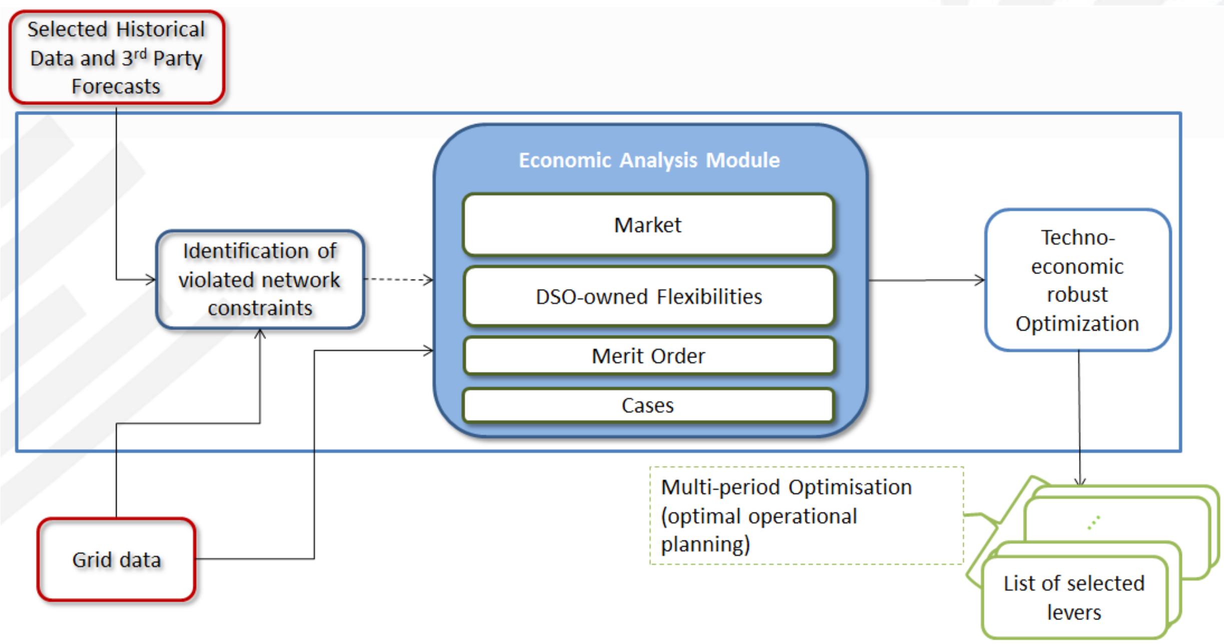


Figure 21 – Operational Planning algorithm

The first module *"Identification of violated network constraints"* identifies the constraints violated in the network through a classic power flow analysis. Its information, together with the market and the DSO preferences are the input for the economic analysis module which aims to give an economic value to the levers the DSO can use to optimize the network. The techno-economic robust optimization module has two different approaches: the former maintains voltages and currents within the desired ranges, minimizing the dispatching costs for the DSO. The latter uses constraint programming to tackle combinatorial complexity.

Both optimization components can run in parallel and their combination delivers the "best of both worlds" quality output. A comparison between the two solutions performance allows tackling the same problem with different approaches, confirming some aspects and/or highlighting some points that could not be considered from one of them.
In the following, each of the modules are described, illustrating the approach, the inputs/outputs and usage within the whole tool.

4.1 Relation with System Use Case

In Figure 22 the main steps of the SUC "Identify and solve network constraints for a given zone and an optimization application period in operational planning", which is fully described in [2], are reviewed. This SUC recalls other SUCs, in particular the SUC "Identify network constraints in operational planning" and "Solve network constraints using optimization levers based on a merit-order". Both these SUCs are fulfilled by different subtools which make up the whole tool, so the main SUC is completely covered by this tool. For this tool the SUC is applied to the MV network.

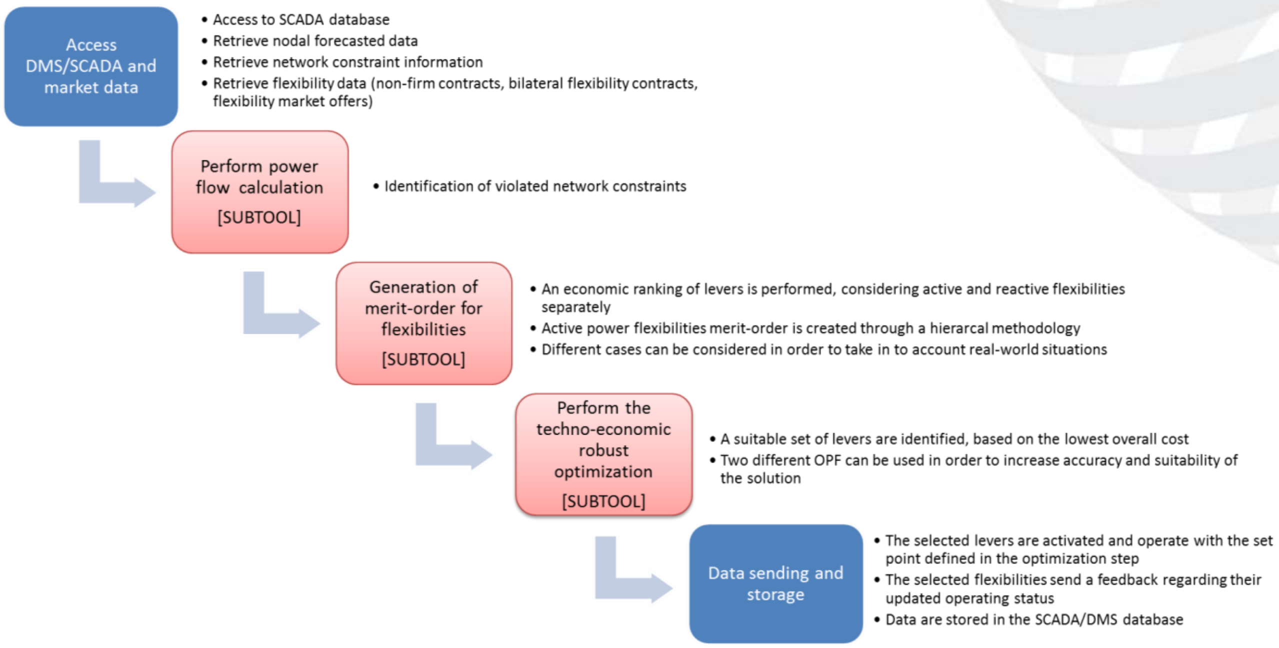


Figure 22 – Relation between system use case steps and the Robust Short-Term Economic Optimization Tool for Operational Planning.

Initially, all data from the DMS/SCADA database are retrieved, as for load and generation profiles, grid data and flexibility data.
In the second step, which formally corresponds to SUC "Identify network constraints in operational planning", a power flow calculation is run in order to identify the violated constraints which are made available for the other subtools. The third step is the core function of this tool, since it creates the merit-order of the available flexibilities allowing a more accurate optimization; the merit-order could be used as an input for other tools.

The minimum cost solution is obtained in the fourth step by the means of the techno-economic robust optimization, which can be performed through two different, and complementary, optimization algorithms. These two steps formally correspond to the SUC ”Solve network constraints using optimization levers based on a merit-order”, which is the most important function of the main SUC. Finally, the results are stored again in the DMS/SCADA database; they can also be used in the activation requests to be send to flexibility providers.

The merit-order and the optimizer subtools are the two core functions of the main SUC and fulfils its main objective and requirements.
The match between WP2 non-functional requirements and Robust Short-Term Economic Optimization Tool for Operational Planning is presented in ANNEX V – Match between Tools and WP2 Requirements.

4.2 Methodology and Algorithm Description

Medium voltage distribution networks usually possess inherent flexibilities that allow Distribution System Operators (DSOs) to manage violations of network constraints; a high integration of DRES, because of their intermittence, can cause an increase in the frequency of occurrence of these violations. In these operating conditions the network management based only on inherent flexibilities may become insufficient or ineffective.
A proactive approach, based both on the inherent flexibilities than on other external flexibilities available for the exploitation, is therefore necessary to deal with this new operating scenario.
However, since these are not inherent to the network, meaning that the devices or equipment that offer these flexibilities are not owned by the DSO, they will come with contractual obligations and a price. While at the transmission network level, a well-defined system and methodology exists for the procurement of flexibilities, at the distribution network level, such a system does not exist yet. However, for the purpose of this tool, which is a tool that looks at the problem from a DSO point of view, dwelling into the procurement methods of flexibilities is out of scope. The consideration made is that the flexibilities are already available through their interfaces, and can be exploited by the tool within the offered limits. This is a valid consideration because in future, a procurement system for distribution networks will have to be instituted anyway.

4.2.1 Grid Data and Forecasts

The tool needs to receive as input: (1) the physical model of the grid under study, as well as (2) a 24h forecast of all planned consumption and production in the grid.
The grid model includes the physical structure of the grid, as well as the impedances of all cables and lines. Also, the ratings of each cable/line are given, as well as the minimal and maximal allowed bus voltages.
For each bus, a forecast of the planned production and consumption has to be available, preferably on a quarter-hour basis (thus 96 data points). Next to this, the production and

consumption model type has to be known: constant impedance, constant power, or other models can be considered.

Since the operational planning tool is developed for MV networks, it is assumed that the phases in the network are balanced. It is thus assumed that single-phase equivalent grid models have sufficient accuracy. Also, for the sake of simplicity, it is further on assumed that every consumption and production unit is of the constant power type. The slack-bus voltage, i.e. the voltage at the connection point with the transmission grid, is assumed to be fixed at 1 p.u.

4.2.2 Identification of Violated Network Constraints

Given the grid data, along with DRES and load forecasts, the "identification of violated network constraints" sub-tool is responsible for identifying, for every time step in the forecasts, the constraints that are violated in the network. In medium voltage distribution networks, two types of constraints exist: voltage and current constraints. Voltage constraints are set at ±5% of the nominal voltage value of the network, according to the European Standard EN 50160 [54], and are imposed on nodes (or buses) in the network. Current constraints depend on the maximum rated current that can flow through power lines and cables present in the network. Unlike voltage constraints, these constraints vary from one power line to another.

The entire tool works with 96 time periods of 15 minutes each, which corresponds to one day. For each of the time periods, a snapshot of the network is obtained by setting the DRES and load forecast values for that time period, and a load-flow routine is run on the network in order to evaluate the bus / node voltages and line currents. This load-flow routine is based on the well-known Newton-Raphson method, modified in order to accommodate DRES in the network. Once the execution of the sub-tool is completed, the results obtained include the location, seriousness, and type of the violated constraints for each time period in the network.

This data is communicated to the other sub-tools in the JavaScript Object Notation (JSON) format. The reason for using this human-readable open standard format will be explained later in the text. A flowchart illustrating the functioning of the tool is shown in Figure 23.

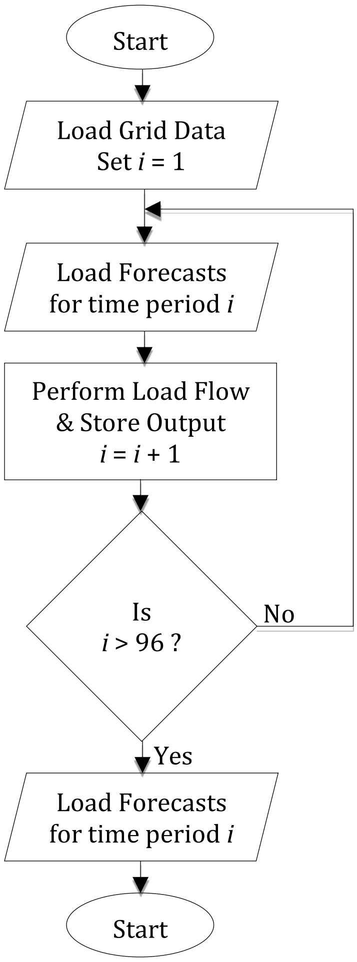


Figure 23 – Flowchart: Identification of Violated Network Constraints

4.2.3 Economic Analysis

As explained earlier, in order to allow DSOs to effectively choose between flexibilities available in their networks, an economic analysis of these flexibilities is required. Once this economic analysis is done a ranking of flexibilities, in the form of a merit order, is needed in order to guide the decision-making process for their usage. This is the aim of the economic analysis module. In this module, concepts and methods have been developed in order to evaluate various distribution network levers in a short-term timeframe, a list of which is presented in the table below. Levers in the table are either DSO owned or offered through another actor. They are also either basic, meaning that they are already used by DSO in their networks, or advanced, meaning that while the potential for their use exists, they are not implemented in a large scale.

Flexibility	Ownership	Type
Grid Reconfiguration	DSO	Basic / Advanced
On-Load Tap Changer	DSO	Basic
Traditional Reactive Power Compensation	DSO	Basic

DRES Reactive Power Compensation	Third-Party	Advanced
Storage	Third-Party	Advanced
Non-Renewable Distributed Generation	Third-Party	Advanced
DRES Curtailment	Third-Party	Advanced
Load Modulation	Third-Party	Advanced

Table 15 – List of Levers for Economic Analysis

The methodology of economic analysis of levers depends on four principal factors. The tool in which this analysis is being performed is designed to work in a short-term timeframe, on a specific type of network. This results in some considerations being made as part of what components of the economics of each of the levers is taken into account.

When a DSO decides to introduce new flexibility assets in its network, the goal will always be to reduce or avoid expenditures related to traditional investments, like network reinforcement. At any moment in time, a cost/benefit analysis is needed in order to see which flexibility asset is most suited to solve existing grid issues in the most cost effective way. An important part of the cost/benefit analysis is related to investment costs and pay-back times. In the long term it is obvious that the investment has to pay itself back in order to be profitable. In the short-term however, there are several reasons due to which the investment may not be considered in the analysis, even though it is understood that the return of investment needs to happen for the flexibility.

Generally, within the economic analysis of the flexibility assets, investment costs have to be considered. Nevertheless, there are specific conditions where the investment costs are subordinate to the variable costs and/or operational costs of the asset. It is not always obvious as to whether investment costs have to be taken into account or not. It depends on several factors. An overview of the major factors which influence the relevance of investment and/or depreciation costs in the actual cost structure of a flexibility asset is presented here.

Factors influencing the relevance of investment and depreciation costs

In its most simple form, the depreciation cost is used as a method to allocate the cost of a tangible asset over its useful life. In the context of evolvDSO it makes sense to relate the depreciation as a cost/MWh or cost/MVArh. Overall, there are four different factors that can influence the relevance of investment and depreciation costs.

Time frame

The evaluation time frame has an impact on the inclusion of a depreciation cost. This is the first factor that has to be considered in the analysis, and is illustrated with 2 extreme examples:

- Time frame = lifetime of the asset: In this case the investment and/or depreciation cost is relevant and in many cases the most important consideration in the decision process. This applies to a time frame of several years, and is mostly useful for network planning.

- Timeframe = now: Once an investment is done, it is considered a “sunk cost”. In economics and business decision-making, a “sunk cost” is a cost that has been made and cannot be recovered. Assuming an asset, which has no maintenance costs and which lifetime is not influenced by using it, has no operational costs. The more this asset is used, the cheaper the cost/MWh this asset will be. For such an asset, irrespective of the investment cost, the aim will be to use it as much as possible in the short-term. This is the only way by which the investment made can be deemed useful. If the asset does have operational costs, other factors described below have to be taken into consideration for the analysis.

Ownership of the flexibility asset and investment costs

- DSO owns the flexibility: When the DSO owns the flexibility, the investment cost has been made and is considered a “sunk cost”. Whether the DSO uses the flexibility asset or not, the investment cost is made. The more the DSO can use his flexibility asset the cheaper the cost/MWh becomes, with a consideration of the kind of depreciation (explained below).
- A third-party owns the flexibility: The only way to recover investment costs made by a third-party is to include a component for the investment costs in the offer made for the flexibility.

Kind of depreciation

Depreciation costs can be considered as relevant for the determination of the economic value of flexibility depending on the way how a flexibility asset depreciates. For that reason, three different cases are considered:

- The use of the flexibility asset has no variable costs and does not influence lifetime: The depreciation of the flexibility asset is independent of the use. This means that the more the flexibility is used, the better it is for the investor, as the unit cost becomes cheaper.
- The use of the flexibility asset reduces the lifetime: In this case the degradation of the asset has to be included in the operational cost/MWh. This degradation, when included in the operational cost, will effectively monetize the reduction of the asset’s lifetime, a higher value for which may have been considered when an investment was made.
- The use of the flexibility asset increases maintenance costs: In this case, the maintenance costs should be included in the operational cost/MWh. This means that by increasing the maintenance costs (more parts to replace every x operations), the lifetime of the asset is maintained constant. Therefore, the depreciation costs need not be included. This increase in the maintenance cost component could either mean that a higher number of maintenance operations is performed, or that a higher amount of money is spent during every periodic maintenance activity.

Purpose of the investment

For a third-party flexibility, the purpose of investment is an essential factor:

- Investment is purely for offering flexibility: In this case the only source of income is using the flexibility and it is important that the investment costs are paid back over the lifetime of the asset. Therefore, investment costs are an essential component of the economic model.
- Investment is not related for offering flexibility: Some assets can offer flexibility services but it is not the original goal of the asset. A good example are the demand response services offered by companies, or the reactive power compensation of DRES. Their goal is production of goods (demand response) or injection of produced power (DRES), and the investment cost analysis is done on their main business goal. Offering flexibility to a DSO is an additional source of income which is purely opportunity cost driven.

In general, the analysis of each flexibility that follows is done in a specific way. First, the purpose and general information related to the lever is ascertained. This is followed by an analysis of the technical functioning of the lever, its limits, and its method. Then the economic parameterization works out the various components that contribute to the cost of use of the lever. If applicable, this is done through an evaluation of the strategies of the owners of the flexibility under normal conditions, and the potential losses incurred when a DSO request for flexibility upsets the normal operating strategy of the device offering the flexibility. A minimum compensation requirement is derived from this information. This minimum compensation becomes therefore the minimum cost that DSO will pay to make use of the flexibility economically feasible for its owner.

4.2.3.1 Flexibility Lever Analysis

In this paragraph the most significant flexibility levers for distribution grids are reviewed. This is only a brief summary of the detailed description of these levers which is presented in Deliverable D3.4, together with a common calculation methodology for flexibility costs, shared and approved by all the project partners, based on the methodology specifically developed by INPG, RSE and VITO for this tool.

1. Grid Reconfiguration

Grid reconfiguration is an operation performed by the DSO to change the topology of the distribution network . The network configuration can be optimized according to the load and generation profiles, with the purpose to limit/avoid congestions and constraints violations. Moreover, quality of supply and network management can be improved through the adoption of opportune network configurations.

Currently, in normal operating conditions, DSOs use a small number of grid topologies. Moreover, the remote control of devices is not adopted for normal operating situations but principally to localize and isolate faults (and consequently to restore the service to the isolated customers) or for maintenance works. The decision of what devices are used to change the network configuration is either based on the experience of network operators or managed by automated self-healing functions.

On one hand, grid reconfiguration can be exploited for several network management purposes, such as the improvement of power quality and/or hosting capacity or the minimization of grid losses, interruption durations, customers affected when faults occur etc. On the other hand, the constant innovation of power systems - also characterized by the increase of network automation points – and the evolution of the objectives for network management demonstrate how the DSO's past experience of operating the grid does not help with network administration anymore

Current habits show how grid reconfiguration is not primarily needed if significant changes do not occur in the system. Furthermore, since nowadays DSOs use an already efficient network topology and operate the network with secure continuity; further investigations are required to check how far they can push network efficiency and reliability using the grid reconfiguration resource.

Changes to the network topology can have positive effects on grid operation, such as the reduction of power losses, the increase of hosting capacity or continuity of supply. However, despite the possibility of monetizing these aspects, they cannot be taken into account since they require load-flow calculations that are out of the scope of this study.

2. *On-Load Tap Changer*

Transformers in primary substations are the connection point between the transmission system (managed by the TSO) and the distribution network (managed by the DSO). During the grid operation, voltage levels have to stay within a pre-defined range. However, the natural changes in the network conditions (for example due to load or generation variations) require control systems able to balance voltage variations and keep them in the desired boundaries.

An On-Load Tap Changer (OLTC) is a DSO owned flexibility – typically installed in primary substations – that contributes to the voltage regulation through the adjustment of the number of winding turns in the primary circuit. The main advantage of OLTCs is related to the possibility of changing the tap position (i.e. adjusting voltages) without disconnecting the transformer from the system, keeping the continuity of supply.

Different kinds of cost functions can be considered for a tap change, such as integral or fixed cost functions. In the former, the cost of each operation depends on the number of available operations before the maintenance.

The main costs that can be considered as key parameters for the economic model are the investment cost, the operating cost, the depreciation and the maintenance cost. Investment costs are independent on the number of operations in the lifetime of the OLTC and hence, they are not directly taken into account in this context, given that the focus is on short-term operation. The operating expenditures are mainly associated to OLTC losses that can be considered constant across the tapping range. In this context, operating costs are not considered.

3. ***Traditional Reactive Power Compensation (Capacitor Banks)***

Reactive power compensation owned by the DSO is an instrument used for network management purposes. As load and generation profiles change, voltages in network buses vary. Among the levers DSOs can use to optimize network voltage profiles, reactive power compensation is more than a candidate. In fact, DSOs use this resource at substation level mainly for the following purposes:

- Voltage regulation:
  In AC power systems, voltages can be controlled by managing reactive power absorption/injection. Shunt capacitors installed at primary substations control voltages, keeping it within the defined boundary when load and/or generation profiles change. This function is usually achieved with centralized systems.

- To decrease power losses:
  The presence of reactive power in the network reduces the active power that can flow in conductors. Hence, for a given transmission capacity, reactive power flows have to be minimized to maximize active power flows. The compensation of the load lagging power factor with the usage of shunt capacitors permits to improve the power factor, leading to a reduction of current flows through conductors. Hence, power losses (which depend on the squared current) decrease and higher network efficiency can be obtained. This function is achieved both with centralized than with decentralized systems.

In addition to traditional capacitor banks, other technologies for voltage regulation purposes (e.g. SVC, STATCOM, etc.) are available for distribution network management. Some of them are still centralized in primary substations while some others (e.g. TVR, Thyristor Voltage Regulators) can be installed along lines. However, the important economic efforts these devices currently require make their application difficult.

When switching contacts are frequently opened and closed, capacitor bank components are worn-out. A more efficient capacitor bank switching schedule can increase lifetime and reduce maintenance works. A preventive approach foresees maintenance operations after a predefined time period. Since capacitors do not have moving or wearing parts, maintenance is mainly related to contactors, regulating relays in automatic capacitor banks and breakers.

Reactive power compensation can provide beneficial effects on the grid operation, such as the reduction of network losses due to lower reactive power flows. However, even if it can be monetized, it cannot be taken into account in the economic model since it requires load-flow analysis (that is out of the scope of this study). Finally, given that reactive power compensators are DSO owned levers, remuneration is not considered.

4. DRES Reactive Power Compensation

Reactive power compensation (Q compensation, Volt VAr control) can be provided through DRES connected to the grid. These generators cannot directly be connected to the grid because of the nature of the power they produce (direct current, or very low frequency current), and therefore a power-electronic interfacing system is used to that end.

The power electronic interfacing system consists of one or more converters. The final converter which is connected to the grid is the actual control element for this flexibility.

Since the tool being developed is an operational planning tool, the introduction of investment costs in the economic modelling will create a capacity-based remuneration system that is unwanted. There is no reduction in active power production when reactive power is produced or consumed, as the inverter is assumed to be oversized. This means that there is no opportunity cost component in the reactive power compensation. The only cost therefore is the cost of the additional power losses in the inverter caused by reactive power compensation.

Reactive power compensation can bring about benefits like the reduction in line reactive power flows, which increase the power capacity (additional active power transmission) of the upstream lines. It also brings about a reduction in losses in many cases. These benefits are monetary in nature in the end. However, these cannot be considered in the model as they represent the effects of the utilisation of reactive power compensation, and to evaluate them, additional load-flow executions are necessary.

For reactive power compensation, the offers that can be made will have to consider only the additional losses incurred by the inverter due to its participation in the offer. This is very low, and can range from 3-5% of the maximum active power that can be supplied by the inverter. Therefore, the offers for reactive power compensation through DRES will have to only consider this cost component. In addition, grid codes in the target country have to be taken into account, potentially allowing for small and mandated ranges of unpaid compensation.

5. Storage (Grid Connected Batteries)

Battery energy storage is a highly flexible way to store excess energy in periods of high DRES production and low demand which can be released later when DRES production is absent and the demand is high. Battery energy storage systems are estimated to be one of the key storage technological enablers of the transition from the current mostly centralized electricity generation networks to distributed ones with increasing penetration of variable and not programmable renewable energy sources. They can be either centralized, meaning they are centrally located at substation level, or decentralized, meaning that several battery energy storage systems are spread over the distribution grid.

