# evolvDSO

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

evolvDSO

COOPERATION

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# Impact assessment at country level

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# Executive Summary

The evolvDSO project defined a set of new and evolving roles and associated services for the DSO, that support Distributed Energy Resources (DER) and Distributed Renewable Energy Sources (DRES) integration. The priority business processes designed to implement the key services associated with the future DSO roles are described by a set of Business Use Cases (BUC). Then, the functions required to execute/enable the associated BUCs were described in a set of System Use Cases (SUC) that represent the most innovative functionalities.

This work allowed the evolvDSO project to develop ten innovative tools within WP3 based on the future DSO's roles and business processes previously identified and that accomplish several steps in the SUCs. All the tools have been validated through computer simulations, considering an adequate set of scenarios based on different hypotheses regarding future scenarios and related objectives defined in WP1 and WP2. Six of ten tools, selected amongst others for their higher innovative content, were tested in a real DSO environment within the WP4. These "field" tests complement the validation tests carried out within the WP3; they helped the DSOs to operate the tools and to assess their value and applicability within the real operational environment of distribution networks. Table 1 reports, for each tool, the countries in which they have been tested.

| Tool Name | WP3 Tests | WP4 Tests |
|---|---|---|
| Interval Constrained Power Flow | Portugal, France, Germany | Portugal, France |
| Sequential Optimal Power Flow | Portugal, France | Portugal |
| Low Voltage State Estimator | Portugal, France | France |
| Low Voltage Control | Portugal, France | - |
| Robust Short-Term Economic Optimization Tool | Italy | - |
| Contingency Co-Simulation Tool | France | France |
| Network Reliability Tool – Replay | Italy | Italy |
| Advanced Asset Management Tool | Ireland | Ireland |
| Short-term network reinforcements considering flexibilities and ICT reliability Tool – FLEXPLAN | Germany | - |
| Long-term planning tool using stochastic modelling Tool-TopPlan | Germany | - |

**Table 1 – Summary of the countries interested by WP3 and WP4 tests.**

This report describes the impact assessment of the tools at a country level, consisting in a high-level technical assessment completed by a detailed benefits evaluation and a cost analysis.

The outcomes of simulation tests and field tests carried out, respectively, in WP3 and WP4 are here summarized and compared in order to present a complete analysis of the tools impact, as well as prompts for future development and integration and lessons learned. Within the technical assessment description, the KPIs and PMs values earned from the WP4 tests are also included.

For each tool the qualitative evaluation of the corresponding benefits is detailed and discussed, explaining their relationship with the specific characteristics of the test scenarios and validating them through the KPIs and PMs calculated within WP3 and WP4 tests.

A qualitative analysis of the costs and efforts necessary for the tools development and deployment has been included in this document. Despite the qualitative nature of this analysis, due to the confidentiality of most of the economic data and the general difficulty to estimate integration costs, an overview of the technical requirements for the exploitation and the integration of the tools in a real distribution network environment is presented.

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# 1. Introduction

## 1.1. Scope of the document

This deliverable, entitled “Impact assessment at country level”, describes the impact of the test demonstrations, simulation tests and field tests, outlining the performance of the tools and lessons learned. Its main purpose is to collect and analyse, overall, the outcomes and the experience gained from the tests carried out for different scenarios and countries.

Here the results of the WP3 simulation tests are summarized in order to present a clear picture of the actual performance of the tools and their capability to enable the functionalities related to the new DSOs roles.

This document is also the recipient for the results of the WP4 tests: the rough data and the evaluation coming from tests described in *Deliverable 4.3* are distilled and the final values of Performance Metrics and KPIs described in *Deliverable 4.2* are presented for the first time. These values are used as “evaluation metrics” for the benefits assessment, in order to provide measurable criteria to assess their degree of fulfilment.

Alongside the technical assessment, this document describes also the high-level Cost-Benefits Analysis (CBA) for the estimation of the economic feasibility of the proposed tools and methodologies. As it is explained in details in the next paragraphs, it was not possible to establish a direct link between the costs and the benefits of each tool; instead, a comprehensive analysis of the achievable benefits and a realistic cost estimation are presented. This analysis is integrated with a detailed description of the technical requirements to be fulfilled for tool implementation in a real operating environment. The intention is to avoid presenting misleading cost figures affected by a very high uncertainty and, at the same time, to give the readers useful information for evaluate the feasibility of tools deployment for their own specific cases.

### 1.1.1. Project background

This deliverable summarizes the activities of the Task5.2 within the WP5 framework. The purpose of Task 5.2 is to evaluate the impact of the developed tools on the electricity system under the scenarios defined in WP1, at country level. Task 5.2 links directly with WP3, WP4 and Task 5.1.

The inputs for this document comes from the following tasks:

- KPI definitions: Task 5.1 (*Deliverable 5.1*)
- Performance metrics definitions: Task 4.2 (*Deliverable 4.2*)
- Simulation tests results and KPI values: Task 3.4 (*Deliverable 3.4*)
- Field test results and raw data for KPI calculation: Task 4.4 (*Deliverable 4.3*)

The detailed description of the tools, their methodology background, and their functionalities are reported in *Deliverables 3.1*, *3.2* and *3.3*.

The country specific impact assessment carried out in Task 5.2 and described in this deliverable will be further distilled into a general impact assessment on a pan-European basis in Task 5.3 (deliverable D5.3).

### 1.1.2. Description of the adopted analysis procedure

This paragraph describes the methodologies adopted in Task 5.2: the specific assumptions made and how the followed approach differentiates from the reference methodologies are explained in details.

As explained in the previous paragraphs, the high-level technical assessment is based on the outcomes of the simulation tests and field tests carried out, respectively, in WP3 and WP4; the details related to the tests, as well as some results, are reported in the corresponding deliverables. The next step was to distil the raw data coming from WP4 field tests in order to calculate KPIs and PMs, or coming from WP3 for tool not tested on the field. This task was jointly accomplished by the partners responsible for the tools and the partners responsible for the tests (when field test there was). Most of the raw data are confidential so, in such cases, the calculation was carried out directly by the partners in charge for the tests. The tests results reported in *D3.4* and *D4.3* were then summarized, compared and commented.
These tasks were accomplished through the compilation of the reference template included in Annex XI, called High Level Technical Assessment (HLA). The partners responsible for the WP3 and WP4 tests, and their roles, are summarized in Table 2.
The content of the templates was then included in the corresponding sections of this deliverable.

| Tool Name | WP3 Tests | | WP4 Tests |
|---|---|---|---|
| | Tested by: | Validated by: | Tested and validated by: |
| Interval Constrained Power Flow | INESCTEC | EDPD, Enedis, Innogy | EDPD, Enedis |
| Sequential Optimal Power Flow | INESCTEC | EDPD, Enedis | EDPD |
| Low Voltage State Estimator | INESCTEC | EDPD, Enedis | Enedis |
| Low Voltage Control | INESCTEC | EDPD, Enedis | - |
| Robust Short-Term Economic Optimization Tool | GINP/RSE/VITO | e-distribuzione | - |
| Contingency Co-Simulation Tool | RSE | Enedis | Enedis |
| Network Reliability Tool – Replay | e-distribuzione | e-distribuzione | e-distribuzione |
| Advanced Asset Management Tool | UCD | ESBN | ESBN |
| Short-term network reinforcements considering flexibilities and ICT reliability Tool – FLEXPLAN | RWTH | Innogy | - |
| Long-term planning tool using stochastic modelling Tool- TopPlan | GINP | Innogy | - |

**Table 2 – Partners involved in WP3 and WP4 tests and their roles.**

For the high-level Cost-Benefits Analysis, the guidelines defined by the European Commission and the Joint Research Centre (JRC) for Smart Grid Projects [1] have been adopted as a reference methodology. Such guidelines are themselves based on the Electric Power Research Institute (EPRI) methodology [2] with some modifications to fit the European context.
For the benefits assessment, the steps reported in the guidelines were followed: each of them is detailed in a corresponding paragraph, within the cost and benefits evaluation of each tool.
Tools' services and functionalities were selected both from the lists included in the guidelines and from the specific services and functionalities analysed in WP2.
The benefits were demonstrated through evaluation metrics based on the KPIs and PMs calculated in WP3 and WP4 tests. Then the impact of each tool on the identified benefits and functionalities was assessed in a qualitative way. Both benefits and functionalities were ranked and compared in a merit deployment matrix (reported in the Annexes), considering the outcomes and lessons learned during the WP3 and WP4 tests. The qualitative evaluation of the tools and the merit deployment analysis were done by the same partners who were in charge for the validation of the tests results, as reported in Table 2. They are the same DSOs who provided the network data for WP3 simulation tests and who carried out the WP4 tests.

The reference methodologies suggest to quantify the benefits in order to compare them with the associated costs on the same numerical basis: unfortunately, this was not possible. The identified benefits, in most cases, don't correspond directly to high-level benefits listed in the reference methodologies, even if they have an impact on them.
To fulfil this task, it would be necessary to identify, with a reasonable accuracy, the boundaries of the tool implementation in a real environment and to have access to all the related data and information: this was not possible mainly for the intrinsic difficulty in identifying the boundaries of the applications and for data confidentiality.
These issues did not allow performing a Cost-Benefits Analysis in the strict theoretical sense, since benefits cannot be linked to costs with the requested accuracy. Furthermore, the Project Consortium wants to avoid giving misleading or erroneous information about these topics. Then, considering that a high-level of analysis is requested, the Project Consortium decided to follow a different approach and to evaluate separately, in the most accurate way actually achievable, the benefits and the costs.

The identified costs can be divided in two main groups: the costs related to the tools development and the costs related to the tool integration and exploitation in a real operating environment. Since the technical readiness of the tools within the project boundaries is, in most cases, far from the industrial level, the development costs were divided in two parts: the cost associated with the actual readiness level of the tools and the costs forecasted for achieving the final readiness level (industrial tool).
These costs were evaluated considering the number of Person/Months required and an average estimation of the PM cost. Since every institution/company has its own PM cost, which can be very different from one another, the resulting figures should not be considered as an absolute reference; indeed, they are intended only as a rough estimation of how much a similar tool could cost to develop.
The integration costs were very difficult to estimate, since they depends strongly on the scale and boundaries of the application. Indeed for some tools the efforts for the integration exceed the boundaries of the test set-up and so they become almost unquantifiable. In addition, confidentiality played an important role.

For these reasons, the integration costs are expressed as a percentage of the tool overall development cost. This percentage was selected at Consortium level to take in to account the specific operating conditions of the tests carried out; furthermore, to avoid confidentiality issues, it is not correlated to any specific DSOs/technical background. Again, like development costs, this percentage is an estimation and should be treated accordingly.

The difficulties encountered in this analysis raised the need to identify an "evaluation pattern". This can be helpful to estimate the necessary efforts for tool deployment in different, and potentially more complex, frameworks than WP3 and WP4 test cases.
As stated before, most of the integration efforts are strongly influenced by the specific environment making difficult to identify an "average case". To overcome these issues, the minimum technical requirements for the tools deployment have been identified: they represent the basic technical level necessary to operate each tool. These requirements are intended to be compared with the actual framework in which the tool will be deployed, in order to identify further actions needed for the deployment and then to quantify them specifically for that case. This way allow the stakeholders to get realistic cost figures for their specific application cases, instead of relying on inaccurate and misleading "reference" cost figures. The minimum technical requirements for each tool are presented in the Annexes.

## 1.2. Structure of the document

This deliverable is divided in twelve chapters. Except from the introduction and conclusion chapters, each of the others corresponds to a tool.
The chapters are structured in sections, as follows:

1. *Introductory section:* it explains the main purpose of the tool and the links with BUCs, SUCs and the associated key functions;
2. *Tool description section:* it contains a summary of the tool framework, its elements, its functionalities and how it works. This is a synthesis of the detailed description reported in WP3 deliverables;
3. *High-level assessment section:* this section presents the synthesis of the outcomes of WP3 and WP4 tests. For the tools tested within WP4, a dedicated paragraph for the KPIs and PMs results is included;
4. *Benefits and costs evaluation section:* this part reports the benefits assessment of the tool, following the steps of the reference methodologies, and a dedicated paragraph for the costs estimation.

The last chapter contains, for each tool, a brief summary of the analysis outcomes, completed with conclusive comments and highlights of the lessons learned.
The Annexes contains the tables and matrixes related to the benefits and cost evaluation, divided by tool, as well as the template used for collecting the technical assessment information.

## 1.3. Notations, abbreviations and acronyms

| | |
|---|---|
| AAM | Advanced Asset Management tool |
| AE | Auto-Encoder |
| AUR | Asset Unavailability Resolution |
| BaU | Business as Usual |
| BUC | Business Use Case |
| CAPEX | CAPital EXpenditure |
| CBA | Cost-Benefit Analysis |
| CCS | Contingency Co-Simulation |
| CHP | Combined Heat and Power |
| CIM | Common Information Model |
| CP | Constraint Programming |
| CRI | Criticalities Reduction Index |
| DER | Distributed Energy Resources |
| DG | Distributed Generator |
| DMS | Distribution Management System |
| DRES | Distributed Renewable Energy Sources |
| DSO | Distribution System Operator |
| DSE | Distribution State Estimator |
| DSM | Demand Side Management |
| EDPD | Energias de Portugal Distribuição |
| EEGI | European Electricity Grid Initiative |
| ENEL | Enel Group |
| EPRI | Electric Power Research Institute |
| ESBN | Electricity Supply Board Networks |
| EV | Electric Vehicle |
| GE | Gross Error |
| GIS | Graphical Information System |
| GPRS | General Packet Radio Service |
| GSM | Global System for Mobile communications |
| GUI | Graphical User Interface |
| HV | High Voltage |
| ICPF | Interval Constrained Power Flow |
| ICT | Information and Communication Technologies |
| I/O | Input/Output |
| JRC | Joint Research Center |
| KPI | Key Performance Indicator |
| LF | Load Flow |
| LV | Low Voltage |
| LVC | Low Voltage Control |
| LVSE | Low Voltage State Estimation |
| MAE | Mean Absolute Error |
| MCS | Monte-Carlo Simulation |
| MDGR | Maximal Distributed Generation Rate |

| | |
|---|---|
| MTTF | Mean Time To Failure |
| MTTR | Mean Time To Repair |
| MV | Medium Voltage |
| NPC | Network Planning Cases |
| NTW | Abbreviation for NeTWork |
| OLTC | On-Load Tap Changer |
| OPF | Optimal Power Flow |
| OP | Operational Planning |
| OPEX | OPerational EXpenditure |
| PLC | Power Line Communication |
| PM | Performance Metric or Person/Month, depending on the context |
| PV | Photo-Voltaic |
| RES | Renewable Energy Sources |
| RT | Real Time |
| RTU | Remote Technical Unit |
| SAIDI | System Average Interruption Duration Index |
| SCADA | Supervisory Control and Data Acquisition |
| SGA | Smart Grid Applications |
| SM | Smart Meter |
| SoC | State of the Charge |
| SOPF | Sequential Optimal Power Flow |
| SRI | SAIDI Reduction Index |
| SUC | System Use Case |
| TAS | Time Activity Saving |
| TPL | Total Power Loss |
| TRL | Technology Readiness Level |
| TSO | Transmission System Operator |
| UCD | University of City of Dublin |
| Wi-Fi | Wireless Fidelity |
| Wi-Max | Worldwide Interoperability for Microwave Access |
| WP | Work Package |

# 2. Interval Constrained Power Flow

## 2.1. Introduction

The Interval Constrained Power Flow (ICPF) tool works in the TSO-DSO coordination domain. It aims to increase the cooperation between TSOs and DSOs in order to improve the system security. By enhancing this cooperation, the DSOs can start interacting with the TSOs at different timeframes (network planning, operational planning, real-time operations, & ex-post) which allows the DSOs to answer to operational requests from the TSOs. To do so, the ICPF tool includes a system process that allows the estimation of the flexibility range of active and reactive power at each primary substation (TSO-DSO interface) for the next 48 hours considering the flexible resources available in each distribution network and their cost. In other words, this tool estimates a region of feasible values of active and reactive power for the power flow exchanged at the boundary nodes between the transmission and distribution networks. Figure 1 shows the scheme of the ICPF tool in the context of the new and evolving DSO activities, as well as the associated services.

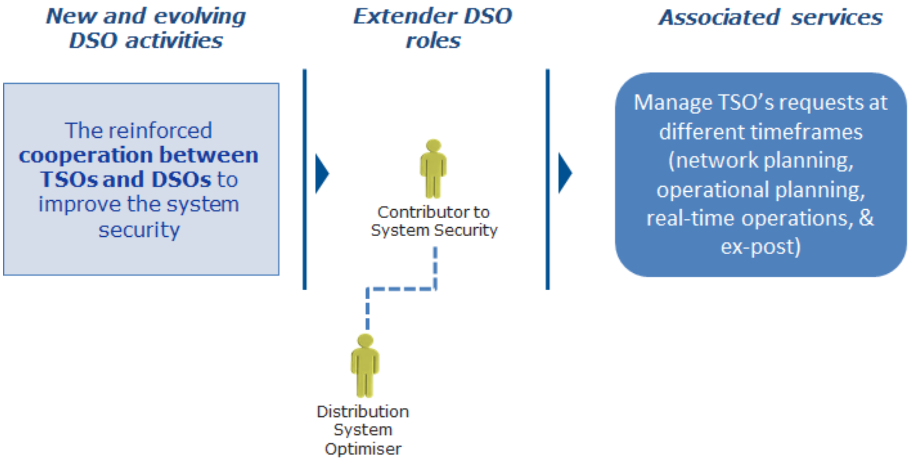



Figure 1 – The impact of the ICPF on the DSO roles

## 2.2. Description of the tool and its elements

The ICPF, through its flexibility monitoring, informs the decision-maker about the potential control actions that can be used to comply with power exchange rules defined by the TSO and voltage limits violations that are typical in distribution networks with high Renewable Energy Sources (RES) penetration. In order to reach the mentioned goal, the following inputs are required for the ICPF:

- Data from the forecasting tool composed by 24h day-ahead forecasts for load and DRES;
- Supervisory, Control and Data Acquisition (SCADA) data: Actual position of grid's equipment such as the OLTC transformers;
- Technical data of grid assets and topology data;

- Technical constraints: grid's equipment technical limits such as voltage limits, branches capacities;
- Flexibility Ranges and Costs.

The flexibility inputs can be divided into three types: the market based, the regulated one and the Technical DSO levers. The first one is purchased in the short-term market or flexibility tenders by the DSO through aggregator offers (loads, storage and DG units). The reactive power compensators and the OLTC transformers compose the Technical DSO lever. The regulated flexibility consists in the non-firm (or dynamic) connection contracts with large consumers and DRES. The outputs of the tool are maps with the flexibility range of active and reactive power in each primary substation (TSO-DSO interface) considering the network constraints, the available flexibility sources and the maximum flexibility cost that the user is willing to pay for the flexibility available in the distribution network. Figure 2 illustrates the main mechanism used by the ICPF and its associated systems.

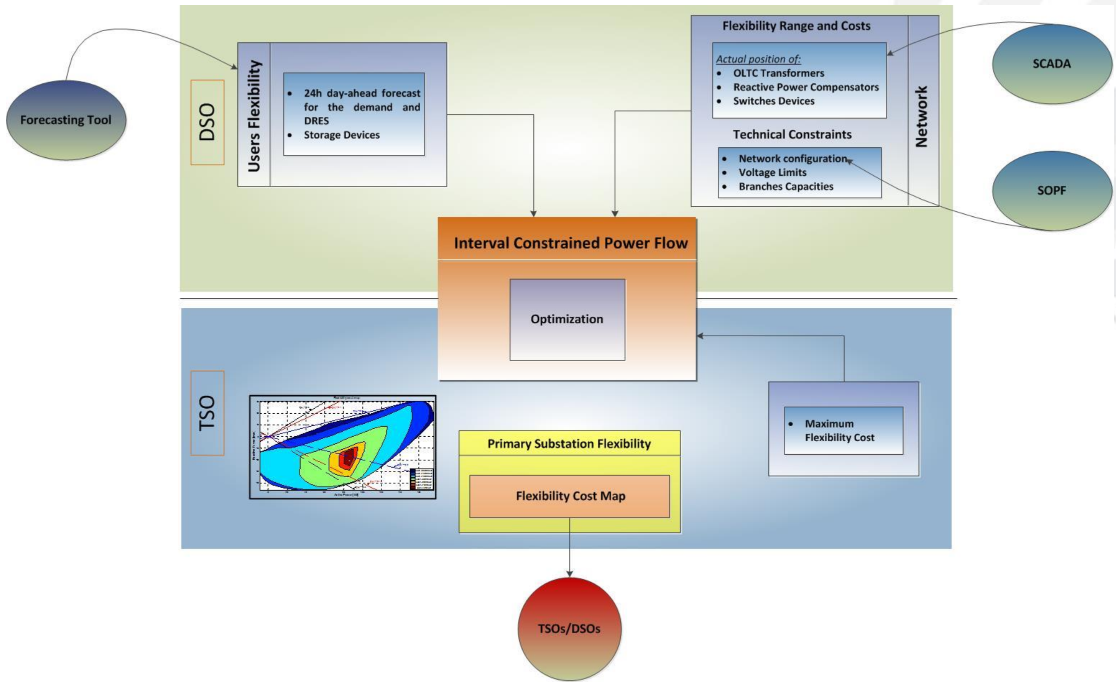



Figure 2 – Interactions between the DSO and the TSO (ICPF tool)

The ICPF tool receives information from what we call associated technologies. The SCADA system is responsible for acquiring data that will be used as input of the ICPF: actual position of taps changers and reactive power compensators, actual position of the switching devices (opened/closed) and State of Charge (SoC) of the storage devices. The SOPF (Sequential Optimal Power Flow) gives to the ICPF the processed network topology, together with the forecasts associated to each node of the distribution network. Another technology needed by the ICPF is the forecasting system. Its goal is to provide load and DRES forecasts for a given time horizon. More implementation details about the ICPF tool are described in *Deliverable 3.3*.

## 2.3. High-level technical assessment of the tool

### 2.3.1. Synthesis of the tool evaluation in WP3 simulation tests

Five real distribution networks were used to test the merits of the ICPF tool: two from France, two from Portugal and one from Germany. Each of these distribution grids have their own specific particularities. While the French distribution networks have a radial MV structure in which the primary substations are equipped with OLTCs, with a small number of tap-changing transformers, the German HV/MV network has a meshed topology and a higher number of OLTCs connected to it. with many tap-changing transformers. The Portuguese networks (HV/MV) both contain high levels of DG while the levels of demand are completely different.
In the analysis of *D3.4*, several simulations considering future scenarios (short, medium and long-term) of DRES and demand growth were considered. Different scenarios for the available flexibility in the distribution networks were also established. Concerning the French networks, seven scenarios were modelled, considering a variation of the demand between -3.1% and 18.4% and of the installed wind power capacity between 34.6% and 253.8%. For the Portuguese networks, the six scenarios used to test the ICPF followed a maximum demand, wind power and Solar PV increase of 37.7%, 50.1% and 404.5%, respectively. In each scenario, a different set of flexible resources was considered (e.g. on-load tap changers transformer, reactive power compensators, wind power curtailment). Regarding the German network, six scenarios with different criteria in terms of flexibility assets and availability were created. Each of these scenarios was run for three different cases considering moderate, high and low level of RES production, respectively.
The ICPF tool proved itself capable of estimating the flexibility range at the primary substations for all these future scenarios, and within a reasonable computational time.

The results revealed the practicality of the ICPF tool for estimating the region of feasible values of active and reactive power exchanges at the boundary between transmission and distribution networks, for scenarios with diverse characteristics. In other words, the ICPF proved itself able to harness the aggregate flexibility available within the distribution grid, and could estimate this flexibility range at the TSO-DSO boundary. Accordingly, flexibility maps that illustrate the flexibility available in the primary substations were drawn. Moreover, the ICPF dealt successfully with the variation of the operating point between scenarios and with the inclusion of a constraint related to the maximum flexibility cost.
The shape of the flexibility area cannot be intuitively derived from the available flexibility in the distribution grid since the amount of it that can be actually activated depends on the network constraints. Therefore, only when the network is operating far from its technical limits (voltage constraints and branch capacities), the flexibility area simplifies into a rectangle whose contours can be derived from the sum of the flexibilities available in the distribution grid. In any case, it is fundamentally difficult to evaluate the reactive power flexibility introduced by the tap-changing on the OLTC transformers without using a dedicated, innovative tool like the ICPF. Thus, the tests performed in WP3 showed the effectiveness of this tool in a clear way.

### 2.3.2. Synthesis of tool evaluation in WP4 field-tests

The WP3 simulations were conducted using a set of possible future scenarios of DRES penetration and demand growth considering a constant configuration of the distribution grids, and it also included flexibility that does not exist, presently, in the distribution system (mainly due to regulatory issues). The WP4 test fields followed a different approach since only the currently available flexibilities were considered, which in this case were the capacitor banks, OLTC and wind power plants curtailment. Within the Portuguese field tests, the ICPF receives information from the Sequential OPF (another tool developed within the evolvDSO project framework) that receives inputs from EDPD's SCADA, and from the forecasting tool developed by INESC TEC. Moreover, the Portuguese field tests were based on 24h daily forecasts with possible changes in the network configuration. This means that network operators received a flexibility map for each hour of the day. Considering this, the WP4 tests were able to evaluate the performance of the ICPF tool in a real environment (DSO control room) interacting directly with operational tools and operators. For the French field tests, the flexibility maps computation was run *a posteriori* using forecasts and network states of specific days chosen by the user.
During the field tests, no assumptions were needed. The existence of valuable field data, together with the possibility of constraining the optimization problem to a maximum flexibility cost, proved suitable to evaluate the benefits of the ICPF tool.
The numerical results of WP3 and WP4 and consequently the corresponding flexibility maps cannot be compared directly as the networks used and the available flexibility are not the same. However, as expected, the results of WP4 (see *Deliverable 4.3*) were in accordance with the conclusions already reached from WP3 (see *Deliverable 3.4*).