It is considered that the battery is owned by a commercial party. This means that the DSO does not have to do the investment of the battery energy storage system but has as consequence that the commercial party reclaims investment and depreciation in the utilization price.

The battery exploitation cost, consists of 3 parts:

- Investment costs: Typically costs which are not (or limited) subject to use of the flexibility but depreciate over time, e.g. invertor, installation etc.
- Battery degradation: The battery is a significant part of the investment which is subject to wear which will be treated separately;
- Variable costs: Maintenance and exploitation costs

As explained in the previous sections, a battery energy storage system is a highly flexible way of managing power flows through the distribution grid. The reaction times are fast and the device can consume electricity as well as produce electricity. The major technical constraint is the amount of energy which can be stored in the battery.

An important part of the costs of a battery energy storage system will be the battery cost itself. The battery typically has a limited number of cycles and the investment cost of the battery must be depreciated over its lifetime. Today, it is debatable whether a battery energy storage system can compete commercially with other flexibilities due to the high battery cost and limited cycle lifetime, but with improved performance and lower prices in the future this might change.

6. ***Non-Renewable Distributed Generation (CHP)***

A combined heat and power (CHP) generator is capable of, as its name suggests, generating both electrical power and useful heat. It can be considered thermodynamically more efficient than conventional generators as the heat generated during the production of electricity is used, instead of being wasted. Several types, and topologies of CHPs exist. The one for which a technical and economic model will be developed in the INPG-RSE-VITO OP Tool is shown in Figure 24.

The CHP generator runs on gas. In the representation above, the following assumptions and considerations are made:

- The CHP is owned by a company, which can tap into its electricity production;
- It operates in parallel with a gas boiler which can directly produce heat from gas;
- The $thermal : electric\ power$ ratio of the CHP is considered constant throughout its operating range of 70-100%. It is 0.6:0.4.

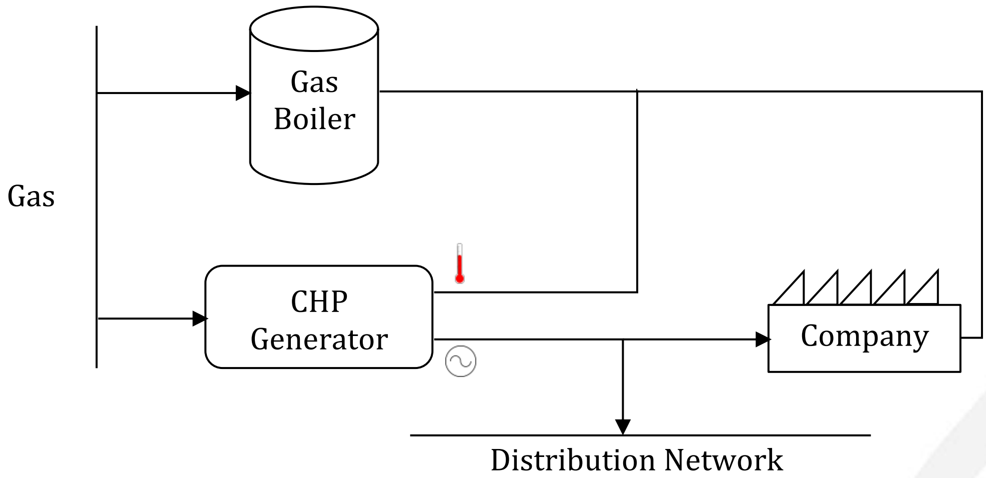


Figure 24 – CHP Representation

For the economic model, since this is an operational planning tool, the investment / capital cost is not considered. Therefore, the data related to cost needed to formulate the economic model for the CHP are the following:

- The price of gas purchased;
- The selling price of electricity in the day-ahead market;
- The purchase price of electricity from the day-ahead market.

There are two separate prices (purchase and selling) for electricity because the purchase price includes the prices for grid access and other components, which will make it much higher than the selling price of electricity. The purchase price of electricity is considered to be greater than its selling price in all scenarios.

Based on the strategies developed, flexibility offers for a CHP can be made in the day-ahead distribution network flexibilities market. The indicative prices of offers can be decided based on what the DSO owes the owner of the CHP at the least.

It is to be noted that for each condition in the network, the flexibility offered will be with respect to the original operating strategy for each condition in the network, not with respect to the previous operating condition of the network. Since the CHP is operated with a gas turbine, it should be able to ramp up and down from one condition to another within the 15 minutes time period.

Other parameters can definitely be added to the offer price. These parameters can be decided based on various global conditions, like weather (which affects solar and wind production, and also consumer consumption patterns) and DSO preferences among others.

7. ***DRES Curtailment***

DRES based generation units enjoy priority dispatch thanks to legislation in several European and world countries. This means that they operate in the same region as base-load generators. However, they are not as reliable as base-load generators in terms of output predictability.

This is the reason why most of these legislations limit the priority dispatch with a condition on system security.

The curtailment of DRES can be carried out for various reasons, either voluntarily (action taken by the owner of the system without any incentive or compensation provided to do so) or involuntarily (action taken due to an incentive or compensation provided by a third party, most likely a DSO, in the distribution network). Several researchers, for example in [55], have argued that curtailment is a means to ensure that DSO avoid further network investments. This depends on a lot of factors, especially on the location of the DRES, and on the network characteristics. Generally, it is understood that curtailing certain DRES for a very small duration, avoiding potentially expensive grid reinforcement costs is acceptable.

Based on the technical and economic parameterization of the flexibility, the minimum compensation to be received by the owner of the DRES when an offer for the same is made has two components.

The first component is the component that corresponds to the loss of revenue. This is simply the price of electricity at which the DRES unit(s) will sell the generated electricity, and is the day-ahead power exchange market price for the time period when it is curtailed.
The second component corresponds to the loss of incentives, which is the additional feed-in tariff component. If the DRES unit has a contract to sell electricity generated at a pre-determined incentivized tariff, this should be the compensated instead.
An additional component, which the DSO has to pay for, but which the owner does not receive can be added: a penalty for the displacement of energy production from a renewable resource to a potential non-renewable and polluting resource. However, this is difficult to calculate. An initial estimation can come from the carbon taxes in the country.

8. Load Modulation

Load modulation is defined as a change in the consumption pattern of a particular load. This can mean one of several things: a simple increase in the consumption from the expected levels, a simple decrease in the consumption, or either of those with a constraint attached to them that equalizes the energy consumed by the load in a given period to be the equal to the energy consumed by the load if no modulation was done.

This lever is often referred to by its widely accepted name “Demand Response”, which encompasses all kinds of modulations that can be done on loads in electrical networks. In networks without DRES, the exact quantity of power generated (from small dispatch-able generators) is known, while the load consumption is forecasted. Since both the parameters have to be equal in order to maintain good network conditions, generators are dispatched to satisfy loads. With high DRES penetration, both the parameters become unknown. In order to manage such networks, it is essential to have the ability to have loads follow the generation, and this lever is therefore very useful.

As for the economics of load modulation, there are several aspects to be considered, and there is no general consensus on what these aspects are. In the scope of this project, Energy Pool and CyberGRID, two companies specializing in the technical and economic aspects of demand response will provide valuable insights into this issue.

4.2.3.2 Generation of Merit Order for Flexibilities

Based on the availability and economic evaluation of flexibilities for a particular distribution network, an economic ranking of the levers is done. In many ways, this can be compared to a merit order for generation in transmission networks. However, there are some differences:

1. **The merit order is location specific**. Unlike in transmission networks, where the merit order generated is for the system as a whole, it is not possible for a merit order of flexibilities to be location independent. This is due to the fact that this merit order is used to help solve congestions and problems in distribution networks that are operated radially, and not to achieve economic dispatch in meshed, well-planned and well-designed networks like transmission networks. There is a location dependent component for congestions. For instance, there would be little or no use in using an active power flexibility at a node when the aim is to solve a congestion downstream of the node. Therefore, a merit order for each node is separately constructed. This does not mean that there is no global merit order. The global merit order is obtained at the end of the optimization, when flexibilities from all over the network are chosen to be used. This resulting merit order is an aggregated merit order for all intents and purposes.

2. **Separate merit orders are constructed for active and reactive power flexibilities**. It is practically impossible to combine them as active and reactive power serve different purposes. This split also reduces the complexity of the problem to be solved. However, this introduces a few assumptions. There is a weak correlation between the active power and voltage. But this correlation is not considered as it necessitates the combining of the two types of merit orders.

3. **The generated merit orders do not provide the final set points for flexibilities**. They are only an economic indication for the optimization routines, and a very good starting point in most cases. This is unlike the case in transmission networks where the merit order can be used to point out dispatch candidates more often than not. Hence, the merit order provides an economic ranking of the levers the DSO can use to solve network constraints and optimize the network.

4. **The merit orders are time specific**. It is possible to make a non-greedy choice of flexibilities that results in an optimal overall cost only after the optimization step. One merit order for each node (as applicable) for each time period is therefore generated. This is especially the case when there are inter-temporal constraints attached to the use of flexibilities. With communication between the optimizers and the merit order generator, an “initial” state of flexibilities, or in other words information about which flexibilities must be used for a particular time period can be provided to the merit order generator, resulting in potentially better starting points for optimization.

With these in mind, the following sections explain how the generation of merit orders for active and reactive power flexibilities is done.

Active Power Flexibilities

Active power flexibilities can be used to solve congestions (i.e overloading) of power lines in a distribution network. There is a strong correlation between the active power consumption at a node and the power flows in the lines feeding the node. If the voltages are considered to be unchanged, a change of x pu in the active power consumption at one node causes a change of x pu in the lines feeding it. This is an approximation which will be eradicated by the optimizers. However, for constructing an active power merit order, this approximation allows for a hierarchical methodology, which is explained below.

Hierarchical Methodology for Active Power Flexibility Merit Orders

Due to the nature of active power, the solution of a network congestion in a particular power line can be potentially provided by a combination of active power flexibilities downstream of the power line. If there is another power line with a network congestion upstream of the current one, the activation of the flexibilities for the former also eases the congestion in the latter. This is the basic principle behind a hierarchical methodology in the merit order for active power flexibilities. A bottom-up approach to constructing the merit order is therefore used. To illustrate and explain the method using a simple example, consider the two-feeder network shown in Figure 25.

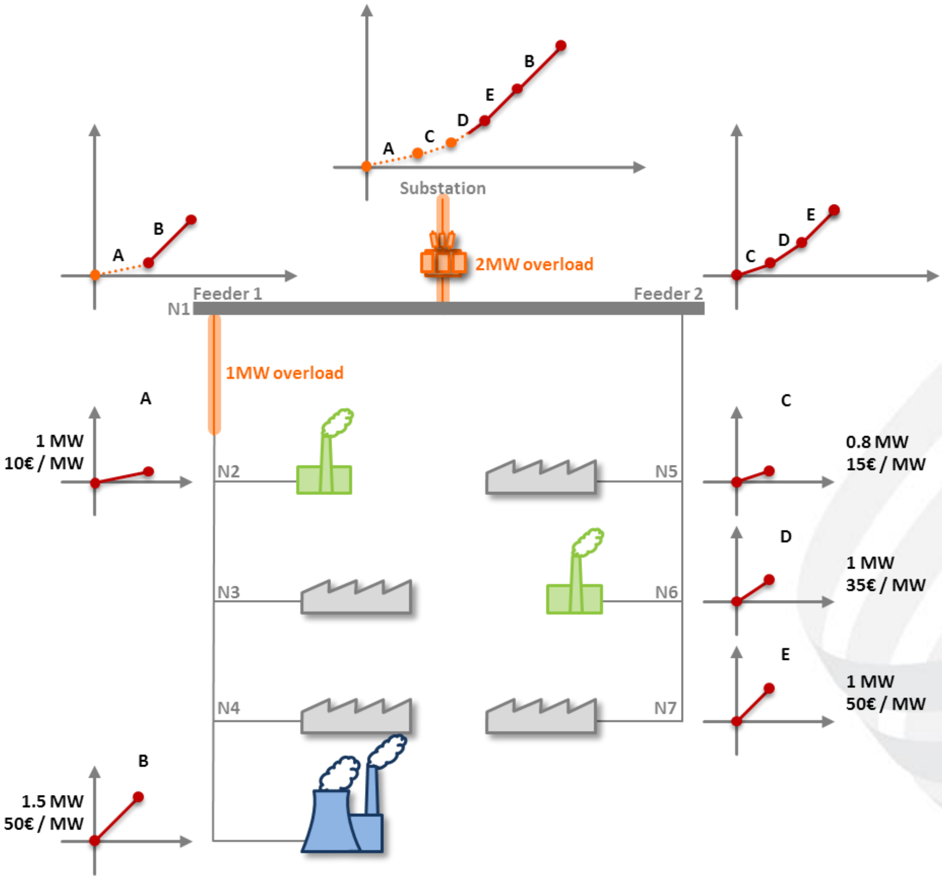


Figure 25 – Hierarchical Active Power Flexibility Merit Order – Illustration

In this network, there is a load connected to every node. For a given 15 minute period, there is a congestion of 1 MW in Feeder 1, in the line between nodes N1 and N2. Also, there is a 2 MW congestion in the substation itself, meaning the transformer is overloaded. There are five flexibilities A, B, C, D, and E, each with their availabilities and unit costs as shown.

The bottom-up approach to constructing the merit order starts from the nodes furthest from the substation, and checks for a network congestion in the power line immediately upstream. If there is a network congestion present, it aggregates all the available flexibilities and ranks them in an ascending order of their prices. Then, it indicates that the use of certain flexibilities can solve the congestion, and updates their status. This is the case with Feeder 1. The first congestion encountered is that of 1 MW. And there are two flexibilities: A and B available to solve it. By ranking them an indication that flexibility A can solve the congestion is obtained. Only the remaining amount of flexibility A can be used for upstream congestion solving. In this case, this amount is 0 MW. Therefore, flexibility A is used completely to solve the congestion, and is unavailable for exploitation to solve congestions that may be found upstream. This is shown in the aggregated merit order curve for Feeder 1, where A is indicated as used up (in orange).

This not only indicatively solves the congestion between N1 and N2, but also decreases the congestion in the substation by 1 MW. This means that when the next encountered congestion in this case is at the substation, and is only 1 MW (as compared to 2 MW originally). At the substation (node N1), there are now four flexibilities: B, C, D, and E. When a new ranking is done, the indication is to use C to its fullest, and D to the tune of 0.2 MW. This also provides the final merit order, with the indications for flexibility use in the entire network.

This simple case can be extrapolated to a radial distribution network of any size, provided that congestions and active power flexibilities exist. In cases where the available flexibility is not sufficient, merit order routine will still generate one with indications to solve congestions as much as possible (even if it means indicating that all levers in the network should be activated).

Reactive Power Flexibilities

In contrast to the merit order for active power flexibilities, there exists no hierarchical system for reactive power flexibilities. This is due to the fact that reactive power does not behave and flow in the same way active power does, and also because its effect on voltages is not as strongly correlated as the effect that active power flexibilities have on congestions.

Therefore, for each node in the network with available reactive power flexibilities, the flexibilities are aggregated, ranked according to their prices, and a merit order is constructed and passed on to the optimizer. It is therefore to be noted that there is no global merit order available for reactive power flexibilities.

4.2.3.3 Cases

In order to be able to change the final economic value of each lever in a manner that will correspond to real-world situations, some additional parameters can go into the economic analysis of each of the levers. This is the result of certain situations and conditions in the network which drives the prices of certain flexibilities up or down. In order to test the effectiveness of the used flexibility, two different cases are described:

Case 1 – The actual grid to be optimized, with set DRES production and load consumption, where only DSO-owned flexibilities can be used.

Case 2 – The exact situation in case 1, with the additional allowance that all flexibilities available (DSO owned or otherwise) can be used.

Apart from these cases, it is also possible to take into account preferences that DSO have in managing their network. For example, some DSO have a strong preference against frequent reconfiguration of their network. Such a situation will drive the price of a switching operation up, to the extent that it is the most expensive flexibility in the merit order. Apart from this, another potential condition that can be considered is the weather (and how it affects DRES production, and subsequently their flexibility).

4.2.4 Techno-Economic Robust Optimization

In this section the two optimization approaches used in the tool are described.

4.2.4.1 VITO Component

This tool adopts the general "optimal sequential decision making" formalism, suggested by Gemine et al. [56] and [57], to express the problems the tool will solve: to find an optimal sequence of control actions for the network. In this model, networks are represented as graphs of electrical elements: the nodes representing busses to which (an aggregation of) devices are connected, power producing and/or consuming devices, and the links corresponding to lines and cables between the busses. Network problems are expressed as a first order Markov Decision Process (MDP) in which:

- The system states at every time period t consist of basic parameters that represent the actual power injections (positive & negative) and voltage magnitudes at each node, and the current magnitude at each link.
- The actions are instructions set by the DSO for the time period t, corresponding to the levers the DSO has available. The VITO component evolved around a benchmark example that has two types of levers: curtailment of DGs and modulation of loads. Load modulations can be activated at any time, but when activated they progress in a restricted way. Other types of levers can be added by modelling the corresponding constraints. For instance, storage levers can be modelled as modulations that are restricted both by the State of Charge (SoC) of the storage device and by the maximal charging and discharging power. Next sections explain how several types of levers can be expressed.
- The transition function f(s, a, s') in a MDP describes the effect actions have on the state. While this transition function is non-deterministic in general, the tool is focused on the deterministic case in which the outcome of every modulation and curtailment instruction is known beforehand.
- The objective function to be optimized (minimized) over the MDP is composed of the activation fees and costs for using and activating the flexibility of each flexible load at time. In a first stage, the VITO component's objective function adds fixed costs for the load modulation activations to variable costs for DG curtailment, the latter being a linear function of the curtailment price at time t, and the level of curtailment requested.
- Constraints are generally not modelled as an explicit part of the MDP formalism.
  Instead, state transitions that violate operational constraints are usually penalized by adding a prohibitive "barrier" cost to the cost function. Because the VITO component integrates a Constraint Programming solver, we have no need for such a barrier cost.

Instead, the transition function itself is automatically restricted to yield only system states that do not violate any (operational or lever-related) constraints.

For the DSO, addressing the operational planning problem in his network is equivalent to determining a mapping (a "policy" in MDP terminology) from states to actions in the above formalism that optimizes the objective function.

The VITO component combines Constraint Programming (CP) with mathematical optimization algorithms. A search engine performing local search is in control of the overall optimisation process, and provides a series of exploration problems to both the single-step OPF optimizer and the CP solver. The latter will use an approximation of the power flow equations, and find solutions that satisfy this approximation. After checking the actual, i.e. non-approximated load flow, the local search engine will build new problems for the CP solver to either exploit earlier results or to explore other promising regions in the search space.

Constraint Programming for local search

The OPF problem of finding a series of actions (a plan or schedule) that globally optimises an objective function is NP-hard. Advanced research indicates that this computational complexity is caused mainly by:

- The inherently discrete (binary) nature of many control actions (e.g. switches, device- and network reconfigurations);
- The inter-temporal restrictions on flexibilities in discrete time (e.g. switching devices that cannot be switched back within a certain period, or load modulations that, once activated, need to progress in a restricted way);
- The inherent non-convexity of the power flow equations used to calculate the state of the network and the network constraints.

These complications turn most actual OPF problems into a combinatorial optimisation problem with exponential time complexity [57]. This is a strong indication that Constraint Programming, could be applied strategically to help find near-optimal OPF solutions in a timely way. As an example of such a NP-hard operational planning problem, the VITO component addresses the benchmark problem set by [56] and [57].

Constraint Programming (CP) is a **global** search technique for combinatorial search spaces, in which constraints are relations between a number of variables that are each enforced by a constraint "propagator" component. The search process iterates over two alternating phases:

1. In the **propagation** phase all propagators repeatedly shrink the domain of their constraint, thus shrinking the whole search space until a fix-point is reached.
2. In the search a "guess" is made: e.g. a particular variable is chosen and that variable's domain is temporarily set to a particular chosen value. Arrangements are made for backtracking, should this guess turn out unsuccessful or non-optimal. Whenever the search space becomes empty, backtracking is performed and the search engine will try another "guess".

Calculations such as made by the merit order component will be available to the CP solver, to help optimize the (global) search strategy of the constraint engine.

CP has been applied to several types of energy-related optimization problems. From pure CP-based approaches [58] to approaches that involve CP-style propagation [59][60] including the use of CP for long period generator outage scheduling [61].

But applying CP alone would not suffice to solve realistic networks with many levers. Notwithstanding recent advances in the field, it remains a known fact that CP does not scale very well because of a worst-case exponential time complexity[62]. In many realistic planning problems, CP is therefore combined with local search.

In the classical "CP-based Large Neighbourhood Search" approach, a (random) subset of the constraints are relaxed every time a solution was found, thus demarking a wide neighbourhood surrounding the solution where a more optimal solution will be searched for next. We apply a heuristic-based search strategy to decide which part of the search space will be explored next and how long to dwell in the same part while searching for iteratively improving solutions. This heuristic search strategy is explained in the dedicated section.

The Overall Component Architecture

Figure 26 depicts the overall architecture of the VITO optimization component. The lower part shows the 3-stage heuristic search strategy that governs the order in which different parts of the search space will be searched for solutions. This strategy will be explained later.

In a Python process (left side of
Figure 26)) the load flow of the initial planning is calculated, and any grid constraint violations are listed. The load flow is solved using PYPOWER (a power flow and optimal power flow solver in Python).
The load flow constraints are modelled as linear approximations of the load flow equations as follows:

$$|V_{bus}| = \left|V_{0_{bus}}\right| + \frac{d|V|}{dP}\Delta P + \frac{d|V|}{dQ}\Delta Q \tag{1}$$

$$\theta_{bus} = \theta_{0_{bus}} + \frac{d\theta}{dP}\Delta P + \frac{d\theta}{dQ}\Delta Q \tag{2}$$

$$|I_{branch}|^2 = \left|I_{0\_branch}\right|^2 + \frac{d|I|^2}{dP}\Delta P + \frac{d|I|^2}{dQ}\Delta Q \tag{3}$$

$|V_{bus}|$ and θ_{bus} are the vectors containing the bus voltage magnitudes, and bus voltage angles respectively. $|I_{branch}|^2$ is the vector containing the squared current magnitudes of every branch. The underscore _'0' indicate the power flow solution of the setpoint problem around which the approximation is calculated.

The sensitivity factors, d|V|/dP, d|V|/dQ, dθ/dP, dθ/dQ, $d|I|^2/dP$ and $d|I|^2/dQ$, can be obtained using a perturb and observe method. However, it is much faster to calculate these factors analytically. The d|V|/dP, d|V|/dQ, dθ/dP, dθ/dQ sensitivities can analytically be obtained from the inverse Jacobian formed in the Newton-Rapson load flow calculations [63]. The $d|I|^2/dP$ and $d|I|^2/dQ$ sensitivities for every branch can then be calculated as follows:

$$\frac{d|I_{1-2}|^2}{dP} = |Y_{1-2}|^2 * \left(a\frac{d|V_1|}{dP} + b\frac{d|V_2|}{dP} + c\frac{d|\theta_1|}{dP} + d\frac{d|\theta_2|}{dP}\right) \tag{4}$$

$$\frac{d|I_{1-2}|^2}{dQ} = |Y_{1-2}|^2 * \left(a\frac{d|V_1|}{dQ} + b\frac{d|V_2|}{dQ} + c\frac{d|\theta_1|}{dQ} + d\frac{d|\theta_2|}{dQ}\right) \tag{5}$$

with Y_{1-2} the branch admittance matrix of the branch (1-2), connecting bus 1 and bus 2, and:

$$a = 2|V_1| - |V_2|(e^{j(\theta_1-\theta_2)} + e^{-j(\theta_1-\theta_2)}) \tag{6}$$

$$b = 2|V_2| - |V_1|(e^{j(\theta_1-\theta_2)} + e^{-j(\theta_1-\theta_2)}) \tag{7}$$

$$c = -j|V_1||V_2|(e^{j(\theta_1-\theta_2)} - e^{-j(\theta_1-\theta_2)}) \tag{8}$$

$$d = j|V_1||V_2|(e^{j(\theta_1-\theta_2)} - e^{-j(\theta_1-\theta_2)}) \tag{9}$$

Directed by the 3-stage search strategy, the PYPOWER suite will also compute OPF solutions for every single time step. This means that no inter-temporal constraints are taken into account yet. Nevertheless, these OPF calculations can be time-consuming and will be used sparsely, for instance at the start of a computation to find a reasonable cost lower bound to be used by the CP component.

The Jacobian matrices (the sensitivity matrices for the network at every time step) are used to construct single-time-step approximate merit orders among the levers, using an algorithm based on the one described in section 4.2.3.