The outputs of the ICPF tool appear to be accurate and fulfil the needs of field application. The ICPF by estimating the aggregated active & reactive power flexibility at the TSO-DSO boundary nodes, while considering the network constraints, the flexibility ranges and different maximum flexibility costs, make a valuable contribution in increasing the information exchange between TSOs and DSOs. Through the flexibility maps, the DSOs hold the necessary information to answer operational requests from the TSOs that may arise over different timeframes. Since it is expected that the DSOs will need to provide a service like this to the TSOs in the near future (in real time), the information given by the ICPF is highly valuable and timely. Moreover, the ICPF output also provides interesting information for the future planning of the distribution network.
Regarding the experience gained from the test fields, the results are in accordance with the expectations. Considering the needs of a deployed field application, it would be useful to reduce even more the computational effort. Recent developments have reduced the computational time and allowed to fulfil an important functional requirement from the end-user. However, other improvements are still possible to further increase the computational performance of the tool. One limitation that was observed relates to the requirement of fixing the operating point of N-1 primary substations for the case with meshed HV networks with several primary substations connected through the distribution network (this was the case of Portugal and Germany). Also the information related with future planned outages in the distribution networks would be interesting to include as input for the tool, as these outages can have impact on the available flexibility, hence changing the flexibility area.

The ICPF graphical user interface provides a set of panels describing the network and with easy access to the editable fields that allowed modification of the flexibility ranges, the flexibility maps considering different maximum flexibility costs and the expected operating point. These were functional requirements defined by the end-user. Some possible improvements to the tool interface were flagged:

- The inclusion of a label that links the flexibility maps to the respective maximum flexibility cost.
- Centralizing the flexibility settings of a network in a single panel in order to speed up the network configuration.
- Allowing the user to set the maximum flexibility costs.
- Automating the importation of battery SoC schedule in the same way as consumption and generation forecasts.

### 2.3.3. Results of the KPIs and PMs calculation in WP4 field tests

The way that the KPIs were calculated for WP4 tests did not present any difference when compared with the procedure for the WP3 tests. The only substantial difference is that in the WP4 case the data considered come from the field. The results provided by the ICPF were compared with the ones provided by the MCS (benchmark model defined and developed in WP3). Therefore, the two KPIs defined in WP3 were computed:

- *Increase of the size of the estimated flexibility area with respect to the MCS:* The aim of this KPI is to evaluate the effectiveness of the ICPF in increasing the size of the estimated flexibility area.
- *Reduction of the computational time with respect to the MCS:* The aim of this KPI is to evaluate how much the ICPF facilitated a reduction of the computational effort needed to construct the flexibility map.

The KPIs results from WP3 and WP4 tests are complementary in the sense that both allowed to highlight the capability of the ICPF in increasing the information exchange between TSOs and DSOs within a reasonable computational time. It is important to note that the KPI's values illustrate the benefit of the ICPF in real-life situations. In the following tables, the name assigned to the Portuguese and French networks is composed by two fields: the real name of the network and the flexibilities available in each scenario. This was defined in *Deliverable 4.3*.

| KPI Name | KPI Value | Comment |
| --- | --- | --- |
| ***Increase of the size of the estimated flexibility area (%)*** | **<u>Portuguese networks</u>**<br>Alto Mira_ DSO& GenFlex:→ ∞<br>Ermesinde_ DSO& GenFlex: → ∞<br><br>Alto Mira_DSOFlex: ∞<br>Ermesinde_DSOFlex: ∞<br><br>**<u>French networks</u>**<br><br>Venteea_AllFlex: 51.94 %<br><br>Venteea_DSOFlex: 5.59 %<br><br>Venteea_DSO&GenFlex: 197.12 %<br><br>Venteea_DSO&BatFlex: 14.38 %<br><br>Sogrid_DSOFlex: 32.81 %<br><br>Sogrid_DSO&GenFlex: 41 % | The ICPF through its optimization process proved to be able to surpass the limitation presented by the MCS in finding extreme points of the flexibility map. The simulations led to clear increases of the flexibility area.<br><br>The simulations through the MCS were run considering 1000, 10 000 and 100 000 samples.<br><br>One important comment regarding the Portuguese test cases: as it is possible to observe the increase of the size of the estimated flexibility area tends to infinite values. This is related with the fact that the Portuguese networks are characterized by a meshed topology with a high number of transformers with OLTC connected to them. This means that the possible number of combinations of tap positions is huge and a lot of them lead to unfeasible *(P/Q)* points. The MCS through its random sampling only found unfeasible points and this is why the increase of the size of the estimated flexibility area has these values.<br><br>The KPIs presented here come from the comparison between the ICPF and the MCS using 10 000 samples. |

| | | |
|---|---|---|
| ***Reduction of the computation al time (%)*** | **<u>Portuguese networks</u>**<br>Alto Mira_ DSO& GenFlex:<br>98.14 %<br><br>Ermesinde_ DSO& GenFlex:<br>99.16 %<br><br>Alto Mira_ DSOFlex:<br>99.21 %<br><br>Ermesinde_ DSOFlex:<br>99.72 %<br><br>**<u>French networks</u>**<br><br>Ventea_AllFlex:<br>1.1. 99.21 %<br><br>Ventea_DSOFlex:<br>98.97 %<br><br>Venteea_DSO&GenFlex:<br>99.10 %<br><br>Venteea_DSO&BatFlex:<br>98.98 %<br><br>Sogrid_DSOFlex:<br>99.09 %<br><br>Sogrid_DSO&GenFlex:<br>99.06 % | The ICPF also allowed a reduction of the computational effort in all the simulations that were performed. Once again, the simulations through the MCS were run considering 1000, 10 000 and 100 000 samples.<br><br>Therefore, the ICPF proved to be a tool with a greatly enhanced performance when compared with the MCS.<br><br>The KPIs presented here come from the comparison between the ICPF and the MCS for 10 000 samples. |

## 2.4. Evaluation of costs and benefits of the tool

### 2.4.1. Mapping the tool onto functionalities

One of the first steps in a cost-benefit analysis is to determine which services/functionalities each tool enables. From the 6 services and 33 functionalities defined in [1], the ones that are associated to the ICPF tool were chosen to develop the tool-functionalities matrix. In addition to these, the ICPF tool enables one more service and three more functionalities to the set available in [1]. The new service entitled *Manage TSO's requests at different timeframes (network planning, operational planning, real-time operations, & ex-post)* was adapted from the BUC. The three new functionalities are listed below:

- Manage TSO's requests and support decision-making near to real time at different timeframes (BUC) (i.e. The ICPF can provide the flexibility maps for a predefined time horizon. Therefore, the network operator obtains in advance the information regarding the flexibility available for the next hours which supports him to take decisions near to real time);

- Support the decision-maker regarding TSO-DSO interface monitoring;
- Estimate the Flexibility Range of the Primary Substations (SUC);

Table 3 shows the mapping of the ICPF tool into functionalities.

| Services | Functionalities |
|---|---|
| Enhancing efficiency in day-to-day grid operation | 1. Support the decision-maker regarding TSO-DSO interface monitoring |
| Manage TSO's requests at different timeframes (network planning, operational planning, real-time operations, & ex-post) | 2. Estimate the Flexibility Range of the Primary Substations |
| | 3. Frequent information exchange on actual active/reactive generation/consumption flexibilities |
| | 4. Manage TSO's requests and support decision-making near to real time at different timeframes |

Table 3 – Mapping of the ICPF tool into the functionalities it provides.

## 2.4.2. Mapping the functionalities onto benefits

The purpose of the third step of the cost-benefit analysis is to identify the benefits provided by each functionality. The JRC guidelines [1] use a list of 22 Smart Grid Benefits put forward by the EPRI methodology [2]. However, since the ICPF tool is more relatable to a qualitative evaluation, four new non-quantitative benefits were used to develop the functionalities-benefits matrix. A brief explanation of how the referred benefits are provided by the ICPF functionalities is presented below. Whenever it exists, the link between the benefits and the correspondent operational KPIs is also presented.

- **Contribute to increase the information exchange between TSOs and DSOs:** The ICPF discovers *P/Q* flexibility zones not explored by the Monte Carlo Simulation (benchmark model) that constitutes an increase for the information exchange between TSOs and DSOs. It provides a much more accurate and detailed information of the flexibility that can be used in the distribution network without violating the network constraints. This benefit is linked with the operational KPI "Increase of the size of the estimated flexibility area with respect to the Monte Carlo Simulation" defined in *Deliverable 3.3*. Furthermore, the tool provides the TSO with information about the *PQ* operating point for the next 48 hours, which enables a more accurate calculation of the power flow values in the transmission network nodes.
- **Enhance the accuracy of the definition of contractual values of electrical energy exchange between TSOs and DSOs:** The Flexibility Cost Maps of the ICPF tool analyses the possibility of moving from one predicted PQ operating point to another, while also providing information concerning the maximum cost. This information can be provided by the DSO to the TSO, in complement to the forecasted PQ operating point in each primary substation. This benefit is also linked with the operational KPI "Increase of the size of the estimated flexibility area with respect to the Monte Carlo

Simulation" since the goal is to estimate all possible points within the feasible flexibility area.

- **Separate the contributions of different type of flexibilities and/or the flexibilities by cost areas:** The ICPF can provide the decision-maker with flexibility maps that have areas separated by maximum flexibility cost or by flexible technology (e.g. storage and DRES).
- **Provide more data for the future planning of distribution network:** The ICPF is informs the flexibility area of a primary substation for future scenarios with different levels of RES penetration, load growth and degree of flexibility. For instance, it can inform the network planner that additional flexibility (e.g. installation of storage units) would contribute to increase the flexibility area. This kind of information can help the decision-maker to plan for future investments in the distribution network. This benefit is also linked with the operational KPI "Increase of the size of the estimated flexibility area with respect to the Monte Carlo Simulation" since having more accurate flexibility cost maps gives more reliable information to the decision-maker.

As seen, these four new benefits are very difficult to quantify. However, a qualitative analysis can be performed. Table 4 shows the functionalities-benefits matrix.

| **Benefits** | **Functionalities** | | | |
|---|---|---|---|---|
| | **1** | **2** | **3** | **4** |
| Contribute to increase the information exchange between TSO and DSO | ♀ | ● ◊ ♀ | ● ◊ ♀ | ● ◊ ♀ |
| Enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO | ● ◊ ♀ | ● ◊ ♀ | ● ◊ ♀ | ● ◊ ♀ |
| Separate the contributions of different type of flexibilities and flexibilities with different costs | ♀ | ◊ ♀ | | ♀ |
| Provide more data for the future planning of distribution network | ● ◊ ♀ | ● ◊ ♀ | ● ◊ ♀ | ● ◊ |

● Assessment performed by Enedis

◊ Assessment performed by Innogy

♀ Assessment performed by EDP Distribuição

**Table 4 – Functionalities-Benefits matrix for the ICPF tool.**

The Functionalities-Benefits matrix was filled by three DSOs: Enedis, Innogy and EDP Distribuição. The differences between each one of the matrixes relate to the kind of assessment each DSO performed. As an example, although the ICPF tool is able to separate the contributions of different type of flexibilities, the tests performed by Enedis focused on the flexibility cost maps and did not address this benefit. Thus, the link between this benefit and the functionalities is not relevant in the French case.

### 2.4.3. Establishment of the baseline

The definition of the "control state" which illustrates the benchmark model is an important part of the cost and benefit analysis. The "control state", commonly called the "baseline scenario", has the goal of allowing the comparison with the new developed tool. The scenarios tested in the ICPF case are:

- **Baseline scenario:** Estimates a region of feasible values of active and reactive power exchanged at the boundary nodes between transmission and distribution networks using Monte Carlo Simulation[1].
- **Project scenario:** Estimates a region of feasible values of active and reactive power exchanged at the boundary nodes between transmission and distribution networks using the ICPF tool.

For each of these scenarios, the most relevant conditions regarding the analysed grids, the load growth and DRES penetration rates, as well as the metrics used to evaluate the correspondent benefits are summarised in Table 5. The metrics described in Table 5 are based on the Operational KPIs described in *Deliverable 3.3*.

| Benefits | Baseline Scenario (BaU) | Project Scenario (ICPF) | Metrics Used |
|---|---|---|---|
| **Contribute to increase the information exchange between TSO and DSO** | Several load and DRES growth rates (with different flexibility criteria) characterised in D3.4 are considered for the French, Portuguese and German Networks | Using the same cases but with the ICPF tool | Flexibility Cost Maps (MW×Mvar) – Increase of the flexibility area (Operational KPI) |
| **Enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO** | | | Flexibility Cost Maps (MW×Mvar) – Increase of the flexibility area (Operational KPI) |
| **Separate the contributions of different type of flexibilities and flexibilities with different costs** | | | Flexibility provided by the different types of assets presented in the distribution network |
| **Provide more information for the future planning of distribution network** | | | Flexibility Cost Maps (MW×Mvar) – Increase of the flexibility area (Operational KPI) |

Table 5 – Baseline and Project conditions for the ICPF benefits

### 2.4.4. Demonstration of the benefits

According to the metrics presented in Table 5, the results of WP3 and WP4 will be analysed in the next sections. The benefits of the tool are demonstrated and their corresponding beneficiaries are identified. The level of uncertainty related with these benefits can be classified as modest (see Table 3 from JRC guidelines for more details), since the accuracy of

[1] The Monte Carlo Simulation (MCS) method estimates the flexibility range of active and reactive power in each primary substation through the simulation of power flows in the MV network. To do so, in each power flow, the consumption/generation in the MV/LV nodes and the DSO controllable resources are randomly selected within the available flexibility. Due to this random process, the MCS finds, most of the times, points in the center of the flexibility area and fails in the identification of extreme points close to the boundary of the area of feasible points.

the information provided by the ICPF was obtained using several different scenarios. Moreover, the ICPF accuracy is only dependent on the quality of the input data: network topology, forecast and SCADA measures.

### 2.4.4.1. Contributes to increase the information exchange between TSO and DSO

As established in Table 5, the flexibility cost maps are the metrics used to analyse the merit of this benefit. In order to quantify its impact we use an operational KPI: *the increase of the size of the estimated flexibility area with respect to the MCS*. In all the simulations of WP3 and WP4, the ICPF provided an increase of the estimated flexibility area, which means that it was able to surpass a problem linked with the MCS: the identification of the high and low cost zones. In summary, the ICPF contributes to increase the information exchange between TSO and DSO by providing more reliable flexibility cost maps. This allows the user to observe all the flexibility that can be used in the distribution network (considering the network constraints and maximum flexibility cost). Considering what is described above, it is easy to understand that the main beneficiaries are the TSOs and DSOs. Based on the flexibility cost maps they can set active and/or reactive limits in each primary substation in accordance with their goals. The following sections will make use of the obtained KPI for a set of test cases of WP3 and WP4 in order to demonstrate this benefit.

#### 2.4.4.1.1. HV/MV German Distribution Network – WP3

As described in *Deliverable 3.4*, the HV/MV German network has a total of 427 nodes, 6 interconnections with the transmission network and 204 transformers with on-load tap change capability. Several scenarios simulated different types of available flexible assets. Each one of these scenarios tested different snapshots of an operating point of the German distribution network. The RES production level differs in each scenario. The KPIs for the cases with high (wind generation at 93% of its maximum capacity) and low (wind generation at 9% of its maximum capacity) levels of RES penetration are shown in Table 6 and Table 7.

| Scenario | Flexibility area increase (% of area) | | | Computational time reduction (% of time) | | |
|---|---|---|---|---|---|---|
| | 1 000 samples | 10 000 samples | 100 000 samples | 1 000 samples | 10 000 samples | 100 000 samples |
| *status quo* | 93.9 | 91.4 | 87.3 | 74.4 | 97.7 | 99.8 |
| 1 | 95.8 | 93.7 | 91.2 | 75.9 | 97.7 | 99.8 |
| 2 | 94.1 | 92.2 | 90.0 | 54.0 | 95.3 | 99.6 |
| 3 | 92.9 | 89.9 | 86.7 | 58.5 | 95.6 | 99.6 |
| 4 | 92.1 | 90.1 | 86.4 | 69.3 | 96.9 | 99.7 |
| 5 | 94.8 | 89.9 | 87.0 | 58.0 | 95.8 | 99.6 |

**Table 6 - Operational KPI's for the German distribution network with high level of RES production (WP3)**

Table 6 shows that for this snapshot and for all scenarios tested, the ICPF tool obtains a considerable flexibility area increase and featured reduced computational time when comparing the MCS with 1 000, 10 000 and 100 000 samples. Although the reduction of the computational time is not directly related with any of the benefits provided by the ICPF, it is provided to show the ICPF is computational time efficient.

| Scenario | Flexibility area increase | Computational time reduction |
|---|---|---|

| | (% of area) | | | (% of time) | | |
|---|---|---|---|---|---|---|
| | 1 000 samples | 10 000 samples | 100 000 samples | 1 000 samples | 10 000 samples | 100 000 samples |
| *status quo* | 81.8 | 75.8 | 65.2 | 91.0 | 99.1 | 99.9 |
| 1 | 98.2 | 97.6 | 96.6 | 88.9 | 98.8 | 99.8 |
| 2 | 97.5 | 96.0 | 94.7 | 88.5 | 98.8 | 99.9 |
| 3 | 96.8 | 94.8 | 93.2 | 86.4 | 98.6 | 99.9 |
| 4 | 98.3 | 97.2 | 96.4 | 85.6 | 98.6 | 99.9 |
| 5 | 98.2 | 97.2 | 96.3 | 87.6 | 98.7 | 99.9 |

Table 7 - Operational KPI's for the German distribution network with low level of RES production (WP3)

Table 7 highlights the effectiveness of the ICPF tool for a different snapshot: it provided an increase of the flexibility area and a reduction of the computational time for all the scenarios. As stated previously, an increase in size of the estimated flexibility areas is directly linked with information exchanged between TSOs and DSOs. Therefore, Table 6 and Table 7 show that the ICPF is able to test different scenarios with different flexibility criteria and evaluate their impact on the distribution network with high accuracy. Within the test cases performed on the German network, the ICPF proved to be able to deal with a meshed network with a high number of transformers with on-load tap change capability. Moreover, by allowing only variation of transformer taps changers, it was demonstrated that a considerable reactive power flexibility range was obtained. The full contribution of the transformer tap changers, or of other flexibility assets, was only provided by the ICPF since the MCS is not able to identify the high and low cost zones of the flexibility maps.

##### 2.4.4.1.2. MV French Distribution Networks – WP3 and WP4

As stated in *Deliverable 3.4*, two French distribution networks ("network 5" and "network 6") were tested. Regarding the test fields that were described in *Deliverable 4.3*, two more French distribution networks were used to evaluate the performance of the ICPF ("Venteea" and "SoGrid"). For each network, several test cases were simulated considering different scenarios of consumption, wind power penetration and available flexible resources. Table 8 shows the KPIs that were obtained for the tests performed with the MV French distribution network 5 – WP3.

| Scenario | Flexibility area increase (%) | | | Computational time reduction (%) | | |
|---|---|---|---|---|---|---|
| | 1000 samples | 10.000 samples | 100.000 samples | 1000 samples | 10.000 samples | 100 000 samples |
| 1 | - | - | - | 85.20 | 98.49 | 99.86 |
| 2 | 388.42 | 210.90 | 116.80 | 72.05 | 97.17 | 99.68 |
| 3 | 406.46 | 216.65 | 120.65 | 62.73 | 96.24 | 99.62 |
| 4 | 999.33 | 426.46 | 205.21 | 66.17 | 96.59 | 99.67 |
| 5 | 748.46 | 444.51 | 212.58 | 53.66 | 95.34 | 99.57 |
| 6 | 1994.7 | 509.8 | 326.5 | 54.26 | 95.34 | 99.49 |
| 7 | 1045.3 | 418.3 | 213.3 | 52.65 | 95.19 | 99.49 |

Table 8 - Operational KPIs for MV network 5 (WP3)

Table 8 concludes that an effective output in a reasonable amount of time is provided by the ICPF. For all scenarios, the ICPF provided a considerable flexibility area increase and computational time reduction when compared with the MCS. Moreover, it is possible to associate this flexibility area increase with the ability of the ICPF to identify the high and low cost zones of the flexibility maps. In other words, through these flexibility area increases, the

TSOs and the DSOs are in possession of a much clearer view of the flexibility that is available in the distribution network.

| Scenario | Flexibility area increase (%) | | | Computational time reduction (%) | | |
|---|---|---|---|---|---|---|
| | 1000 samples | 10.000 samples | 100.000 samples | 1.000 samples | 10.000 samples | 100.000 samples |
| DSOFlex | 24.68 | 5.59 | 2.86 | 88.88 | 98.97 | 99.9 |
| DSO&GenFlex | 319.84 | 197.12 | 162.13 | 91.57 | 99.1 | 99.9 |
| DSO& BatFlex | 32.08 | 14.37 | 10.07 | 90.36 | 98.98 | 99.9 |
| AllFlex | 117.79 | 51.94 | 32.98 | 92.03 | 99.21 | 99.92 |

Table 9 - Operational KPIs for Venteea MV network (WP4)

Table 9 presents the KPIs results obtained for the test field performed on Venteea MV French distribution network. These results confirm the conclusions of WP3 tests. When comparing the performance of the ICPF with the MCS using 1 000, 10 000 or 100 000 samples, the ICPF is clearly more effective. Considering the KPIs, it is possible to state that the ICPF leads to flexibility maps that provide a much more accurate vision of the flexibility that can be achieved in distribution network without violating the network constraints.
Due to the radial structure of the French networks analysed with a low number of transformers, the flexibility presented by the distribution network is almost equal to the sum of flexibilities available in the network. This conclusion illustrates the increasing information exchange between TSOs and DSOs.

#### 2.4.4.1.3. MV Portuguese Distribution Networks – WP3 and WP4

As described in *Deliverable 3.4*, two MV Portuguese distribution networks were tested using the ICPF tool: the Northeast characterised by low levels of consumption and high amount of DG connected to it and the Western characterised by medium to high levels of consumption and high amount of DG connection. Regarding the test fields described in *Deliverable 4.3*, two more Portuguese distribution networks evaluated the performance of the ICPF ("Alto de Mira" and "Ermesinde"). Several scenarios considered different flexibility criteria and different trends of DG and demand increase.

| Scenario | Flexibility area increase (%) | | | Computational time reduction (%) | | |
|---|---|---|---|---|---|---|
| | 1 000 samples | 10 000 samples | 100 000 samples | 1 000 samples | 10 000 samples | 100 000 samples |
| 1 | 91.83293 | 75.61094 | 64.0509 | 27.4024 | 92.95494 | 99.2935 |
| 2 | 79.7726 | 64.9415 | 52.152 | 5.44369 | 90.66553 | 99.062 |
| 3 | 66.28776 | 46.05476 | 34.5623 | 30.42187 | 93.1437 | 99.31094 |
| 4 | 80.9 | 66.5 | 55.1 | 35.3 | 93.6 | 99.4 |
| 5 | 59.6705 | 41.01083 | 34.4108 | 35.1103 | 93.8548 | 99.3985 |
| 6 | 70.1 | 59.8 | 57.5 | -89.9 | 81.5 | 90.9 |

Table 10 - Operational KPIs for the Northeast network (WP3)

Table 10 shows that for all the tested scenarios in the Northeast network (WP3) the ICPF allowed to obtain a considerable flexibility area increase when comparing to the MCS with 1000, 10 000 and 100 000 samples. This means that the full potential of the flexibility assets presented in the distribution network is illustrated in the flexibility cost maps provided by the ICPF. Therefore, the TSOs and the DSOs are in possession of reliable information regarding the flexibility that can be used in order to, for example, answer to operational requests from the TSOs. The KPIs for the Western network followed the same behaviour.

| Scenario | Flexibility area increase (%) | | | Computational time reduction (%) | | |
|---|---|---|---|---|---|---|
| | 1 000 samples | 10 000 samples | 100 000 samples | 1 000 samples | 10 000 samples | 100 000 samples |
| TAPS&ShuntsFlex | ∞ | ∞ | ∞ | 90.23 | 99.21 | 99.94 |
| TAPS&Shunts&GenFlex | ∞ | ∞ | ∞ | 82.78 | 98.13 | 99.84 |

Table 11 - Operational KPIs for the Alto de Mira network (WP4)

Table 11 shows the same good performance of the ICPF tool in increasing the area of the flexibility cost maps when comparing with the MCS. Table 11 illustrates the KPIs obtained for one of the Portuguese Distribution networks tested in WP4. The KPIs for the Ermesinde network followed the same behaviour. These tests led to increases of the flexibility areas that tended to infinite values. The explanation behind this fact relates to the characteristics of the networks: meshed topology with a high number of transformers with OLTC connections. Considering this, the possible number of combinations of tap positions is huge and many lead to unfeasible $P/Q$ points. In summary, the random sampling process that characterizes the MCS only found unfeasible points, which explains the infinite increase of the flexibility areas when using the ICPF.

#### 2.4.4.2. Enhancing the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO

The ICPF through the Flexibility Cost Maps illustrates the possibility to move from one predicted operating point to another, providing information concerning the maximum cost. This means that through the flexibility cost maps, the TSOs and the DSOs will understand how much flexibility is available in each transmission node (distribution network) and at what cost. This is possible because the ICPF is able to estimate the flexibility area in each primary substation, which is a significant contribution to the increase of information exchange between TSOs and DSOs. Therefore, the main beneficiaries will be the TSOs and DSOs. This benefit is also related with the operational KPI "*Increase of the size of the estimated flexibility area with respect to the Monte Carlo Simulation*" since more realistic flexibility cost maps allows for a more precise definition of the contractual values. For example, the increase of information exchange provided by the ICPF gives to the decision maker the possibility to manage correctly the TSO's requests without spending unnecessary costs by activating expensive flexibility assets with lower impact in the flexibility at the TSO connection node. Figure 3 is an example of the kind of information the DSOs and the TSOs can receive from the ICPF tool. On the one hand, the ICPF shows the flexibility that is available in the distribution network only considering the network constraints (yellow area). On the other hand, the ICPF provides different flexibility areas if the user establishes different maximum costs to pay for the available flexibility (red and green areas). With this exchange of information, the DSOs have the necessary knowledge to answer an operational request from the TSOs. This enhances the accuracy of the definition of contractual values of electrical energy exchanged between them. Figure 3 was obtained through the field tests performed in a French MV distribution network.

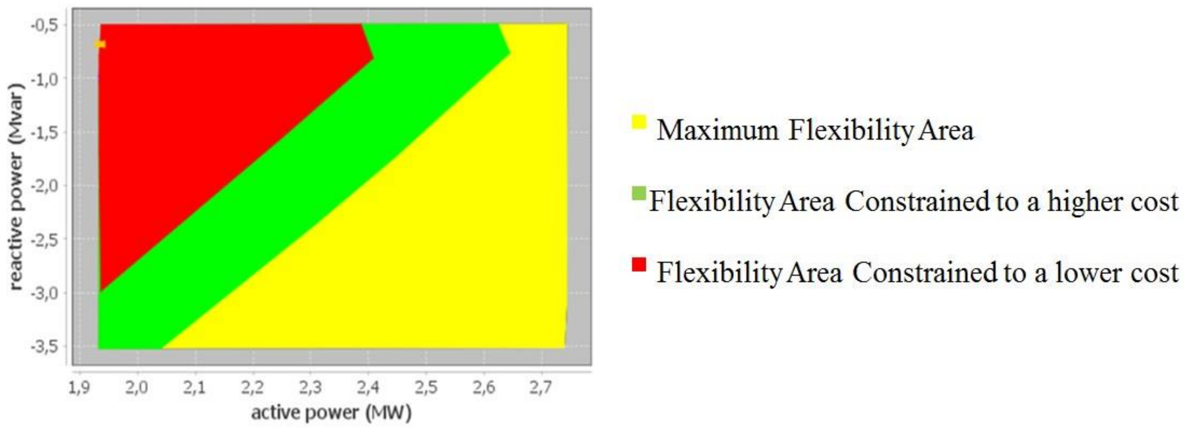



Figure 3 - Flexibility Cost Map for different maximum flexibility costs for the Venteea MV network (WP4)

#### 2.4.4.3. Separate the contributions of different types of flexibilities and flexibilities with different costs

The ICPF separates the contributions of each type of flexibility asset including its cost. This means that the TSOs and DSOs will know which flexibility assets they should engage in order to move from one predicted operating point to another. Therefore, the ICPF informs the decision-maker about the potential control actions available. Considering this, we can conclude that the main beneficiaries are the TSOs and the DSOs.

##### 2.4.4.3.1. HV/MV German Distribution Network – WP3

In this section, an example of the effectiveness of the ICPF in separating the contributions of different types of flexibility is demonstrated on the HV/MV German distribution network.

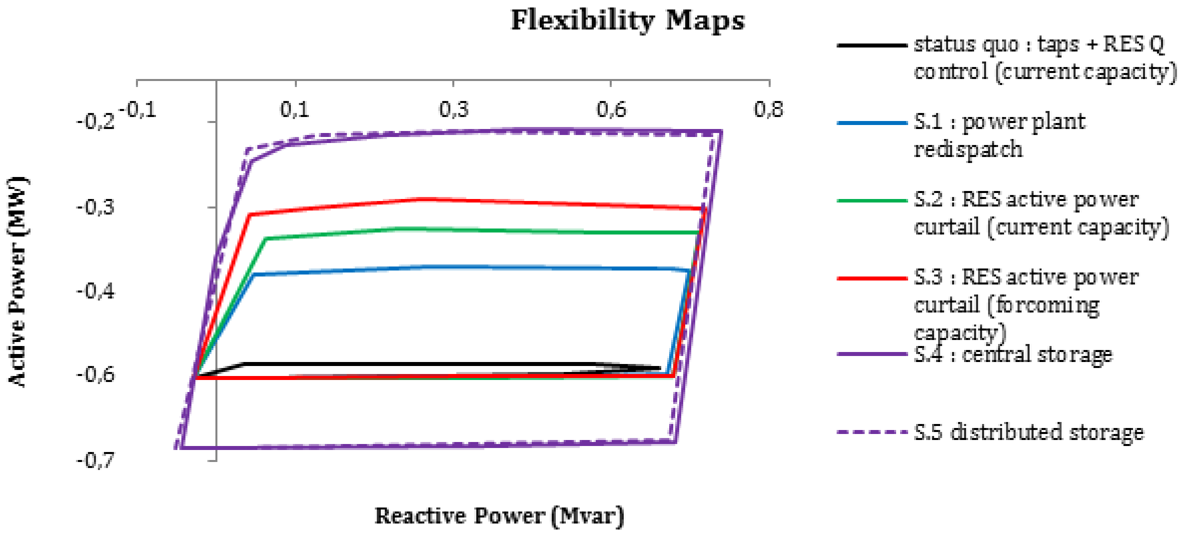



Figure 4 - Flexibility Maps for all the simulation scenarios (Germany-WP3)

Figure 4 shows the flexibility maps obtained by simulation for the German HV/MV distribution network. As seen, the ICPF separates the contributions of different types of flexibility sources. In each simulated scenario, the available flexibility sources in the distribution network were different. As an example, in the status quo, only the transformers with OLTC and reactive power control provided by the existing RES allows while in scenario 1, the power plant re-dispatch was also available. This differentiation between the flexibility that each source is able to provide can be very helpful for the decision making process.

#### 2.4.4.3.2. MV Portuguese Distribution Networks – WP4

In WP4 two MV Portuguese Distribution Networks were used in order to access the benefits provided by the ICPF tool. Two test cases were performed:

- Flexibility provided only by the DSO assets
- Flexibility provided by the DSO assets and possibility of curtailment until 100% of the active power forecasted for hour i

The characteristics of these two test cases evaluates the effectiveness of the ICPF tool in separating the contribution of different types of flexibilities.

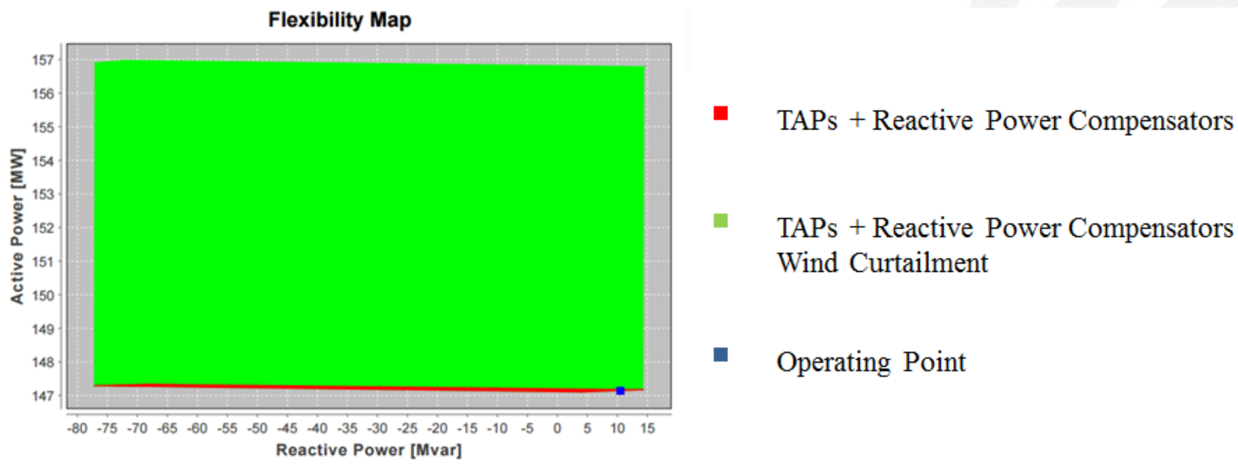



Figure 5 - Flexibility Maps for all the simulation scenarios (Portugal-WP4)

Figure 5 proves that the ICPF separates the contributions of different types of flexibilities in the test fields performed with EDP Distribuição .

### 2.4.4.4. Provide more information for the future planning of distribution network

The following sections will show some examples of this benefit provided by the ICPF.

#### 2.4.4.4.1. HV/MV German Distribution Network – WP3

In the snapshot with high level of RES production, it was possible to state that the network's maximum operating point was reached in scenarios 3, 4 and 5 meaning that additional flexibility would not contribute to the flexibility area increase. This is a very interesting conclusion that allows the DSOs to understand the maximum amount of flexibility that the distribution network is able to host. This can help the DSOs to plan future investments in the distribution networks.

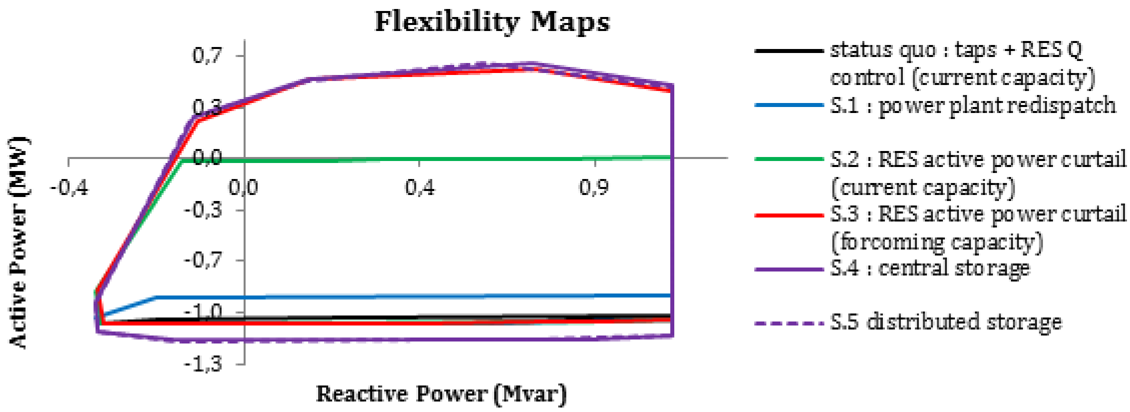



Figure 6 - Flexibility Maps for the snapshot with high level of RES production (Germany-WP3)

Figure 6 shows that in scenario 3 the maximum operating point was reached. For this reason, adding the central storage (scenario 4) or the distributed storage (scenario 5) did not have any effect in terms of flexibility presented in the distribution network.
Another important information for the German DSO relates to the fact that no significant differences is observed between the flexibility ranges for the centralised and distributed storage scenarios. This is illustrated in Figure 4 showing the snapshot of low level of RES production.

#### 2.4.4.4.2. MV French Distribution Networks – WP3 and WP4

The simulations for the MV French Distribution Networks (WP3) detect the maximum amount of flexibility that the distribution networks were able to host. The tests considered for the French MV network 5 led to the conclusion that no branch reinforcements were necessary in order to support an increase of 253.8% of the wind power installed capacity. However, performing the same tests for the French MV network 6 led to the opposite conclusion. This means that an increase in the maximum flow capacity of some branches was necessary in order to provide a degree of flexibility near to its maximum (long-term scenarios). This proves that the ICPF is able to give to the DSOs interesting information for planning the future of the distribution networks. Regarding the tests performed on Venteea network (WP4), Figure 3 illustrates that the flexibility presented by the distribution network is almost equal to the sum of flexibilities available in the network (yellow area). This means that the network's maximum operating point was not reached. Thus, the network planner knows that additional flexibility would contribute to increase the flexibility area, which is valuable information for the future planning of the distribution network.

#### 2.4.4.4.3. MV Portuguese Distribution Networks - WP3 and WP4

The ICPF tool showed its impact in analysing the maximum flexibility that the distribution networks can host. As it can be observed in Figure 7, in the case of the northeast network not all the available reactive power flexibility was used due to network constraints.

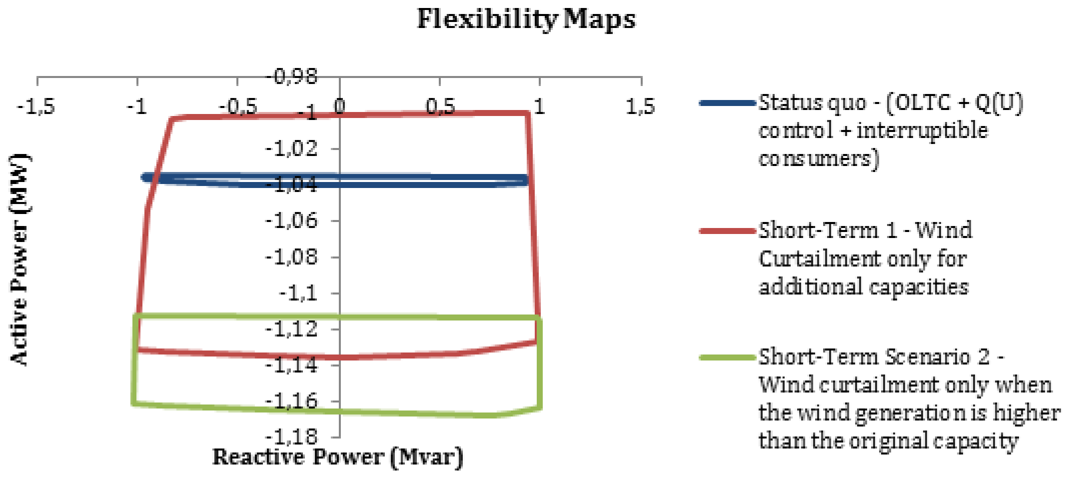



**Figure 7 - Flexibility Maps for the Northeast network (Portugal-WP3)**

Figure 7 also shows the ability of the ICPF in testing future scenarios with different levels of RES penetration. Moreover, a situation of overload was observable in some branches due to a significant increase of wind power penetration (long-term scenario) in the northeast network. These situations are not present in the western network since the network constraints were far from their limits. Considering the increasing penetration of DRES, this information will aid the DSOs to plan for future investments in the distribution network. Regarding the test fields performed on Alto de Mira network (WP4), Figure 5 shows that the distribution network was able to host all the available flexibility. In other words, additional degrees of flexibility can be added to the network aiding, for example, the DSOs to react to operational requests from the TSOs.

## 2.4.5. Qualitative impact analysis

Often a project assessment addresses both quantifiable and non-quantifiable benefits. This means that certain benefits described in a cost-benefit analysis are difficult to monetise. Considering the benefits presented in Section 2.4.2, their quantification is not possible. As an example, quantifying the impact of separating the contributions of different types of flexibilities is a hard task. Therefore, in these cases it is very important to do a detailed description of the qualitative appraisal of these benefits. The assessment framework used to link benefits and functionalities in order to capture the merit of the project deployment is based on a merit deployment matrix where benefits are given in rows and functionalities are given in columns. Table 67, Table 68, Table 69 of Annex I list the merit deployment matrixes that the DSOs have received and completed. The main conclusions to be drawn from these matrixes will be detailed in the following sections through the assessment of the project impact across benefits and functionalities.

### 2.4.5.1. Project impact across functionalities and benefits

The Merit Deployment Matrixes that allowed developing Figure 8 and Figure 9 are detailed on Table 67, Table 68 and Table 69.

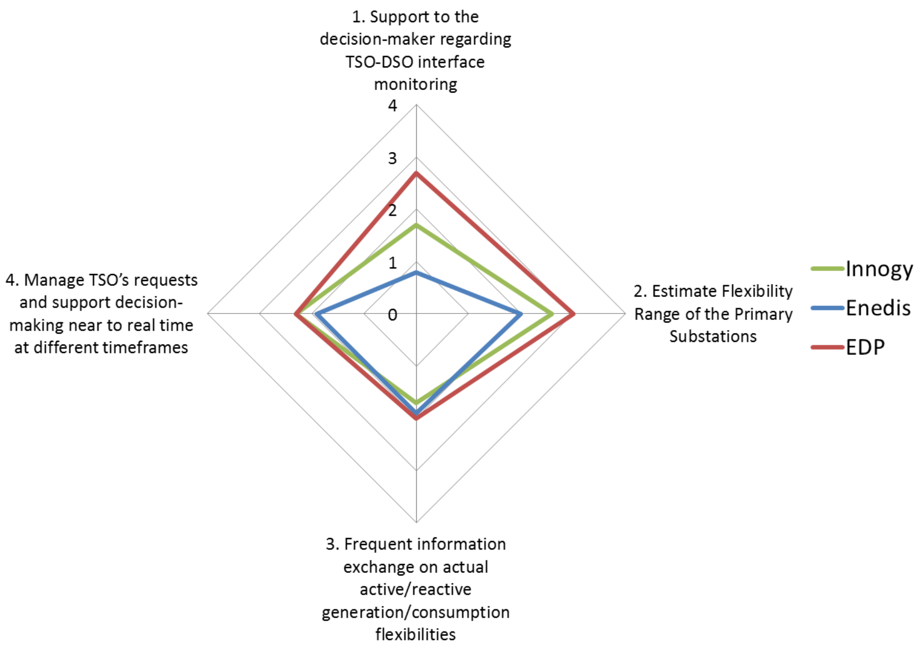



Figure 8 - Project impact across functionalities

A common standard is observable when analysing the project impact across functionalities performed by each DSO: the estimation of the flexibility range at the TSO/DSO boundary node has the highest weight. This common evaluation is in accordance with the expectations since the SUC linked with the ICPF tool is "*Estimate Flexibility Range of the Primary Substations*". In other words, this functionality is one of the main goals of the ICPF tool. On the other hand, the estimation of the flexibility range is what gives the DSO the necessary information to manage TSOs requests, which explains the high weight linked with this functionality.

Regarding the frequent information exchange on actual active/reactive generation/consumption flexibilities, Enedis considers it useful for post analysis. In other words, a post analysis can lead to extra information regarding, for example, the future planning of the distribution network.

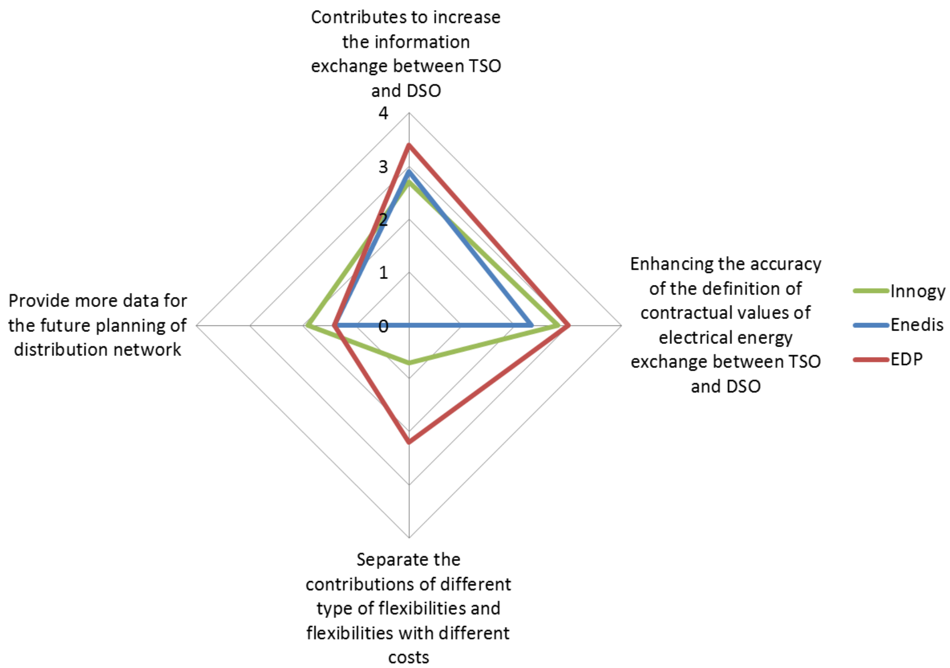



**Figure 9 - Project impact across benefits**

Figure 9 evaluates the impact of the benefits linked with the ICPF tool. The benefits stated below are linked with the higher weights:

- Contribute to increase the information exchange between TSO and DSO;
- Enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO;

As stated in Figure 1 the new DSO activity that the ICPF tries to fulfil is the reinforcement of the cooperation between TSOs and DSOs. By increasing the information exchange between them, the ICPF answers to this requirement, which explains the high weight assigned to this benefit. On the other hand, the flexibility maps provided by the ICPF allow the analysis of the possibility to move from a predicted point to another giving also the information concerning the relative cost. This is valuable information for enhancing the accuracy of the definition of contractual values of the electrical energy exchange between TSO and DSO.
An interesting difference is that Enedis did not assign any weight to one of the benefits. This is because the functionalities of the tool considered by the French DSO were not exactly the same as the ones considered by the two other DSOs.

### 2.4.6. Identification and quantification of the costs

The costs associated with the ICPF were also divided into two categories: (a) industrialisation of the algorithms/tools developed in WP3, which comprises all the effort (in person-month cost of INESC TEC in Portugal) to create a tool ready to be integrated in the business processes of a DSO; (b) integration of the industrial tool within DSO information system.

The industrialization cost is the sum of the person-month spent during the project in WP3-4 to develop and improve the tool, plus additional effort to complete the following developments:

- Standardization of the input/output data (i.e. adoption of CIM standards);
- Improvement of the computational efficiency;
- Improvement of the functions' error handling processes;
- Improvement of the GUI.

It should be stressed out that around 44% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 12 PM spent during the project (with a rough estimation of the average PM cost around 4400€) and 15 PM for the additional developments towards industrialization.

The minimum technical requirements listed in Annex I, Table 64 and Table 65, estimated the integration costs for France and Portugal.

The ratio industrialisation/integration cost for France is 22.8%. However, it is important to stress that the integration costs do not include several categories where the cost quantification is not possible at this phase (see Annex I, Table 64). This ratio shows that the industrialization cost is a small fraction of the integration cost, however the choice of the architecture (centralized versus decentralized) might have a significant impact in the integration cost. For Portugal, the ratio was 39.6% since the integration cost was lower than in France.

The ICPF was not demonstrated in the framework of WP4 for Innogy (Germany) and only computer simulations were made in WP3. Therefore, an accurate and quantitative identification of integration costs is not possible. The different categories of the integration costs that were analysed in a qualitative way and are presented in Annex I, Table 66. The main conclusions from this qualitative analysis are:

a) High level of uncertainty in quantifying the costs associated to the forecasting tool that will provide input data to the ICPF and the costs related to computational requirements for a large-scale deployment of the tool;
b) The costs for data management and access to monitoring information are expected to be low and easy to quantify since the majority of this information is already available in the SCADA/DMS, nevertheless communication costs should be considered.

# 3. Sequential Optimal Power Flow

## 3.1. Introduction

The deployment and effective implementation of Smart Grid concepts will certainly imply deep modifications in the relations between DSOs and the other actors of the Electric Power System, such as Grid Users, Regulators, TSOs, and Suppliers. Regarding the TSO-DSO cooperation domain, technical solutions, such as the Sequential Optimal Power Flow (SOPF), promote a closer interaction between these two actors, enabling several challenges to be overcome relating to planning and operation at the distribution/transmission level. The SOPF provides a list with set points for all the flexible resources for each interval inside operational planning period in order to comply with the P and/or Q limits in the primary substation. In this sense, the SOPF promotes a more active contribution of the DSO to operational requests from the TSO in the short-term operational planning domain, in normal real-time operations and emergency conditions. Figure 10 summarises the most relevant new and evolving DSO activities, as well as the main services related with the SOPF tool.

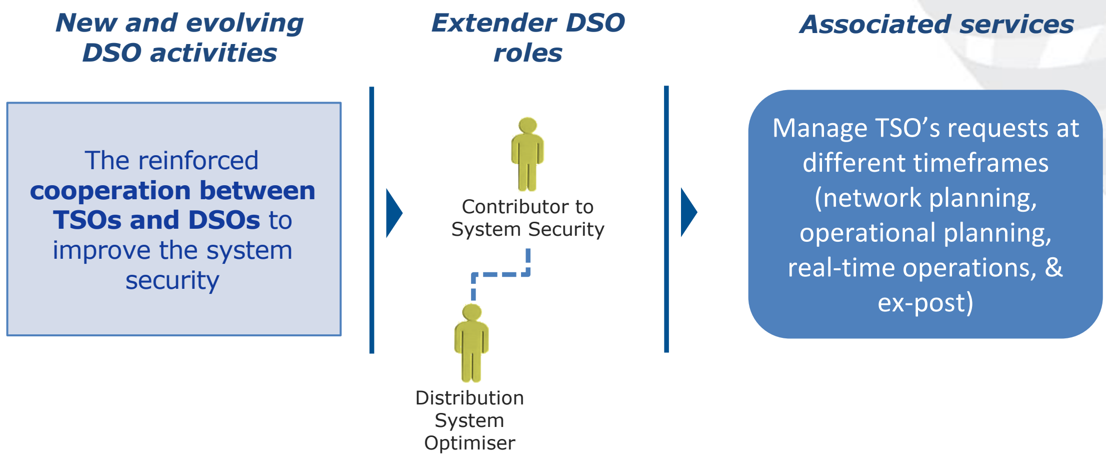



Figure 10 – The SOPF goals in the DSO roles.

## 3.2. Description of the tool and its elements

The main objective of the SOPF is to minimise the costs associated with the activation of flexibilities on distribution networks, maintaining the TSO agreed power profiles at primary substations. To do that, the solver searches for the optimal values of the decision variables considering consecutive periods of analysis using a slide window approach that takes into account inter-temporal and technical constraints. The decision variables are the OLTC transformer tap position (or voltage set points), the capacitor banks tap position, the states of switching devices and the flexibility resources operating point (e.g. storage, DRES). *Deliverable 3.3* details the complete mathematical formulation of the methodology applied by the SOPF tool and the algorithm used for solving the optimisation.

The main input elements required by the SOPF tool are divided in the following categories:

- Active and reactive power forecasts for load and DRES;

- SCADA data: status of the grid equipment;
- Technical data of grid assets and topology data;
- Grid's equipment technical limits such as voltage limits, branches capacities;
- Inter-temporal constraints, e.g. maximum number of tap changes in the programming period; maximum duration of flexibility activation;
- Flexibility Ranges and Costs: Consists of the ranges and costs of the non-firm (or dynamic) connection contracts with large consumers and DRES.

The outputs of the tool are decision variables already mentioned, i.e. a set of control actions to grid equipment (transformer taps, generation unit, power storage unit, etc.), operations that regard the modification of grid topology or activated flexibility offers/contracts. Figure 11 presents a flowchart that summarises the input and output data related with the SOPF tool, as well as the interactions between its associated systems at the DSO level.