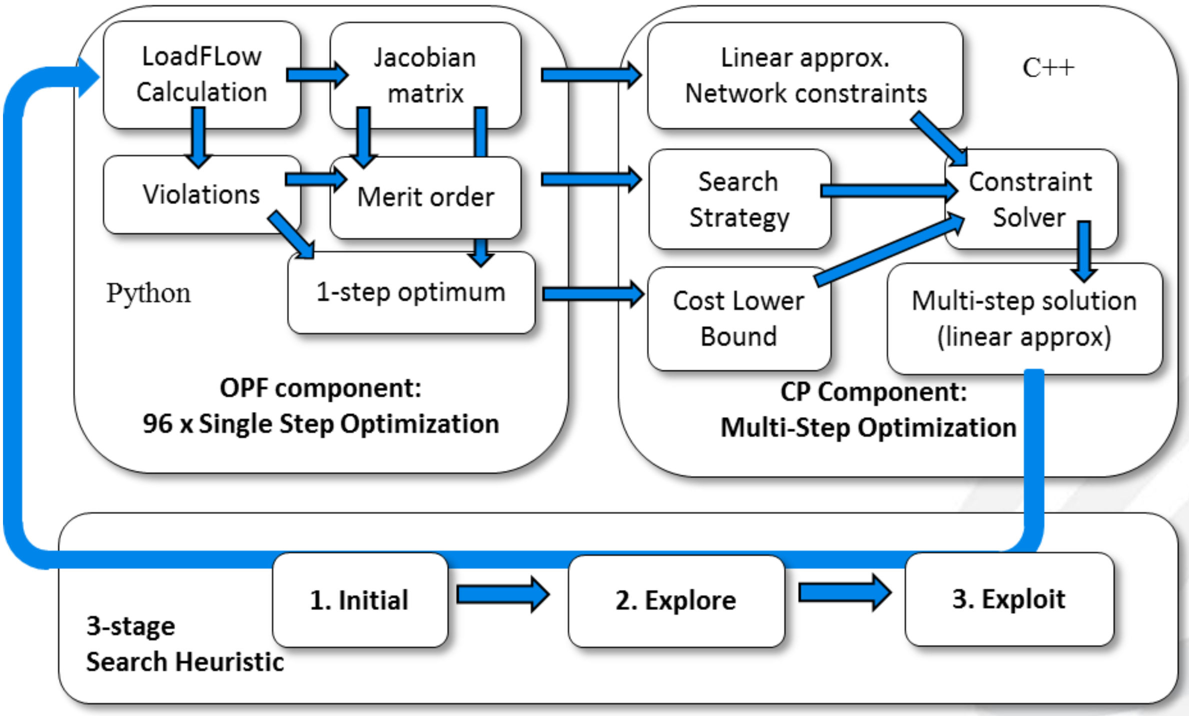


Figure 26 – VITO component architecture

The CP component on the right side of
Figure 26 makes use of the Gecode C++ library [64]. The network constaints are expressed using linear approximations based on the derivatives in the Jacobian matrix. Apart from the network constraints, additional inter-temporal constraints are added to express restrictions in sequences of lever activations, including load-modulation constraints. In the following section we explain how the constraint problem is modeled.

The sum of the costs of all single-step optimized solutions is used as a lower-bound for the cost of the multi-step optimization. Adding more (inter-temporal) constraints to the problem will only invalidate potential solutions, never add extra solutions, so the cost can only be higher than the sum of the individually optimal costs.

Modelling the Constraint Optimization Problem

A constraint optimization problem consists of:

- A set of constraint variables, each with a domain of possible values (often an interval, though not necessarily so);
- A set of constraints: relations between subsets of the constraint variables that have to be enforced;
- An optimization function, often expressed as a constraint variable (cost variable) that is appropriately constrained. Whenever a solution is found, this cost variable will have a defined value, and the CP engine will add an extra constraint enforcing that from then on, all solutions will need a strictly lower cost.

We express OPF problems as constraint optimization problems as follows:

1 Constraint Variables:

- The Voltage magnitude |V| on every bus at every time step is modelled as a constraint variable. Its domain is the range of voltages allowed.
- The squared current magnitude $|I|^2$ on every link at every time step is modelled as a constraint variable. Its domain is the acceptable range.
- The active power P and the reactive power Q generated by all devices connected to a bus at every time step are modelled as constraint variables with their proper domain limits. Because loads consume power, their constraint variables will have a negative domain. It is no problem if some devices a capable of consuming as well as producing power: their constraint variable will have a domain with a negative minimum and a positive maximum.
- One global cost variable, and some additional help variables to define the cost.

2 Constraints:

- **Network constraints** at every time step are approximated by a linear constraint.
  Voltage constraints:

  mathematical : $|V| = \sum_{devices} P_{dev} * \frac{\delta|V|}{\delta P} + Q_{dev} * \frac{\delta|V|}{\delta Q}$

  pseudo C++ code : `linear(PQs, dV_dPQs, '==', V);`

  This `linear()` constraint enforces equality '==' between the voltage magnitude V at a certain bus, and the dot product of the vector of constraint variables PQs corresponding the active and reactive power of all devices in the network with the constant vector of derivatives dV_dPQs extracted from the Jacobian matrix.

  Network current constraints are similar:

  mathematical : $|I|^2 = \sum_{devices} P_{dev} * \frac{\delta|I|^2}{\delta P} + Q_{dev} * \frac{\delta|I|^2}{\delta Q}$

  pseudo code : `linear(PQs, dI_dPQs, '==', I)`

- **Flexibility constraints**:
  For every type of flexibility we can use constraints to express how its use is restricted.

  Power curtailment and reactive power compensation:
  For these types of flexibilities, it suffices to put proper limits on the domain of the variable. This is a trivial type of constraint and can be used to express other similar types of levers.

  mathematical: $P_{min} \leq P \leq P_{max}$
  $Q_{min} \leq Q \leq Q_{max}$

$$|P|^2 + |Q|^2 \leq Const$$

pseudo C++ code:

```
dom(P, Pmin, Pmax);
dom(Q, Qmin, Qmax);
rel(P*P + Q*Q == C);
```

The `dom()` constraint restricts the domain of a constraint variable to a range between a minimum and a maximum (both included). The `rel()` constraint takes a relation expression and enforces that relation.

Levers with discrete settings.
A simple variant of the above constraints can be used for levers with discrete settings. For example:

mathematical: $P \in \{P_1, P_2, \dots, P_n\}$
$Q \in \{Q_1, Q_2, \dots, Q_m\}$

pseudo C++ code:

```
dom(P, {P1,P2, …, Pn});
dom(Q, {Q1,Q2, …, Qm});
```

This variant of the `dom()` constraint restricts the domain of a constraint variable to an enumerated set of values.

Load modulation may be restricted over time in many ways, for instance:

- The total amount of consumed energy of a device over all time steps should not change:

  mathematical : $\sum_{t=1}^{timesteps} |P_{dev}|_t = Const$

  pseudo C++ code:

  ```
  rel(sum(Ps) == C);
  ```

- The modulation, once started, should follow a given pattern, e.g. to model a single activation of an extra load with a fixed long-term load profile covering *n* time steps. Gecode provides "extensional" constraints to restrict the possible values in a list of constraint variables to a number of allowed sequences. This type of constraint uses a Deterministic Finite Automaton (DFA) to assess if a sequence is valid. DFA's can be easily expressed using regular expressions. Assume $DP_{dev} = \left[|\Delta P_{dev}|_1, \dots, |\Delta P_{dev}|_{timesteps}\right]$ is the array of modulation variables for device *dev* and *LP* is the load profile of an additional load. The regular expression of valid time-sequences for modulation in device *dev* would look like:

$$DP_{dev} = 0^* | \ (0^* \ LP_1 \ LP_2 \dots \ LP_n \ 0^*)$$

pseudo C++ code:

```
        REG r0(0); //regular expression single 0
    REG rSeq;
    /* initialize rSeq to contain the load profile */
        REG r = r0(timeSteps) | (*r0 + rSeq + *r0);
    extensional(DPdev, DFA(r));
```

The extensional () constraint enforces the constraint variables in the DPdev array (the modulations) to form a pattern described by the regular expression r.

Note that a major advantage of CP is lost if we use this constrained-pattern type of flexibility: strong propagation. The propagation of extensional constraints is rather weak: the propagator will usually not be able to prune the domains of its variables, before one of the variables becomes fixed (domain reduced to a singleton).

Storage levers are similar to load modulations, but need something extra:

- An additional array of constraint variables SoC to express the State of Charge at every time t, with appropriate domains between zero and maximum SoC.
- Constraints on the relation between every pair of consecutive SoC's, to express:
  - How the State of Charge of the device changes in time, in relation to the power consumed/delivered by the storage device. Note that this constraint could also take leakage into account if required.
  - What the limitations are on the rate of charging/discharging.

3 Cost Function

CP models that perform optimisation have to define an instance method "cost" that returns a constraint variable used to calculate the cost. This constraint variable will be inspected by the CP engine every time a solution is found, and a new constraint will be added to find only solutions with strictly lower cost. Assuming $cost_k$ is the cost of the k^{th} solution found, then after any solution is found a constraint will be added to enforce $cost_{k+1} < this.cost_k$

The following is an example of how cost could be modelled. Assume that:

- energyPrice_t is the energy price per unit at time t
- Curtailment cost is the product of curtailed power and energy price
- $\text{activationPrice}_{load}$ is a one-off fee for initiating modulation of device *load*

mathematical:

$$curtailCost_{gen} = \sum_{t\in timesteps} \Delta|P_{gen}| * \ energyPrice_t$$
$$totalCurtailCost = \sum_{g\in generators} curtailCost_g$$
$$modCost[load] \ \in \{0, activationPrices[load]\}$$

$$modCost[load] = 0 \Leftrightarrow \sum\nolimits_{t \in timesteps} \Delta|P_{load}| = 0$$
$$totalModCost = \sum\nolimits_{l \in loads} nonZero(\Delta|P_{load}|) * activationPrice_l$$
$$cost = totalCurtailCost + totalModCost$$

pseudo C++ code:

```
      //or every generator: curtailment cost is a
dot product
      linear(energyPrices, deltaPs_at_t, '==',
curtailCosts[gen]);

      //total curtailment cost over all generators
      rel(sum(curtailCosts) == totalCurtailCost);

      //only two values in domain of load modulation
cost
      dom(modCosts[load], {0,
activationPrices[load]})

      //using a reified boolean constraint for the
one-off fee
      rel((modCosts[load] == 0) ==
(sum(delta_P_loads) == 0))

      //now the modulation cost is a dot product
      linear(activationPrices, modCosts, '==' ,
totalModCost);

      //the total cost
      rel(totalCurtailCost + totalModCost == cost);
```

<u>The 3-stage Heuristic Search Strategy</u>

The heuristic search engine in Figure 26 makes use of a 3-phase search strategy to guide the overall search process. The three phases are sequential, as illustrated below in Figure 27. Several variants of this local search strategy involving a CP solver have been described in the literature [65]. Most use randomized constraint relaxations to build a neighbourhood around the latest found solution, where the next search effort will take place.

Figure 27 – Local Search Phases

In the **initial phase**, the calculated load flow and the corresponding identified network constraint violations will be used to create a series of CP problems with increasing

"resolution". The network constraints in the CP problems are expressed as linear approximations of the load flow equations.
We use the term "resolution" of a CP problem to indicate the granularity of the applied discretisation. We express CP problems with finite integer domain variables, which can only take integer values. The resolution is a measure for the finite precision resulting from the discretisation. At low resolution the search space is smaller and solutions will be rough approximations. Low resolutions can therefore speed up the process of finding a first solution. However, when a resolution is too low, no solutions may be left.

In the initial phase, the search engine trades precision for speed, and tries to find a good balance for the resolution.

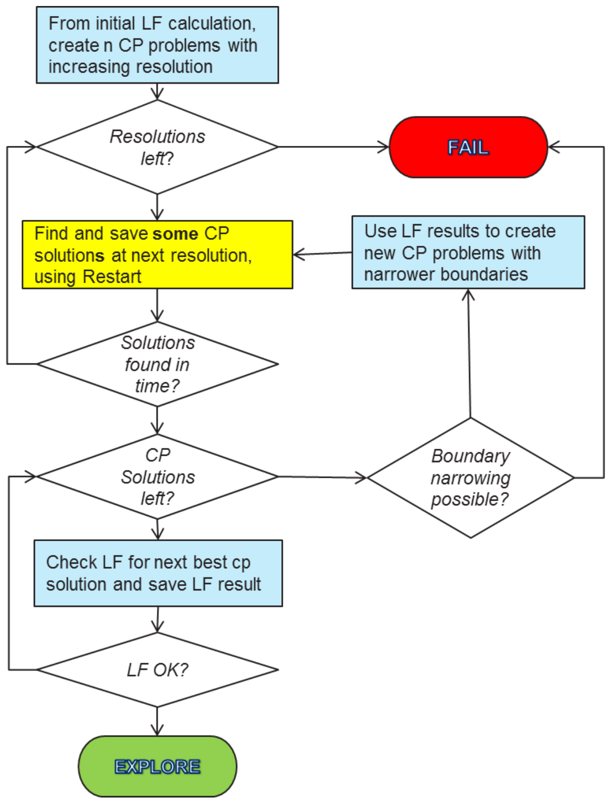


Figure 28 – An example of the process flow in the initial search phase

Figure 28 shows an example of a possible process flow during the initial phase. Activities to be performed solely by the CP solver are indicated with a yellow background. The CP solver has the ability to use a "Restart" option: indicating that it will not necessarily keep using the same internal search tree when looking for consecutive solutions, but instead starts afresh with a new search tree as soon as a solution is found. This strategy allows alternative ways of exploring a search space by the CP solver itself. A balance has to be found between the exploration capabilities inside the CP solver and the local search strategy of the overall search engine.

Each time the CP solver finds a solution, a load flow calculation is performed on this solution to check its feasibility. Note that the CP solver only takes approximations of the network constraints into account. All CP solutions that do not violate the network constraints are saved.

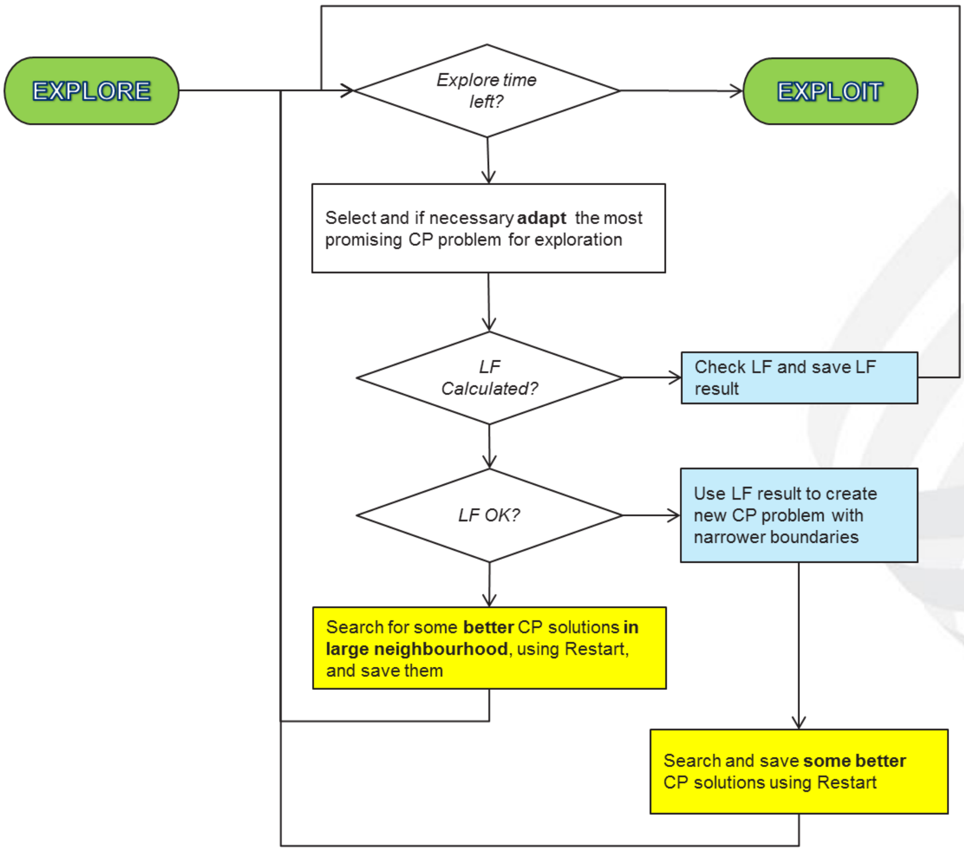


Figure 29 – Explore phase

In the explore phase, Figure 29, Large Neighbourhood Search (LNS) [66] is applied to explore promising regions in the search space. Because of the approximation of the operational network constraints, the CP solver may stray too far from the calculated Load Flow conditions. The Local Search Engine can try to solve this by narrowing the boundaries of the constraint variables in consecutive constraint problems it will generate.
This phase is limited in time; it will automatically transition to the last phase as soon as it's time budget is consumed.

In the exploit phase (Figure 30), a single, most promising, and currently optimal solution, is chosen for further refinement. Its corresponding CP problem will be tuned and its resolution will be increased to find the best problem it its neighbourhood.

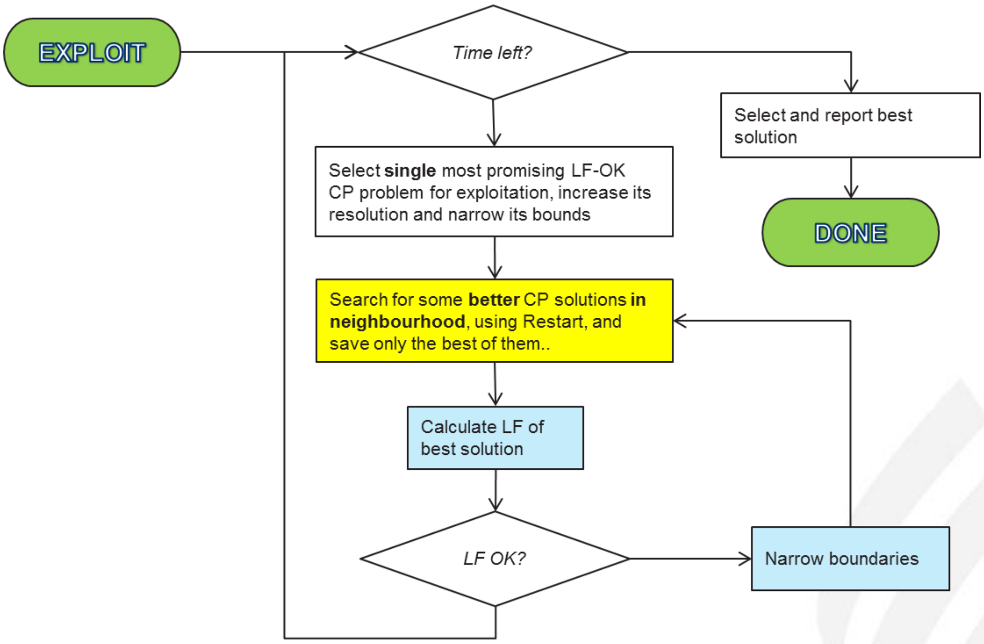


Figure 30 – Exploit phase

4.2.4.2 RSE Component

The RSE optimizer is based on an OPF (Optimal Power Flow) algorithm coupled with an interface module for input data pre-processing.
Briefly, the scope of the optimization procedure is to determine, on a MV network with DG, feasible operating conditions at the lowest cost. This procedure is commonly composed by 96 or 24"scenarios" (representing respectively quarter-hour or hourly time intervals).
The objective function consists in the minimization of the overall cost of the deviation of energy from its programmed value. This delta energy cost is given by the algebraic sum of the energy purchase costs for the increase dispatching orders and of the energy revenues for the decrease dispatching orders:

<u>Objective Function</u>: $$\min_{p,c}\left(\sum_{i=1}^{NG}\pi_{Gi}(p_i)-\sum_{i=1}^{NC}\pi_{Li}(c_i)\right) \qquad (10)$$

where:

p_i	displacement for i-th controllable generator;
c_i	displacement for i-th controllable load;
π_{Gi}	cost for displacement p of i-th controllable generator;
π_{Li}	cost for displacement c of i-th controllable load;
NG	number of controllable generators;
NL	number of controllable loads;
p, c	total cost for controllable resources.

The starting point of the optimization process is defined by the initial working point ("**SP**$_{\mathbf{e}}$"),

coming from input data, and the description of all the flexibility levers and their cost functions, coming from the merit order module.
Operating points are defined for each individual time section by the modulus and phase (V and θ) of node voltages and by active power (P) and reactive power (Q) flows in branches.

The optimizer can use all the levers and flexibilities described in Section 4.2.3, depending on the considered scenario.

Each dispatchable generator "G" is divided, starting from its planned operating point SP_e, in a generator "G_p" and a load "G_c" which represent the increase/decrease margin above and below the operating point.

Storage batteries are modeled by two generators - one positive and one negative – including charging and discharging losses, connected through a virtual branch to the network interface node, represented by the inverter. This modeling is suitable to consider storage plants, owned by a third-party, which can be directly controlled by the DSOs SCADA/management system; in the case of storage plants integrated in RES plants or, in general, fully controlled by the owner, the same model for dispatchable generators can be used.

The output of the optimization process is a suitable set point with the lowest dispatching cost ("$\mathbf{SP_{op}}$").

The suitability of SP_{op} is verified considering the following constraints:
a. Active and reactive power balance in all the nodes
b. Maximum allowable current level in the branches
c. Maximum/minimum allowable voltage levels in the nodes
d. Controllable load/generators power flow in the considered time period
e. Battery charging/discharging power flow constraints (not dependent from the SoC)
f. Maximum/minimum battery SoC
g. Battery SoC in the previous period
h. Desired battery SoC in an intermediate period or in the last too

In the following the hypothesis and data considered in the optimization problem are summarized:

- *Spatial perimeter:*
  - The whole MV grid connected to a primary substation. Only fixed configuration can be considered[1].

[1] Even if grid reconfiguration has been included in the flexibility levers description, its usage should be considered less frequent and essential in respect to other levers so, at present, this optimizer isn't able to automatically reconfigure the network; anyway, future improvement could be take into account reconfiguration functionalities.

- *Time perimeter:*
  - The actual network state and the following periods considered;
  - Future trends are implemented from forecast load/generation profiles according to all periods considered.

- *Inputs:*
  - Grid configuration (topology, physical electrical parameters);
  - Load/generation time series;
  - Technical data of devices (Generators, batteries, etc.);
  - Grid state at the beginning of each time period (section), inclusive of actual conditions of controllable resources;
  - Levers/flexibilities costs (obtained from economical models implemented in the merit order module).

- *Constraints:*
  - Voltage range in the nodes;
  - Current range in the branches;
  - OLTC technical constraints;
  - Batteries technical constraints;
  - Generators technical constraints (capability curve).

- *Control variables*
  - Controllable resources: all the available flexibilities (OLTC, controllable generators and loads, storage systems).

- *Outputs*
  - Actions/set points to be implemented for constraints violation resolution for the specific time frame considered.

In Figure 31 the optimization process flow chart is reported. It starts from the acquisition of all the relevant input data, i.e. topology, constraints/grid limits, load and generation forecasts (or profiles if forecasts are not available) and the economic data coming from a merit order block. After all the input data are available for calculation, a load-flow is run in order to check the state of the grid and detect the presence of violated constraints; if any violation is found the process loops again to the initial data acquisition step.
If one or more violations are detected, then the optimization process is started. The process ends after an optimal solution at the lowest feasible cost is found; the levers suitable to solve violations are identified and all the relevant data, i.e. levers technical data, their cost, activation details, overall cost of the optimization actions, etc.. are stored in a database or shared with SCADA or other control systems.
Finally, the process returns to the data acquisition step, ready for another optimization analysis.

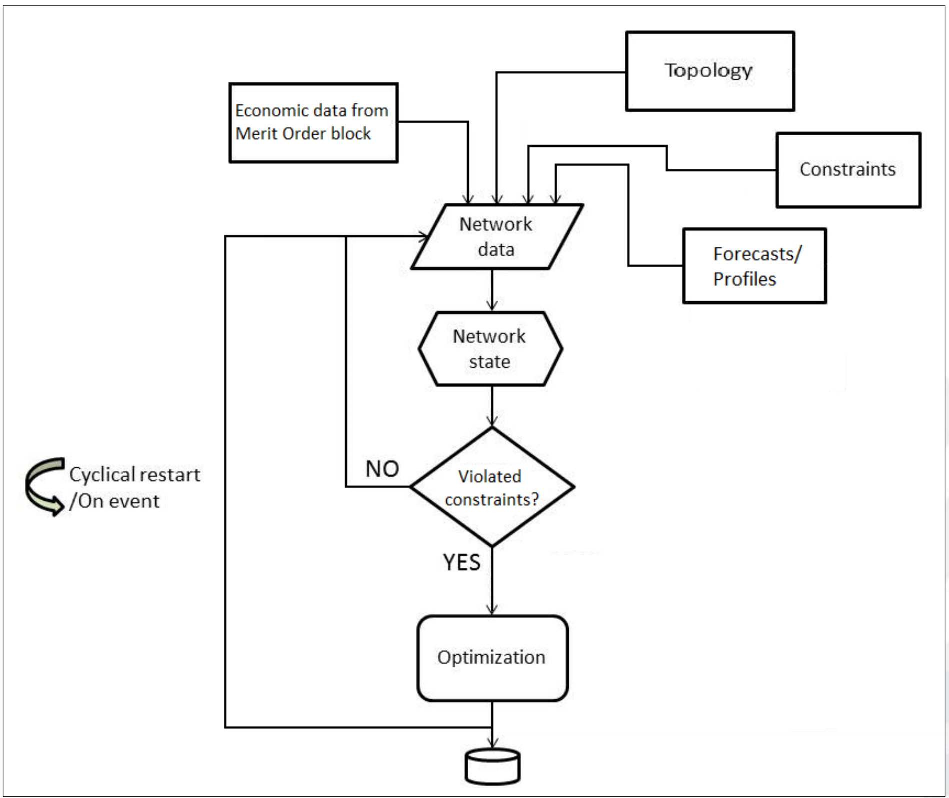


Figure 31 – RSE Optimization process

Mathematical formulation of the optimization problem

As mentioned above, an operating point can be considered admissible if it satisfies the constraints specified for the network, namely:

- *Active power balance at nodes;*
- *Reactive power balance at nodes;*
- *Voltage constraint at nodes*;
- *Maximum current range in branches;*
- *Minimum/maximum limits of problem variables (OLTC tap, generators' capabilities etc.);*
- *Maximum capacity and final SoC for storage batteries*.

These constraints are mathematically described by the following expressions:

- **Nodal active/reactive power balance equations** (load flow equations)

$$\sum_{j\in\alpha_i} TA_{i,j} + IA_i = 0; \qquad \sum_{j\in\alpha_i} TR_{i,j} + IR_i = 0 \qquad i = 1,\ldots,N \text{ (number of nodes)} \quad (11)$$

where:

$$TA_{i,j} = -\frac{V_i \cdot V_j \cdot K_{i,j}}{z_{i,j}} \cdot \cos\left(\vartheta_i - \vartheta_j + \delta_{i,j}\right) + \frac{V_i^2}{z_{i,j}} \cdot \cos\delta_{i,j} \tag{12}$$

$$TR_{i,j} = -\frac{V_i \cdot V_j \cdot K_{i,j}}{z_{i,j}} \cdot \sin\left(\vartheta_i - \vartheta_j + \delta_{i,j}\right) + V_i^2 \cdot \left(\frac{\sin\delta_{i,j}}{z_{i,j}} - \frac{y_{i,j}}{2}\right) \tag{13}$$

$TA_{i,j}$ is the active power flow in the connection *i, j* (positive from *i* to *j*);
$TR_{i,j}$ is the reactive power flow in the connection *i, j* (positive from *i* to *j*);
IA_i is the active power injection in the node *i* (positive if exiting from the node);
IR_i is the reactive power injection in the node *i* (positive if exiting from the node);
α_i is the group of nodes connected to node *i*;
$z_{i,j}$ is the series impedance of connection *i, j*;
$\delta_{i,j}$ is the loss angle associated to the series impedance of connection *i, j*;
$y_{i,j}$ is the shunt susceptance of connection *i, j*;
$K_{i,j}$ is the transformation ratio.

- **Current flow constraints**:

  The current flow between *i* and *j* nodes must not be higher than the maximum allowable value:

$$TI_{i,j} = \frac{1}{\sqrt{3} \cdot V_i} \sqrt{TA_{i,j}^2 + TR_{i,j}^2} \le \overline{TI}_{ij} \tag{14}$$

  Replacing the active and reactive power flows in the previous expression, results:

$$\frac{1}{\sqrt{3}}\left(\left(\frac{K_{i,j} \cdot V_j}{z_{i,j}}\right)^2 + \left(\left(\frac{\sin\delta_{i,j}}{z_{i,j}}\right)^2 + \left(\frac{\cos\delta_{i,j}}{z_{i,j}} - \frac{y_{i,j}}{2}\right)^2\right) \cdot V_i^2 + \right.$$
$$\left. 2 \cdot \frac{K_{i,j} \cdot V_i \cdot V_j}{z_{i,j}}\left(\frac{\sin\delta_{i,j}}{z_{i,j}} \cdot \sin\left(\vartheta_i - \vartheta_j - \delta_{i,j}\right) - \left(\frac{\cos\delta_{i,j}}{z_{i,j}} - \frac{y_{i,j}}{2}\right) \cdot \cos\left(\vartheta_i - \vartheta_j - \delta_{i,j}\right)\right)\right)^{1/2} \le \overline{TI}_{ij} \tag{15}$$

- **Problem variables min/max limits constraints**:

$$
\begin{array}{ll}
\vartheta_{\min,i} \le \vartheta_i \le \vartheta_{\max,i} & i = 1,\ldots,N \\
V_{\min,i} \le V_i \le V_{\max,i} & i = 1,\ldots,N \\
P_{\min,i} \le P_i \le P_{\max,i} & i = 1,\ldots,NG \\
Q_{\min,i} \le Q_i \le Q_{\max,i} & i = 1,\ldots,NG \\
VT_{\min,i} \le VT_i \le VT_{\max,i} & i = 1,\ldots,Ntap \\
TI_{\min,i} \le TI_i \le TI_{\max,i} & i = 1,\ldots,Nl
\end{array}
\tag{16}
$$

where:

ϑ	is the node voltage phase angle;
V	is the node voltage modulus;
P	is the active power produced by each generator;
Q	is the reactive power produced by each generator;
VT	is the voltage level in nodes equipped with a tap changer;
TI	is the current level in connections;
N	is the number of nodes;
NG	is the number of generators;
$Ntap$	is the number of tap-changers;
Nl	is the number of branches;

- **Battery capacity constraints**:

This is the only inter-temporal constraint problem considered here. This issue is handled by taking into account the power flows between the network and the battery for each time period starting from the first: the battery SoC at the end of each time period is “frozen” and it is considered as an input for the next time period. In this way the inter-temporal constraint turns into a simple constraint which is “updated” from a time section to the next.

Starting from the initial SoC, E_0, and the minimum and maximum capacity limits E_{min}, E_{max}, the algebraic sum of all the energy injections (pI_{acc}) and absorptions (pP_{acc}) must be within the capacity limits:

$$
E_{\min} - E_0 \le \sum_{t=1,\ldots,T_i} pI_{acc} \cdot \Delta T_i - \sum_{t=1,\ldots,T_i} pP_{acc} \cdot \Delta T_i \le E_{\max} - E_0 \qquad T_i = 1,\ldots,NI \tag{17}
$$

where ΔT_i is the time duration of each time section, expressed in the adopted time interval and NI is the number of time sections. If ΔT_i value is fixed during the whole day as commonly used to, the constraint expression becomes:

$$
\frac{E_{\min} - E_0}{\Delta T_i} \le \sum_{t=1,\ldots,T_i} pI_{acc} - \sum_{t=1,\ldots,T_i} pP_{acc} \le \frac{E_{\max} - E_0}{\Delta T_i} \qquad T_i = 1,\ldots,NI \tag{18}
$$

The constraints related to reverse flows to HV grid, even if out of the scope of this tool, can be also modeled in this optimization problem. Two virtual generators are connected to the HV bus bar node of the primary substation, respectively to simulate direct and reverse power flow (HV⇨MV and MV⇨HV); in this way both flows can be analyzed separately with specific limits and energy cost functions to simulate different operating conditions.

Network data formulation in the optimization problem

The RSE optimizer needs a specific formulation of the problem in order to perform the optimization process. Starting from input data, a suitable input format is compiled by the pre-processing module, based on the following assumptions:

I. In order to manage inter-temporal constraints, the integral (temporal) bond which links all the time periods is transformed in a spatial bond: this transformation is made through the replication of the network as many times as the time periods are. Then to each network the corresponding temporal variables (load/generation time series, battery state and so on) are applied. The temporal sequence is maintained connecting all the networks in series, from the first to the last time period.

II. For each flexibility/dispatchable generator the following quantities are compiled:
   a. *Scheduled/forecasted operating point* (P_G, in MW): it is modeled through a fixed dummy generator;
   b. *Active/reactive max/min power limits* (P_{max} P_{min} Q_{max} Q_{min}): these quantities are used to build the boundaries of the capability curve (see Figure 32). Alongside these values, all other relevant information should be specified; these data can be retrieved from the techno-economic models of the levers as reported in the merit order section
   c. *Increase/decrease margin* (ΔP^+, ΔP^-): these are the allowed regulation intervals defined starting from the actual operating point and capability curve boundaries. They are modeled through a dummy generator "G_p" and a dummy load "G_c" (see Figure 32). An energy cost is associated to both; it is retrieved from the techno-economical models, taking into account the specific features and constraints of the lever considered.

III. Each storage battery is modeled through the following elements:
   a. A dummy generator for modeling the battery discharge mode and a dummy load (or a generator with negative sign) for modeling the battery charge mode; the active power limits are defined according the maximum battery charge/discharge power levels. As for other flexibilities/dispatchable generators the energy costs for charging/discharging are derived from the techno-economic model of the storage systems;
   b. One virtual connection line from the interface node to dummy generator and load to allow the time-spatial model (related to energy charge constraint).

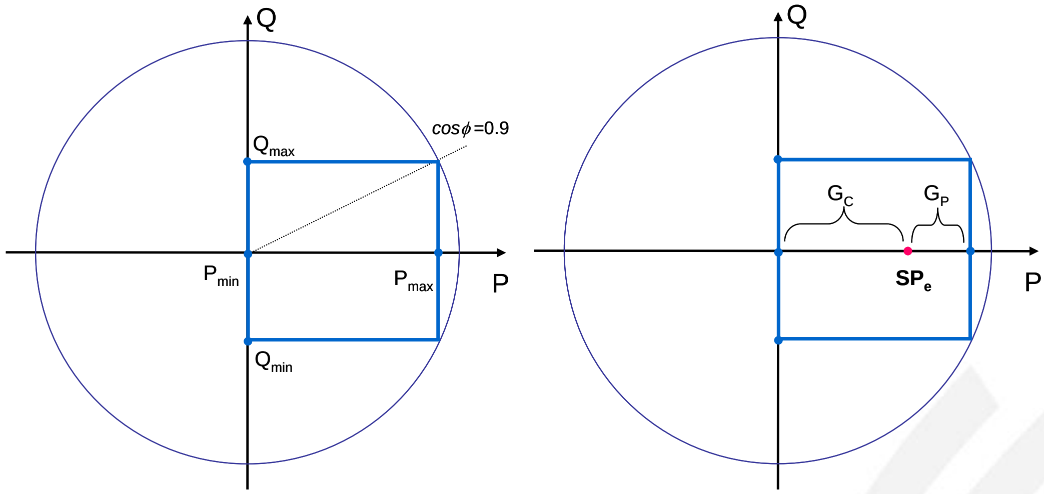


Figure 32 – Simplified diagram of a photovoltaic generator capability curve; increase/decrease margin G_P and G_C (linked to current working point SPe) are represented

4.3 Operational Key Performance Indicators

The tool has three operational KPIs, which help us to identify and analyse the operational performance characteristics of the tool. They are:

Increased uses of Flexibility resources by DSOs

This operational KPI is applicable to the economic analysis sub-tool. The generation of a merit order by the economic analysis sub-tool will make it possible for the optimization sub-tool to have access to an evaluation of different types of flexibilities based on the relevant costs, and choose the ones that can be used to operate the network under non-emergency, yet undesirable conditions, with the lowest operating costs for the DSOs.

The KPI will measure the improvement in the number of types of flexibility used in order to maintain normal operating conditions in the network. It is notable that this KPI does not measure the increase in number of flexibilities of one type (10 load reduction flexibilities will be counted as 1 because they are all of the same type). Therefore, the goal of the measurement is to know how many new types of useful flexibilities are introduced by the tool, through a relevant economic analysis for each of them.

Voltage Profiles Quality

This operational KPI is applicable to Robust Short-Term Economic's Optimization component of the optimization sub-tool. Voltages in distribution networks where DRES is not installed typically decrease as the distance from the substation increases. However, the presence of DRES influences the voltage profiles in the feeders. An optimal voltage profile can contribute to having a secure operating point where losses are limited and a more comfortable scenario for DRES integration is possible. The voltage levels have to be kept in the predefined standard limits, as suggested in the EN 50160 standard [54] or other relevant national rules.

This KPI is a measure of the quality of the voltage profiles, and it is measured by evaluating the duration of voltage constraints in the network to be optimized, without and with this optimization module. This means that one voltage constraint during a 15 minute period is considered to be 15 minutes of voltage constraints. The impact is seen in the decrease of the duration of voltage constraints when the sub-tool is used.

Efficiency Improvement Optimization

This operational KPI applies to VITO's optimization component, part of the optimization sub-tool. As described earlier in the working, the optimization routine iteratively solves the given network for technical and economic optimality. This means that, with every iteration, the solution provided by it is strictly equal to, or better than, that of the previous iteration.

Given the fact that a user-defined time limit can be set for this operation, it is interesting to see how the solutions evolve over time, and what the effects of time limits on the solutions are. This is the purpose of the KPI. Through the measurement of this KPI, two valuable results can be obtained, pertaining to the speed, and the correctness of the optimizer.

4.4 Functional Specification

The functional block diagram of the Robust Short-Term Economic Optimization Tool for Operational Planning is shown in Figure 33. Each block is given a colour corresponding to its function.

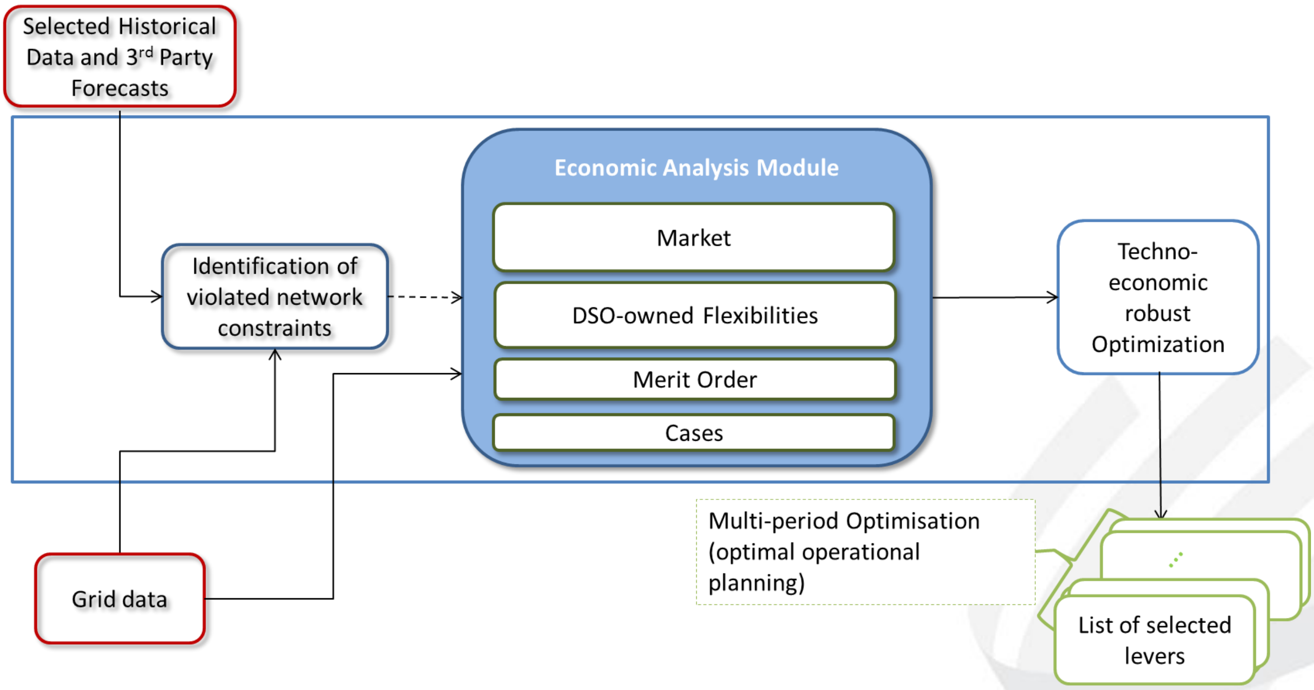


Figure 33 – Functional Block Diagram of the OP Tool

Input blocks are outlined in red. For the tool, the inputs required are the grid data, and historical data/third party forecasts for loads and DRES in the network. For the purpose of demonstration, historical data can be used. All the requirements for the inputs have been set out as a part of the deliverable D2.3. The format for the inputs related to the grid can either be in the Common Information Model (CIM), an open standard set by IEC 61968/IEC61970 [67], or in a simpler excel/comma separated values (CSV) form.

All the process blocks are outlined in blue. The different processes communicate with each other as shown in the function block diagram, and the JavaScript Object Notation (JSON) format is used to this end. This is useful since all the blocks are not developed in the same programming language. The JSON format is compatible with many languages, due to its simplicity and human readability, and therefore is a suitable choice.

The output of the tool is a list of levers and their set points for each time period. This is a multi-period optimal set point list that will result in the lowest DSO expenditures, and can be provided in the form of a human readable list, an Excel table, and also in another format as requested.

4.5 Illustrative Examples

4.5.1 Example 1: RSE Optimizer

In this Section the RSE optimization approach is applied to a 32 busses MV network. The analysed network and the final results are described.

A case study (32 nodes MV network) is built acting on multiple parameters: load/generation profiles and costs, see Figure 34.

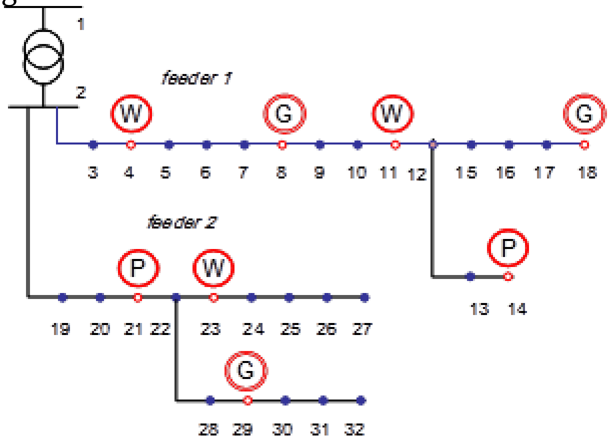


Figure 34 – RSE Test network (W=Wind generators, P=PV generators, G=Synchronous generators)

In this analysis, only a linear cost for active power displacement is considered. In particular it is equal to 320 €/MWh for synchronized generators, while renewable generators are paid only for a complete switch off (1000 €/MWh). Power flow inversions is penalized, fixing a very high cost for injecting power to the HV level (up to 3200 €/MWh).
Injection/absorption of reactive power is set to a low value for all resources (1 €/MVArh), considering it as a compelling service. Finally, for OLTC changes a low cost was considered in order to include maintenance costs and to prevent excessive requests by the optimization algorithm.
The reward schemes for ancillary services adopted in this application is reported in Table 16; cost values are only for illustrative purpose and case are only a tentative hypothesis not based on real regulation.

Power resource type	Cost
Active power	320 €/MWh
RES curtailment (complete switch off)	1000 €/MWh
Reverse power flow	3200 €/MWh
Reactive power	1 €/MVArh

Table 16 – Revenues considered in this application example

This allows to evaluate how the optimization results are affected by different boundary conditions based on a self-consistent framework that aims to fix ratios between costs at reasonable values. Current wholesale market prices and incentives for generation from renewable sources are taken into account as well.

4.5.2 Results

The proposed RSE technical-economic optimization technique can help to improve hosting capacity of DRES in MV networks, maintaining technical parameters in desired range minimizing the operational cost. The procedure permits the evaluation of the effect of several parameters on optimization results, in terms of ancillary services (costs and capabilities) especially when strong constraints on power flow inversion are fixed.

The considered baseline scenario assigns proper generation and load profiles to relevant nodes to obtain a power flow inversion towards the HV network during all day, as shown in Figure 35. The proposed scenario is quite representative of the current situation, given that currently –as PV generators spread – it may occur more frequently, especially in sunny areas such as in south Italy, where weak networks with modest load are common.

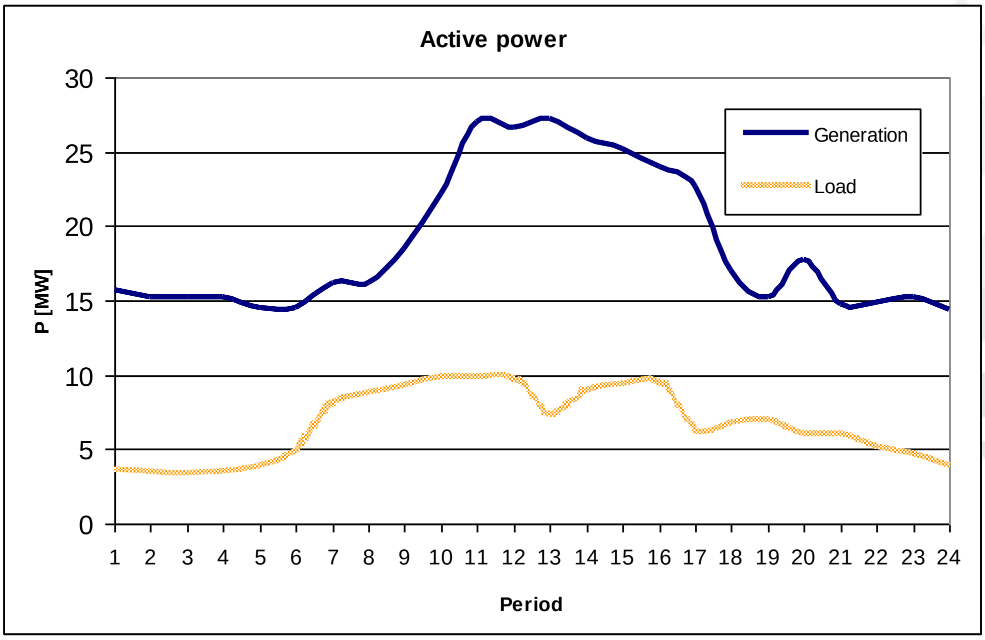


Figure 35 – Total expected generation and load profiles (active power) before optimization

Table 17 shows forecasted (for renewable generators) and scheduled (for synchronous generators) power at time period 15 (3 PM) before optimization, when unbalance respect to load is remarkable.

Generator	Node #	P [MW]	Q [MVAR]	Control.
GD7 – wind	4	3.58	0	N
GD2 – sync	8	2.87	2.10	Y
GD8 – wind	11	3.58	0.0	N
GD1 – sync	18	4.94	0.0	N

Table 17 – Baseline scenario (scheduled/forecasted generation at 15, feeder 1)

A load flow calculation shows that overvoltages are expected, and in particular the generator placed at node #18 may disconnect (see Figure 36).

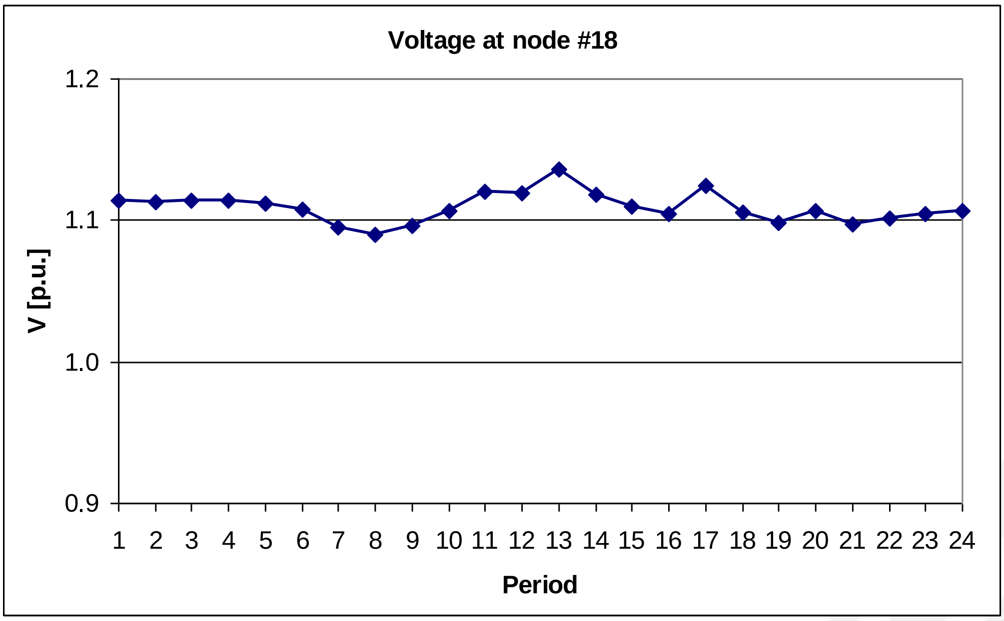


Figure 36 – Scenario voltage profile at node #18 before optimization. Overvoltages are expected in most time periods

The algorithm finds a minimum point in the cost function that guarantees technical parameters to respect their allowed ranges.