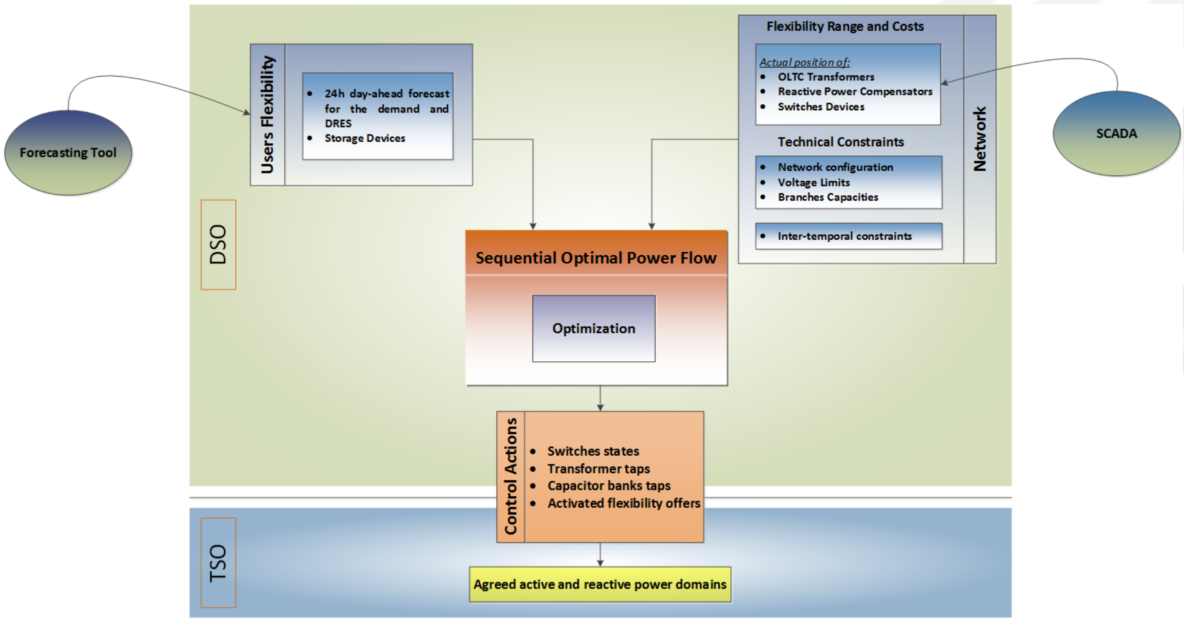



Figure 11 – Input/output variables of the SOPF tool and interactions between DSO and TSO

## 3.3. High-level technical assessment of the tool

### 3.3.1. Synthesis of tool evaluation in WP3 simulation tests

Four real distribution networks were used to test the merits of the SOPF tool: two from France (MV) and two from Portugal (HV/MV). The Portuguese networks are located in the Northeast and in the West of the country. The Northeast Portuguese network has low demand and a large amount of distributed generation. The Western network has medium-to-high demand and also a large amount of distributed generation. Concerning the French distribution networks, they are characterized by a radial structure with a low number of transformers, all of them are OLTC transformers. In terms of flexibility, resources, diverse DER were considered, demand flexibility, wind curtailment, as well as capacitor banks and OLTCs transformers. Based on the data received from the DSOs, several scenarios were

constructed. For French networks, 28 scenarios, varying the demand by 18.4% and the wind power by 253.8% were used. For the Portuguese networks, 12 scenarios, varying the demand by up to 37.7%, the wind power to 50.1% and the Solar PV to 404.5%, were established. The simulations considering these scenarios were tested for 24 consecutive periods of one hour using the historical measurements of demand and generation of a pre-specified day.
The diversity of scenarios covering several sequential timeframes, different seasons of the year and different available flexibilities constitutes a validation of the SOPF tool that was able to manage all these variables applied on large networks.

In general, the simulations were successful, and confirmed the expectations of the tool's performance. The implemented algorithm achieved its goals by reducing the costs of activating flexibilities and the costs of penalizing power out of boundaries. By activating flexible resources and changing the control variables states it allowed the network to maintain the power flow within the voltage limits and within the primary substations power limits most of the time, avoiding expensive penalties. The results revealed that the flexibility costs tended to be higher in winter scenarios or any scenario where the power demands is higher, which causes more values out of boundaries and therefore more activated flexibilities. At the same time, the simulation results clearly demonstrated a reduction of active power losses for all tested scenarios and for all the networks.
The reconfiguration of the topology was not employed in any of the networks used for simulations. There are some reasons that can explain this behaviour. Regarding the Portuguese networks, the Northeast network is normally operated in closed loop, which makes it difficult to obtain an enhanced solution. Both Portuguese networks had active power limits at primary substations that were high compared to the effective power injection. The fact that these limits were not breached may be the reason why no configuration change was registered. A constraint imposed to all networks was the number of operable switches in their initial configurations, which reduced the flexibility (or freedom) to change the configuration.
The results obtained show that the total power losses grow along with the increase of demand and generation injections. Therefore, the improvement of power losses followed the same trend. The changes in the operation of the capacitor banks and transformer taps helped the SOPF tool to reduce the active power losses in all simulations by managing the flexibilities and by controlling the voltage and reactive power.

### 3.3.2. Synthesis of tool evaluation in WP4 field-tests

The major differences between WP3 and WP4 test networks are related to the type of flexibilities available in the distribution network (only the currently available flexibilities were considered) and the scale of the considered networks. In WP4, two real Portuguese distribution networks were used in the field-test. One is located in the North and other in the South of the country. Both networks have medium/high load profiles, but only a single generation unit each (one co-generation unit and one wind park respectively). In terms of flexibility resources, only capacitors banks and OLTC transformers are currently available to the DSO. The conducted tests were part of a live demonstration that provided a high level of interaction between the SOPF tool and the DSO's SCADA systems. During the trials, the SOPF tool received daily updates on the network topology and other equipment's live status and also load/generation forecasting information. Moreover, the considered network operational costs were based on the actual regulatory obligations that the DSO has to follow. The applied

costs for power losses were segmented by voltage level (MV and HV) and for reactive power limits violation, penalties were imposed in relation to the tan φ (i.e., P/Q ratio) value on the TSO-DSO frontier. Along this live demonstration, a specific objective for the SOPF tool was also defined: it has to generate a summary report, which would provide a set of optimal manoeuvres for changing the network capacitor banks' status over the considered time horizon.
Comparing the outcomes of the WP3 and WP4 tests, their complementarities are clearly visible. The results of WP4 further support the encouraging conclusions already drawn from WP3.

The major results obtained in WP4 test fields proved that with just the availability of capacitor banks and OLTCs transformer, the SOPF tool optimization process is able to reduce the overall operating costs on network. The tool provided a significant reduction in the reactive power limits violation penalty costs. In terms of power losses reduction, the results were around a 1.7 to 2.0 % in relation to the losses observed on both Portuguese networks tested in WP3 (see *Deliverable 3.4*).
Since the SOPF tool can run on the same computer as the DSO's typical network supervision and control software, the tool output data can be easily integrated as input to SCADA/DMS systems. The tool is useful for distribution network operational planning, considering multiple inter-temporal constraints. It provides set points for the network main flexibility assets, aiming for operation cost reductions, with attendant environmental benefits.
The tool runs as a standalone process in any computer system and it does not require any major computational resources. Regarding the tool interface, it is clear to understand and operate. Once deployed, the SOPF tool will automatically optimize the network operating point for the number of periods and the main problem constraints specified by the user. Once finished, it presents all the major results in a single folder and can also be sent to the appropriate recipient through email.

### 3.3.3. Results of the KPIs and PMs calculation in WP4 field tests

In WP3, the SOFP tool KPIs allow to prove the tool's potential in improving distribution network operational costs and technical constraints. In WP4, the SOPF tool was part of a live demonstration whose main goals were the optimisation of the possible active power losses and operational costs reduction related to tan φ at the primary substation. Considering this, it is possible to understand the complementarity between the tests performed in WP3 and WP4. Therefore, WP3 and WP4 KPIs were the same:

- *Minimize the active power losses of the MV network.*
- *Minimize the operational costs associated with the activation of flexibilities plus penalties for violating active and reactive power limits in the TSO/DSO interface.*
- *Maintain the active and reactive power flow at the TSO/DSO interface within the pre-defined minimum and maximum limits.*
- *Minimize total runtime.*

The KPI's values obtained in WP4 illustrate the added value of the SOPF in real-life situations.

| *KPI Name* | *KPI Value* | *Comment* |
| --- | --- | --- |
| ***Active Power Losses Improvement*** | **<u>Portuguese networks</u>**<br>Real Measurement Data<br>North: 156.86 kW (2.09 %)<br>South: 196.18 kW (1.94 %)<br><br>Forecast Obtained Data<br>North: 126.57 kW (2.26 %)<br>South: 174.70 kW (1.31 %) | The total power losses improvement KPI is defined as the comparison between the power flow solution obtained with the initial topology/operating point for all time intervals, with the one obtained by an optimized topology/operating points.<br><br>The SOPF tool is able to reduce the active power losses. Such a reduction can be more/less significant depending on the considered network constraints/flexibility resources. |
| ***Operating Cost Improvement*** | **<u>Portuguese networks</u>**<br>Real Measurement Data<br>North: 5030.20 € (318.47%)<br>South: 2898.68 € (330.37 %)<br><br>Forecast Obtained Data<br>North: 4240.26 € (396.52 %)<br>South: 2918.65 (327.31 %) | The operational cost improvement KPI is defined as the comparison between the operational cost obtained by a power flow calculation with the initial topology/operating point for all time intervals, with the one obtained by the sequential OPF.<br><br>By considering multiple flexibility resources, the SOPF tool is able to reduce the overall network operational costs. |
| ***Active and Reactive Distance to Limits*** | **<u>Portuguese networks</u>**<br>Real Measurement Data<br>North: 426.73 MVA (83.67 %)<br>South: 558.92 MVA (82.19 %)<br><br>Forecast Obtained Data<br>North: 413.58 MVA (60.82 %)<br>South: 544.46 MVA (80.07 %) | The distance to the active and reactive power flow limits KPI is defined as the ability of the tool to maintain the $P$ and $Q$ power flows at the TSO/DSO interface within their limits. It is obtained by calculating the distance to these limits.<br><br>The SOPF tool succeeds in maintaining the active and reactive power within its minimum/maximum allowed technical limits. |
| ***Total Computational Runtime*** | **<u>Portuguese networks</u>**<br>North: 14 min. 8 sec.<br>South: 6 min. 1 sec. | The computational runtime KPI is calculated by running the sequential OPF and measuring the time before and after the process.<br><br>The total computational time required by the SOPF tool is influenced by the size of the network (the Portuguese Northern network is bigger than the Southern one). |

## 3.4. Evaluation of costs and benefits of the tool

### 3.4.1. Mapping the tool onto functionalities

This section identifies the services and functionalities for the evolvDSO project that the SOPF tool enables. Applicable services and functionalities, available in [1], were selected to develop the tools-functionalities matrix shown in Table 12. In addition to the services and functionalities presented in [1], another service (BUC - *Managing TSO requests at different timeframes*) and the corresponding functionality (SUC - *Optimise the network by providing active and reactive power profiles to the TSO*) were included.

| Services | Functionalities |
|---|---|
| Enhancing efficiency in day-to-day grid operation | 1. Enhance monitoring and control of power flows and voltages |
| | 2. Identify technical power losses by power flow analysis |
| | 3. Frequent information exchange on actual active/reactive generation/consumption |
| Managing TSO requests at different timeframes | 4. Optimise the network by providing active and reactive power profiles to the TSO |

Table 12 – Mapping between services and functionalities of the SOPF tool.

### 3.4.2. Mapping the functionalities onto benefits

The mapping between the functionalities identified in the previous section and the benefits that they provide is presented in this section. Such functionalities may provide four benefits, resulting in the functionalities-benefits matrix shown in Table 13. The first benefit is as proposed in [1], whereas the last three are new benefits derived from the operational and EEGI KPIs (see respectively *Deliverable 3.3* and *Deliverable 5.1* for further details on these KPIs).

| Benefits | Functionalities | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| Reduced electricity losses | ● Ϙ | ● Ϙ | | ● Ϙ |
| Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries | ● Ϙ | ● Ϙ | ● Ϙ | ● Ϙ |
| Reduced energy curtailment of RES/DER | ● Ϙ | | ● Ϙ | ● Ϙ |
| Increased RES and DER hosting capacity | ● Ϙ | Ϙ | | |

● Assessment performed by Enedis
Ϙ Assessment performed by EDP Distribuição

Table 13 – Functionalities-Benefits matrix for the SOPF tool

A brief description of the possible benefits by the SOPF functionalities is given below:

- **Reduced electricity losses:** The SOPF tool optimises network configuration and load/generation flexible resources, which may result in the reduction of the power losses in the network. This benefit links to the EEGI KPI "*Power Quality and Quality of Supply*", since the reduction of network technical losses corresponds in general to an improvement of the network performance.
- **Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries:** The SOPF includes in its formulation the minimisation of the operational costs of the flexibilities activated plus the penalty costs for violating the limits on primary substations. This benefit is based on the operational KPI "*Operational cost improvement*".
- **Reduced energy curtailment of RES/DER**: In the SOPF formulation, the cost function includes the minimisation of costs related to the activation of flexibilities and costs associated to the penalties for RES and DER curtailment. The percentage of RES and DER is separately quantifiable. This benefit links to the EEGI KPI "Reduced energy curtailment of RES and DER"**.**
- **Increased RES & DER hosting capacity:** This benefit measures the additional RES/DER capacity that can be installed in the MV network using the SOPF and is linked with the EEGI KPI "Increased RES and DER Hosting Capacity".

### 3.4.3. Establishment of the baseline

Regarding the SOPF, the baseline and the project scenarios to be tested are the following:

- **Baseline scenario:** Only conventional power flow is considered, i.e. studies are conducted without the use of the SOPF tool abilities such as managing taps, reconfiguration and activation of flexible resources;
- **Project scenario:** The contribution of the SOPF is considered.

For each one of two scenarios above, the most relevant conditions regarding grids analysed, load growth and DRES scenarios, as well as the metrics used to evaluate the corresponding benefits is summarised in Table 14.

| Benefits | Baseline Scenario (BaU) | Project Scenario (SOPF) | Metrics Used |
|---|---|---|---|
| **Reduced electricity losses** | Several load growth and DRES scenarios characterised in D3.4 are considered for the French and Portuguese networks | Using the same scenarios but with the SOPF tool abilities (controlling the tan ϕ, number of tap changes, reconfiguration and activation of flexibilities) | Total power losses absolute improvement (kWh) and Total power losses relative improvement (%) (EEGI KPI) |
| **Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries** | Several load growth and DRES scenarios characterised in D3.4 are considered for the French and Portuguese networks | Using the same scenarios but with the SOPF tool abilities (controlling the tan φ, number of tap changes, reconfiguration and activation of flexibilities) | Percentage of total costs improvement (Operational KPI) |

| | | | |
|---|---|---|---|
| **Reduced energy curtailment of DER/RES** | A scenario with low demand and high DER/RES is considered for one French and Portuguese networks | Using the same scenarios but with the SOPF tool abilities (controlling the tan φ, number of tap changes, reconfiguration and activation of flexibilities) | Percentage of reduced energy curtailment (EEGI KPI) |
| **Increased RES and DER hosting capacity** | A scenario with high generation levels close to situation where the constraints reach its admissible limit values is considered for one network for one French and Portuguese networks | Using the same scenarios but with the SOPF tool abilities (controlling the tan φ, number of tap changes, reconfiguration and activation of flexibilities) | Percentage of increased RES and DER hosting capacity (EEGI KPI) |

Table 14 – Baseline and Project conditions for the SOPF benefits

It is important to state that the metrics described in Table 14 are based on the Operational and EEGI KPIs. More information can be found respectively in *Deliverable 3.3* and *Deliverable 5.1*. The correspondent expressions are presented next for each one of the benefits considered.

### 3.4.4. Demonstration of the benefits

In line with the metrics previously presented, the next few sections demonstrate the benefits and correspondent beneficiaries.

#### 3.4.4.1. Reduced electricity losses

Table 15 and Table 16 respectively compile the Portuguese and French networks displaying results of the reduced electricity losses benefit attained in the different load growth and DRES scenarios analysed (characterised in *Deliverable 3.4*).
The obtained field test results that involved the optimization of the operational point of two distribution networks for EDP Distribuição are also included. One of these networks is located in the north and the other in the south of Portugal. Figure 12 and Table 17 compile the reduced electricity losses benefit attained for both networks.

| **Scenarios** | **Northeast network** | | **Western network** | |
|---|---|---|---|---|
| | **TPLa (kWh)** | **TPLr (%)** | **TPLa (kWh)** | **TPLr (%)** |
| 1 | 135.13 | 3.7% | 104.69 | 7.5% |
| 2 | 115.96 | 2.6% | 128.00 | 8.0% |
| 3 | 117.39 | 2.6% | 127.36 | 7.9% |
| 4 | 146.06 | 2.5% | 162.39 | 8.3% |
| 5 | 118.28 | 2.2% | 168.62 | 8.6% |
| 6 | 140.78 | 2.5% | 257.61 | 9.9% |

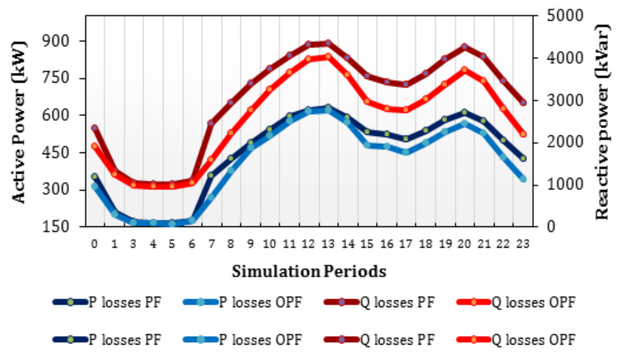
Table 15 – Results for reduced electricity losses benefit attained in the Portuguese networks

As seen in Table 15 the differences between scenarios are relatively small in both Portuguese networks. These results are influenced by the network initial operating point, which is already optimized in terms of power losses. This reason may also explain the small value of losses improvement attained for Northeast network. Nevertheless, the SOPF utilisation achieves a total improvement in reduction of electricity losses ranging between 118.28 kWh (2.2%) in the scenario accounting for the worst results (Northeast network - scenario 5) and 257.61 kWh (9.9%) in the scenario accounting for the best results (Western network - scenario 6).

| Scenarios | MV5 network | | | | MV6 network | | | |
|---|---|---|---|---|---|---|---|---|
| | Winter | | Summer | | Winter | | Summer | |
| | TPLa (kWh) | TPLr (%) | TPLa (kWh) | TPLr (%) | TPLa (kWh) | TPLr (%) | TPLa (kWh) | TPLr (%) |
| 1 | 5369.54 | 20.2% | 2976.34 | 17.4% | 422.24 | 10.2% | 353.88 | 10.4% |
| 2 | 10151.09 | 28.6% | 6477.32 | 28.1% | 294.54 | 7.9% | 223.25 | 7.2% |
| 3 | 9441.46 | 28.5% | 5841.69 | 27.1% | 258.22 | 7.2% | 223.67 | 7.5% |
| 4 | 10221.71 | 28.1% | 6390.31 | 26.9% | 264.31 | 7.2% | 200.62 | 6.7% |
| 5 | 8230.75 | 26.1% | 5063.81 | 24.4% | 212.97 | 6.4% | 181.33 | 6.5% |
| 6 | 13143.22 | 27.6% | 7907.15 | 25.3% | 341.38 | 8.3% | 223.14 | 6.8% |
| 7 | 6662.64 | 20.9% | 3974.83 | 17.7% | 172.24 | 5.7% | 140.68 | 5.7% |

Table 16 – Results for reduced electricity losses benefit attained in the French networks

For the French networks, the reduction of electricity losses is more significant in the MV5 network, due to the particular characteristics of this network. In this network, the SOPF utilisation promotes a total improvement in electricity losses ranging between 5369.55 kWh (20.2%) in the scenario accounting for the worst results (scenario 1 - winter) and 10150.62 kWh (28.6%) in the scenario accounting for the best results (scenario 2 - summer).



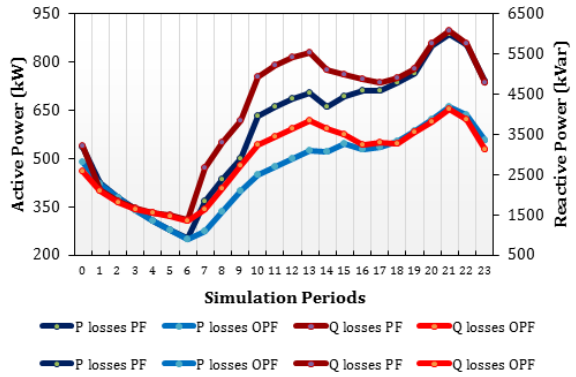




Figure 12 - Hourly active and reactive absolute power losses reduction for the Southern Site (on the left) and for the Northern Site (on the right)

The obtained losses reduction for the field tested Portuguese networks was achieved through the development of control actions performed over the capacitor banks installed on the MV bus bars of each HV/MV substation. The possibility of altering OLTCs was also considered. Like previously observed for the Portuguese and French networks, it is possible to verify that because of the SOPF optimization procedure, both active and reactive power losses are reduced for every hourly optimization period.

| **Southern network** | | **Northern network** | |
|---|---|---|---|
| **TPLa (kWh)** | **TPLr (%)** | **TPLa (kWh)** | **TPLr (%)** |
| 2946.85 | 20.88% | 805.69 | 7.69% |

**Table 17 – Results for reduced electricity losses benefit attained in the field tests conducted for the Portuguese networks**

The main beneficiary with the reduction of the power losses are DSOs, since loss reduction implies that DSOs successfully optimise the operation of the distribution assets, which means improvements in network efficiency. Loss reduction brings economic benefits to DSOs. In several countries, there are economic incentives established by the regulators for energy efficiency improvements in general and the reduction of technical power losses in particular.
The uncertainty level linked to this benefit can be classified as modest, since the accuracy of the information provided by the SOPF depends on the network characteristics (see Table 3 from [1] for more details).

### 3.4.4.2. Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries

Figure 13 presents the results of the Portuguese networks regarding the benefit of reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries attained in the different load growth and DRES scenarios analysed (characterised in *Deliverable 3.4*). The improvement is obtained considering the total costs of the initial solutions (baseline scenario) as reference values. For the French networks, similar results are presented in Figure 14 and Figure 15, respectively for the winter and summer scenarios.
For the field tests conducted for the Portuguese networks, Table 18 presents the obtained results for the benefit of reduced costs of penalizations of power out limits at the TSO/DSO boundary. The presented results correspond to the operational cost reduction obtained for a 24-hour operational optimization window.

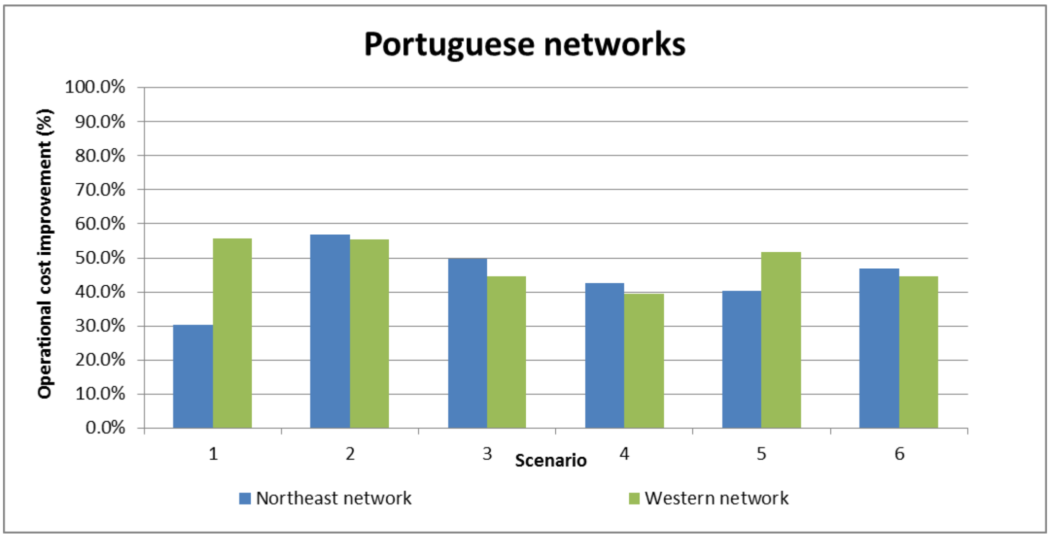



**Figure 13 – Total costs improvement for Portuguese Northeast and Western networks**

Among the two grids and scenarios analysed for the Portuguese case, the best improvement regarding the total costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries is around 57% and is verified for the Northeast network in Scenario 2. The lowest improvement is around 30% and occurs for the Northeast network in Scenario 5. Considering both the two networks and the six scenarios analysed, the average percentage of total cost improvement verified for the Portuguese case is 46.55%.