In the Figure 37 the calculated set point for controllable generators are presented, together with net power exchange with the HV network. Despite a strong reduction in power generation a power flow inversion is still present (see periods from 12 to 15). In this case study, the behaviour of networks with massive presence of DG and limited load can be foreseen.

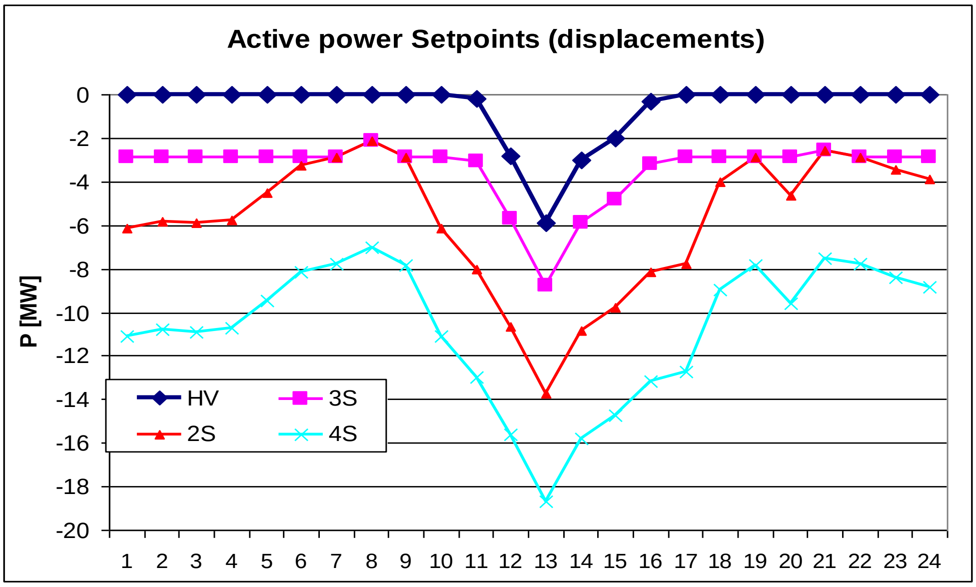


Figure 37 – Scenario calculated set point for controllable generators. HV: net power exchange with the High Voltage network

4.5.3 Example 2: VITO Optimizer

The VITO component was completely designed and developed in the EvolvDSO project, to optimize realistically-sized MV networks that connect challenging types and amounts of DRES devices. Even at the time of writing, no such networks are available for testing. With this obstacle in mind, we chose a theoretical but challenging example from recent literature [56] and [57] that was positioned as a "benchmark problem" to evaluate optimization algorithms on speed and scalability.

The network of this benchmark is shown in Figure 38. It consists of 77 busses to which 59 distributed generators are connected, 6 of which are wind turbines and the other 53 solar generators. This network also contains 53 loads, all of which can be modulated.

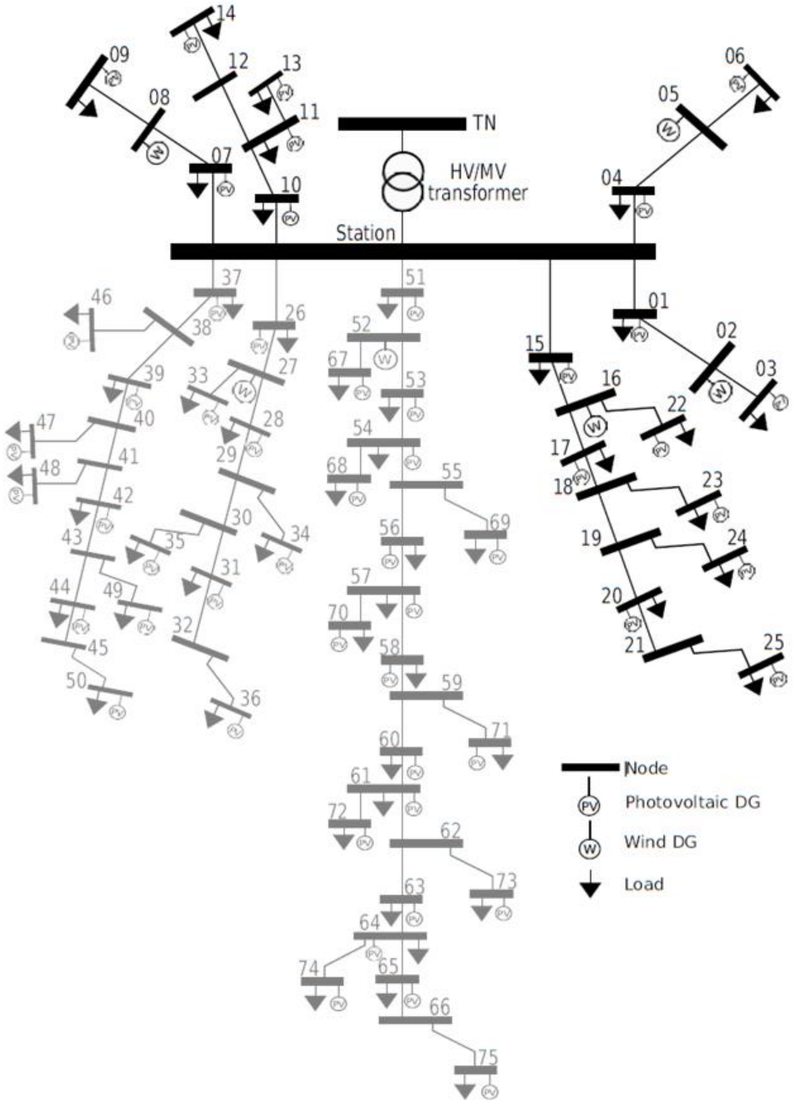


Figure 38 – Benchmark problem test network

Curtailment of the generators comes at a cost equal to the level of curtailment multiplied by the curtailment price at that time interval.

The cost of applying load modulation cost is a one-off activation fee. The loads can only be modulated by a fixed sine wave pattern, different in period and amplitude for every load.

Figure 39 – Sine Wave Modulation at t=1

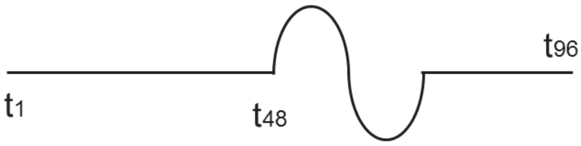


Figure 40 – Sine Wave Modulation at t=48

As mentioned in section 4.2.4.1 above, pattern-restriction of load modulations represent a challenge to the CP solver, because of the weak propagation of extensional constraints. This makes us even more confident that the VITO component, once it can handle the benchmark problem, will have no difficulties to also handle more realistic network problems.

At the time of writing, the authors are still working to increase the execution speed and improve the scalability of the components. Nevertheless, our current implementation is ready to optimize small networks. Therefore we restrict the current example to the black (not greyed-out) subset of the benchmark problem in Figure 38. It contains:

- 27 busses;
- 17 loads all of which can be modulated;
- 17 solar panel installations all of which can be curtailed;
- 4 wind generation units that can also be curtailed.

We also restrict the time horizon to 12 hours, more precisely 48 periods of 15 minutes.

The example is set up to qualitatively illustrate the major advantages of the combined OPF-CP approach we explained in previous sections. For that, we accentuate the potential of exploiting flexibilities with inter-temporal constraints by exaggerating the difference between the cost for curtailment (high cost proportional to the amount energy curtailed during the time span) and the cost for activating load-modulation (low cost, one-off fee). Therefore our results do not mention any absolute figures on costs or cost reduction.

4.5.4 Results

At 30% of the time periods, the benchmark load and generation scenarios cause overvoltage in 6 busses and current problems in 1 network link. In Figure 41, the lines and busses that experience network violation problems are depicted in red. The voltage magnitudes of every bus during 48 time steps is shown in Figure 42. It can be noticed that overvoltages occur from time step 32 and beyond.

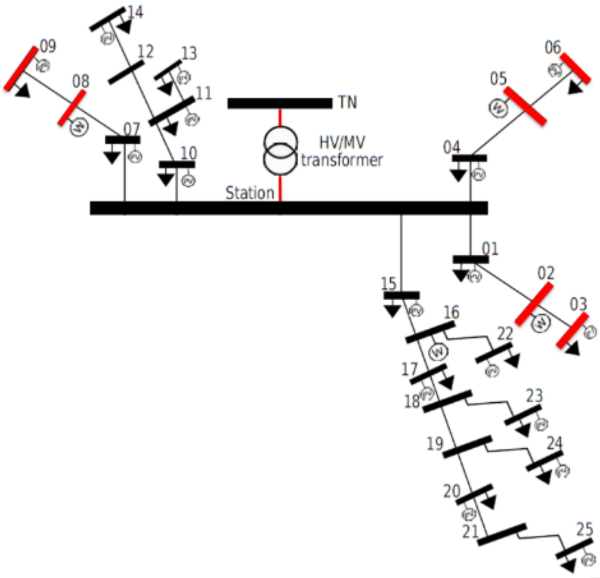


Figure 41 – Overloaded sub-network

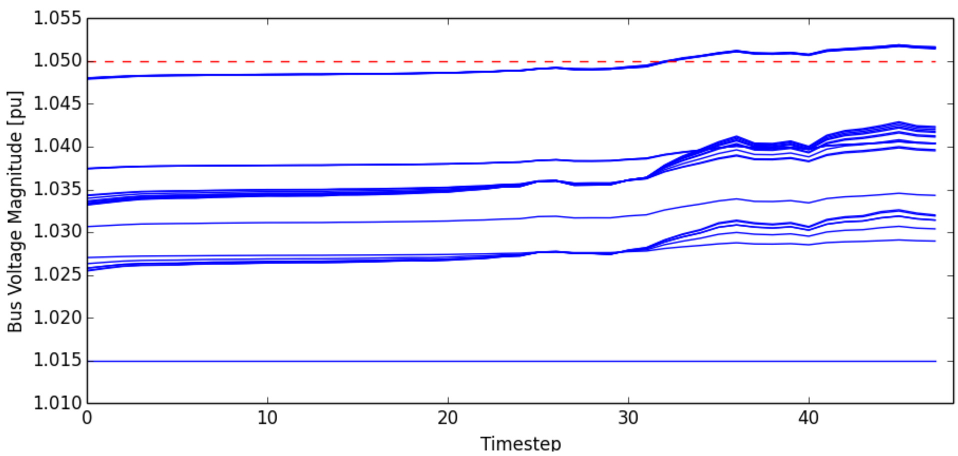


Figure 42 – The voltage magnitude of every bus during 48 time steps. The maximum voltage limit is indicated as a red dashed line.

For reasons of clarity we have chosen to split our solution into two parts, exactly corresponding to the two main components depicted before in Figure 26.

1. The OPF component first solves all the conflicts, only making use of the curtailment flexibilities. That solution is valid and feasible, but it can be improved upon by including the load-modulation flexibilities.

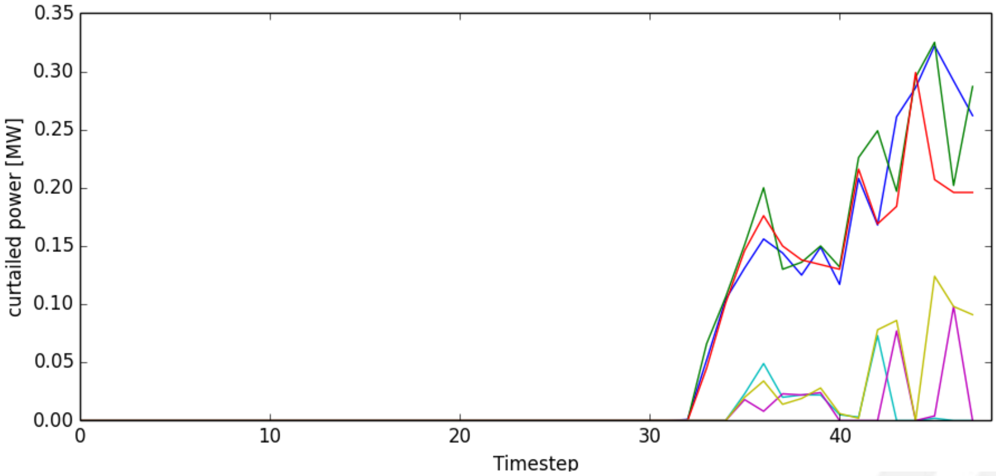


Figure 43 – Curtailment power solving network problems.

Figure 43 shows how much every generator needs to curtail to solve the network problems according to the solution from the OPF component. The figure shows that 6 out of 21 generators need curtailing, starting at time step 32 up to time step 48.

2. Since the load-modulation flexibilities have inter-temporal constraints – they follow a sine-wave modulation representing a fixed load profile that is added to the load – we use the Constraint Programming component to try to improve the previous results.

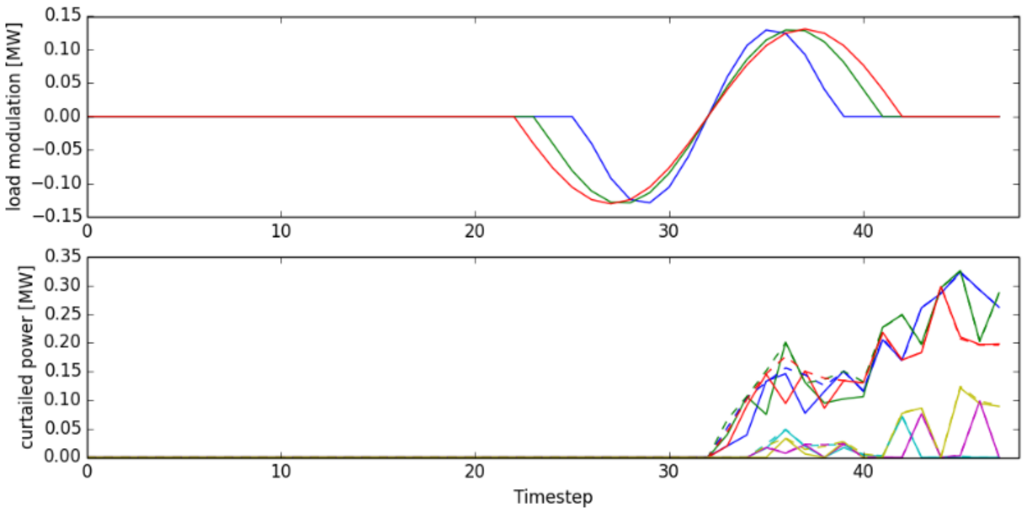


Figure 44 – Upper part: load modulation added to alleviate curtailment. Lower part: solid lines show the remaining curtailment needed with load modulation, the dashed lines show the initial curtailment required without load modulation.

The upper part of Figure 44 shows how the CP component activates 3 load modulations at time steps 23, 24 and 26, consuming additional power following a sinus wave load profile to assist in solving the overvoltage problems.

The lower part of Figure 44 shows the curtailment of the solution including load modulation. The curtailment requirement without load modulation is also shown as a dashed line. This plot indicates that a part of the curtailment and its associated costs are now avoided by strategically activating load modulation at earlier time steps.

5 Network Reliability Tool - Replay

Here below is a schematic representation of the tool architecture that will be described in section 5.2.

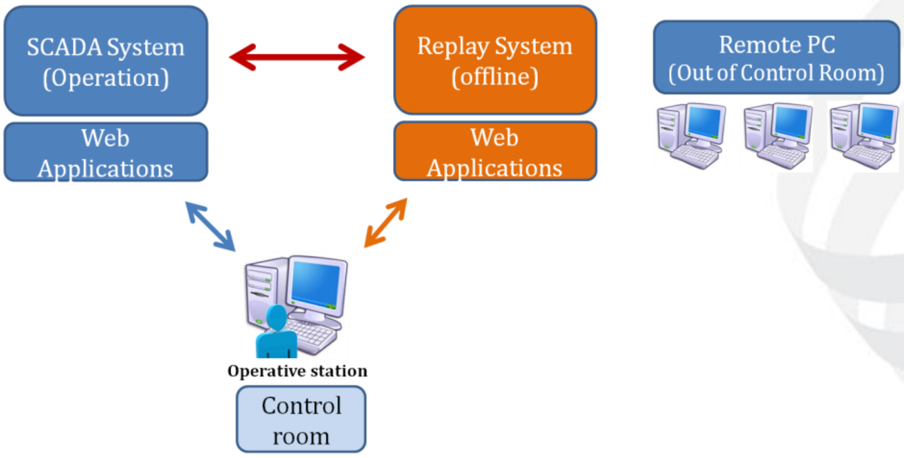


Figure 45 – Replay tool functional architecture

As shown in the above picture, Replay tool acts as an independent platform, using a copy of the real SCADA system (and its ad-hoc web sections) to elaborate studies in the control room[2]. Due to safety reasons, to date external operators have access to the network real-time schemes without the possibility to act on them and use all the related tools available in the control room. A full access will be enabled, allowing a large number of operators to train themselves on a “future active network”.

Concerning the scalability potential, Replay tool can be supported by a virtualized architecture (e.g. VMWARE HW) as well as physical machines. Since some DSO are now working to enable virtualized architectures. The possibility to reproduce a complete system with its configuration means that this system could be installed in different places, thus reducing costs for the installation because of the savings obtained on the physical hardware.

[2] The possibility to open a connection to the external remote PC DSO units is not investigated in this project, but it will investigated in the near future

5.1 Relation with System Use Case

The scope of the Replay tool is linked to the Business Use Case "Optimize network operations until market gate closure based on a schedule". It describes how the DSO predicts network operations in medium-term (month and week ahead) and short-term (2-3 days time horizons) operational planning. This tool is able to:

- Evaluate the operating points based on local load and generation forecasts, identifying risks of constraints on the distribution network especially in case of DER production and/or in the presence of Flexibility Operators;
- Define the network configuration and solve detected constraints, by using several optimization levers according to a merit order and in compliance with the contractual commitments,;r
- Evaluate the impact of work programs and the real-time network constraints ((faults, transmission limitation or transmission outage, load transfers) on the operating points in all the timeframes;
- Validate from a technical perspective the flexibility offers proposed or activated in the balancing market and/or flexibility market.

The System Use Case "*Simulate contingency analysis in Operational Planning*", linked with the BUC above mentioned ,highlights the importance of two innovative functionalities that will be implemented by specific tools:

- Real distribution network analysis on the basis of occurred events (Replay);
- Simulated network analysis considering electrical and ICT aspects (Co-Simulator).

In particular Replay is able to simulate and analyze contingency situations on the distribution network on the basis of real network scheme and historical events. As a first step, Replay analyzes the events in the past with related critical situations ("Replay function"). The aim of this first step is to build the basis for preventing similar situations in the future and improving the network management procedures in the future. Concretely, this analysis could lead to a decrease in the number of interruptions and their duration (SAIDI), as well as a higher compliance of the network parameters to quality of service and power quality standards Regarding the compliance to the parameters, the replay tool could support the operator in the evaluation of the network configuration in different operating conditions (faults, availability of flexibility from prosumers, emergency situations, etc...).

Figure 46 shows the main steps of the SUC "*Simulate contingency analysis in Operational Planning*", and their match with Replay tool; the links between WP2 non-functional requirements and Replay tool are presented in ANNEX V – Match between Tools and WP2 Requirements

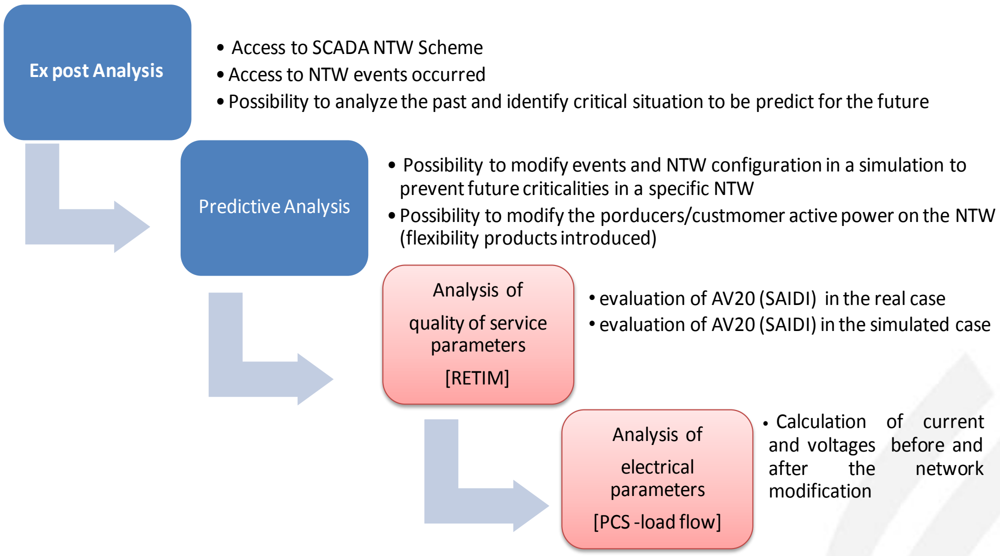


Figure 46 – Relation between system use case steps and the Network Reliability Tool-Replay

5.2 Methodology and Algorithm Description

As described in the previous chapter the REPLAY System is developed on the basis of the current Enel SCADA platform. This is why the detailed algorithm and software codes are not available for copyright reason. In this section an overview of the main functionalities developed within the tool is given.

The Replay performs **network analysis** reproducing the network and its dynamics with a high fidelity representation and using a real time approach.

In order to realize the functionalities foreseen in the SUC two types of analysis are envisaged: 1) ex-post analysis and 2) predictive analysis

As shown in Figure 47, Replay performs an *ex-post analysis* on past situations and a *predictive analysis* in the short term future period.

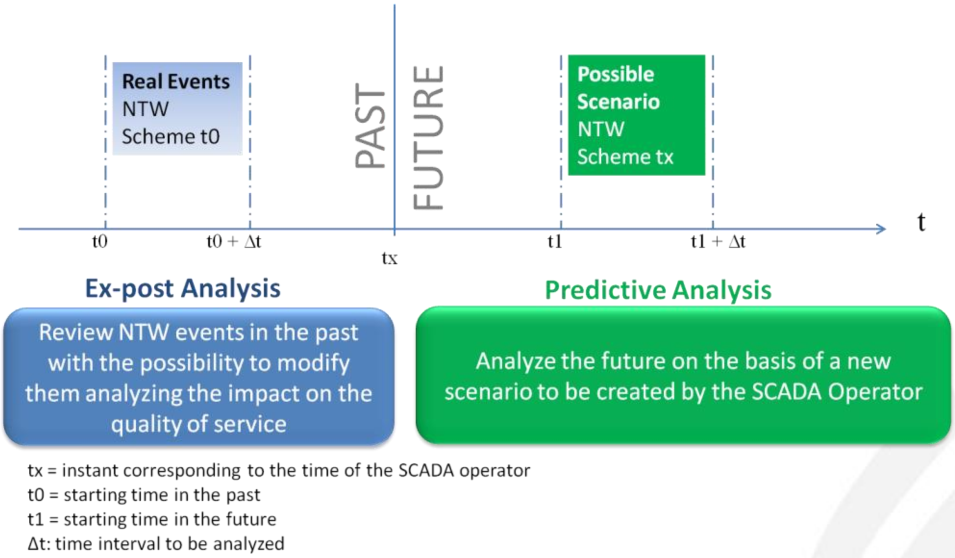


Figure 47 – Scope of the different analysis performed by the Replay Tool

In Figure 47, the time axis represents the **time horizon** to be investigated by the Replay operator during the analysis. For the Ex-post Analysis, a period in the past and the related complete list of **occurred events are selected**. The occurred events are recorded in the external data base of the SCADA system and will be identified and integrated by the Replay tool for further elaboration.
When an event is stored in the database,, all the activities of field components and central system are monitored and stored as well. In this way all network conditions such as faults, problems occurring on electrical, TLC or communication equipment and all the criticalities are always monitored by specific signals and available for the Replay analysis.

The Replay tool within the evolvDSO project will be used as a support to network management activities, therefore a subset of the signals available to the operator have been chosen from the complete list available within the SCADA operator interface with the aim to focus on electric faults and electric aspects of the network.

Apart from the list of events, the tool shows the **network schemes** corresponding to each selected timeframe. The interface would give the operator the possibility to see series of network scheme screenshots and to analyse the list of events before starting the elaboration.

Once the operators select the time interval to be analyzed, an automatic tool procedure chooses the correct database to be elaborated. It is important to highlight that for each modification on the electric network the SCADA scheme must be "updated" and this is why it is necessary to divide the database in different sections.

Ex –post analysis

The purpose of this functionality is the analysis of the occurred events, alarms, faults and other criticalities , i.e. the analysis of the signals collected from the fie and recorded in the SCADA database.

A concrete example is the signal given by a fault detector on the network. Furthermore all the other signals necessary for the operator to manage the network are represented. The complete list of these signals and the possibility to carry out an analysis on them are possible by an effective representation of the event list and their representation on the SCADA network scheme. The tools provides a user friendly interface supporting SCADA and Replay operators in their analysis.

This basic functionality ("Ex Post analysis") is the core of the replay tool and it is essential for the correct implementation of the related sub functionalities.

The idea of a didactical platform relies on the possibility to carry out modifications on the events occurred in the past, in particular to add or eliminate records in the list of events. In this case, the modifications on the network mean opening or closing switches in order to simulate a fault or modifying the network scheme/configuration creating in this way an off-line simulation SCADA.
At a glance, the *ex-post analysis* covers the following aspects:

- Revision of the events occurred in the past timeframe (*Replay Interface*);
- Analysis of the effects in terms of quality of service (inputs are collected from the *RETIM* Interface- REal Time Interruption Monitoring*);
- Possibility to modify occurred events analyzing the complete list of events (*Replay Interface);*
- Calculation of the network operation set points (PCS - *Replay Power Flow*);
- Analysis of the effects in terms of quality of service *(RETIM Interface).*

Replay tool is also able to calculate the ***real SAIDI*** associated to each interruption on the basis of the sequence of occurred events as well as the ***potential SAIDI*** obtained by the modified sequence of events introduced by Replay operator.

The interface used in this elaboration is the *RealTime Monitoring Interface,* already integrated in the Enel Distribuzione systems and used to monitor all the interruptions.

The *RETIM interface* is able to show a full set of information regarding the service interruptions, in particular:

- Interruption Codes (used for classification needs);
- Time interval (Starting and ending time)
- Duration of the interruption;
- Motivation for interruption: accidental, with/without notice to customers;
- Kind of interruption: transitory, long, short;
- HV/MV substation involved;
- MV line involved;
- Number of MV/LV substations involved;
- Number of MV customers involved;

- Number of LV customers involved
- AV20: min *customer/1000 (corresponding to SAIDI);
- AI45: AV20/clients;
- Number of LV customers involve more than 8 hours;
- Number of MV customers involved more than 4 hours;
- Special customers involved (e.g. hospitals, airports, etc...).

The system integration level of RETIM gives the operator visibility into all the data related to the real occurred network events/the events modified by the use of the Replay. In this way a complete ex-post analysis can be realized with concrete evaluation of the impact on the quality of service for the potential modifications introduced by the Replay operator. This will be further investigated in the section (n. ?) related to KPIs.

Predictive–analysis

The objective of the Replay is to allow a wide group of operators, including those that do not usually work in the DSO control room, to operate the electricity network by the use of a SCADA simulation tool and to support them in the choices in the short term planning domain.

A concrete example consists in the analysis of the network conditions in case of a work planned in the next three days and the possibility to modulate the active power of a customer or a producer. To allow the active power modulation in the Replay tool, a direct data flow (INPUT) from a forecasting tool is needed. In Enel Distribuzione the forecasting tool is already available (*MAGO –Monitoring and control of Active distribution Grid Operation*). The Replay tool must be supported by a source of forecasted data; more details will be given in the next section.

Concerning the active approach in the network management, the analysis of a scenario and its related electrical network condition is the basis for implementing market flexibility scenarios within the DSO. Flexibility scenarios could indeed introduce criticalities on the network in terms of overloads, overvoltage and other situations that should be evaluated by the SCADA operator as well as by the planning analyst.
This is why scenarios of flexibility must be analyzed with tools like *Replay* to reproduce the network with all the characteristics of the real-time approach as well as the long term planning tools. The purpose for the future could be the realization of a complete tool with integration of all the DSO databases (commercial, technical network, real-time scheme, future network development, etc.).

At a glance, the predictive analysis should potentially cover the following aspects:

- Import of real time/standard NTW scheme and related configuration;
- Definition of specific scenarios by the operator (faults, overloads, etc.);
- Elaboration of measurements (*MAGO -forecasting data source*);
- Calculation of the network physical characteristics (*Replay Power Flow*);

- Analysis of the related consequences in terms of quality of service *(RETIM Interface).*

The approach consists in:

- Drafting of a simulation scenario and the definition of a specific network section and
- Analysis by the use of the_Replay Power Flow and the RETIM interface to elaborate results. The methodology of the analysis is the same explained in the ex-post analysis section.

The function is based on the possibility of elaborating sets of information related to planned work on the basis of maintenance needs.

The possibility to operate the Replay tool from a remote web station could be concretely realized in Enel Distribuzione once the tool is developed and tested on specific network sections.

The active contribution of people today not involved in the real-time network management will open new perspectives in the network management.

<u>Supporting functionalities for replay tool</u>

In the table above a synthetic representation of the Replay sub functionalities are included. Even though not all the functionalities are necessary for the implementation of the methodology, each of them contributes to the recreate the behaviour of the network with high fidelity.

The green box and the yellow one represent functionalities within the evolvDSO project (already developed –green- and in progress – yellow), whereas the functionality in the red box represents the possibility to introduce a sub-simulator in the Replay tool able to reproduce the automated fault detection logics applied on the Enel Distribution network.

Power Flow	Event Coherency control	Automation logic	Resources modulability
• Voltage at nodes and current on branches using measurements, forecasts or profiles.	• if a new event is added into the event list the coherency of the added one with the others will be verified.	• The tool will react to new events as the real automation system intervened.	• MV generators, MV passive loads and MV/LV transformers can be set in the defined time interval of a scenario.

Table 18 – Sub Functionalities to be implemented in the Replay tool

Power flow executes a calculation on the network on the basis of the current grid configuration (real-time or off-line). The calculation gives the voltages at nodes and current on branches compared with reference values and using different sets of parameters.

The *Event Coherency Control* checks the time of occurrence of the events, i.e. it compares the time recorded by equipment installed on the field and the time detected by the central system. must be included and represented for each event in the list. This check is relevant when issues related to the communication system occur, such as communication delays,

In order to give a complete representation of the network, DSO it could be useful include a simulator of the *automation logic* since DSO use different kind of automation systems.

Resource modulation gives SCADA operators the possibility to module active power for customers and generators to solve punctual criticalities on the network. This sub functionality could be useful to test some specific flexibility products and evaluate specific network conditions.

5.3 Functional Specification

In this section a detailed description of the data flow and the related tools is given.

Replay tool Architecture

In Figure 48 a simple representation of the structure is shown. The blue box represents the system in operation, composed of the following elements:

- ***SO***: the "Operative Station" used by the SCADA operator in the control room;
- ***STM ESE***: the real-time SCADA operation system;
- ***Multifunctional server***: a PC to manage all the functionalities of the SCADA and related tools;
- ***Archivi STM ESE***: a PC where all the occurred events are recorded (storage of events);
- ***STWEB***: a web platform with all the tools related to SCADA for the back office activity.

Replay is an independent off-line system always connected with the real-time system in operation. Indeed, Replay works in parallel and uses the same network scheme and the same list of events.
As already explained all the machines involved could be physical or virtualized.

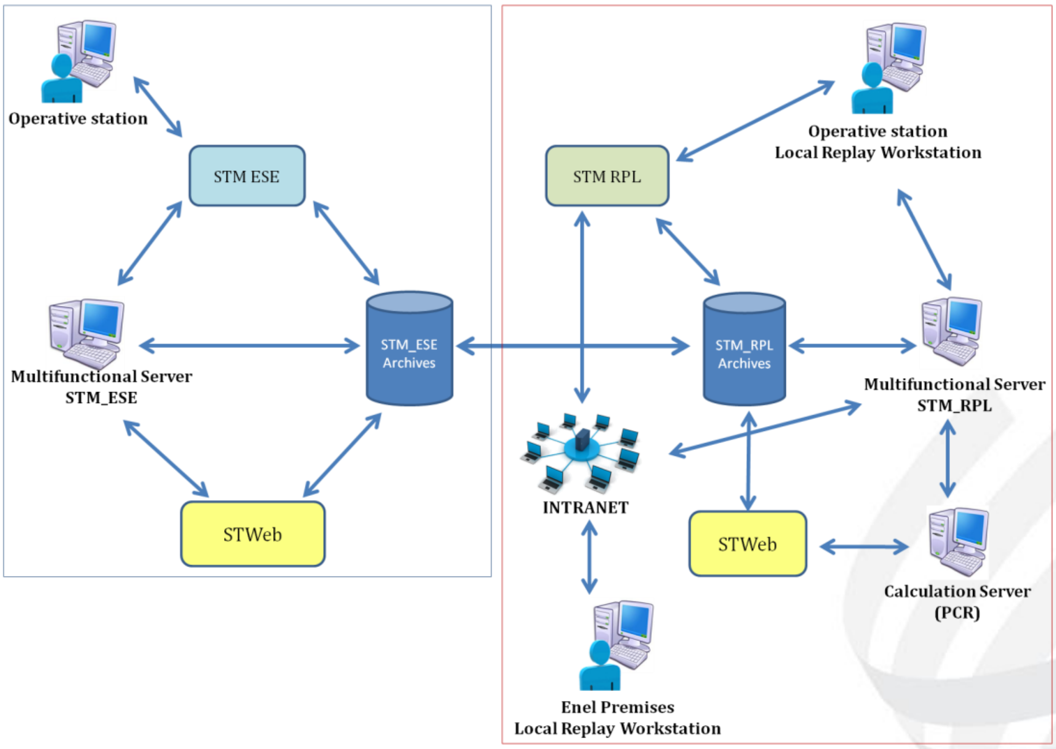


Figure 48 – Replay tool functional architecture schematic

Scalability and dissemination opportunities

The possibility to operate the Replay tool from a remote web station could be concretely implemented in Enel Distribuzione once the tool is developed and testes over specific network sections. This opportunity could open new perspectives in the network management because of the active contribution of people today not involved in the real-time network management.

Data flow

Figure 49 shows the data flow of the tool.. In particular in the red box the main databases (DB) sources are represented: the network data and the customer/producer data base.

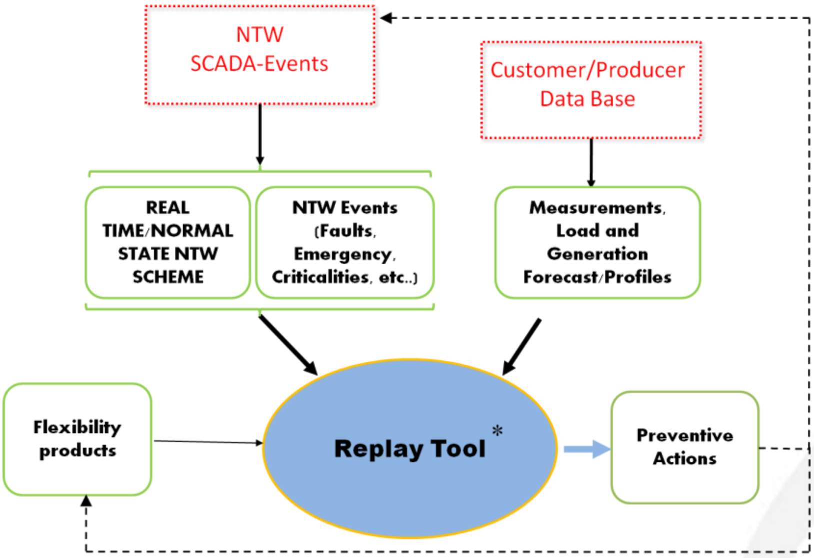


Figure 49 – Relevant data flow

The real-time and the normal state network data schemes are essential for the tool to create a detailed graphical representation of the network. The other important aspect is the list of the network events occurred in a defined period in the past., including the related faults, alarms and other signals collected from the field.
Concerning the customer/producers database, all the historical data related to consumption as well as the historical data of the generation are collected. Furthermore, in order to realize predictive analysis generation forecast profiles are also needed and provided by the specific tool used for forecasting.

In a future perspective, the replay tool could be also used to evaluate the impact of flexibility in the short term (e.g. bilateral contracts with producers). In this case, an additional information flow stored in a specific database is expected.

Two main inputs are relevant for the Replay:

- Network scheme from the SCADA;
- Network events.

Regarding the network scheme from the SCADA a real-time asset of the network as well as the normal state is available while all the occurred events signals from the fault detectors and protections are recorded from the real-time SCADA.

To allow the modification of the network configuration and to elaborate load flow calculation Customers/producers measurements and load/generation forecasts data are collected from a specific Enel tool called *MAGO*)

Replay is indeed born as a didactical platform: it helps training SCADA operators to manage the network in the operational daily activities and enable an active management approach of the DSO operators.

It is important to highlight the importance of the box called "flexibility products". This box represents the list of potential modifications on the customers/producers active power to be tested and verified by the Replay tool. To date, this functionality is manually applied for didactic reasons, even though in the future it could be automated for a complete integration in the real-time operation system.

Inputs Required for the reliability tool
Identification of criticalities
• Real Network data: ❑ Real Network Scheme (off line) ❑ List of network events occurred ($\dot{t} \div \dot{t}+\Delta t$); • Load and Generation (Measurement, Forecasts, profiles) • Action changes defined by the SCADA operator in the considered time frame

Table 19 – Input required by the Replay tool

Regarding the output, the main one is the possibility to collect a group of information to support the operator in order to improve the management of the network (ex-post analysis) and to support the operator in making the best choice in the future (predictive analysis).

OUTPUT
Ex post Analysis
• NEW Real Network data: ❑ Real Network Scheme (off line) ❑ General behavior of the automated NTW (occurred TW events)

Table 20 – Replay tool: Output of the "Ex Post analysis"

The concrete output for this kind of analysis is given by the load flow calculation on the real network scheme, furthermore all the information are available on the off-line SCADA interface with the same representation in order to support the SCADA operator in the training.

5.4 Operational Key Performance Indicators

In the current section a general overview of the defined key performance indicators to test Replay tool features is given. The complete KPIs definition is included in the ANNEX II.

The following KPIs are mainly refer to the DSO cost saving as well as the quality of service, but aspects related to the technical performance of the network are also considered from the perspective of the SCADA operators.

- **CRI-Criticalities Reduction Index**: The KPI measures the reduction of the number of criticalities on the network in terms of overvoltages and overloads.
- **TTS-Training Time Saved:** The KPI measures the reduction of time needed to train SCADA operators with and without the Replay tool as well as a support for the operator daily activities.
- **TCS-Training Cost Saving**: The KPIs measures the cost reduction to train SCADA operators by the use of Replay tool.
- **TAS-Time daily Activity Saved**: The aim is to evaluate the time saved on the operator daily activity by the use of replay in order to coach a SCADA operator to become independent as well as for the other daily activities.
- **SPRI-SAIDI Potential Reduction Index**: The KPI measures the potential reduction of SAIDI for specific events managed in the past.

5.5 Illustrative Example

Here below is a concrete example of how the tool works when an ex-post analysis is carried out In the user interface, operators can select the DB considered for the events of the network. By choosing “Replay Esercizio” in the main index,, users can select the event of interest. In the second window it is possible to select the time interval to be considered for the analysis(Figure 50 – Figure 50).

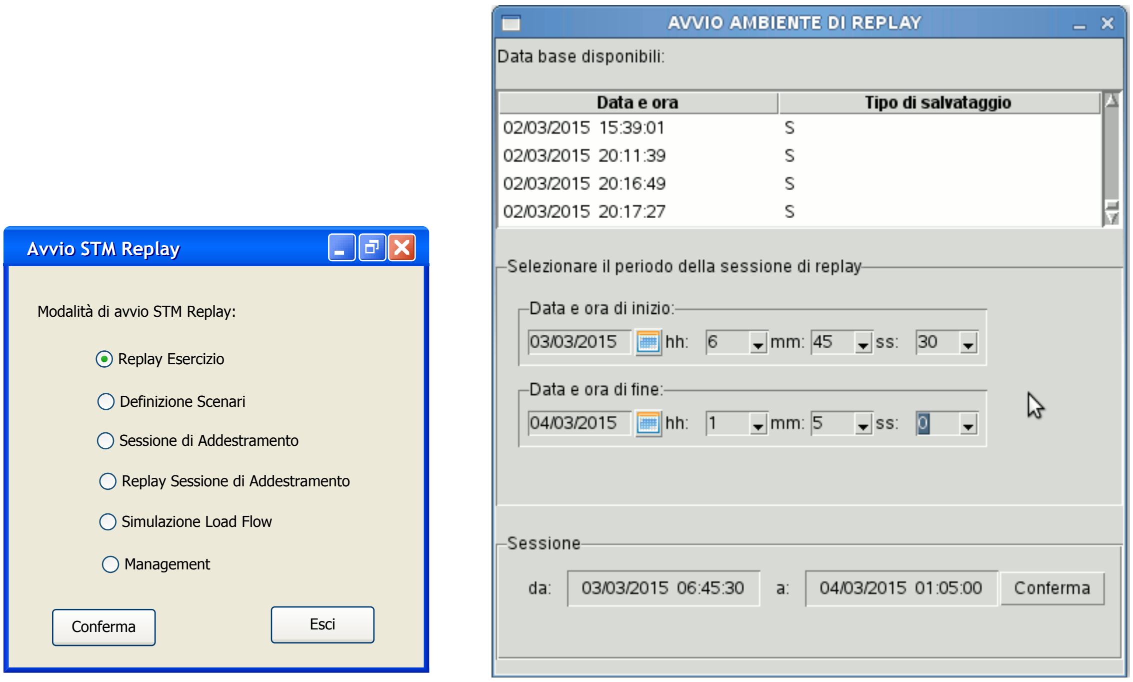


Figure 50 – Replay control windows

Figure 51 represents a list of the main events occurred on the network .. It is worth noting that in the left part of the window a list of machines is available, including both involved in the real system in operation (e.g. stations and server machines) as well as the those strictly related to the Replay tool.

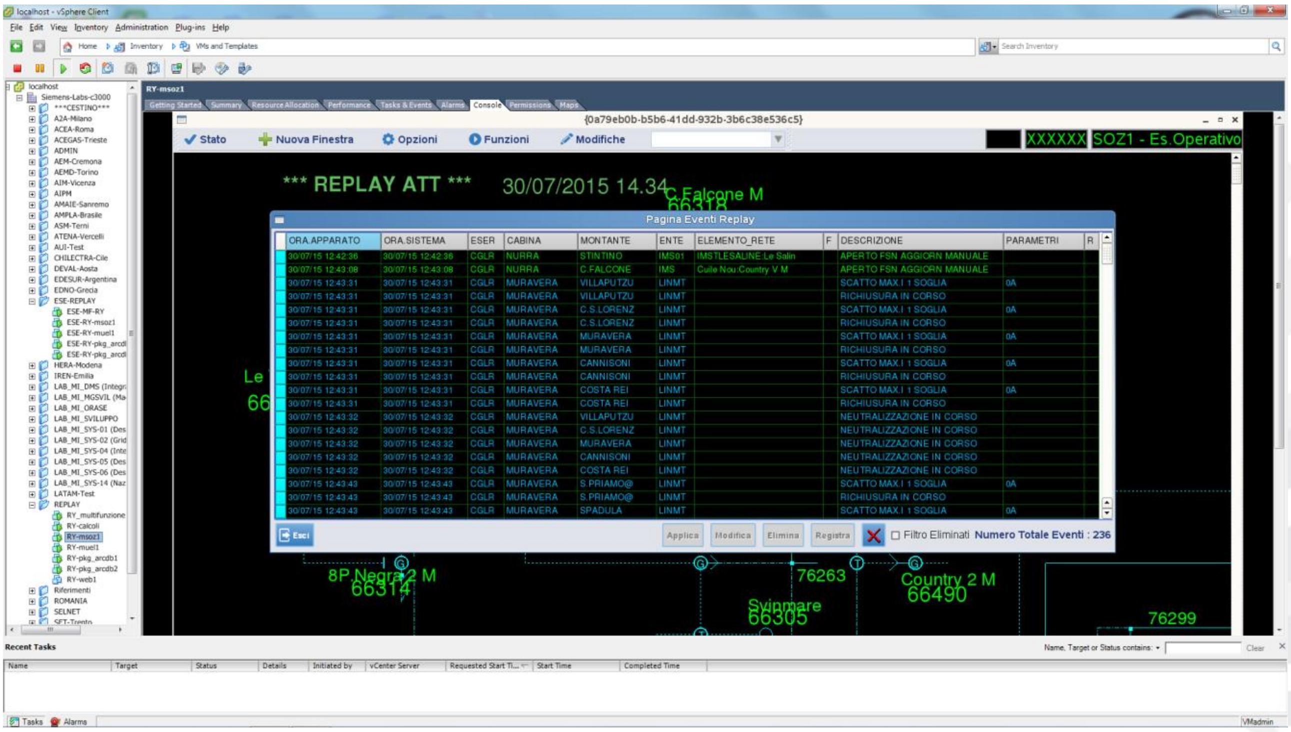


Figure 51 – example of events list visible to the SCADA Operator

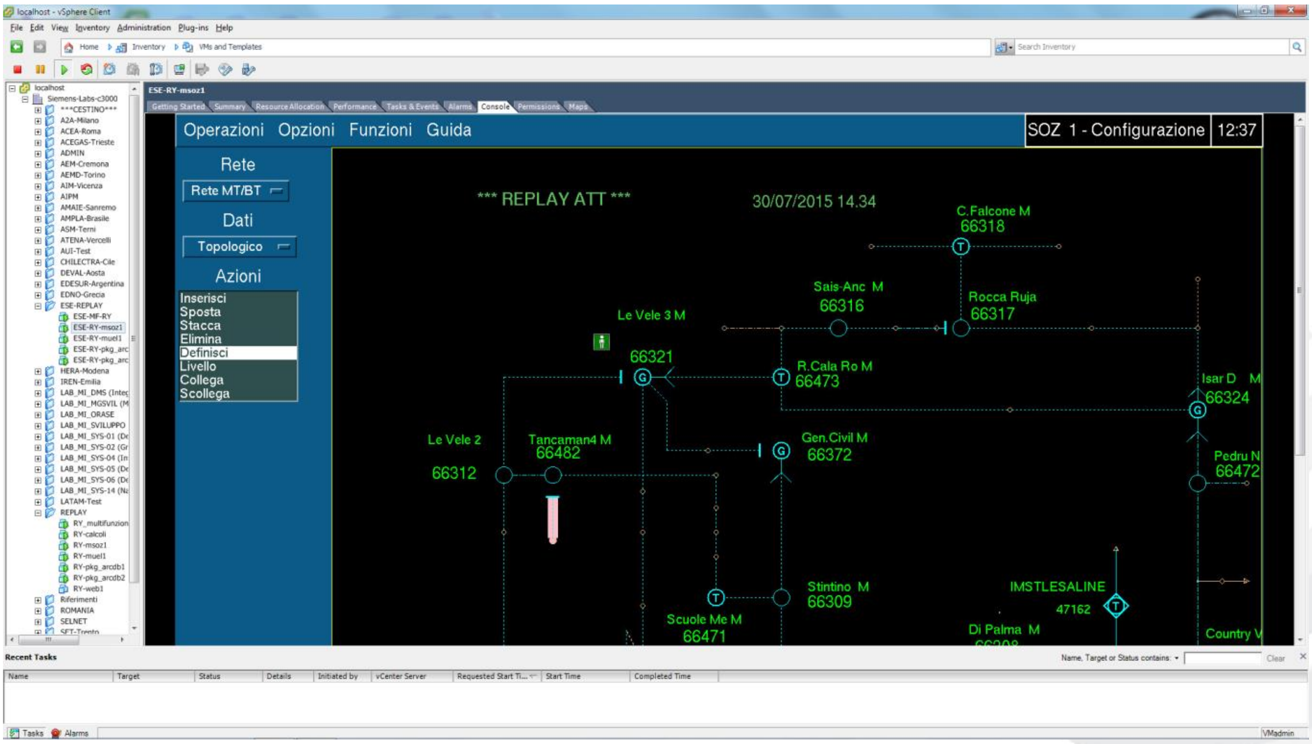


Figure 52 – example of network electric scheme available to the SCADA Operator

Figure 52 shows the electric network representation available to the operator. The interface is the same of the Enel's SCADA system. This allows new control room operators to become familiar with it and allows the expert operators to perform simulations. .

Another important feature of the tool is the one related to RETIM (Real Time Interruption Monitoring). The interface can be used for analysing the characteristics of the interruption in the real SCADA system as well as in the Replay simulations. In this way by the use of this interface it is possible to compare the quality of service in the selected interval in the past applying the same parameters used in the simulated situations. RETIM interface guarantees the integration between different systems actually used in Enel. Indeed, it is possible to collect all the needed information related to the interruption schemes and graph without the need for searching the data and the schemes by the use of other tools
The idea is indeed to analyse the interruptions and the related features by accessing other connected tools and get information on cartography, historical data, planned work, single-line diagram, etc.