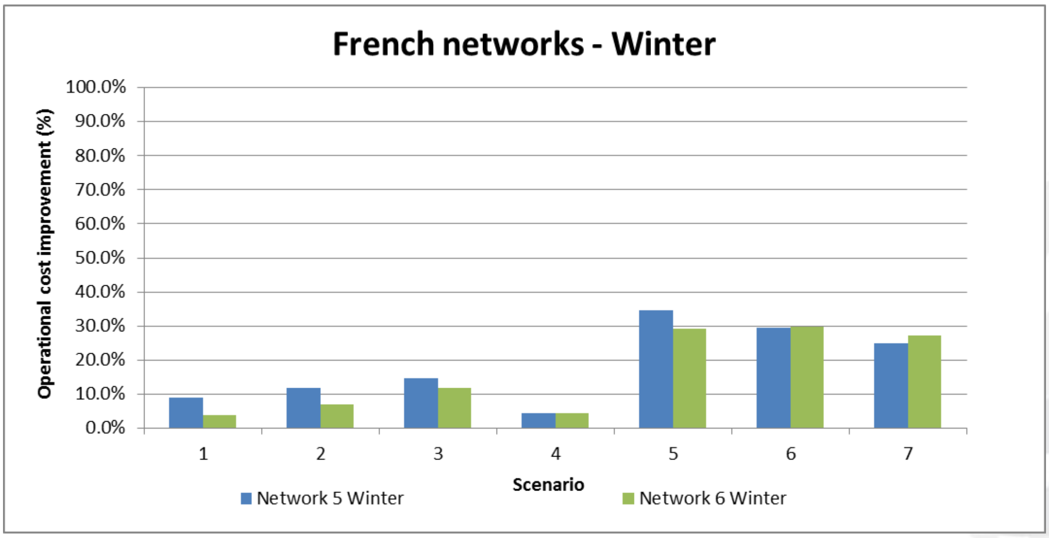



Figure 14 – Total costs improvement for French networks in winter

In the French networks, the higher percentage of total cost improvement accounts for 91.6% (MV network 6, scenario 7 and summer) and 34.5% (MV network 6, scenario 1 and winter) respectively.

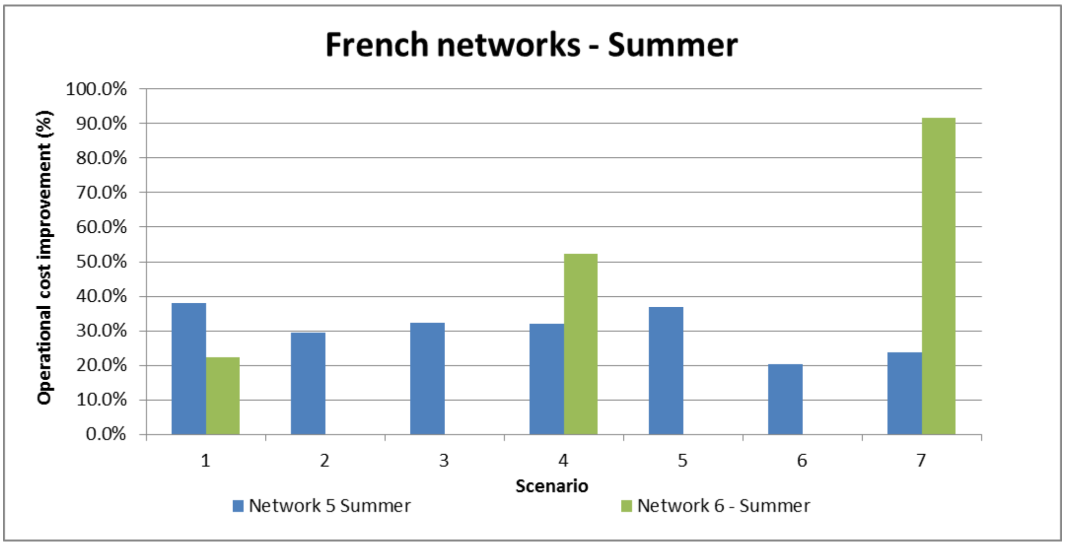



Figure 15 – Total costs improvement for French networks in Summer

Considering all the networks and scenarios analysed, the average percentage of total cost improvement verified for the French case is 34.5%.

For the field test Southern Portuguese network, no cost improvement was observed. Such observation is due to the fact that the optimization resultant action suggestions over capacitor

banks state is, in terms of reactive power control, similar to the pre-defined EDP Distribuição capacitor banks state.
On the other hand, for the Northern Portuguese site a total of 93.04 % improvement for the operational cost was observed. This is due to the fact that the resultant optimization capacitor banks states contributed to reduce the reactive power flow in the TSO/DSO boundary, thus reducing the cost penalizations.

| Units | Northern Site | Southern Site |
|---|---|---|
| € | 503.69 | 0 |
| % | 93.04% | 0% |

Table 18 – Total cost improvement for the field tests conducted for the Portuguese networks (24-hour period)

### 3.4.4.3. Reduced energy curtailment of DER/RES

In order to evaluate the benefit of reduced energy curtailment of DER/RES, one French and one Portuguese network are used considering an operational scenario with low consumption and with initial generated power by the DRES units higher than total consumption. More details on these scenarios, namely regarding the amount of power consumed by loads and produced by DER/RES, can be in found in *Deliverable 3.4*.

The results regarding the reduced energy curtailment of DER/RES are depicted in Table 19. The activated power of flexible loads, energy curtailment and injected power by the substations are similar, since the reductions in energy curtailed from the baseline to the project scenario are quite low for the Portuguese network and almost inexistent in the French network. This result is because no topological change occurred in both networks.

| | Portuguese network | French network |
|---|---|---|
| $Ecurt_{BAU}$ | 2.67 MWh | 5.487MWh |
| $\text{Ecurt}_{\text{SOPF}}$ | 2.33 MWh | 5.488MWh |
| $\text{E}_{Curt.}$ | 12.77%=(2,67-2,33)/2,67 | 0.16%=(%=(5,487-5,488)/5,487 |

Table 19 – Results for reduced energy curtailment of DES/RES benefit (SOPF)

The main beneficiary is the DSOs, by enabling more power to be produced by DRES sources (the power that does not need to be curtailed).

The level of uncertainty related to this benefit can be classified as significant (see Table 3 from JRC guidelines for more details), since the accuracy of the information provided by the SOPF was obtained using only one scenario with low demand and high penetration of DER/RES.

### 3.4.4.4. Increased DER/RES hosting capacity

As before, only one French and one Portuguese network evaluate the increased DER/RES hosting capacity benefit. In this case, an operational scenario with high generation levels close to situation where the constraint reaches its admissible limits values was considered for both networks (see *Deliverable 3.4* for more details).

The results obtained for this benefit are presented Table 20. For both the Portuguese and French networks, the differences between the values attained with the SOPF tool (project scenario) and the ones obtained in baseline scenario are not significant. The main reason is that no topological configuration occurred in these networks. Additionally, it is important to note that, in both networks, the baseline scenario corresponds already to a situation as close as possible to the power limits. In fact, the hosting capacity in the baseline scenario used for the evaluation of this benefit was increased by more than 22% in the Portuguese case and by about 328% in the French case, comparing with default values defined initially for the operational scenarios of each network (WP1 load growth and DRES scenarios).

| | Portuguese network | French network |
|---|---|---|
| $HC_{BAU}$ | 102.4 MW | 35.5 MW |
| $HC_{SOPF}$ | 102.8 MW | 35.7 MW |
| $EHC_{\%}$ | 0.39% | 0.56% |

Table 20 – Results for increased DER/RES hosting capacity benefit (SOPF)

The main beneficiary of this benefit is DSO. With more DER/RES hosting capacity in their distribution systems, DSOs will see an increase in the operational benefits related to the integration and use of energy sources such as the reduction of peak loads and the, provision of reactive power for voltage support.

The level of uncertainty related to this benefit can be classified as significant (see Table 3 from JRC guidelines for more details), since the accuracy of the information provided by the SOPF was obtained using only one scenario with high generation levels.

### 3.4.5. Qualitative impact analysis

In Annex II the generic merit deployment matrix that results from the qualitative assessment done for the SOPF tool is shown, as well as the one filled by the involved DSOs (EDP Distribuição and Enedis).

#### 3.4.5.1. Project impact across functionalities and benefits

Based on the provided merit deployment matrixes, it is possible to quantify the impact of the SOPF tool in terms of functionalities and benefits (see respectively Figure 16 and Figure 17). Such figures were obtained through the analysis of Table 72, filled by EDP Distribuição and Enedis.

In Figure 16, the impact that each functionality has upon the global assessment of the tool can be inferred. In what concerns the functionalities enabled by the SOPF, according to Table 72 the functionality related to “Enhance monitoring of power flows and voltages” is the one with highest weight. In fact, voltage and reactive power control present a significant impact on electricity losses reduction, contributing also to reduce the costs associated with the activation of flexible resources plus the penalisations of power out of limits at TSO/DSO boundaries.

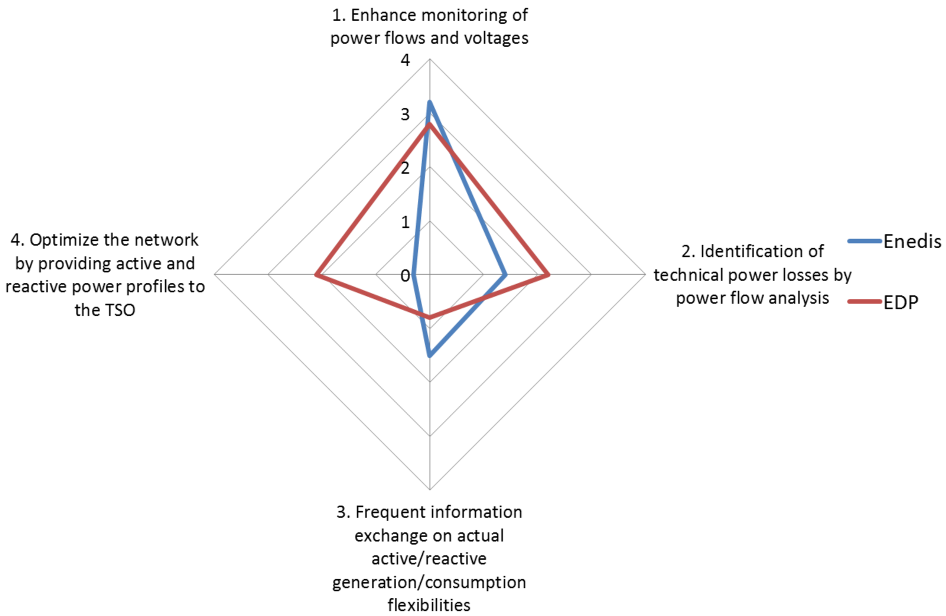



**Figure 16 – SOPF tool impact across functionalities**

Regarding the tool impact across the benefits, EDP Distribuição and Enedis chose the functionalities depicted in Figure 17 as those that have the greatest impact:

- Reduced electricity total power losses;
- Reduced costs of activating flexible resources plus penalizations of power out of limits at TSO/DSO boundaries.
- Reduced energy curtailment of RES/DER.

Such an evaluation could be expected, since the SOPF tool presents a very quantifiable set of benefits. Instead of just providing information to the user, SOPF is able to output a set of suggestions quantified as optimal operating points for various equipment types present in a distribution network. The major optimization results, such as power losses and operational costs reduction are presented to the DSO as being related with the suggested set points. Then, based on such information, the DSO can evaluate the adequacy of using the provided set points.
The relevance of these functionalities for the DSO are supported by the test field results presented in section 3.4.4. The conducted simulations proved that a reduction of the total active and reactive power losses was achieved. The calculated KPIs also showed that by developing voltage and reactive power control actions, a significant reduction in the network operational cost can be achieved.
Enedis also assigned a high weight to the benefit "Reduced energy curtailment of RES/DER".

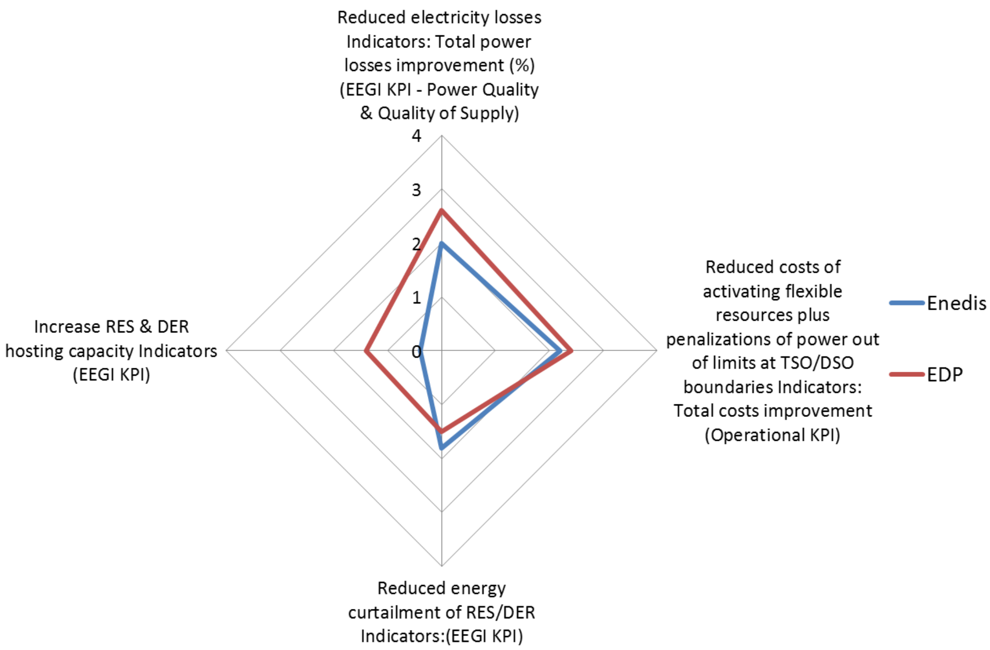



Figure 17 – SOPF tool impact across benefits

### 3.4.6. Identification and quantification of the costs

The costs associated to the SOPF were divided into industrialisation and integration costs.
The industrialization cost is the sum of the person-month spent during the project in WP3-4 to develop and improve the tool plus the additional effort to complete the following developments:

- Standardization of the input/output data (i.e. adoption of CIM standards);
- Improvement of the human-machine interface.

It should be stressed out that around 63.3% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 15 PM spent during the project (with a rough estimation of the average PM cost around 4400€) and 8 PM for the additional developments towards industrialization.
For France and Portugal, the integration costs were estimated based on the minimum technical requirements listed in Annex II, Table 70 and Table 71.
The ratio industrialisation/integration cost for France is 18.5%, however it is important to stress out that the integration costs do not include several categories where the cost quantification is not possible at this phase (see Annex II, Table 70). Compared to the ICPF costs, this tool exhibits the same integration cost but the industrialization cost is smaller since the tool tested in WP4 for EDP Distribuição already had a technology readiness level close to "system complete and qualified" (the non-adoption of CIM standards is the main gap to an industrial solution). For Portugal, the ratio was 32% since the integration cost was lower than France.

# 4. Low Voltage State Estimator

## 4.1. Introduction

The increasing connection of new loads and generation units, as well as the integration of storage devices and electric vehicles into Low Voltage (LV) networks, will contribute to increase significantly their complexity. This will result 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, for sure, economically infeasible, a Distribution State Estimator (DSE) module will remain a crucial function in future Distribution Management Systems (DMS).
In summary, the presence of new assets in the LV networks will require new and evolving DSO activities, leading to its roles extension. In order to fulfil such roles, the creation of new services will be mandatory, namely in what concerns the optimised operation of the LV networks. In Figure 18 some of the new and evolving DSO activities, as well as the associated services, mainly those related with the DSE tool are brought to light.

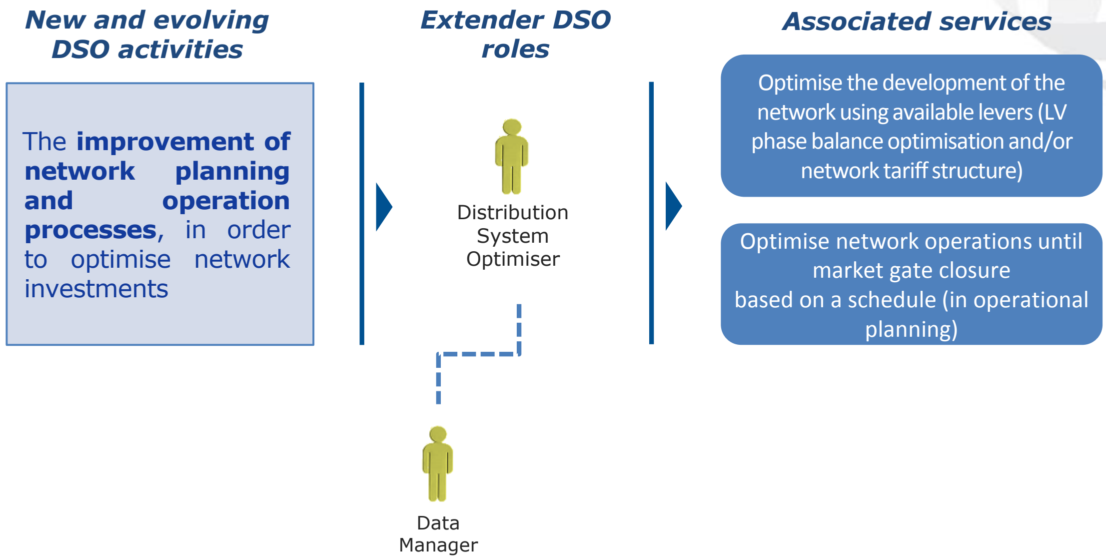



Figure 18 – The LVSE goals in the DSO roles and new services.

## 4.2. Description of the tool and its elements

The Low Voltage State Estimator (LVSE) provides to the DSO a complete and reliable view of their LV networks in real-time and, at the same time, its solution can be used as an input for other power system related modules (e.g. voltage control). In this sense, the LVSE improves the operation of LV grids by knowing in real-time the operational network state, since it provides a voltage solution, in all phases, in terms of voltage magnitudes (state variables). In addition to that, variables such as active and/or reactive power injections at customers' premise may also be estimated, if desired.

The main advantage of the developed LVSE 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 developed LVSE and the traditional state estimation algorithms relates to the guarantee of observability. While for the traditional techniques a given area/network can become unobservable, the same does not happen for the developed LVSE – see *Deliverable 3.2* for more details.
After having the Autoencoder (AE) properly trained (based on Extreme Learning Machine techniques), the measurements available in real-time are used as its inputs to guide 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, if desired, the active power and reactive power injections.
As described in *Deliverable 3.2*, an effective state estimation using AE inevitably requires an historical database with all data temporally synchronised. Without, it is not possible for the AE to learn effectively the patterns/correlations between the electrical variables of a given network. Such 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. Thus, the main elements necessary to perform state estimation using the LVSE tool are:

- **Smart Meters (SM):** responsible for gathering values of the voltage magnitude, active and reactive power. Some customers are monitored in real-time, i.e. their SMs sends synchronous measurements of the referred electrical variables every 10-15 minutes to the RTU located at the MV/LV substation. The remaining SM send to the RTU the same data type, but as a batch on a regular basis (e.g. once a day).
- **Remote Terminal Unit (RTU):** measurement equipment installed at the MV/LV substation level, capable of monitoring in real-time the voltage magnitude at the LV side of the transformer, as well as active and reactive power flow of each LV feeder. Each RTU also operates as a data concentrator, i.e. data from the downstream SM are stored for later exploitation.
- **Grids/Communications:** equipment and technologies for information transmission (e.g. GSM/GPRS technology, PLC protocol, etc.).
- **LVSE tool:** can be located at the DMS level or installed in local machine at the MV/LV substation level.

The interactions between these elements from the lower level (customer' premise) up to the MV/LV substation level can be seen in the architecture shown in Figure 19.

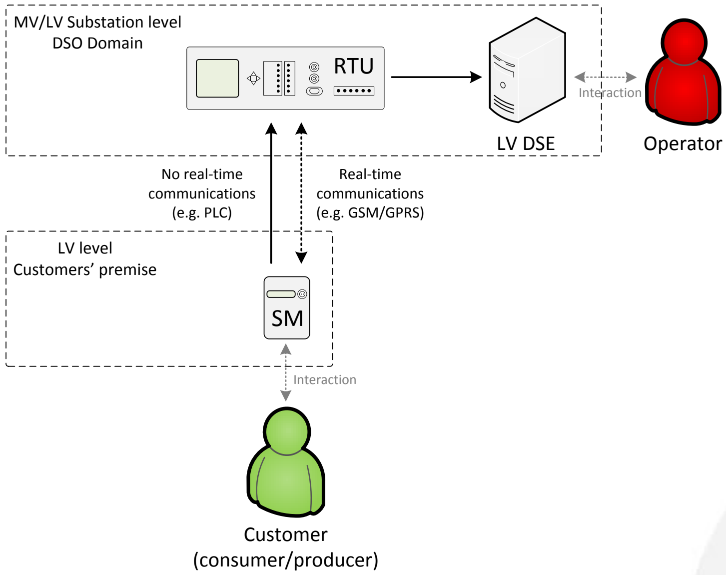



Figure 19 – Technical architecture of the LVSE.

## 4.3. High-level technical assessment

### 4.3.1. Synthesis of tool evaluation in WP3 simulation tests

The presented tool was evaluated for two distinct real LV distribution networks, one from Portugal and the other from France. Several scenarios were considered where a different number of Smart Meters with the capability of transmitting data in real-time ($SM_r$) were assumed. In addition to this, for the French case study, the influence of the quantity of historical data used to train the LVSE on the state estimation accuracy was also assessed. Regarding the historical database, real average records gathered by the SM installed at customers' premise were used for the Portuguese case study, whereas for the French one, due to the unavailability of SM data for the network under study, data were generated using a small real historical database from another French LV network.
The simulations demonstrated the capability of the LVSE to estimate voltage magnitude, and power values, even when only a small number of real-time measurements were available. The simulations also showed the tool's ability to effectively deal with the measurement errors associated with real data.

On the one hand, the simulations confirmed the good performance of the LVSE tool regarding the estimation of voltage magnitude values, when a representative historical dataset exists. On the other hand, the estimation of electrical power quantities seems to be more difficult to perform, mainly due to the different behaviour of customers (high variability in their power consumption) and due to the variability introduced by micro-generation units based on DRES. In WP3 tests, the results achieved supports that there is no rule of thumb regarding the quantity of historical data to be used in the training procedure. It was verified that a non-representative historical database (with small number of data samples) yields the worst results. State estimation accuracy tends to be improved when more historical data is added, but only up to a certain point, where the results begin to worsen because the size of the

database reach enormous proportions while the new additional data do not bring any added value.
The simulated tests allowed two recommendations to be drawn that lead to a general improvement of the state estimation accuracy:

- Adding more real-time measurements.
- Using methodologies to find the most suitable locations for the installation of smart metering devices with the capability of transmitting data in real-time.

Regarding the additional real-time measurements, the trade-off between a better accuracy and an increased cost should be carefully analysed.
Finally, the tool's capability to achieve a state estimation solution without any knowledge of the networks' parameters and topology was confirmed. This would be impossible with the traditional state estimation techniques. The simulations also evidenced the short computation time required for both training and state estimation procedures; this needs to be emphasised as another important advantage over traditional techniques.

### 4.3.2. Synthesis of tool evaluation in WP4 field-tests

The major difference between WP3 and WP4 test networks is related with the availability of real power measurements. In WP3, the LVSE was applied on only one single French LV network with few real power measurements. In WP4, the LVSE was applied on several real LV networks of the SoGrid project. The majority of the tests considered simulations computed by load flow on one year and a half of real SM active power 30 min measurements and real voltage 10 min measurements at an LV substation. Various settings and configurations were tested to assess the tool's accuracy and computational performance. Real measurements collected from the field were also considered, but a sufficiently consistent training database could not be constituted because of the resilience problems encountered with the prototype of ICT architecture that had just been installed and was under its start-up phase during the tests.
Pre- and post-processing routines of the tool inputs and outputs were developed in order to feed the tool and compute its KPIs. The pre-processing mainly consisted in efficiently extracting synchronised data from the historical database in order to provide consistent training data. In fact, one of the requirements of the tool is that consistent measurement data is required for all the SMs considered in the training at each time instant. It means that if one measurement is missing for one SM at one particular instant considered in the training, this instant is excluded from the training set.
Comparing the outcomes of WP3 and WP4 test networks, both highlighted the capabilities of the LVSE in efficiently and cost-effectively estimate LV network voltages.

Since the tool provided by INESC did not calculate power estimates, the WP4 tests were only focused on the correct estimation of voltage profiles. Real field data were considered to evaluate the tool performance.
The accuracy of the tool outputs proves to be interesting in regards to the needs of potential applications relying on state estimation (e.g. asset control). Only a limited amount of historical data (a few weeks) is required to efficiently train the tool. A limited number of SMs is

sufficient to obtain accurate voltage estimations. The LVSE is also able to work if one or more RT (real-time) SMs data are lost, but at the expense of some of the estimation accuracy.
The tool comes with no GUI since it is a RT computation block. It is operated with a command line whose parameters and input file formats are well defined. For the tests a GUI was developed by Enedis in order to configure the tool and display performance results.
Regarding the complementarity between the performed tests, while in WP3 future scenarios with more DRES penetration and flexible assets were evaluated, in WP4 deeper insights about the tool's behaviour and requirements in regards to current LV networks was possible.

### 4.3.3. Results of the KPIs and PMs calculation in WP4 field tests

As stated before, the WP4 tests were solely focused on the correct estimation of voltage profiles and, for this reason, not all WP3 KPIs and PMs were applicable or relevant in WP4. In addition, new PMs and KPIs were computed to better assess the tool's performance, but also to understand its technical requirements in regards to communication and computational capabilities. The KPI's values obtained in WP4 illustrate the added value of the LVSE in real-life situations. The following tables present the obtained EEGI KPIs and PMs.

| *KPI Name* | *KPI Value* | *Comment* |
|---|---|---|
| ***Accuracy of voltage magnitude*** | 1.056 % | As a whole, the LVSE provides accurate estimation of the network voltage.<br><br>It is however to be noticed that the LV networks considered in the study were well designed, i.e. they did not have large voltage drops / increases in regards to their consumption. |
| ***Error Estimation Index*** | 2.35 V | |

| *PM Name* | PM *Value*[2] | *Comment* |
|---|---|---|
| *Minimal voltage estimation error (V)* | -3.1 / -14.0 / -16.9 / -34.1 | As a whole, the LVSE provides accurate estimation of the network voltage. In average, about 85% of the estimation has less than 2% of error.<br><br>It is, however, to be noticed that the LV networks considered in the study were well designed, i.e. they did not have large voltage drops/increases in regards to their consumption. |
| *Maximal voltage estimation error (V)* | 0.23 / 13.5 / 13.9 / 28.6 | |
| *Average voltage estimation error (V)*[3] | -1.54 / 0.34 / 0.54 / 2.35 | |
| *Average of the absolute voltage estimation error (V)* | 0.1 / 2.35 / 2.44 / 5.90 | |

[2] PM values are presented as: minimum / median / average / maximum values obtained over the set of test configurations studied
[3] For the sake of clarify we choose to use the absolute-value norm instead of the Euclidian distance defined in D4.2.

<table>
<tr><td>Percentage of absolute voltage estimation error below 1% of Vn</td><td>24.1 / 58.2 / 60.6 / 99.9</td><td rowspan="2"></td></tr>
<tr><td>Percentage of absolute voltage estimation error below 2% of Vn</td><td>45.6 / 87.7 / 84.3 / 100</td></tr>
<tr><td>Average data pre-processing for training duration (s)</td><td>400 / 3115 /3600 / 16125</td><td rowspan="2">The training time is limited even when large data history is considered. The pre-processing ensuring its consistency, i.e. that for every time instant a value is present for every SM, is much more demanding</td></tr>
<tr><td>Average training duration (s)</td><td>0.6 / 5.27 / 10.5 / 48.9</td></tr>
<tr><td>Average duration of the real-time state estimation (s)</td><td>0.07 / 0.28 / 1.67 / 13.37</td><td rowspan="2">The average computation time of the state estimation is reduced (less than 15 s in the worse conditions) and compliant with a decentralized application</td></tr>
<tr><td>Standard deviation of the real-time state estimation (s)</td><td>2.34</td></tr>
<tr><td>Percentage of Under/Over Voltage False Alarms</td><td>/</td><td rowspan="2">Not relevant here since the voltage drops/increases were not sufficient</td></tr>
<tr><td>Percentage of Under/Over Voltage Correct Detections</td><td>/</td></tr>
</table>

## 4.4. Evaluation of costs and benefits of the tool

### 4.4.1. Mapping the tool onto functionalities

The present section maps the LVSE into the evolvDSO project. In addition to the six services presented in [1], another service related to the BUC associated to the LVSE was added: *Optimise network operations until market gate closure based on a schedule (in operational planning)*. Table 21 illustrates the mapping of the LVSE tool into functionalities.

<table>
<tr><th>Services</th><th>LVSE Functionalities</th></tr>
<tr><td>Optimise network operations until market gate closure based on a schedule (in operational planning)</td><td>1. Update network performance data on voltage quality</td></tr>
<tr><td rowspan="2">Enhancing efficiency in day-to-day grid operation</td><td>2. Enhance monitoring and observability of grids down to low voltage levels</td></tr>
<tr><td>3. Improve monitoring of network assets</td></tr>
</table>

**Table 21 – Mapping of the LVSE tool into functionalities.**

### 4.4.2. Mapping the functionalities onto benefits

The functionalities provided by the LVSE enable some Smart Grid benefits. In this section, a mapping between the functionalities identified in the previous section and the three benefits they provide is presented:

- **Contribute to the increase of information about the network operating conditions in real-time (increase situation awareness):** With the LVSE tool, operators and/or DSO systems can obtain a real-time snapshot of their distribution networks using a low number of real-time measurements gathered by SM. Without the referred tool, operators and/or DSO systems could only know in real-time the operational state of the points that are being monitored in real-time (in the case off SM with such capabilities are deployed), whereas information regarding the remaining network points would be transmitted with a minimum delay of 24 hours (e.g. using PLC protocol). Such data transmission delay can be a problem, mainly in what concerns the technical decision-making. Furthermore, the information provided by the LVSE can be used to feed several other DMS advanced applications, such as voltage control.
- **Identification/correction erroneous data gathered from SMs:** When a SM gathers an erroneous measurement the LVSE can identify it and turn it into a variable to be estimated. Thus, such measurement is likely to be corrected around the true reading, or, at least, will not influence negatively the algorithm convergence by passing to it bad data. The same happens when a measurement that was previously available in real-time becomes no longer available due to some abnormal event that may have occurred. In both cases, the overall estimation accuracy may decrease. However, the global outcome will be compensatory, since erroneous control actions would be avoided, either if they are taken by network operators, or triggered by automatic power system control algorithms fed by the LVSE tool.
- **Detection of network technical constraints violation:** The LVSE can detect the violation of network technical constraints (e.g. undervoltages, overvoltages, etc.) using a reduced set of SM having the capability of transmitting real-time measurements, i.e. when the system is not fully observable (considering the traditional definition of observability). These violations can then be fixed through a voltage control tool, such as the one presented in chapter 5, for example.

Table 22 summarises the assessment done for the LVSE tool.

| | Benefits | Functionalities | | |
|---|---|---|---|---|
| | | 1 | 2 | 3 |
| Reliability | Contribution to the increase of information about the network operating conditions in real-time (increase situation awareness) | ● | ●◊ | ●◊ |
| | Identification/correction erroneous data gathered from SM | ● ◊ | ●◊ | ◊ |
| | Detection of network technical constraints violation | ●◊ | ●◊ | |

● Assessment performed by EDP Distribuição
◊ Assessment performed by Enedis

Table 22 – Mapping of the functionalities on to a set of benefits of the LVSE.

### 4.4.3. Establishment of the baseline

In order to quantify or, at least, demonstrate any particular benefit, it is necessary to define and compare the baseline scenario and the scenario in which the developed tool is deployed (project scenario). In this sense, the scenarios that allow demonstrating the LVSE benefits are defined as follows:

- **Baseline scenario:** no SM with the capability of transmitting data in real-time ($SM_r$) is assumed to be installed at customers' premises. Therefore, in this scenario, the LVSE usage is not considered and no real-time network monitoring is performed. However, the existence of SM, which sends data as a batch once a day (through PLC protocol) is assumed.
- **Project scenario:** some customers connected to the network are assumed owning a $SM_r$. In this scenario, the deployment of the LVSE is considered, thus, a suitable real-time monitoring of the network using a few real-time measurements gathered by SMs is possible. It should be noted that the number of customers owning a $SM_r$ will vary accordingly with the scenarios defined in *Deliverables 3.4 and 4.3*.

Table 23 summarises the information above as well as the metrics used to demonstrate each benefit mentioned in section 4.4.2

| Benefits | Baseline scenario | Project scenario | Metrics used |
|---|---|---|---|
| **Contribution to the increase of information about the network operating conditions in real-time (increase situation awareness)** | No real-time information is available. The LVSE is not considered (no real-time network monitoring is performed). | The LVSE is considered. Some real-time network monitoring is performed accordingly the scenarios defined in *D3.4* and *D4.3*. | • Absolute error<br>• Mean absolute error |
| **Identification/correction erroneous data gathered from SM** | | | • Mean absolute error<br>• Accuracy of voltage magnitude (Operational KPI) |
| **Detection of network technical constraints violation** | | | • Percentage of under/ overvoltage false alarms<br>• Percentage of under/ overvoltage correct detections |

Table 23 – Baseline and project conditions for the LVSE benefits.

### 4.4.4. Demonstration of the benefits

The quantification of the benefits provided by the LVSE tool is not straightforward, since they relate to the improvement in monitoring and operation of LV grids by the knowledge of the operational network state – voltage magnitude values in all phases (and the active and reactive power values, if desired). In this sense, only their demonstration can be performed, which is done in the following sections. For simplicity in carrying out the evaluation of cost and benefits, only the voltage magnitudes estimation is taken into account. Therefore, only the scenarios defined in *Deliverables 3.4 and 4.3*, where voltage magnitudes were estimated are shown.

### 4.4.4.1. Contribute to the increase of information about the network operating conditions in real-time (increase situation awareness)

Since there are no $SM_r$ installed at customers' premises in the baseline scenario, the LVSE cannot be used. Consequently, no real-time network monitoring is performed in this scenario. In this sense, the demonstration of this benefit is made only for the project scenario, through the assessment of the LVSE accuracy after performing state estimation for each considered scenario.
The beneficiaries of this benefit are the DSOs, since the LVSE tool provides them a reliable snapshot of the distribution networks through the estimation of non-telemetered (real-time) points, giving them a complete perception of its operating conditions.

In [1], it is recommended that an uncertainty assessment should be undertaken. As the accuracy of the information provided by the LVSE is highly dependent on the number of $SM_r$ considered, this benefit has a high level of uncertainty (see Table 3 from [1] for more details).
In the following sections, the results for the metrics presented in section 4.4.3 are shown considering the voltage magnitude values of all customers not being monitored in real-time. A deeper and more complete analysis is performed in *Deliverables 3.4 and 4.3*.

#### 4.4.4.1.1. LV Portuguese network

As described in *Deliverable 3.4*, the Portuguese LV network has a total of 74 nodes containing 44 customers: 42 single-phase and 2 three-phase customers. There are no micro-generation units installed in this network.
Observing Figure 20 and Figure 21 it can be seen that the estimation accuracy is improved when more real-time measurements are available, which was expected. However, it should be recalled that, in this particular case, the improvement verified in scenario 2, comparing with scenario 1, was not only due to the number of real-time measurements available (twice the number of scenario 1), but also to their location.
The state estimation error obtained in scenario 1 accounts for the worst results. Nevertheless, the estimation error is lower than 4 V in 75% of the samples analysed in the large majority of the SM. In what concerns scenario 2, this error is lower than 1.08 V in 75% of the samples analysed. The Mean Absolute Error (MAE) obtained for scenarios 1 and 2 was 1.77 V and 0.49 V, respectively. The results achieved give good indications regarding the added value of the LVSE in improving the networks monitoring, through the increase of information about their operating conditions in real-time.

#### Scenario 1

In this scenario, there are 6 customers owning a $SM_r$ (14% of total customers).

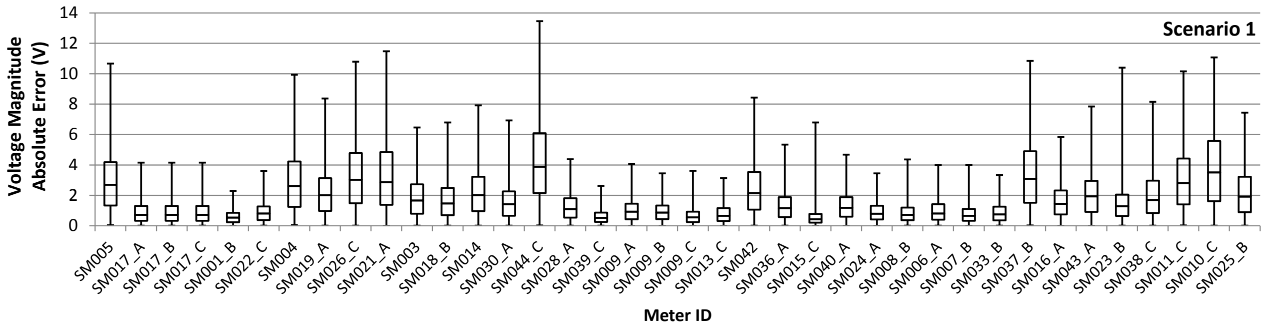



Figure 20 – Voltage magnitude absolute error for all customers (not being real-time monitored) in scenario 1.

### Scenario 2

In scenario 2, 12 customers are considered owning a $SM_r$ (27% of total customers).

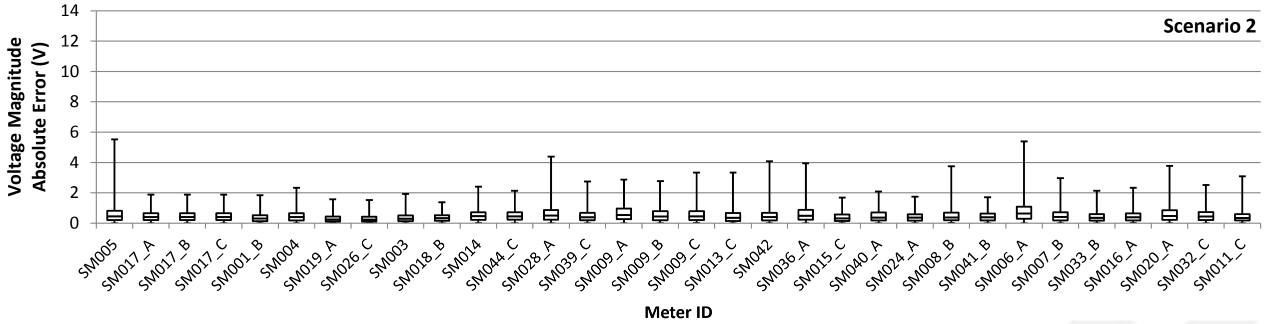



Figure 21 – Voltage magnitude absolute error for all customers (not being real-time monitored) in scenario 2.

#### 4.4.4.1.2. LV French network

The results presented in this section were derived from field tests performed with the LVSE algorithm on Enedis LV networks. These networks are part of the SoGrid French demonstrator, which are described in *Deliverable 4.1*.

Similarly, to the results presented for the Portuguese LV network, there is a clear general improvement in the state estimation accuracy when more measurements are available in real-time, as per Figure 22. However, a reduced number of $SM_r$ can be sufficient to so that LVSE tool provides a state estimation solution with adequate accuracy, as seen in Figure 22. In fact, on average, about 85% of the state estimations performed have less than 2% error, which is compliant with the LVSE capability to provide accurate state estimation solutions.

The effect of the $SM_r$ location on the state estimation accuracy is also presented in Figure 22. Although the location of the $SM_r$ seems to have a limited impact on that for the example shown, it should be always evaluated for each network where the LVSE deployment is intended.

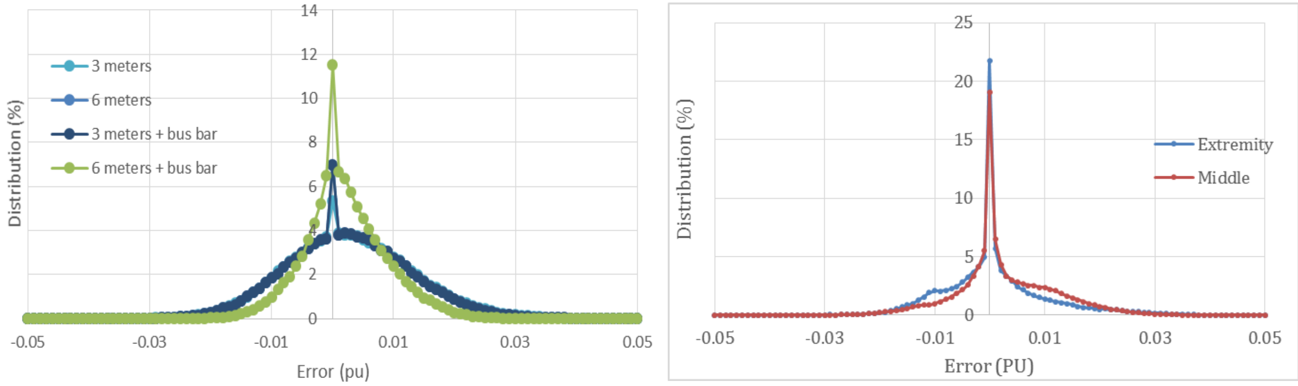



Figure 22 – LVSE accuracy on a LV feeder of 150 SM. Different $SM_r$ number (on the left) and location strategies (on the right) are compared.

### 4.4.4.2. Identification/correction erroneous data gathered from SM

The demonstration of this benefit is not simple as the true values of the measurements gathered from the SMs are unknown, i.e. the only data available regarding the network electrical variables are the readings gathered from the SMs. Moreover, and similarly to the demonstration of the previous benefit, this benefit demonstration only takes into account the project scenario, since without the LVSE tool (baseline scenario) the real-time identification and correction of erroneous data gathered from the SMs is not possible. This benefit

demonstration will be presented in two parts: (1) taking into account the identification of erroneous data and (2) related with the erroneous data correction. This benefit has the DSO as beneficiaries, since the LVSE provides a complete and reliable view of the operational network state in real-time.
Regarding the uncertainty assessment, due to the reason pointed out in the beginning of the section, the uncertainty level of this benefit is assumed to be high (see Table 3 from [1] for more details).
In the next two sections, this benefit demonstration is completed for each network (one Portuguese and one French) described in *Deliverable 3.4*.

#### 4.4.4.2.1. Identification of erroneous data (gathered from SM)

In order to demonstrate the Gross Errors (GE) identification, half of each evaluation set (Portuguese and French LV networks) was polluted with GE considering ±10% and ±20% of the voltage magnitude gathered by the $SM_r$. The number of $SM_r$ associated to such errors was increased until 50% of the $SM_r$ installed was reached. It should be noted that the data records gathered from the SM was assumed as the true data for demonstration purposes.
In Figure 23, an example of the difference between the input variables measured by the $SM_r$ and the same variables estimated by the state estimator is shown, considering a scenario where 6 $SM_r$ are present (scenario 1 of the Portuguese case). For this representation was assumed a GE of 10% associated to only one $SM_r$ – SM032 (connected to phase C). Observing this figure, where a single time instant is represented, the mismatch between the measured input and estimated output obtained due to the GE presence is obvious, facilitating an effective identification of this error.

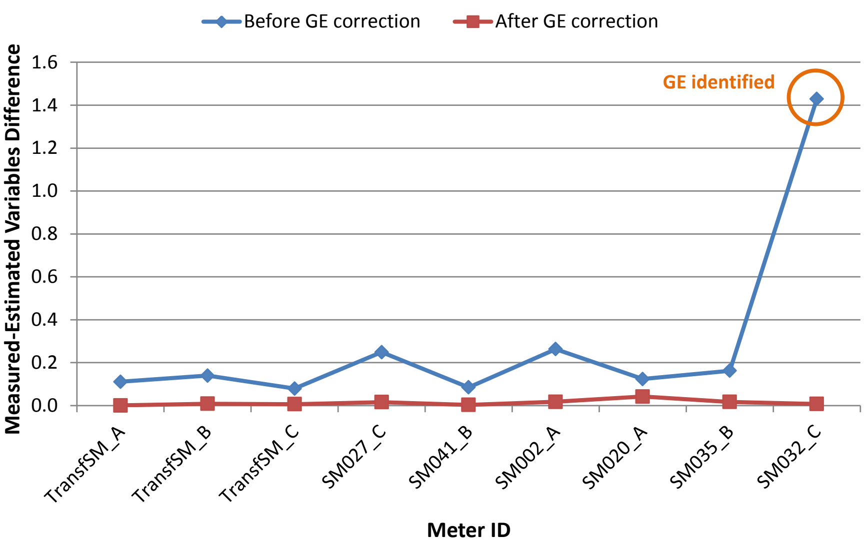



**Figure 23 – Example of the difference between the input and output (before and after GE correction), considering a GE of 10% associated to SM032.**

After the GE identification, the algorithm proceeds to its estimation in order to correct it. The difference between the state estimator input and output after the GE correction, which is very small, is also shown in Figure 23. Comparing both graphical representations makes the impact of a GE clear. For this reason, when more than one GE exists, the algorithm corrects them one at a time in order to avoid the estimation of a non-GE.

Table 24 and Table 25 present the number of GE whose identification is intended as well as the number of GE identified by the LVSE for each network. As seen, these tables show that the LVSE was able to identify all the existing GE. Nevertheless, it should be noted this LVSE feature could fail for other type of errors. In particular, this can happen in case of smaller errors. An example is the errors related with the accuracy of the metering devices.

### LV Portuguese network

| Scenario | No. $SM_r$ associated to GE | No. GE to be identified | No. GE identified | |
|---|---|---|---|---|
| | | | **10%** | **20%** |
| **1 (6 $SM_r$)** | **1 $SM_r$** | 336 | 336 | 336 |
| | **≅ 25% of $SM_r$** | 672 | 672 | 672 |
| | **≅ 50% of $SM_r$** | 1008 | 1008 | 1008 |
| **2 (12 $SM_r$)** | **1 $SM_r$** | 336 | 336 | 336 |
| | **≅ 25% of $SM_r$** | 1008 | 1008 | 1008 |
| | **≅ 50% of $SM_r$** | 2016 | 2016 | 2016 |

Table 24 – Number of GE identified by the LVSE for the Portuguese LV network.

### LV French network

| Scenario | No. $SM_r$ associated to GE | No. GE to be identified | No. GE identified | |
|---|---|---|---|---|
| | | | **10%** | **20%** |
| **1 (5 $SM_r$)** | **1 $SM_r$** | 504 | 504 | 504 |
| | **≅ 25% of $SM_r$** | | | |
| | **≅ 50% of $SM_r$** | 1008 | 1008 | 1008 |
| **2 (10 $SM_r$)** | **1 $SM_r$** | 504 | 504 | 504 |
| | **≅ 25% of $SM_r$** | 1008 | 1008 | 1008 |
| | **≅ 50% of $SM_r$** | 2520 | 2520 | 2520 |
| **3 (15 $SM_r$)** | **1 $SM_r$** | 504 | 504 | 504 |
| | **≅ 25% of $SM_r$** | 2016 | 2016 | 2016 |
| | **≅ 50% of $SM_r$** | 3528 | 3528 | 3528 |
| **3 (20 $SM_r$)** | **1 $SM_r$** | 504 | 504 | 504 |
| | **≅ 25% of $SM_r$** | 2520 | 2520 | 2520 |
| | **≅ 50% of $SM_r$** | 5040 | 5040 | 5040 |

Table 25 – Number of GE identified by the LVSE for the French LV network.

#### 4.4.4.2.2. Correction of erroneous data (gathered from SM)

As previously mentioned, when the LVSE identifies a real-time erroneous measurement, it changes that measurement into a variable to be estimated in order to correct it. In this section, the impact of this situation on the state estimation accuracy is assessed, through the estimation of the measurements identified as GE in the previous section. The case where no GE has occurred will also be presented for comparison purposes.

It is important to remember that when a real-time measurement is not delivered to the LVSE, either due to a failure in the measurement acquisition process or due to a failure in the sending process (e.g. communication problem), the algorithm behaviour is similar to what was described before, i.e. the LVSE also estimates the missing measurement. Thus, the results presented can represent both situations, when a real-time erroneous measurement is identified or when a real-time measurement is missing (considering that, it happens to the same $SM_r$). It should be stated that the evaluation of this benefit was done by considering only half of the evaluation set polluted with the GE previously referred.

As seen in Table 26 and Table 27, in both networks analysed the estimation accuracy decreases as a function of the increasing percentage of $SM_r$ associated to GE (or $SM_r$ with failure on data sending). This decrease in accuracy is more important when a higher number of $SM_r$ is considered.

### LV Portuguese network

Following the description of section 4.4.3, in Table 26 the MAE used to demonstrate this benefit is shown.

| Scenario | MAE (V) | | | |
|---|---|---|---|---|
| | No GE occurred | 1 $SM_r$ with GE | ≅ 25% of $SM_r$ with GE | ≅ 50% of $SM_r$ with GE |
| **1 (6 $SM_r$)** | 1.76 | 2.21 | 2.38 | 2.84 |
| **2 (12 $SM_r$)** | 0.48 | 0.52 | 0.81 | 1.55 |

Table 26 – Voltage magnitude MAE obtained when no GE has occurred and when exist some $SM_r$ responsible for GE.

### LV French network

Table 27 presents the MAE used to demonstrate this benefit for the French case study.

| Scenario | MAE (V) | | | |
|---|---|---|---|---|
| | No GE occurred | 1 $SM_r$ with GE | ≅ 25% of $SM_r$ with GE | ≅ 50% of $SM_r$ with GE |
| **1 (5 $SM_r$)** | 4.21 | 4.32 | | 4.41 |
| **2 (10 $SM_r$)** | 3.54 | 3.63 | 3.82 | 4.26 |
| **3 (15 $SM_r$)** | 2.77 | 2.90 | 3.25 | 3.62 |
| **4 (20 $SM_r$)** | 2.33 | 2.42 | 2.81 | 3.43 |

Table 27 - Voltage magnitude MAE obtained when no GE has occurred and when exist some $SM_r$ responsible for GE.

## 4.4.4.3. Detection of network technical constraints violation

This benefit can be demonstrated by evaluating the reliability of the tool in the detection of voltage constraints violation. This assessment can be done through the percentage of under/overvoltage false alarms and the percentage of under/overvoltage correct detections (true alarms). The first metric counts the number of times the LVSE detects an under/overvoltage situation that did not occur, whereas the second one counts the number of times the LVSE successfully detects an under/overvoltage situation. These metrics can be defined as follows:

$$\%\ of\ False\ Alarms = \frac{FP}{TP + FP} \tag{1}$$

$$\%\ of\ True\ Alarms = \frac{TP}{TP + FN} \tag{2}$$

Where:

TP (true positives): Number of positive cases correctly detected, i.e. the detection of an under/overvoltage that occurred.
FP (false positives): States incorrectly assigned as positive.
FN (false negatives): States incorrectly assigned as negative, i.e. under/overvoltage not detected.

Remember that in the baseline scenario, no $SM_r$ installed in customers' premise was considered. Thus, no real-time network monitoring is performed and, consequently, the real-time detection of voltage constraint violations is not possible. In this sense, and similarly to

the previous benefits, the demonstration of this one only considers the project scenario. The beneficiaries of this benefit are the DSO, directly, and the customers in general, indirectly. LVSE tool allows DSOs to make decisions accordingly, ensuring the network security as well as the continuity of energy supply. Regarding the customers, this benefit is related with the power quality improvement in terms of variations of their voltage profiles and of their satisfaction.
With respect to the uncertainty assessment, this benefit is highly dependent on the contractual voltage limits defined in each country. For this reason, the level of uncertainty related to it is high (see Table 3 from [1] for more details). The demonstration of this benefit presented in the next two sections for both networks described in *Deliverable 3.4*.

#### 4.4.4.3.1. LV Portuguese network

The contractual voltage limits for the LV Portuguese networks are ±10% of the nominal voltage level. However, with such limit no voltage constraint violation is registered in the historical database available. In order to demonstrate this benefit, the voltage limits were tightened until a considerable number of violations exists. Thus, the new values considered for the voltage limits are ±6% of the nominal voltage level, which defines the acceptable voltage range within the interval [216.2 V; 243.8 V].