6 Final Remarks

State Estimation for LV Networks

The results attained for the illustrative network considered in the present study indicate that with an ELM-AE properly trained, the proposed DSE provides an effective and accurate estimation of the system state, even when a low number of real-time measurements are available. Furthermore, the proposed DSE can achieve a state estimation solution without any knowledge of the networks' parameters and topology, what would be impossible with the traditional state estimation techniques usually employed.

As expected, the addition of real-time measurements leads in general terms to an accuracy increase of the state estimation solution achieved. However, in a real-world application, the trade-off between a better accuracy and an increased cost should be carefully analysed. The results obtained also highlight the importance of the use of methodologies to find the most suitable locations for the installation of metering devices with the capability of transmitting data in real-time. These approaches could enable a smaller state estimation error using the same number of telemetry devices with such capabilities, resulting in a more cost-effective solution.

The results obtained also confirm one of the so referred advantages of the ELM techniques, the very low time needed to train the ELM-AE. In fact, the training procedure is much faster than if conventional training algorithms (e.g., back-propagation based algorithms) are employed. In what concerns the estimation time, the proposed DSE takes less than one second to perform the state estimation for the network considered in this work, which makes it suitable for real-time applications.

Although the obtained results give good indications about the proposed DSE accuracy performance, it should be pointed out that it is essential to perform state estimation using a real historical database in order to make a final validation about these results.

Voltage Control for LV Networks

A Voltage Control tool for LV Networks has been developed in order to mitigate voltage problems. It takes advantage of the DER present in the grid (either owned by the DSO or by LV customers) and uses a merit order that aims at minimizing the overall costs associated to the control actions used. The output is a set of control actions for the various available resources in the form of set points. The proposed approach addresses two different scenarios depending on the level of information about the grid that is available:

- Full knowledge of the LV grid: Using a three-phase unbalanced power flow to test the set points that are determined by the tool;
- Limited knowledge of the LV grid: Using the State Estimation for LV Networks to evaluate the effects of the set points that are determined by the tool.

The tool showed a satisfactory performance in the several tests that have been performed for both scenarios considered.

Robust Short-Term Economic Optimization Tool

The developed tool has many key contributions and innovative features for the state of the art. The primary and most important contribution is the introduction of a comprehensive economic analysis for flexibilities, which will enable DSO to operate and control their networks at the lowest possible cost. This economic analysis introduces a concept of merit order for flexibilities, which differs from merit order for power exchange. The hierarchical principle of constructing active power flexibility merit orders can help any search-based optimization algorithm by providing initial indications for the search.

Secondly, the complementary optimization modules are capable of optimizing large networks with inputs from the economic analysis, and can handle inter-temporal constraints in two complementary ways. This provides a proof-of-concept of two different types of technical and economic optimization, which with sufficient testing, can show what conditions are optimal for use of either one.

Finally, the entire tool is modular in nature, meaning that modules currently used by DSOs can replace the ones in the tool with a little effort. Since communication between the modules is based on an open standard, the task is easier. The tool is also multi-temporal in nature, meaning that the optimization is done over a period of time, and not just for one time “snapshot” of the network, which is most often the case in research work today.

Network Reliability Tool

The methodology behind Replay tool represents an innovative approach in the reliability analysis of distribution networks: the reliability and suitability of the actions undertaken for events resolution can be evaluated not only from the assets and protection devices perspective but also from the human behaviour and policies perspective.
It is a concrete support to help operators improving their ability in managing active networks with suitable responsibility and knowledge of the innovative mechanisms behind the new DSO roles.

The ex-post and predictive analysis have been described. The replay approach leads to an innovative way to train operators and manage the network,. Indeed different scenarios could be built to simulate, for instance, the effects of criticalities on the networks, maintenance activities, or the consequences of the flexibility activation ..

Furthermore the possibility to have an independent test platform could create new possibilities to test other tools off- line , recreating conditions similar to those of the real time system.

ANNEX I – Operational KPIs (State Estimation for LV Networks)

<table>
<tr><th colspan="5">A) BASIC KPI INFORMATION</th></tr>
<tr><td>KPI Name</td><td colspan="2">Accuracy of active and reactive branch power flow</td><td>KPI ID</td><td>#1</td></tr>
<tr><td>Scope of KPI</td><td>To measure operational aspects
☑</td><td colspan="3">To validate WP1 scenarios
☑</td></tr>
<tr><td>Strategic Objective</td><td colspan="4">It is desired that estimated quantities be as close as possible to their true values.</td></tr>
<tr><td>KPI Description</td><td colspan="4">Accuracy of active and reactive branch power flow KPIs are defined by choosing a power flow solution quantity of interest and defining a norm-like calculation on the difference between the “true” value (derived from the power flow solution) and the “estimated” value (derived from the state estimation solution).</td></tr>
<tr><td>KPI Formula</td><td colspan="4">1-norm $\sum_{j=1}^{L}\left|Pf_j^{true}-Pf_j^{est}\right|$ $\sum_{j=1}^{L}\left|Qf_j^{true}-Qf_j^{est}\right|\sum_{j=1}^{L}\left|Pf_j^{true}-Pf_j^{est}\right|$
2-norm $\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{est}\right)^2$ $\sum_{j=1}^{L}\left(Qf_j^{true}-Qf_j^{est}\right)^2$
$\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{est}\right)^2$
Infinity norm $\max_{j=1,\dots,L}\left|Pf_j^{true}-Pf_j^{est}\right|$ $\max_{j=1,\dots,L}\left|Qf_j^{true}-Qf_j^{est}\right|$

Where:
L is the number of network branches
Pf_j^{true} = “true” value (derived from the power flow solution) active power flow on line j
Pf_j^{est} = “estimated” value (derived from the state estimation solution) active power flow on line j
Qf_j^{true} = “true” value (derived from the power flow solution) reactive power flow on line j
Qf_j^{est} = “estimated” value (derived from the state estimation solution) reactive power flow on line j</td></tr>
<tr><td>Unit of measurement</td><td colspan="4">Kilowatt (kW) and KiloVAr (kVAr)</td></tr>
<tr><td>Relevant Standards</td><td colspan="4"></td></tr>
</table>

Explanation of the Link with other relevant defined KPIs (Within the same tool)	No
Expected link with EEGI KPIs	This is an operational KPI.
OTHER (please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Load flow calculation for a time step considering a load scenario
2	Generation of measurements values by affecting load results by random errors
3	Run state estimation algorithm (previously trained) to obtain operational state
4	Compute all active and reactive branch power flows and compute the KPIs values for each norm

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Real-Time Measurements Data	Measurement ☑	Database Query ☐	SCADA	Every 15 minutes	At least 1 week period	Yes
#2	Measurements Historical Data	Measurement ☐	Database Query ☑	SCADA	1 Time	at least 4 months period, ideal one year	Yes
#3	Technical data of grid assets and topology data	Measurement ☐	Database Query ☑	SCADA	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	If power flow is needed to simulate historical data due to the unavailability of real data, voltage measurements are available for the secondary substation at MV bus bar while all LV loads for a scenario are fixed, both active and reactive			

	values, for all time period.
GENERAL COMMENTS	

A) BASIC KPI INFORMATION			
KPI Name	**Accuracy of active and reactive bus power injections**	**KPI ID**	#2
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☑	
Strategic Objective	It is desired that estimated quantities be as close as possible to their true values.		
KPI Description	Accuracy of active and reactive bus power injections KPIs are defined by choosing a power flow solution quantity of interest and defining a norm-like calculation on the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution).		
KPI Formula	1-norm $\sum_{j=1}^{N}\left\lvert Pi_j^{true}-Pi_j^{est}\right\rvert$ $\sum_{j=1}^{N}\left\lvert Qi_j^{true}-Qi_j^{est}\right\rvert$ $\sum_{j=1}^{N}\left\lvert Pi_j^{true}-Pi_j^{est}\right\rvert$ 2-norm $\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{est}\right)^2$ $\sum_{j=1}^{N}\left(Qi_j^{true}-Qi_j^{est}\right)^2$ $\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{est}\right)^2$ Infinity norm $\max_{j=1,\ldots,N}\left\lvert Pi_j^{true}-Pi_j^{est}\right\rvert$ $\max_{j=1,\ldots,N}\left\lvert Qi_j^{true}-Qi_j^{est}\right\rvert$ Where: N is the number of network buses Pi_j^{true} = "true" value (derived from the power flow solution) active power injection on bus j Pi_j^{est} = "estimated" value (derived from the state estimation solution) active power injection on bus j Qi_j^{true} = "true" value (derived from the power flow solution) reactive power injection on bus j Qi_j^{est} = "estimated" value (derived from the state estimation solution) reactive power injection on bus j		
Unit of measurement	Kilowatt (kW) and KiloVAr (kVAr)		
Relevant Standards			
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	This is an operational KPI		
OTHER			

(please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Load flow calculation for a time step considering a load scenario
2	Generation of measurements values by affecting load results by random errors
3	Run state estimation algorithm (previously trained) to obtain operational state
4	Compute all active and reactive bus power injections and compute the KPIs values for each norm

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Real-Time Measurements Data	Measurement ☑	Database Query ☐	SCADA	Every 15 minutes	At least 1 week period	Yes
#2	Measurements Historical Data	Measurement ☐	Database Query ☑	SCADA	1 Time	at least 4 months period, ideal one year	Yes
#3	Technical data of grid assets and topology data	Measurement ☐	Database Query ☑	SCADA	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	If power flow is needed to simulate historical data due to the unavailability of real data, voltage measurements are available for the secondary substation at MV bus bar while all LV loads for a scenario are fixed, both active and reactive values, for all time period.			

GENERAL COMMENTS

A) BASIC KPI INFORMATION			
KPI Name	**Accuracy of voltage**	**KPI ID**	#3
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☑	
Strategic Objective	It is desired that estimated quantities be as close as possible to their true values.		
KPI Description	Accuracy of voltage KPI is defined by choosing the power flow solution for the voltage magnitudes and using a norm metric that captures the effect of calculation, doing the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution).		
KPI Formula	$M acc_V = \left\Vert \vec{V}^{error} \right\Vert_2 = \left(\sum_{j=1}^{N} \left\vert \vec{V}_j^{true} - \vec{V}_j^{est} \right\vert^2 \right)^{\frac{1}{2}}$ Where: *N* is the number of network buses $\vec{V}_j^{true}$ is the true complex phasor voltage at the *j*th bus $\vec{V}_j^{est}$ is the estimated complex phasor voltage at the *j*th bus		
Unit of measurement	Volt (V)		
Relevant Standards			
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	This is an operational KPI		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Load flow calculation for a time step considering a load scenario
2	Generation of measurements values by affecting load results by random errors
3	Run state estimation algorithm (previously trained) to obtain operational state

4	Compute the KPI value

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Real-Time Measurements Data	Measurement ☑	Database Query ☐	SCADA	Every 15 minutes	At least 1 week period	Yes
#2	Measurements Historical Data	Measurement ☐	Database Query ☑	SCADA	1 Time	at least 4 months period, ideal one year	Yes
#3	Technical data of grid assets and topology data	Measurement ☐	Database Query ☑	SCADA	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	If power flow is needed to simulate historical data due to the unavailability of real data, voltage measurements are available for the secondary substation at MV bus bar while all LV loads for a scenario are fixed, both active and reactive values, for all time period.			

GENERAL COMMENTS

A) BASIC KPI INFORMATION			
KPI Name	**Error Estimation Index (EEI)**	**KPI ID**	#4
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☑	
Strategic Objective	It is desired that estimated quantities be as close as possible to their true values.		
KPI Description	Accuracy of state estimated are defined by choosing a power flow solution quantity of interest and compute the difference between the "true" value (derived from the power flow solution) and the "estimated" value (derived from the state estimation solution).		
KPI Formula	$EEI = \sum_{i=1}^{M}\left(\frac{Z_i^{true} - Z_i^{est}}{\sigma_i}\right)^2$ Where: *M* is the number of measurements σ_i is the actual standard deviation of the Guassian, with zero-mean Z_i^{true} is the noise-free measurement Z_i is the noisy measurement Z_i^{est} is the estimated value for the measurement		
Unit of measurement	Volt (V), kilowatt (kW) and kiloVAr (kVAr)		
Relevant Standards			
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	This is an operational KPI		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Load flow calculation for a time step considering a load scenario

2	Generation of measurements values by affecting load results by random errors
3	Run state estimation algorithm (previously trained) to obtain operational state
4	Compute all quantities related with measurements and compute the KPI value

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Real-Time Measurements Data	Measurement ☑	Database Query ☐	SCADA	Every 15 minutes	At least 1 week period	Yes
#2	Measurements Historical Data	Measurement ☐	Database Query ☑	SCADA	1 Time	at least 4 months period, ideal one year	Yes
#3	Technical data of grid assets and topology data	Measurement ☐	Database Query ☑	SCADA	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	If power flow is needed to simulate historical data due to the unavailability of real data, voltage measurements are available for the secondary substation at MV bus bar while all LV loads for a scenario are fixed, both active and reactive values, for all time period.			

GENERAL COMMENTS

A) BASIC KPI INFORMATION			
KPI Name	**Ability to Accurately Discern Measurements (PIPf, PIQf, PIPi, PIQi)**	**KPI ID**	#5
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☑	
Strategic Objective	It is desired that estimated quantities be as close as possible to their true values.		
KPI Description	Ability of the state estimator to accurately discern active and reactive power flow and injection measurements, are defined by choosing a power flow solution quantity of interest and defining a norm-like calculation on the relative difference between the "true" value (derived from the power flow solution), the "estimated" value (derived from the state estimation solution) and the "measured" value (derived from measuring devices or forecasting tools).		
KPI Formula	$$PIPf=\frac{\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{est}\right)^2}{\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{meas}\right)^2}$$ $$PIQf=\frac{\sum_{j=1}^{L}\left(Qf_j^{true}-Qf_j^{est}\right)^2}{\sum_{j=1}^{L}\left(Qf_j^{true}-Qf_j^{meas}\right)^2}$$ $$PIPi=\frac{\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{est}\right)^2}{\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{meas}\right)^2}$$ $$PIQi=\frac{\sum_{j=1}^{N}\left(Qi_j^{true}-Qi_j^{est}\right)^2}{\sum_{j=1}^{N}\left(Qi_j^{true}-Qi_j^{meas}\right)^2}$$ $$PIPf=\frac{\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{est}\right)^2}{\sum_{j=1}^{L}\left(Pf_j^{true}-Pf_j^{meas}\right)^2}\quad PIPi=\frac{\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{est}\right)^2}{\sum_{j=1}^{N}\left(Pi_j^{true}-Pi_j^{meas}\right)^2}$$ $$PIQi=\frac{\sum_{j=1}^{N}\left(Qi_j^{true}-Qi_j^{est}\right)^2}{\sum_{j=1}^{N}\left(Qi_j^{true}-Qi_j^{meas}\right)^2}$$ Where: *L* is the number of network branches *N* is the number of network buses Pf_j^{true} = "true" value (derived from the power flow solution) active power flow on line j Pf_j^{est} = "estimated" value (derived from the state estimation solution) active power flow on line j Pf_j^{meas} = measurement value for active power flow on line j		

	Qf_j^{true} = "true" value (derived from the power flow solution) reactive power flow on line j Qf_j^{est} = "estimated" value (derived from the state estimation solution) reactive power flow on line j Qf_j^{meas} = measurement value for reactive power flow on line j Pi_j^{true} = "true" value (derived from the power flow solution) active power injection on bus j Pi_j^{est} = "estimated" value (derived from the state estimation solution) active power injection on bus j Pi_j^{meas} = measurement value for active power injection on bus j Qi_j^{true} = "true" value (derived from the power flow solution) reactive power injection on bus j Qi_j^{est} = "estimated" value (derived from the state estimation solution) reactive power injection on bus j Qi_j^{meas} = measurement value for reactive power injection on bus j
Unit of measurement	%
Relevant Standards	
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No
Expected link with EEGI KPIs	This is an operational KPI
OTHER (please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Load flow calculation for a time step considering a load scenario
2	Generation of measurements values by affecting load results by random errors
3	Run state estimation algorithm (previously trained) to obtain operational state
4	Compute all active and reactive bus power injections, and all active and reactive branches power flows and compute the KPIs values for each norm

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Real-Time Measurements Data	Measurement ☑	Database Query ☐	SCADA	Every 15 minutes	At least 1 week period	Yes
#2	Measurements Historical Data	Measurement ☐	Database Query ☑	SCADA	1 Time	at least 4 months period,	Yes

						ideal one year	
#3	Technical data of grid assets and topology data	Measurement ☐	Database Query ☑	SCADA	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)				
Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	If power flow is needed to simulate historical data due to the unavailability of real data, voltage measurements are available for the secondary substation at MV bus bar while all LV loads for a scenario are fixed, both active and reactive values, for all time period.			
GENERAL COMMENTS				
For a good estimation, the estimate of each flow/injection will lie closer to the true than the measured value and the entire metric will be less than one.				

ANNEX II – Operational KPIs (Voltage Control for LV Networks)

A) BASIC KPI INFORMATION			
KPI Name	**Reduction of Technical Losses**	**KPI ID**	#5
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☐	
Strategic Objective	Quantify the reduction of the technical losses in the LV grid.		
KPI Description	This KPI measures the reduction of energy losses in the grid due to an increase of RES integration as a result of the LVC tool.		
KPI Formula	$$L\% = \frac{L_N - L_{LVC}}{L_N} * 100\%$$ Where: L_N = Total energy losses in the baseline scenario without the LVC tool for a defined time period (kWh). L_{LVC} = Total energy losses in the corresponding scenario with LVC tool over the same period (kWh).		
Unit of measurement	Percentage of energy (%)		
Relevant Standards			
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs			
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Load flow calculation to retrieve the total energy losses in the grid for the BAU scenario.
2	Load flow calculation to retrieve the total energy losses in the grid with the LVC tool.

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Grid topology and characteristics	Measurement ☐	Database Query ☑	SCADA	1 Time	/	Yes
#2	Voltage and active power of nodes and RES/DER	Measurement ☑	Database Query ☐	SCADA	1 Time	15 minutes	Yes
#3	Technical data of grid assets	Database Query ☑	Database Query ☑	SCADA	1 Time	/	Yes

D) KPI BASELINE

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☐	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	The BAU consists on a scenario based on typical profiles for load and generation for a given time period where voltage violations occur that can be managed without the use of the LVC tool.			

GENERAL COMMENTS

ANNEX III – Operational KPIs (Robust Short-Term Economic Optimization for Operational Planning)

A) BASIC KPI INFORMATION			
KPI Name	**Increased RES and DER hosting capacity**	**KPI ID**	OP_01
Scope of KPI	To measure operational aspects ☐	To validate WP1 scenarios ☑	
Strategic Objective	Aim of the tool is to have an effective use of available flexibilities, ranked according to a merit order approach that will allow to perform an optimization of the operational planning that will solve (estimated) network violations at a minimal cost.		
KPI Description	The KPIs measures the increase of the hosting capacity of RES/DER (with and without the operational planning tool) in the network with respect to the baseline scenario.		
KPI Formula	The KPI can be evaluated as follows: $$\Delta HC_{\%} = \frac{HC_{tool} - HC_{BL}}{HC_{BL}} * 100$$ Where: $\Delta HC_{\%}$ is the variation of hosting capacity with respect to the Baseline approach; HC_{tool} is the hosting capacity with the tool; HC_{BL} is the hosting capacity in the Baseline scenario. The KPI expresses the variation of DER that can be connected to the network when the Smart Solution is introduced with respect to the Baseline scenario. When the index is positive the Smart Solution allows a higher penetration of DG. On the other hand, a negative index means that the introduction of the Smart Solution does not lead to a higher DG penetration.		
Unit of measurement	Percentage [%]		
Relevant Standards	EN 50160		

Explanation of the Link with other relevant defined KPIs (Within the same tool)	▪ See KPIs of sub-tools:
	  ○ Identification of violated network constraints: no KPI available
	  ○ Merit order module
	  ○ Optimization module (both VITO and RSE)
	▪ The KPI for the entire tool will be influenced by the quality of the developed tool. This is guaranteed via the operational KPIs as determined for the sub-tools.		

Expected	The link with the EEGI KPI "Increased RES and DER hosting capacity," "Increased flexibility from		

link with EEGI KPIs	energy players", "Reduced energy curtailment of RES and DER", Power Quality and Quality of Supply" and "Extended asset life-time" is confirmed. • For the EEGI KPI "Increased RES and DER hosting capacity", the tool will allow a higher integration of RES and DER through the use of flexibility offers – see KPI determined for this tool. • For the EEGI KPI "Increased flexibility from energy players", we can confirm that a well working tool will contribute to increased flexibility through the use of flexibility offers (valid for both DSO and prosumers). However, we cannot quantify the impact. • For the EEGI KPI "Reduced energy curtailment of RES and DER", we can confirm that the use of the tool will change the level of curtailment, but we cannot define upfront if it will be more or less as it depends on the cost function of flexibility, DSO preference and even the business model or market model that will determine the sources of flexibility. • For the EEGI KPI "Power Quality and Quality of Supply", we expect that due to the use of the tool, voltage levels can be respected in case of increasing RES/DER. For the EEGI KPI "extended asset life-time", we can assume that the use of flexibility in the operational planning will allow to defer future investments. However, we cannot quantify the impact.
OTHER (please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Calculation of the initial maximum hosting capacity HC_{BL-i} of each bus for the considered network, without violation of any network constraint (e.g. over voltages, over currents, reverse power overflows etc.). This calculation is done via optimal power flow/ via a step-wise simulation approach.
2	Definition of the total initial hosting capacity HC_{BL} as the sum of all the busses HC_{BL-i}: $$HC_{BL} = \sum_{i=1}^{n_b} HC_{BL-i}$$ Where n_b is the number of busses in the considered distribution network.
3	Calculation of the maximum hosting capacity HC_{SG-i} of each bus for the considered network in the Smart Grid scenario, without violation of any network constraint (e.g. over voltages, over currents, reverse power overflows etc.). This calculation is done via optimal power flow.
4	Definition of the maximum hosting capacity HC_{SG} as the sum of all the HC_{SG-i}: $$HC_{tool} = \sum_{i=1}^{n_b} HC_{tool-i}$$ Where n_b is the number of busses in the considered distribution network.
5	The variation of hosting capacity is calculated as: $$\Delta HC_{\%} = \frac{HC_{tool} - HC_{BL}}{HC_{BL}} * 100$$

C) KPI DATA COLLECTION.

Data ID	Type of data	Source for Data collection	Location of Data collectio n	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)

#1	Network topology (Voltage and current values of nodes and branches respectively (including HV bus), Reference voltage and current values of the line analyzed	Measurement ☐	Database Query ☑	DSO internal system	1 Time	24 hours	Yes
#2	Network conditions (load and generation profiles)	Measurement ☐	Database Query ☑	DSO internal system	96 times	24 hours	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☐	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	The baseline will be the DSO-network without additional network reinforcements, with the level of RES and DER that allows the network to be optimized without congestion (in case this level is higher than the highest scenario of RES/DER as defined in WP1, the tool has no added value for the specific network)			

GENERAL COMMENTS

- The HC evaluation is a rough activity that needs well defined hypothesis, boundary conditions and methodology. However, currently in literature hosting capacity methods are available as reference.
- The scalability and replicability of the entire tool are two parameters for measurement, but should not be considered as KPIs but as properties of a certain tool.

Economic Analysis module

A) BASIC KPI INFORMATION			
KPI Name	**Increased use of sources of flexibility by DSO**	**KPI ID**	OP_02
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☐	
Strategic Objective	The aim is the generation of a merit order that will make it possible for the optimization sub-tool to evaluate different types of flexibilities (technical, semi-commercial and commercial) based on the relevant costs, and choose the ones that can be used to operate the network under normal conditions, with the lowest operating costs for the DSO.		
KPI Description	The KPI will measure the improvement in the number of types of flexibility used in order to maintain normal operating conditions in the network. To note that this KPI does not measure the increase in number of flexibilities of one type (10 load reduction flexibilities will be counted as 1 because they are all of the same type).		
KPI Formula	$\text{Increase in Flexibility Use (in \%)} = \frac{\text{No. of (one of each type of) flexibilities provided in the merit order}}{\text{No. of (one of each type of) flexibilities currently used by the DSO}} * 100$		
Unit of measurement	%		
Relevant Standards	n/a		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	▪ See template for the entire tool – Robust short term economic optimization tool for operational planning; ▪ The output of this sub-tool determines the cost function of flexibility used in the optimization module; The impact of the merit order sub-tool will depend on the quality of the optimization routine.		
Expected link with EEGI KPIs	▪ The link with the EEGI KPI "Increased flexibility from energy players" is confirmed. The more flexibilities are made available in a cost-efficient way and are used by DSO, the higher the flexibility of energy players (both prosumers and network operators); The result of the merit order sub-tool will also influence the EEGI KPI "Reduced energy curtailment of RES and DER". However, similar as for the entire tool, the impact on curtailment cannot be quantified as it depends on several factors such as DSO preferences, lever availability and use etc.		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Count number of used types of flexibilities for DSOs without use of merit order sub-tool

2	Count number of used types of flexibilities for DSOs with use of merit order sub-tool						
3	Calculate the % increase between step 1 and step 2						
C) KPI DATA COLLECTION							
Data ID	**Type of data**	**Source for Data collection**		**Location of Data collection**	**Frequency of data collection**	**Monitoring period**	**Data type already included in the RWTH matrix (D2.3)**
#1	Flexibilities Currently Available	Measurement ☐	Database Query ☑	DSO Internal System	1 Time	-	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)				
Source of baseline values	SIMULATED VALUES ☐	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	DSO network without merit order sub-tool (and in addition entire operational planning tool) and with amount of RES and DER as it exists today			
GENERAL COMMENTS				
An additional KPI: 'Quality of the cost function and merit order generated' will not be considered as operational KPI. Although of high importance for the impact assessment, there is no basis on which the accuracy or improvement of cost assessment of flexibilities can be made. However, these parameters will be carefully modeled and verified during the development of the tool. Baseline of merit order sub-tool is not the same as baseline entire tool – looks at the use of flexibility today (with the level of RES and DER today <> targeted level of RES and DER as defined in WP1 scenarios). Reason is that we do not know what will be the use of flexibility in the targeted level without the tool.				