In Table 28 the percentage of under/overvoltage false alarms, as well as the percentage of under/overvoltage correct detections attained by the LVSE tool are presented.

| Scenario | Total number of violations to be detected | TP | FP | FN | % False alarms | % True alarms |
|---|---|---|---|---|---|---|
| **1 (6 $SM_r$)** | 596 | 401 | 306 | 195 | 43% | 67% |
| **2 (12 $SM_r$)** | 544 | 518 | 31 | 26 | 6% | 95% |

Table 28 – Percentage of under/overvoltage false alarms and correct detections in the Portuguese case study.

Observing Table 28 it seems that LVSE is able to successfully detect under/overvoltage situations. The successful detection rate is higher when a higher number of $SM_r$ is considered. Nevertheless, the LVSE has a correct detections rate of about 95% in scenario 2, which gives a good indication of this LVSE benefit, mainly if the fact that only 27% of customers own a $SM_r$ is to be kept in mind.
It is important to state that some of the identified false positives and false negatives are quite close to the values gathered from the SM, i.e. the estimation error obtained is very reduced (less than 0.5 V in some time instants). Therefore, an alternative way of analysing the results could be based, for instance, on a probabilistic analysis taking into account the error distribution of the estimation process.

#### 4.4.4.3.2. LV French network

It should be noted that the results presented in this section do not take into account the field tests, since no voltage constraint violations did occur. Thus, the network described in *Deliverable 3.4* was used to demonstrate this benefit. Regarding this network and similarly to the Portuguese case, the voltage limits were also tightened. In this case, a considerable number of voltage constraint violations exists when the voltage limits are set as ±8% of the nominal voltage level, which is defined by the interval [211.6 V; 248.4 V].
The percentage of under/overvoltage false alarms and correct detections achieved by the LVSE tool are shown in Table 29.

| Scenario | Total number of violations to be detected | TP | FP | FN | % False alarms | % True alarms |
|---|---|---|---|---|---|---|
| **1 (5 $SM_r$)** | 104 | 5 | 0 | 99 | 0% | 5% |
| **2 (10 $SM_r$)** | 95 | 6 | 0 | 89 | 0% | 6% |
| **3 (15 $SM_r$)** | 91 | 17 | 0 | 74 | 0% | 19% |
| **4 (20 $SM_r$)** | 87 | 21 | 0 | 66 | 0% | 24% |

Table 29 – Percentage of under/overvoltage false alarms and correct detections in the French case study.

Although the percentage of under/overvoltage correct detections seems to be low, these results should be analysed considering the results attained for the estimation accuracy presented in *Deliverable 3.4*. There, it is possible to confirm that the algorithm fails to identify a higher number of true positives in a very short range around the limits defined (due to estimation errors of 1.5 V or less). Additionally, the more optimistic scenario of $SM_r$ (with 20 $SM_r$) corresponds only to 13% of the total customers, which is a relatively low percentage. If more $SM_r$ had been considered, a larger number of correct detections would be expected.

## 4.4.5. Qualitative impact analysis

As stated in section 4.4.4, only the voltage magnitudes estimation is taken into account for carrying out the evaluation of costs and benefits. In this sense, only KPIs related with voltage measurements are considered.

In Annex III Table 76 and Table 77, the merit deployment matrix resulting from the qualitative assessment done for the LVSE tool is shown. This matrix was filled by each of the entities that have tested the tool. The main conclusions to be drawn from these matrices will be detailed in the following sections through the assessment of the tool impact across functionalities and benefits. The areas spanned in the functionality and benefit planes represent the deployment merit of the tool: the larger the area in the graph, the greater the LVSE tool impact.

### 4.4.5.1. Tool impact across functionalities and benefits

As seen in Figure 24 both the Portuguese DSO (EDP Distribuição) and Enedis seem to agree regarding the LVSE functionalities with the highest impact: the *"Update network performance data on voltage quality"* and *"Enhance monitoring and observability of grids down to low voltage levels"*. This assessment is not a surprise since the main goal of the LVSE tool is to provide to the DSO a complete and reliable view of their LV networks in real-time, namely in terms of voltage magnitudes, which fully contributes to the monitoring enhancement (and observability as well) of such networks. Nevertheless, from the Enedis perspective the last functionality mentioned was considered with twice the importance of the first one.

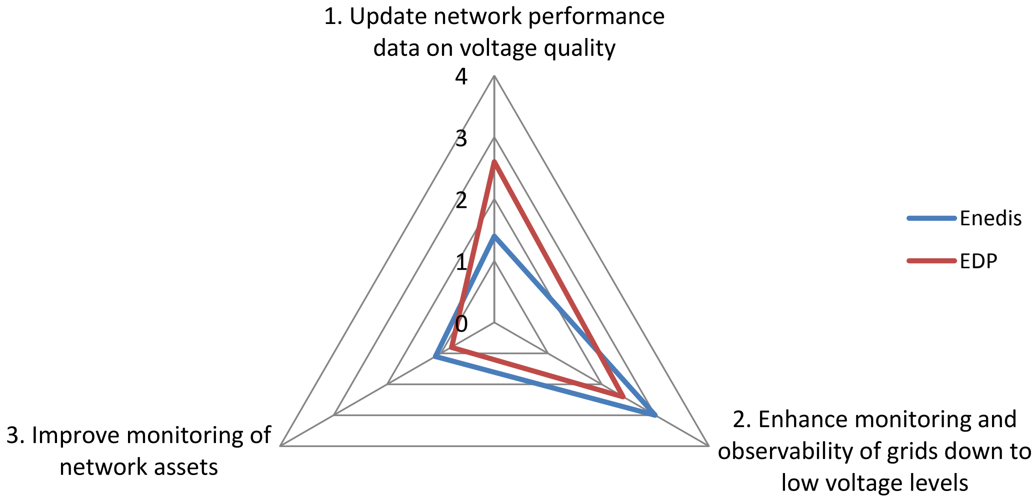



Figure 24 – LVSE tool impact across functionalities.

Regarding the impact of the tool across benefits (Figure 25), the assessment done by the Portuguese DSO and by Enedis is quite similar, i.e. the *"Contribute to the increase of information about the network operating conditions in real-time (increase situation awareness)"* seems to be the LVSE benefit with higher impact. This evaluation was expected since the referred benefit is totally related with the main goal of the tool.

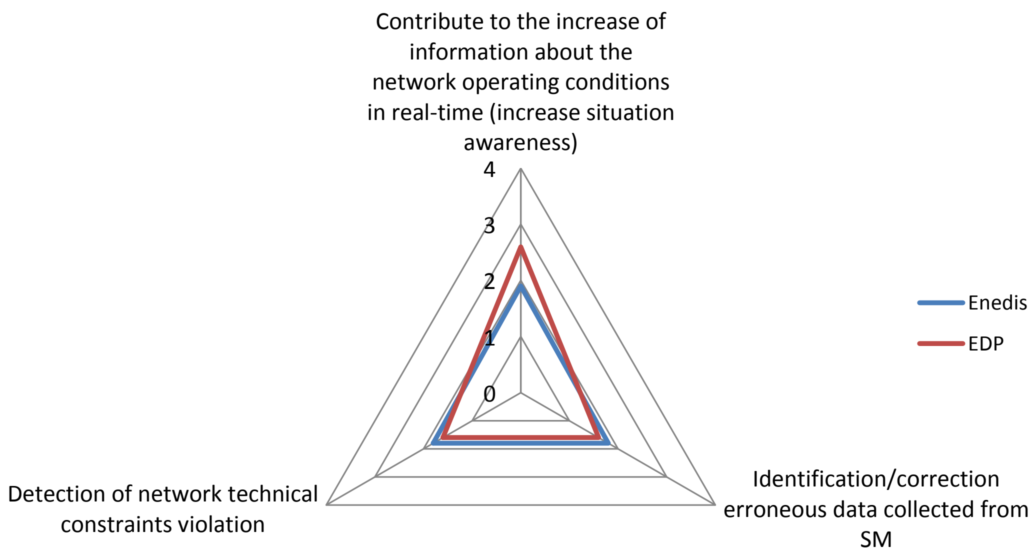



Figure 25 – LVSE tool impact across benefits.

## 4.4.6. Identification and quantification of the costs

The costs associated to the LVSE were divided into two categories: (a) industrialisation of the algorithms/tools developed in WP3, which comprises all the effort (in person-month cost of INESC TEC in Portugal) to create a tool ready to be integrated in the business processes of a DSO; (b) integration of the industrial tool within DSO information system.

The industrialization cost is the sum of the person-month spent during the project in WP3-4 to develop and improve the tool plus the additional effort to complete the following developments:

- Standardisation of the input/output data model, i.e. adoption of common information model (CIM) standards;
- Development of data quality control and pre-processing functions for the input data;
- Integration of the tool in commercial data concentrators or distribution transformer controller (DTC)[4].

Around 2/3 of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 10 PM spent during the project (with a rough estimation of the average PM cost around 4400€) and 5 PM for the additional developments towards industrialization.

The industrialization cost is only considered one time, even if the tool is installed one or more times. The integration cost for this tool should be scaled with the number of substations considered.
For France, the integration costs were estimated considering the installation of the tool in 15 MV/LV substations. The minimum technical requirements listed in Annex III, Table 74, Table 75, were considered to calculate the total costs. The ratio industrialisation/integration cost for France is 14.6%, however it is important to stress that the integration costs do not include several categories where the cost quantification is not possible at this phase (see Table 74) and the costs here are for a prototype scale (only a few MV/LV substations). It is important to stress that in France the architecture (centralized versus distributed) is not yet defined and the impact in the cost is non-marginal.
For Portugal, the integration costs were estimated for a single network considering the minimum technical requirements listed in Annex III, Table 75. The following assumptions were made:

- Information acquisition and storage is part of EDP Distribuição business-as-usual processes, and thus is not considered as an additional cost. The same assumption applies to the development, maintenance, and operation of the smart grid infrastructure (assets, services, databases and AMI system).
- In scenarios A and B (showed in Table 30) it is considered that from the functional point of view, $SM_r$ consist in GPRS smart meters. Therefore, since EDPD's majority of smart meters are PLC PRIME-based, the additional number of GPRS smart meters that would have to be installed in order to adopt this functionality is calculated.
- It is also assumed that LVSE processing is performed at a distributed level, particularly, it will be executed by the DTC installed at secondary substation level. Therefore, the deployment of different firmware version for the DTC must be considered, which has additional licensing costs.
- Since the regular smart meter deployment consists of PLC PRIME smart meters, it is assumed that we are unable to know in advance the LV nodes that will need to have a $SM_r$ in order to allow LVSE functionality. For these, a field task for smart meter replacement must always take place. However, we assume that in the first smart

[4] The DTC is the name used in Portugal (InovCity test pilot) for a component similar to an RTU.

meter deployment we will install the necessary $SM_r$ quantity and that, in some of these situations, the location will be the optimal one and in other situations it will not. We assume the first deployment will have a success rate of 75% regarding optimal $SM_r$ location. For the remaining 25% it will be necessary to replace a SM by a $SM_r$, and to perform the opposite operation in locations where a $SM_r$ was initially deployed, but it will not be necessary.

- For the communications cost (SIM card), the present value according to the smart meters lifespan (15 years) and EDPD's capital cost was calculated.
- The additional configuration effort for the $SM_r$ must be also taken into account. This account is reflected in the Supervision's Centre workforce additional hours.

Since the integration cost was calculated to only one substation, Table 30 shows the ratio between integration and industrialisation cost for Portugal (instead of the ratio industrialisation/integration), considering two scenarios tested in WP3. The estimated costs for both scenarios show that the integration costs are just a small fraction of the industrialisation cost (which around 66% were already covered by the evolvDSO project). It should be stressed that if the LV SE is installed in more networks, this ratio would decrease even more, which shows that the industrialization cost is very marginal for this tool.

| Scenario | Integration/Industrialisation Cost [%] |
|---|---|
| A [$SM_r$=14%] | 0.9% |
| B [$SM_r$=27%] | 2.1% |

**Table 30 – Ratio between integration and industrialisation cost for the LVSE in Portugal**

# 5. Low Voltage Control

## 5.1. Introduction

In order to enhance system operation and allow further expansion of Distributed Energy Resources (DER) in Distribution networks, it is necessary to shift from the traditionally passive philosophy of operating these systems into a fully active approach. In this new active approach, advanced functionalities will help the current and future control and management needs of distribution networks, by supporting DSO in its decision making process. In the specific case of LV grids, the main technical issue relates to voltage profiles that can be out of admissible limits due the high presence of several DERs or due to high peak load conditions. Through appropriate control actions sent to the available assets connected at the LV level, such as storage devices, MV/LV On-Load Tap Changer (OLTC) transformer, flexible micro-generation and loads, the Low Voltage Control (LVC) tool allows DSOs to tackle such type of problems, so that all regulatory limits are met and operational efficiency and reliability are increased. Figure 26 depicts the new and evolving DSO activities, as well as the associated services related with the LVC tool.

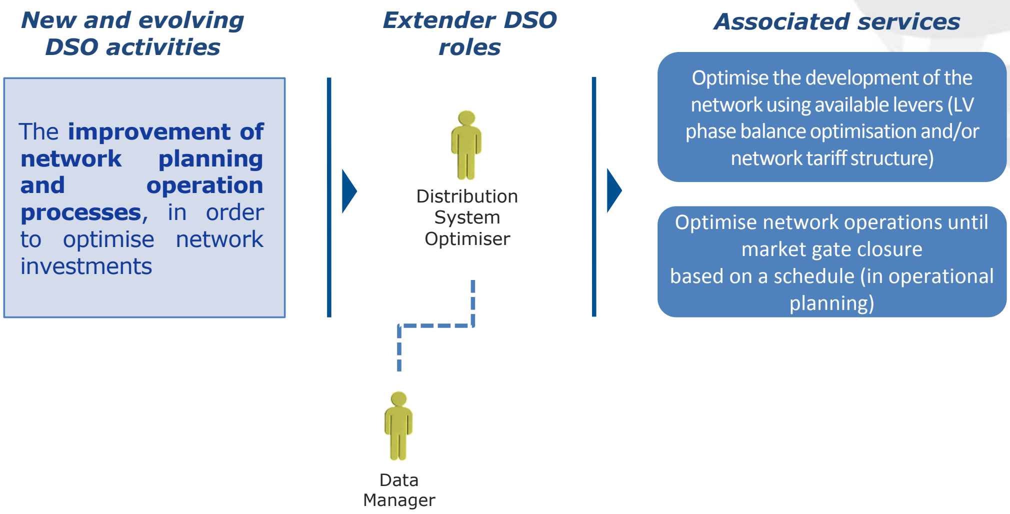



Figure 26 – The LVC goals in the DSO roles.

## 5.2. Description of the tool and its elements

The LVC is particularly suitable for mitigating potential grid constraints related to under voltage or overvoltage problems that may occur. The approach follows a merit order (that combines flexibility costs and technical information) to select the most suitable grid asset(s) to be activated. Depending on the level of information about the grid that is available, the LV control tool can be applied to LV networks with known and unknown topology/electrical characteristics as follows:

- 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 main elements necessary for the LVC tool are the same ones identified for the LVSE in section 4.2.
The output of the tool is a set of control actions for the voltage control devices and the DERs present in the LV network, namely new tap positions for MV/LV OLTC transformers and new points of operation for DERs. The detailed methodology of the LVC tool can be found in *Deliverable 3.2*.

## 5.3. High-level technical assessment of the tool

### 5.3.1. Synthesis of the tool evaluation in WP3 simulation tests

For the LVC tool, a set of test cases was defined in order to test the efficiency of the proposed methodology, considering the representative networks for France and Portugal. For each of the networks, the three scenarios defined (status quo, mid-term forecast and long-term forecast) were analysed considering different levels of RES penetration, load growth and flexibility. Within each scenario, situations of under- and over-voltage were considered. Both the state estimation and the smart power flow approaches were tested in order to assess the performance of the tool.
The simulations undertaken proved that the tool adapts itself well to different operation conditions. For each scenario, the severity of the voltage deviation varied and the number of available controllable equipment to be actuated was also different. Higher voltage deviations required an increased number of controllable equipment to be utilized.

The results obtained are in line with the expectations for the LVC tool. Preliminary simulations led us to believe that this solution could work in real grids if all the necessary data were to be provided. Since this tool has an adaptive behaviour, the solutions provided were consistent and solved the voltage problems for all the scenarios explored both for the Portuguese and French networks. The attained results give a solid demonstration concerning the value of this tool with respect to the *status quo* of current LV networks. As the mid/long-term scenarios are considered, the KPI improvement from using this tool proved to be greater.
The LVC tool's main limitations are linked with the set of input data available. For simulations using the state estimation routine, a representative historical database supporting the state estimation tool is required in order to have a better correlation between the power curtailed and the real voltage variation in the network. Using the smart power flow, a full knowledge of the network technical characteristics is a mandatory requisite: otherwise, the method will not give reliable results.
Considering the lack of historical data for the state estimation hypothesis, a safer approach can be used. This approach may be executed by modifying some input parameters, corresponding to the percentage of nominal power to be curtailed (which is calculated as a function of the electrical distance of the selected equipment to the problem node and the magnitude of the voltage variation). With these new set points and considering a higher estimation error value (that is also an input parameter), the resulting LVC outputs would be set points which would imply higher power curtailments assuring, with a higher security degree, that the voltage deviation is solved. Still, a compromise between estimation error and reliability of the solution must always be maintained.

## 5.4. Evaluation of costs and benefits of the tool

### 5.4.1. Mapping the tool onto functionalities

Table 31 presents the tools-functionalities matrix and identifies the services and functionalities for the evolvDSO project that are enabled by the LVC tool. The first three services and the corresponding five functionalities were adapted from [1]. The service *Optimise network operations until market gate closure based on a schedule (in operational planning)* is based on the BUC with the same name, as defined in *Deliverable 2.1*. The correspondent functionality for this service is adapted from the sub-SUC *Solve network constraints using optimisation levers based on a merit order* as defined in *Deliverable 2.2*. The last service entitled *Efficient management of the controllable assets* and the two correspondent associated functionalities are new and are specific to the LVC tool.

| Services | Functionalities |
|---|---|
| Integrate users with new requirements | 1. Facilitate connections at all voltages/locations for any kind of devices |
| | 2. Facilitate the use of the grid for the users at all voltages/locations |
| Enhance efficiency in day-to-day grid operation | 3. Enhance monitoring and control of power flows and voltages |
| Optimise network operations until market gate closure based on a schedule (in operational planning) | 4. Solve network constraints using optimisation levers based on a merit order |
| Efficient management of the controllable assets | 5. Minimise the cost of the voltage deviation control |

Table 31 – Mapping of the LVC tool into the functionalities it provides.

### 5.4.2. Mapping the functionalities onto benefits

The mapping between the functionalities and the benefits provided by the LVC tool resulted in the functionalities-benefits matrix shown in Table 32. Regarding the LVC tool, there is no strong relation with the set of benefits described in [1]. Therefore, all the benefits enabled by the LVC tool are derived from the Operational and EEGI KPIs characterised in *Deliverable 3.2* and D*eliverable 5.1*.

A brief explanation of how the referred benefits are provided by the LVC functionalities is presented below. Where applicable, the link between the benefits and the correspondent operational or EEGI KPIs is also presented:

- **Increase RES and DER hosting capacity:** with the LVC tool, a higher amount of RES and DER can be connected to the LV networks without breach voltage constraints. This benefit can be achieved due to the control actions proposed by the LVC tool that are done taking into account not only all the new RES and DER equipment, but also the rest of the available grid assets. This accommodates the additional amount of power coming from the connection of new DER and RES units without causing technical problems. This benefit is linked with the EEGI KPI "Increased RES and DER Hosting Capacity".

- **Reduce RES and DER total energy curtailment:** When a voltage problem occurs, instead of disconnecting the RES/DER, set points of operation can be sent to these or to other equipment (e.g. transformers with OLTC). This enables a controllable operation of these resources, avoiding the total (or even none) curtailment of RES and DER while voltage is maintained within the admissible limits. This benefit is linked with the EEGI KPI "Reduced energy Curtailment of RES and DER".

- **Limit voltage deviations:** The LVC tool provides a solution that fully corrects the voltage deviation occurrences. The set of set points to be sent to the equipment are validated within the tool, assuring that the problem can be properly managed in the field by making use of the existing controllable assets. This benefit is linked with the operational KPI "Quantify the number of regularised voltage deviations".

| Benefits | Functionalities | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Increase RES and DER hosting capacity | ●◊ | ●◊ | ●◊ | ●◊ | |
| Reduce RES and DER total energy curtailment | | ◊ | ●◊ | ●◊ | ◊ |
| Limit voltage deviations | | | ●◊ | ●◊ | ●◊ |

● Assessment performed by EDP Distribuição
◊ Assessment performed by Enedis

Table 32 – Mapping of the functionalities on to a set of benefits (LVC tool).

### 5.4.3. Establishment of the baseline

Regarding the LVC tool, the baseline and the project scenarios to be tested are the following:

- **Baseline scenario**: The LVC tool is not executed, so the potential voltage problems that may appear are dealt with the existent infrastructure (e.g. circuit breakers are activated disconnecting the prosumer from the grid in case of a voltage violation).

- **Project scenario**: The LVC is executed and set points are calculated and sent to the network assets to manage their operation in order to maintain the voltage within the admissible limits.

The most relevant conditions regarding grid, load growth and DRES scenarios, as well as the metrics used to evaluate the correspondent benefits are summarised in Table 33, both for the baseline and project scenarios. The metrics described in Table 33 are based on the Operational and EEGI KPIs (see respectively *Deliverable 3.2* and *Deliverable 5.1* of the project).

| Benefits | Baseline Scenario (BaU) | Project Scenario (SOPF) | Metrics Used |
|---|---|---|---|
| **Increase RES and DER hosting capacity** | Load growth and DRES scenarios characterised in D3.4 are considered for the | The LVC tool is executed for Load growth and DRES scenarios | Increase RES and DER hosting capacity at the secondary substation level (EEGI KPI) |

| | | | |
|---|---|---|---|
| **Reduce RES and DER total energy curtailment** | French and Portuguese Networks without the LVC tool being executed | characterised in D3.4 are considered for the French and Portuguese Networks | Reduce RES and DER total energy curtailment at the secondary substation level (EEGI KPI) |
| **Limit voltage deviations** | | | Quantify the number of regularised voltage deviations (Operational KPI) |

Table 33 – Baseline and Project conditions for the LVC benefits

### 5.4.4. Demonstration of the benefits

In the next sections, the results regarding the demonstration of the benefits, according to the metrics presented in last section are shown. The corresponding beneficiaries are also identified for each benefit.
It is important to keep in mind that, in the baseline scenario, the LVC is not executed and the prosumer(s) that have voltage deviation(s) above the defined thresholds is (are) disconnected. In contrast, in project scenario, all benefits are demonstrated considering that the LVC is executed and set points of operation are sent to field equipment.

#### 5.4.4.1. Increase RES and DER hosting capacity

This benefit is evaluated measuring the additional DRES that can be installed in the LV network using the LVC tool compared to the baseline scenario without causing voltage limit violations. To achieve this, the generation levels are increased until the voltage reaches its maximum admissible value in any node of the networks (baseline scenario), and the DRES hosting capacity is retrieved. Afterwards, the generation levels with the LVC tool are increased until the limit where RES curtailment is required in order to maintain the voltage maximum admissible value. Then, the total DRES hosting capacity is retrieved. Finally, with these results, the increase of RES and DER hosting capacity benefit can be calculated.
In Table 34 the results regarding the increase of RES and DER hosting capacity benefit, attained for the Portuguese and French networks in the different load growth and DRES scenarios analysed are presented. More details about these scenarios can be found in *Deliverable 3.4*.

| Scenario | Portuguese Network | French Network |
|---|---|---|
| A1 | - | 1.5% |
| A2 | 3.5% | 0.7% |
| B1 | 3.8% | 1.0% |
| B2 | 7.5% | 0.6% |
| C1 | 2.7% | 3.0% |
| C2 | 5.9% | - |

Table 34 – Increase RES and DER hosting capacity benefit (LVC tool)

The LVC tool enables to increase the RES and DER hosting capacity, but the gain is not too expressive. The major benefits are obtained for the scenario C2, where the LVC tool enables an increase of RES and DER hosting capacity by 5.9%. It is important to note that the hosting capacity is calculated taking into account the total hosting capacity existing in the grid. Only a few of DER/RES equipment needed to be disconnected or managed to solve the problems (representing a small capacity comparing to the total amount of power capacity) in all the scenarios analysed. It explains the low values for values achieved for this benefit.

The main beneficiaries of the increase of RES and DER hosting capacity are both the DSOs and the prosumers. From the DSOs point of view, an increment in RES and DER hosting capacity means potential technical benefits regarding the planning and operation of their electric systems, such as: peak load reduction, improvements in power quality and reliability, and the possibility to provide ancillary services such as voltage support. With respect to the prosumers, the main advantage is economical, i.e. the prosumers can have direct profits regarding the additional amount of energy injected into the grid, either because they can increase the installed capacity on their production units or install new ones. In addition, in the scope of Demand Side Management (DSM) programs, they can use DER and RES to maintain near-to-normal operations (importing less power from grid) and be paid if financial incentives and/or price signals are provided to customers to reduce their electricity consumption during peak periods.

The uncertainty level of this benefit is significant (see Table 3 from [1] for more details). The accuracy of the information provided by the LVC depends on the knowledge of the networks' parameters and topology, network type and characteristics, the technology associated with controllable assets (e.g. technology that allows fine control of the injected power through set points versus On/Off equipment), and the locations where the RES and DER may appear in the grid.

### 5.4.4.2. Reduce RES and DER total energy curtailment

This benefit is evaluated by measuring the reduction in energy curtailment of RES/DER generation due to technical and operational problems (namely over and under voltages). The evaluation process, first consists in retrieving the total amount of energy curtailed in a given time period for the baseline conditions without the LVC tool. Next, over the same time period as in the baseline scenario, the total amount of energy curtailed is retrieved but for the case where the LVC tool is used to solve voltage occurrences. Finally, these values are used within established metric to demonstrate the benefit.