RSE Optimization module

A) BASIC KPI INFORMATION			
KPI Name	**Voltage profiles quality**	**KPI ID**	OP_03
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☐	
Strategic Objective	Voltages in distribution networks where DG is not installed typically decrease as the distance from the substation increases. However, nowadays the presence of DG influences the voltage profile of a feeder. An optimal voltage profile can contribute to have a secure operating point where losses are limited and a more comfortable scenario for DG integration is possible. Of course, voltage levels has to be kept in the predefined standard limits, as suggested in the EN 50160 standard or other relevant national rules.		
KPI Description	The KPI evaluates voltage profiles through the quantification of the duration of voltage constraint violations due to the introduction of Distributed Generation (DG) in distribution networks.		
KPI Formula	The KPI can be evaluated as follows: $$\Delta \mathrm{DV} = \mathrm{DV}_{\mathrm{BL}} - \mathrm{DV}_{\mathrm{SS}}$$ where: ΔDV represents the variation of voltage violation duration with respect to the Baseline scenario; $\mathrm{DV}_{\mathrm{SS}}$ represents the voltage violation duration when the Smart Solution is introduced; $\mathrm{DV}_{\mathrm{BL}}$ represents the voltage violation duration in the Baseline scenario. This parameter can be evaluated for every bus where the voltage profile is available. For a given time horizon (e.g. 24h) and periodicity of network information readings (e.g. 15') it is possible to check if there are voltage violations. Hence, the accuracy of this indicator strongly depends on the granularity of the periodicity used to read network data. In fact, the lower the periodicity (e.g. from 15' to 5') the more precise the information related to the duration of the voltage violations. However, the periodicity has to take into account the computational time required from the optimization phase, that depends also on the analyzed network. The KPI can be interpreted as follows: - If it is positive the duration of voltage violations has been reduced thanks to the introduction of the Smart Solution; - If it is negative the introduction of the Smart Solution increases the duration of voltage violations.		
Unit of measurement	Second [s]		
Relevant Standards	EN 50160		
Explanation of the Link with other relevant defined KPIs	Voltage violations have an impact on the secure and efficient operation of electrical networks. In fact, a limited value of hosting capacity can be related to a bad voltage profile due to several voltage violations or high network losses. Hence, there is a link with KPI_OP1 and KPI_OP3.		

(Within the same tool)	
Expected link with EEGI KPIs	KPI_OP2 is correlated with the EEGI KPI "Power quality and quality of supply". In fact, the way line voltage profiles fulfill network requirements (as defined by EN 50160) is a useful indicator for DSOs to monitor their power quality and quality of supply.
OTHER (please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Definition of the boundary conditions and hypothesis (e.g. load/DG conditions etc.) for the different conditions (BL vs. SS).
2	Evaluation of the duration of voltage profiles violations in the Baseline scenario through DV_{BL}.
3	Evaluation of the duration of voltage profiles violations when the Smart Solution is introduced through DV_{SS}.
4	Computation of the indicator ΔDV.

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Voltage values of nodes	Measurement ☐	Database Query ☑	SCADA	10'	24 h	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☐	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline				

GENERAL COMMENTS

VITO Optimization module

A) BASIC KPI INFORMATION			
KPI Name	Efficiency Improvement Optimization	**KPI ID**	OP_04
Scope of KPI	To measure operational aspects ☑	To validate WP1 scenarios ☐	
Strategic Objective	• The aim is to iteratively find the most economic next-day schedule of flexibility sources which brings/keeps the grid operation within its physical constraints.		
KPI Description	• The KPIs measures the quality of the optimization at a minimum cost. Because the algorithm iteratively finds solutions with improving costs, time-efficiency and effectiveness can be combined into one KPI: How correct is the result: robustness, effectiveness • How fast is the result: efficiency, calculation time The KPI will reveal the relationship between calculation time and error of result compared to optimum.		
KPI Formula	Relative overcost (relative to a conservative under-estimation of the minimal cost) at x % of the maximally available computation time (t_max):| $\frac{\text{Cost of solution found after x\% of t\_max} - \text{Estimated minimal cost}}{\text{Estimated minimal cost}} * 100$ where t_max = [the latest possible time the schedule should be ready (e.g. for the day-ahead market)] – [the time at which all necessary data for the calculation is guaranteed to become available] with x = 25 %, 50 %, 100 %, 200 %, 400 %. The relative overcost measures the extra cost of the solution compared to the (under-) estimated minimal cost.		
Unit of measurement	%		
Relevant Standards	n/a		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	▪ See template for the entire tool – Robust short term economic optimization tool for operational planning; This sub-tool calculates the most cost-efficient operational planning, based on inputs from the merit order sub-tool and the identification of violated constraints sub-tool. The result of the optimization is dependent on the KPIs of the performance of the sub-tools (sources and cost of flexibility) that serve as an input.		
Expected	In case the optimization tool is well programmed, it will contribute to the overall performance		

link with EEGI KPIs	of the tool and support the EEGI KPIs as determined in the KPI sheet for the Robust short term economic optimization tool for operational planning (Increased RES and DER hosting capacity, extended asset life-time and increased flexibility from energy players). Mainly as the tool will make it possible to have more renewables in the grid without new investments by the use of flexibility from a variety of energy players. The tool will also have an impact (more or less) on the EEGI KPI Reduced energy curtailment of RES and DER, but the curtailment decision is mainly driven by the cost function determined in the merit order tool.
OTHER (please specify)	

B) KPI CALCULATION METHODOLOGY

KPI Step #	Step description (max 50 words)
1	Make a conservative under-estimation of the minimal cost to keep the network within its operational limits. In some (very specific and limited) circumstances, an exact minimal cost can be calculated by allowing the algorithms to run until finished. Usually the combinatorial solution space will be too large for the latter approach.
2	Run the algorithm to iteratively improve the cost of scheduling flexibility sources, until a given percentage x of the maximally available calculation has passed: with x in {25%, 50%, 100%, 200% and 400%}.
3	Calculate the relative cost overshoot at each time.

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Network topology	Measurement ☐	Database Query ☑	SCADA	1 Time	24 hours	Yes
#2	Network condition	Measurement ☐	Database Query ☑	SCADA	96 Times	24 hours	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☐	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	Calculated minimum cost of optimization			

GENERAL COMMENTS

The scalability and replicability of the entire tool are two parameters for measurement, but should not be considered as KPIs but as properties of a certain tool.

ANNEX IV – Operational KPIs (Network Reliability Tool)

A) BASIC KPI INFORMATION			
KPI Name	**Criticalities Reduction Index**	**KPI ID**	RP_01
Scope of KPI	To measure operational aspects ☑☐	To validate WP1 scenarios ☑☐	
Strategic Objective	The aim is to solve specific network criticalities using the tool.		
KPI Description	The KPIs measures the reduction of the number of criticalities on the network in terms of overvoltage and overloads.		
KPI Formula	$CRI = \left[\frac{(n_v)_{Pn} - (n_v)_{Pc}}{(n_v)_{Pn}}\right]_{lineX}$ Where: $(n_v)_{Pn}$ = number of criticalities identified based on the nominal power injected on the grid by consumers/producers $(n_v)_{Pc}$ = number of criticalities identified based on the modulated power injected on the grid by consumers/producers Line x = Network line under analysis		
Unit of measurement	Number (n)		
Relevant Standards	CEI 0-16		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	The link with the EEGI KPI "Reduced energy curtailment of RES and DER" is confirmed. The lower the number of criticalities present on the network, the lower the need to ask end users to modulate their power and the lower the need to reduce consequently the energy injected/consumed.		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Load flow calculation considering baseline conditions and identification of potential

	criticalities
2	The scada operator acts on the potential levers (e.g. power modulation, grid configuration, etc.) to solve network criticalities
3	A new load flow calculation is performed to verify if the problem is solved. If not, actions 1, 2 and 3 are repeated again.

C) KPI DATA COLLECTION

Data ID	Type of data	Source for Data collection		Location of Data collection	Frequency of data collection	Monitoring period	Data type already included in the RWTH matrix (D2.3)
#1	Voltage and current values of nodes and branches	Measurement ☑	Database Query ☐	SCADA	1 Time	24 hours	Yes
#2	Reference voltage and current values of the line analyzed	Measurement ☐	Database Query ☑	SCADA	1 Time	/	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☐	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	Current and voltage measurements are available for the primary substation MV bus bar while the same measurements are estimated along the line.			

GENERAL COMMENTS

General Comment area to include any information that can be useful that has not been detailed above

A) BASIC KPI INFORMATION			
KPI Name	**Criticalities Reduction Index**	**KPI ID**	RP_02
Scope of KPI	To measure operational aspects ☑☐	To validate WP1 scenarios ☑☐	
Strategic Objective	The aim is to evaluate the training time saved by the use of replay in order to coach a SCADA operator to become independent in the daily activities.		
KPI Description	The KPIs measures the time reduction to train SCADA operators.		
KPI Formula	*a* $$TTS[\%] = \frac{(n_g \times t_F)_{BAU} - (n_g \times t_F)_{REPLAY}}{(n_g \times t_F)_{BAU}}$$ Ng= number of frequentl “kind of fault/situation” to be managed by the SCADA operator tf= medium time needed to manage a single fault		
Unit of measurement	Minutes		
Relevant Standards	CEI 0-16 –Del.334 AEEG		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	The link with the EEGI KPI “Power quality and quality of supply“		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Estimation of the standard time to allow a SCADA Operator to become expert in the NTW management. Estimation could be elaborated on the basis of the DSO standard approach to the NTW or acting levers of the Active Distribution System (Active Power Modulation).
2	Evaluation of the time to coach a SCADA operator on the basis of a defined fault/events typology occurring on the network by the use of the replay tool as a simulator.

C) KPI DATA COLLECTION (urgent for THE DELIVERY OF D5.1) . The aim is to check

if the data already defined in Deliverable D2.3 Data Set configuration are sufficient to calculate these KPIs.							
Data ID	**Type of data**	**Source for Data collection**		**Location of Data collectio n**	**Frequency of data collection**	**Monitoring period**	**Data type already included in the RWTH matrix (D2.3)**
#1	TIME (Baseline)	Measurement/ Estimation ☑	Database Query ☐	Excel sheet	1 Time	Defined by the time analyst	Yes
#2	TIME (Replay)	Measurement ☑	Database Query ☐	Excel sheet	1 Time	Defined by the time analyst	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)				
Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☐	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	Not optimized (with potential improvement areas)			
GENERAL COMMENTS				
None				

A) BASIC KPI INFORMATION			
KPI Name	**Criticalities Reduction Index**	**KPI ID**	RP_03
Scope of KPI	To measure operational aspects ☑☐	To validate WP1 scenarios ☑☐	
Strategic Objective	The aim is to evaluate the training cost saved by the use of replay in order to coach a SCADA operator to become independent in the daily activities.		
KPI Description	The KPIs measures the cost reduction to train SCADA operators by the use of Replay tool.		
KPI Formula	$$TCS\ [\%] = \frac{(n_g \times C_{F1}\ )_{BAU} - (n_g \times C_{F2}\ )_{REPLAY}}{(n_g \times C_{F1}\ )_{BAU}}$$ Ng = number of frequentl "kind of fault/situation" to be managed by the SCADA operator. Cf= medium cost needed to manage a single fault. This cost is calculated on the basis of the table of cost for the company and the time tf nedeed to manage the fault.		
Unit of measurement	Minutes		
Relevant Standards	CEI 0-16 –Del.334 AEEG		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	The link with the EEGI KPI "Power quality and quality of supply"		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Evaluation of SAIDI/AV20 for specific events occurred on the NTW in a defined framework
2	Ex-Post Analysis for the managing the same fault in a better way by the use of Replay
3	Evaluation of the new SAIDI/AV20 value on the new events in a defined framework.

C) KPI DATA COLLECTION						
Data ID	**Type of data**	**Source for Data collection**	**Location of Data collectio**	**Frequency of data collection**	**Monitoring period**	**Data type already included in**

				n			the RWTH matrix (D2.3)
#1	Cost (baseline)	Measurement ☑	Database Query ☐	SCADA	1 Time	For each fault	Yes
#2	Cost (Replay)	Measurement ☑	Database Query ☐	SCADA	1 Time	For each fault	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)				
Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☑	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	Not optimized (with potential improvement areas)			

GENERAL COMMENTS
None

A) BASIC KPI INFORMATION			
KPI Name	**SAIDI reduction Index**	**KPI ID**	RP_04
Scope of KPI	To measure operational aspects ☑☐	To validate WP1 scenarios ☑☐	
Strategic Objective	The aim is to decrease SAIDI values for fault management by the use of Replay. The use of specific optimization actions could improve the quality of service by a specific ex-post analysis. Replay allows the scada operator to select a time interval in the past in order to analyze the NTW management potentially improving actions in the past in order to improve the management for the future.		
KPI Description	The KPis measures the reduction of SAIDI for specific events managed in the past.		
KPI Formula	a $$AV20[\%] = \frac{AV20_{BAU} - AV20_{REPLAY}}{AV20_{BAU}}$$ AV20 Index is number (client*minutes) interested by the fault in a specific NTW portion. AV20 BAU = it is the value (client*minutes) elaborated on the basis of the situation already managed. AV20 Replay = it is the value (client*minutes) elaborated on the basis of the situation optimized through the “ex-post analysis” elaborated by Replay.		
Unit of measurement	Minutes		
Relevant Standards	CEI 0-16 –Del.334 AEEG (Italian Regulator reference)		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	The link with the EEGI KPI “Power quality and quality of supply“		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Evaluation of SAIDI/AV20 for specific events occurred on the NTW in a defined framework.
2	Ex-Post Analysis for the managing the same fault in a better way by the use of Replay.
3	Evaluation of the new SAIDI/AV20 value on the new events in a defined framework.

C) KPI DATA COLLECTION (urgent for THE DELIVERY OF D5.1). The aim is to check if the data already defined in Deliverable D2.3 Data Set configuration are sufficient to calculate these KPIs.							
Data ID	**Type of data**	**Source for Data collection**		**Location of Data collectio n**	**Frequency of data collection**	**Monitoring period**	**Data type already included in the RWTH matrix (D2.3)**
#1	SAIDI (baseline)	Measurement ☐	Database Query ☑	SCADA	1 Time	Defined by the SCADA operator	Yes
#2	SAIDI (Replay)	Measurement ☐	Database Query ☑	SCADA	1 Time	Defined by the SCADA operator	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)				
Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☐	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☑
Details of Baseline	Not optimized (with potential improvement areas)			

GENERAL COMMENTS
None

A) BASIC KPI INFORMATION			
KPI Name	**Time Activity Saving**	**KPI ID**	RP_05
Scope of KPI	To measure operational aspects ☑☐	To validate WP1 scenarios ☑☐	
Strategic Objective	The aim is to evaluate the time saved on the operator daily activity by the use of replay in order to coach a SCADA operator to become independent.		
KPI Description	The KPis measures the time reduction to train SCADA operators.		
KPI Formula	a $$\text{Time Activity Saved [\%]} = \frac{\text{t BAU} - \text{t REPLAY}}{\text{t BAU}}$$ where t BAU= time needed to manage a specific activity by a SCADA operator t REPLAY = time needed to manage a specific activity (the same) by a SCADA operator		
Unit of measurement	Minutes		
Relevant Standards	CEI 0-16 –Del.334 AEEG		
Explanation of the Link with other relevant defined KPIs (Within the same tool)	No		
Expected link with EEGI KPIs	The link with the EEGI KPI "Power quality and quality of supply"		
OTHER (please specify)			

B) KPI CALCULATION METHODOLOGY	
KPI Step #	**Step description (max 50 words)**
1	Definition of a list of operation standard activities to be analyzed by the time analyst.
2	Evaluation of the time generally spent for managing standard operation activities with standard tools.
3	Evaluation of the time spent for managing the same activities by the use of Replay.

C) KPI DATA COLLECTION						
Data ID	**Type of data**	**Source for Data collection**	**Location of Data collection**	**Frequency of data collection**	**Monitoring period**	**Data type already included in the RWTH matrix**

							(D2.3)
#1	TIME (Baseline)	Measurement/ Estimation ☑	Database Query ☐	Excel sheet	1 Time	Defined by the time analyst	Yes
#2	TIME (Replay)	Measurement ☑	Database Query ☐	Excel sheet	1 Time	Defined by the time analyst	Yes

D) KPI BASELINE: Please refer to the reference value of the KPI in the Business As Usual case (=tool not applied)

Source of baseline values	SIMULATED VALUES ☑	LITERATURE VALUES ☐	COMPANY HISTORICAL VALUES ☐	VALUES MEASURED BEFORE THE BEGINNING OF THE TEST ☐
Details of Baseline	Not optimized (with potential improvement areas)			

GENERAL COMMENTS

None

ANNEX V – Match between Tools and WP2 Requirements

Tool: State Estimation and Voltage Control Tools for LV Network **System Use Case:** Solve network constraints using optimization levers based on a merit order			
Requirements		**Degree of Fulfilment**	**Evaluation metric**
Requirement ID	**Requirement Description**		
R-2	Integrated system for techno-economic calculations	The LV control tool creates a merit order of flexibilities based on flexibility cost, contracted flexibility band (e.g., state of charge, rated power) and distance to the node/branch with technical problems	Qualitative evaluation
T-1	Define the application period	The LV state estimation and voltage control tools can be applied to the current snapshot of the network as well as to future states (only if forecasts are available)	Qualitative evaluation
QoS-1	The system has to provide the results in X seconds	The state estimation takes around 2 seconds and the voltage control takes around 60 seconds (if state estimation is needed) and 30 seconds if the smart power flow is used	Running time (in seconds)
QoS-2	The network configuration and measurements at the defined time has to be shown in X seconds	The state estimation tool can estimate the active power and voltage in each LV node in less than 2 seconds	Running time (in seconds)
DM-10	Set points for the selected levers: - Selected levers - Voltage level - Injected/absorbed active power - Common format (e.g. .txt, .csv)	The voltage control tool generates set-points to the available levers in a common format (text file) with resource ID and set-point (see Figure 18 in section 3.5.2)	Qualitative evaluation
DM-11	Constraints information: - Location - Involved network element(s) - Type - Status - Common format (e.g. .txt, .csv)	The state estimation tool estimates: voltage in all phases, and neutral wire in each network bus; power injections per phase in each network bus; error code if no success on estimation. The output of the voltage control tool identifies the node, phase and voltage value of technical constraint violation	Qualitative evaluation

DM-12	Solution information: - Cost of the optimal solution (e.g. costs associated to the losses, to load shedding, generation curtailment, etc.)); - Common format (e.g. .txt, .csv)	The voltage control tool generates a merit order list of the available levers in a common format (text file) (see Figure 18 in section 3.5.2)	Qualitative evaluation

Tool: Robust Short-Term Economic Optimization Tool for Operational Planning **System Use Case:** Identify and solve network constraints for a given zone and an optimization application period in operational planning			
Requirements		**Degree of Fulfilment**	**Evaluation metric**
Requirement ID	**Requirement Description**		
R-2	Integrated system for techno-economic calculations	The OP tool first calculates the economic value of flexibilities, creates a merit-order based on their cost, contracted flexibility band (e.g., state of charge, rated power) and then proceeds to optimize the network with the flexibilities and the merit-order.	Qualitative evaluation
R-3	Availability of a cost-based merit-order for levers	As explained in R-2, the OP tool contains an analysis of the economic value of various types of flexibilities. This analysis leads to the generation of a cost-based merit-order for flexibility levers.	Qualitative evaluation
T-1	Define the application period	The OP tool is a short-term scheduling tool that can be applied to the current snapshot of the network as well as to future states (only if forecasts are available). However, it is intended to be used in the day-ahead to week-ahead time-frame.	Qualitative evaluation

QoS-1	The system has to provide the results in X seconds	The calculation time of the VITO optimizer depends on the complexity of the network (number and type of levers, size of network, etc.). The results of a network with 100 nodes and 35 levers, results are available within 5 minutes. Still, a maximum calculation time limit can be set by the user (e.g. results should be available within 10 minutes). RSE optimizer takes less than 60 seconds overall without considering storage systems; in particular for a grid with 600 nodes and 12 controllable elements results are available in 0,4 seconds. If storage systems are included times become higher; for a 650 nodes grid and a 96 periods time frame, results are available in 3-4 minutes.	Running time (in seconds)
DM-10	Set points for the selected levers: - Selected levers - Voltage level - Injected/absorbed active power - Common format (e.g. .txt, .csv)	The OP tool generates set-points for the flexibility levers chosen to be used in the network. This means that the flexibility ID, the amount used for each time period, and the associated total cost incurred is made available.	Qualitative evaluation
DM-11	Constraints information: - Location - Involved network element(s) - Type - Status - Common format (e.g. .txt, .csv)	The Identification of Violated Constraints sub-tool identifies the location, nature and seriousness of constraints violated in the network to be optimized. The output is in the open JSON format.	Qualitative evaluation
DM-12	Solution information: - Cost of the optimal solution (e.g. costs associated to the losses, to load shedding, generation curtailment, etc.)); - Common format (e.g. .txt, .csv)	The OP tool provides the cost of the solution found. This means that the cost incurred due to the activation and use of the flexibilities, and also the technical losses in the network. The output is in the open JSON format.	Qualitative evaluation

Tool: Replay Tool **System Use Case:** Identify and solve network constraints for a given zone and an optimization application period in operational planning			
Requirements		**Degree of Fulfilment**	**Evaluation metric**
Requirement ID	**Requirement Description**		
QoS 1	Requirements related to the specification of the time horizons as well as the duration of the analysis for the load flow calculation,	The user can define the time resolution of the analysis by a specific filter	Running time (h/m/s)
QoS 2	Load and generation forecasts for specific timeframes,	The system can elaborate values as an input of the Enel forecast system	Quantitative values
QoS 3	Available flexibility in the specific timeframes and related non-firm contracts	The usercan modifiy the active power of loads and generators acting contracts	Quantitative values
T-1	Application period	The user can define the lenght and/or the instant when the analysis is performed by using a specific filter	Time interval or past/future instant (h/m/s)
T-2	Specify the time frame for the collection of the historic data	Replay collects historical data from the Enel database	Qualitative
Cnf-1	The system has to save all the solutions in a related database	The user can choose any solution (previously elaborated)	Qualitative evaluation
Cnf-2	The solution has to be ordered by date	The user can choose any solution (previously elaborated)	Qualitative evaluation
Cnf-3	A list of faults occurred in the selected timeframe has to be shown	The tool updates automatically the output when a network simluation is performed	Qualitative evaluation
Cnf-4	The time frame dt of the analysis has to be definable by the operator	The user can define the lenght and/or the instant when the analysis is performed by using a specific filter	Time interval or past/future instant (h/m/s)
Cnf-5	The analysis time frame has to be at least X minutes and at the most Y minutes	The user can define the lenght and/or the instant when the analysis is performed by using a specific filter. An alert is shown if the conditions are not met	Time interval or past/future instant (h/m/s)
Cnf-9	Sampling interval of the load/generation profile is X	Fixed by the developer on the basis of the need for the squential load flow calculation (15min)	Quantitative values
QoS-4	The system has provide the reliability analysis results	Data of Quality of Service are available from an integrated tool (RETIM)	Quantitative values (SAIDI)
S-1	The Operator has to access with an authorized profile to the system	For all the Enel tools, only authenticated operators are able to get access.	Qualitative evaluation
S-2	The Database (state, topology, events) has to provide automatic access	Confirmed	Qualitative evaluation

DM 11	Output data of the reliability analysis: - SAIDI; SAIFI; EENP.	after the simulations, resulting data of Quality of Service are available from an integrated tool (RETIM)	Quantitative values
ICT-1	Operator panel on PC desktop for data merging, compilation of contingencies list, tool operation control, etc.	Scada Interface available	Qualitative evaluation

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