The results are presented in Table 35 for the Portuguese and French networks regarding the load growth and DRES scenarios analysed in WP3. As seen the LVC tool allows substantial reductions in the percentage of RES and DER in both the Portuguese and French networks total energy curtailed. This is more important in the scenarios with higher penetration of RES (scenarios B1 to C2). For example, in the scenario B1 and B2 (both in Portuguese and French networks), due to the effective management of other controllable assets performed by the LVC tool, no power in any RES and DER units is curtailed. In these specific cases, the change of the OLTC position of the MV/LV secondary substation transformers performed by the LVC was the only asset required to be managed in order to respect all the grid technical constrains.

| Scenario | Portuguese Network (%) | French Network (%) |
|---|---|---|
| A1 | - | 35 |
| A2 | 40 | 33 |
| B1 | 100 | 100 |
| B2 | 100 | 100 |
| C1 | 100 | 80 |

| | | |
|---|---|---|
| C2 | 88.6 | - |

Table 35 – Results for reduce RES and DER total energy curtailment benefit (LVC tool)

The main beneficiaries of the reduction of RES and DER total energy curtailment are the prosumers. The reduction of the energy curtailed in RES implies that the prosumers are able to extract more power from their units and thus be paid for the energy sold. Otherwise, in a case where the LVC tool is not used, prosumers would see their units being disconnected in order to deal with violations of the grid technical constraints.
The uncertainty level of this benefit is significant (see Table 3 from [1] for more details) due to the reasons stated in section 5.4.4.1.

### 5.4.4.3. Limit Voltage Deviations

This benefit measures the number of regularised voltage deviations, i.e. the percentage of voltage deviations beyond the regulated limits that are solved after the LVC tool is executed. To evaluate this benefit, a load flow calculation or state estimation is first run in a given time period in order to calculate the total number of voltage deviations beyond the regulated energy limits in the baseline scenario (without the LVC tool). Next, the LVC is executed in order to calculate the number of voltage deviations that are corrected by the tool. The percentage of regularised voltage deviations is then calculated. These two computations are done for the different grids, load growth and RES scenarios under analysis. Table 36 presents the results attained.
As seen, for the French network all voltage violations are corrected by the LVC tool in all the scenarios analysed. In contrast, in the Portuguese network, in two of the five scenarios analysed (B2 and C2) some problems persist after the execution of the LVC tool. The percentage of not solved violations is related with voltage violations that occurred in other phases. It is important to bear in mind that only one execution of the LVC was performed in this analysis and that, for each execution, the LVC tool tries to solve the worst voltage violation occurring in a given phase. Therefore, voltage problems verified in different phases (in the same time-period) may eventually be unsolved during this execution. Nonetheless, they would be dealt with in the next execution of the LVC.

| Scenario | Portuguese Network (%) | French Network (%) |
|---|---|---|
| A1 | - | 100 |
| A2 | 100 | 100 |
| B1 | 100 | 100 |
| B2 | 76 | 100 |
| C1 | 100 | 100 |
| C2 | 80 | - |

Table 36 – Results for the correct voltage deviations benefit (LVC tool)

The main beneficiaries of the voltage deviations correction are the DSO and the prosumers. Maintaining voltages within the regulated limits is something that DSOs have to ensure in order to guarantee the required power quality at the customer's service.
The uncertainty level of this benefit is significant (see Table 3 from [1] for more details) due to the reasons previously mentioned for the other benefits.

### 5.4.5. Qualitative impact analysis

The benefits directly connected to the LVC are not easily quantified. So, a qualitative impact analysis is a common approach to estimate the tool impact regarding their functionalities and benefits.
In Annex IV (Table 81 and Table 81), the merit deployment matrixes show the results from the qualitative assessment done for the LVC tool. In these matrixes, a link between functionalities and each benefit is established and a weight is assigned. It should be pointed out, that the weights assigned to each identified link are defined in accordance to the DSO preferences.
By adding up all columns and rows of the whole merit deployment matrix it is possible to quantify the impact of the LVC in terms of functionalities and benefits.

#### 5.4.5.1. Tool impact across functionalities and benefits

As seen, Figure 27 illustrates the impact that each functionality has in the global performance of the LVC tool. For this particular case, the *"solve network constraints using optimization levers based on merit order"* is the functionality which has a greater impact as expected, since this is a contingency focused tool that solves voltage problems through operation management of the grid controllable assets.

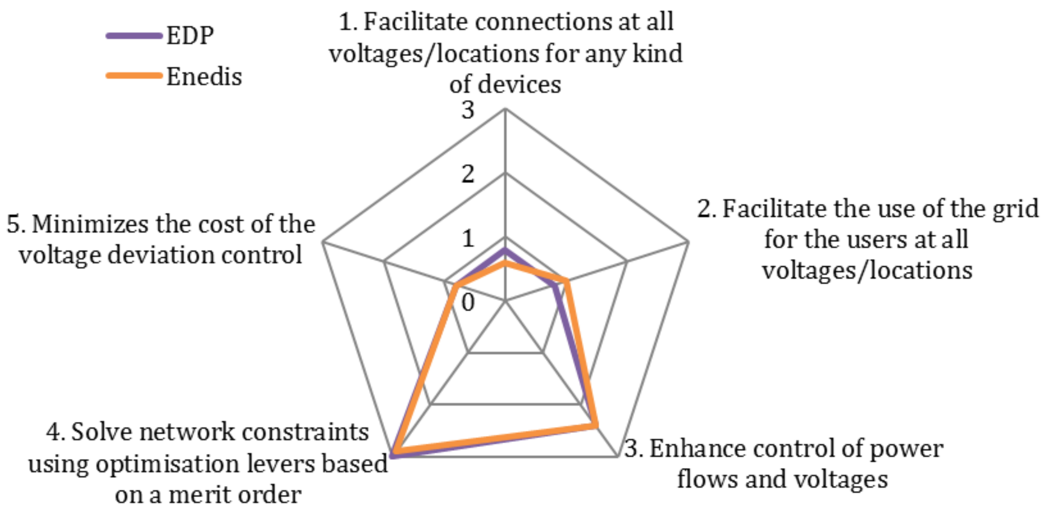



Figure 27 – LVC tool impact across functionalities.

Regarding the tool impact across the benefits, concluded from the results depicted in Figure 28, the highest impact is connected to the *"Increase RES and DER hosting capacity"* benefit.
Unlike the EDP Distribuição analysis, the "*Reduce RES and DER total energy curtailment*" has a slightly greater impact than "*Limit voltage deviations*" benefit.

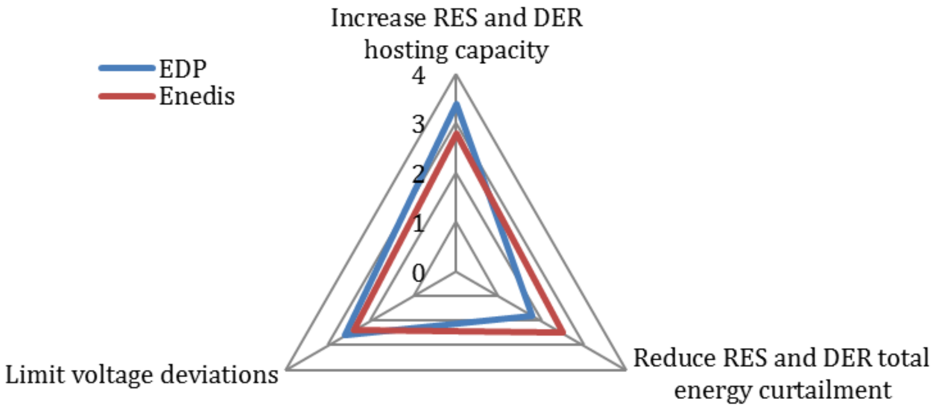



**Figure 28 – LVC tool impact across benefits.**

## 5.4.6. Identification and quantification of the costs

The costs associated to the LV control were divided into two categories: (a) development of the algorithms/tool (b) integration of the industrial tool within DSO information system.

The industrialization cost is the sum of the person-month spent during the project in WP3 to develop and improve the tool plus additional effort to complete the following developments:

- Standardization of the input/output data model, i.e. adoption of common information model (CIM) standards;
- Integration of the tool in commercial data concentrators or distribution transformer controller (DTC).

Around 60% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 10 PM spent during the project (with a rough estimation of the average PM cost around 4400€) and 7 PM for the additional developments towards industrialization.

The industrialization cost is considered only once for all whether the tool is applied one or more times. The integration cost for this tool should be scaled with the number of substations considered.
For France, the integration costs were estimated considering the installation in 15 MV/LV substations and considering that a functional LV state estimation is already available (which decreases the monitoring costs). The minimum technical requirements listed in Annex IV, Table 78 were considered to calculate the total cost. The ratio industrialisation/integration cost is 30.8%, however it is important to stress that the integration costs do not include several categories where the cost quantification is not possible at this phase (see Table 78) and the costs here are for a prototype scale (only a few MV/LV substations).

For Portugal, the integration costs were estimated for a single network considering the minimum technical requirements listed in Annex IV, Table 79. The following assumptions were made:

- The assumptions for LVSE (see section 4.4.6) in terms of DTC licensing costs, communication, field replacement and configuration are also valid for the LV control.
- An additional cost is introduced regarding the number of DER (e.g. storage) per LV network. We assume the DSO will have two DER available per LV network. We consider that these DER belong to the final consumer (that manifests his availability to participate in market and/or contract mechanisms to provide voltage regulation services). We consider that the meter cost will be transferred to the client (as it happens nowadays with producers), as well as the cost of the DER and its installation. The cost for promoting the participation of the customer in this mechanism is not considered since only integration costs are being considered.
- Since the reading of the billing data is the DSO responsibility, the communication cost of the DER's meter (seen as SMr meter) is considered.
- Any potential cost for sealing the meter (prevent third party adulteration of meter configurations.) after physical connection to DER (for communication purposes) is not considered.

Since the integration cost was calculated for only one substation, Table 37 shows the ratio between integration and industrialization cost for Portugal. The estimated costs for both scenarios show that the integration costs are a small fraction of the industrialization cost (which around 58% was already covered by the evolvDSO project). The cost variability regarding the number of meters used in each scenario is explained in section 4.4.6. It should be stressed that if the LV control tool is installed in more networks, this ratio would decrease even more, which shows that the industrialization cost is very marginal for this tool.

| Scenario | Integration/Industrialization Cost [%] |
|---|---|
| A [SMr=14%] | 0.9% |
| B [SMr=27%] | 2.0% |

Table 37 – Ratio between integration and industrialization cost for the LV control in Portugal.

# 6. Robust Short-Term Economic Optimization Tool

## 6.1. Introduction

Medium voltage distribution networks usually possess inherent flexibilities that allow Distribution System Operators (DSOs) to manage violations of network constraints. The high integration of DRES can cause an increase in the frequency of occurrence of these violations, due to the intermittent nature of DRES. In these operating conditions, the network management based only on inherent flexibilities becomes insufficient.
A proactive approach, based on both inherent flexibilities on the one hand and external flexibilities on the other hand, are therefore necessary to deal with this new operating scenario. The robust short-term economic optimization tool will enable the DSO to contract these external flexibilities in an economic and efficient way. A market for flexibilities is assumed to exist at the distribution level and the DSO is allowed to contract flexibilities from this market.
The Figure 29 summarises the most relevant new and evolving DSO activities, as well as the main associated services related with the OP-tool.

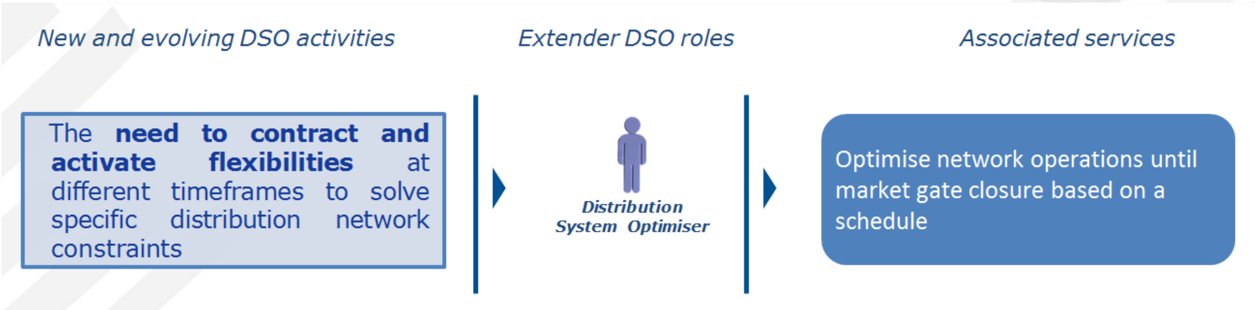



Figure 29 – The OP-tool goals in the DSO roles.

## 6.2. Description of the tool and its elements

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 levers the DSO can use. It is basically composed of three modules described in the following sub-sections, these are:

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

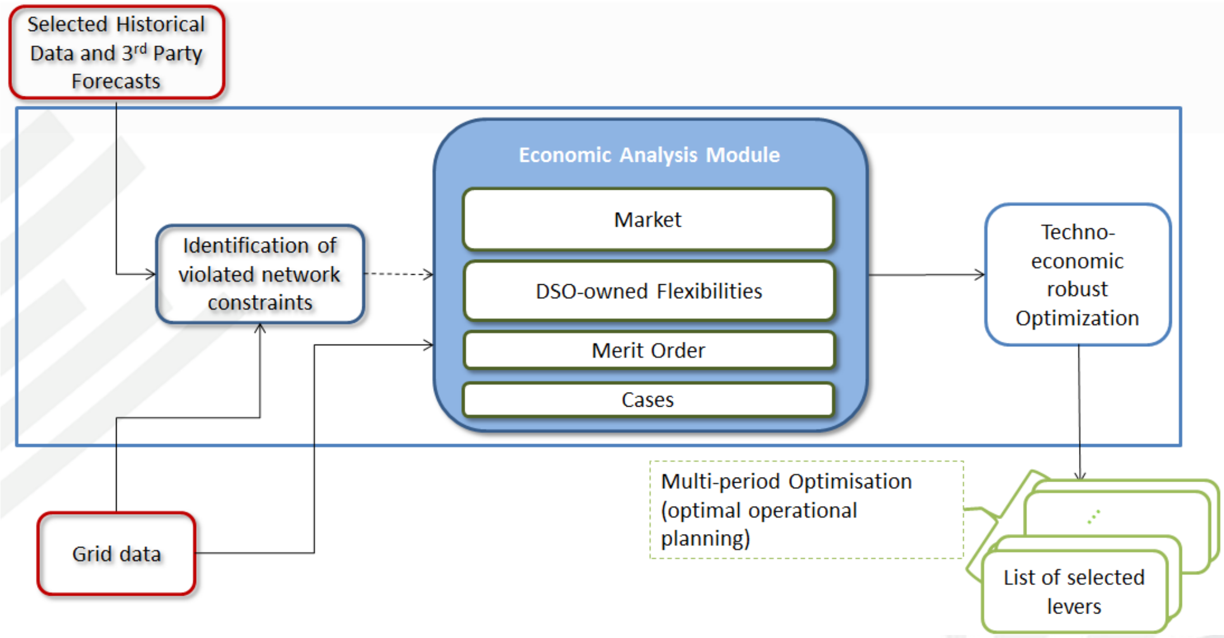



**Figure 30 – Operational Planning algorithm (OP tool)**

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; to maintain voltages and currents within the desired ranges, minimizing the dispatching costs for the DSO and; to use 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 one of them could not consider.

## 6.3. High-level technical assessment of the tool

### 6.3.1. Synthesis of the tool evaluation in WP3 simulation tests

e-distribuzione provided the test network, through the Atlantide project. It is a typical radial distribution network where commercial, residential and industrial customers are connected. In some cases, load and generation are connected to the same bus. Only one OLTC transformer is installed in the network, which permit the MV/HV connection.
The radial network has 101 AC lines connecting the 100 AC buses with a 15 kV rated voltage. The total length of the lines is 120.42 km, divided into overhead lines (53.32 km) and cables (67.10 km). A total of 128 loads are connected to the network, divided in residential (65), commercial (28), and industrial (35) loads. Moreover, the 28 generators connected to the network are either rotating (3 wind and 3 CHP) or static (22 PV).
Given the Atlantide network elaborated before, three test cases were created. They correspond to the status quo (2012), short-term scenario (2018) and mid-term scenario

(2023) for Italy. For each scenario, one test case was identified and so levels of connected load, PV generation, wind generation, storage, combined heat and power generation were defined based on those scenarios and used accordingly.

In order to simulate the given network with the OP tool, various hypotheses were made. These mainly concern the amount and type of flexibilities, the regulatory framework in place, and the market rules.

For the tool to work, the regulatory framework has to allow the establishment of a market-like portal where the flexibilities in the network can be traded. In addition, the DSO should be able to exploit these flexibilities as long as an offer for such flexibility is made.

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. In addition, 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-hourly basis (thus 96 data points per day). Next to this, the production and consumption model type should be specified: 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. This means 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.

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 limits are set at ±5% of the nominal voltage value of the network, according to the European Standard EN 50160 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 correspond 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.

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.

Two optimization approaches are finally used to find an optimal sequence of control actions for the network, either considering time correlations, or not.

The tool consists of 3 sub tools developed by Grenoble INP, RSE and VITO. The impact assessment focuses on each of the sub-tools and also on the overall impact of the tool. For the sub tools, operational KPIs were defined to measure the specific impact. These were then linked (directly or indirectly) to one or more high level KPIs. The only high level KPI for the

tool is the 'Increased RES and DER Hosting Capacity', calculated as a ratio of the difference between the hosting capacity with the tool compared to the hosting capacity without the tool.
The tests performed in WP3 show the capability of the tool to define a set of economically listed flexibilities and then to optimize the use of that merit order list of flexibilities to deal with voltage and current violations which can originate in realistic networks of average size and complexity. Since it is a novel application, only lab trials with simple test networks were run before.

These simulations were also useful for demonstrating the effectiveness of the idea behind the tool and the basic functionality of the code. OP sub-tools proved valuable to test the capability of the available active resources to face voltage and current violations and to analyse the most effective solutions to rank flexibilities based on their economic model, allowing the verification of the effective exploitation of these flexibilities.
Since the tool is still in development it was not possible to exploit its full potential but these trials gave the developers the impetus for the updates necessary for its improvement.
The simulations performed in WP3 flagged certain weaknesses related to the input of the tool or the test environment and could be further refined during the next development phase.. Here are the most significant:

- The economic model is based on costs of flexibilities. These costs depend on the considered grid and DSO and could be very specific. In addition, extensive research is needed to assess in detail the cost of different types of flexibility.
- The test-network and the type of production/load profiles have an impact on the results. Stochastic simulations could propose a way to better cover unexpected scenarios.

In conclusion, the tests showed the efficiency of the whole tool for Operational Planning purposes and identified what are the resources that support network management and their cost.

## 6.4. Evaluation of costs and benefits of the tool

### 6.4.1. Mapping the tool onto functionalities

In the present section, the mapping of the OP-tool to functionalities for the evolvDSO project is done. In addition to the six services presented in [1], another one, related with the Business Use Case (BUC), associated to the OP-tool was added: *Optimise network operations until market gate closure based on a schedule (in operational planning)*. This BUC is further described in D2.1. Table 38 illustrates the mapping of the OP- tool into functionalities.

| Services | Functionalities |
|---|---|
| Enabling the network to integrate users with new requirements | 1.Facilitate connections at all voltage levels/locations for any kind of device |
| Ensuring network security, | 2. Operation schemes for voltage/current control |

| | |
|---|---|
| system control and quality of supply | 3. Intermittent sources of generation to contribute to system security |
| | 4. System Security assessment and management of remedies |
| Enabling cost-effective network management in full electricity market scenario | 5. Facilitate the techno-economic ranking of all the available flexibilities |
| Optimize network operations until market gate closure based on a schedule (in operational planning) | 6. Identify network constraints in operational planning |
| | 7. Solve network constraints using optimisation levers based on a merit order |
| | 8. Store and provide data about the network |

**Table 38 – Mapping of the OP-tool on to the functionalities it can provide**

## 6.4.2. Mapping the functionalities onto benefits

In Table 39, the mapping between the functionalities and the benefits provided by the OP-tool is presented. The benefits that are relevant for the OP-tool are derived from the Operational and EEGI KPIs that were described in *Deliverable 3.2* and *Deliverable 5.1*.

| Benefit category | Specific benefits | Relevant functionalities | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| Economic | 1 Cost-effective full exploitation of flexible network resources | • | | • | | • | | • | • |
| Reliability | 2 Adequate capacity of distribution grids for 'collecting' and bringing electricity to the consumers | • | | | | | • | • | • |
| | 3 Satisfactory levels of quality and supply | | • | • | • | | | • | • |

**Table 39 - Mapping of benefits and functionalities performed by Grenoble INP/RSE/VITO and checked by e-distribuzione**

A more detailed explanation of the benefits delivered by the OP-tool follows:

- **Cost-effective full exploitation of flexible network resources** allows the use of available flexibilities through the valorisation of their short-term economic aspects. This benefit is linked to two operational KPIs. The first KPI is related to the economic analysis sub-module and is called: '*Increased Use of Sources of Flexibilities by DSOs*'. This KPI measures the improvement in the number of flexibilities that will be used by DSOs to maintain normal operating conditions. The second KPI is linked to the VITO optimisation component and is called '*Efficiency Improvement Optimisation*'. This KPI measures the quality of the optimisation, i.e. it compares the optimal solution (minimum cost) with the solution found after a fixed time period. Both operational KPIs show how DSOs use in a cost-efficient way additional sources of flexibility for grid operation.

- **Adequate capacity of distribution grids for 'collecting' and bringing electricity to the consumers** is a measure of the capacity of distribution grids to function properly even with a high integration of DRES. The OP-tool allows the grid to host additional capacity of DRES without causing additional grid constraints. This benefit is achieved by including multi-temporal constraints together while considering both technical and economic optimization goals. This benefit is linked with the EEGI KPI "*Increased RES and DER Hosting Capacity*".
- **Satisfactory Levels of Quality and Supply** measures the voltage quality in the network. The OP-tool guarantees that voltage quality is maintained. This benefit is linked to the operational KPI related to the RSE optimization module, called 'voltage profiles quality'. This KPI measures the quality of the voltage profiles by evaluating the duration of voltage constraints in the network to be optimized, without and with this optimization module.

## 6.4.3. Establishment of the baseline

For the OP-tool, the baseline and the project scenario to be tested are listed in the Table 40. The metrics to evaluate the relevant benefits are based on the Operational and EEGI KPIs (see also *Deliverable 3.2* and *5.1*).

| Benefits | Baseline Scenario (Network as is) | Project Scenarios | Metrics Used |
|---|---|---|---|
| Cost-effective full exploitation of flexible network resources | In the baseline scenario, the DSO does not use any of the flexibilities potentially available in the network. | In the project scenarios, the DSO is able to use available flexibilities in a cost-effective manner. | • Increased Use of Sources of Flexibility by DSOs ((Operational KPI)<br>• Over-cost percentage (Operational KPI) |
| **Adequate capacity of distribution grids for 'collecting' and bringing electricity to the consumers** | In the baseline scenario, the network does not have adequate capacity to perform its role, due to constraint violations. | In the project scenarios, the tool is able to find a solution for ensuring normal operation of the network with the integrated DRES. | • Increased RES and DER Hosting Capacity (EEGI KPI) |
| Satisfactory Levels of Quality and Supply | In the baseline scenario, the given network faces several voltage problems, resulting in non-delivered energy. | In the project scenarios, all the bus voltages and line currents in the network are maintained within the required limits. | • Duration of Voltage Constraint Violations in a Period (Operational KPI) |

Table 40 - Baseline and project scenarios for quantification OP-tool benefits

## 6.4.4. Demonstration of the benefits

The full results of the test of the OP-tool are described in *Deliverable 3.4*. The main results are summarized below and demonstrate the benefits as described in previous section.
The operational KPI, linked to the economic analyses module takes into account the number of types of flexibilities that are present in the merit order and that could, consequently, be

used by DSOs. Today, DSOs only have the HV/MV On-Load Tap Changer transformer to manage networks in the short-term.
The number of types of flexibilities provided in the merit order amounts to six (Battery Storage, CHP Active Power, DRES Curtailment, DRES Reactive Power Compensation, Load Modulation, and On-Load Tap Changer), while we assume that the DSO uses only the HV/MV On-Load Tap Changer transformer to manage networks in the short-term. This translates to an increase of 600% in the types of flexibilities used with the OP tool compared to a regular grid with only one flexibility (the OLTC).
For the EEGI KPI, increased RES and DER Hosting Capacity, simulations show that there is a significant increase when the tool is used. The increase in hosting capacity ranges between 50% and 600% compared to the initial installed capacity of RES and DER, dependent on the scenario, for the particular network used for the simulations (refer to *Deliverable 3.4* for more details).

For the operational KPIs for the two optimizers, the results are the following:

- For the VITO-component: the additional costs of the solution (compared to the minimal solution cost), after a fixed % of the maximal available calculation time, gave following result: with a maximal available calculation time assumed to be 15 minutes, the overcost reached after 5% of the calculation time is 7.8%. After 10% of the calculation time, the overcost reaches 2%.
- For the RSE-component: the use of the optimizer resulted in a decrease of voltage violations from 3105 to 2145 minutes, dependent on the scenario.

The functionalities of the tool provide in the first place some important benefits for DSOs who are able to operate the grid at a lower cost in scenarios with increasing DRES. In addition, the use of the OP-tool by DSOs provides also advantages for end consumers and flexibility providers. The former will benefit due to lower grid tariffs and a guaranteed quality of supply. The latter will benefit, as DSOs will be an additional customer to whom they can sell their flexibilities.

### 6.4.5. Qualitative impact analysis

Starting from the Merit Deployment Matrix reported in Annex V, Table 83, the following graphs are derived: they qualitatively assess the impact of the tool across functionalities on the one hand and across benefits on the other hand. Figure 31 shows that the functionality *solve network constraints using optimisation levers* is the most important. This is logic as this is the core functionality of the tool.

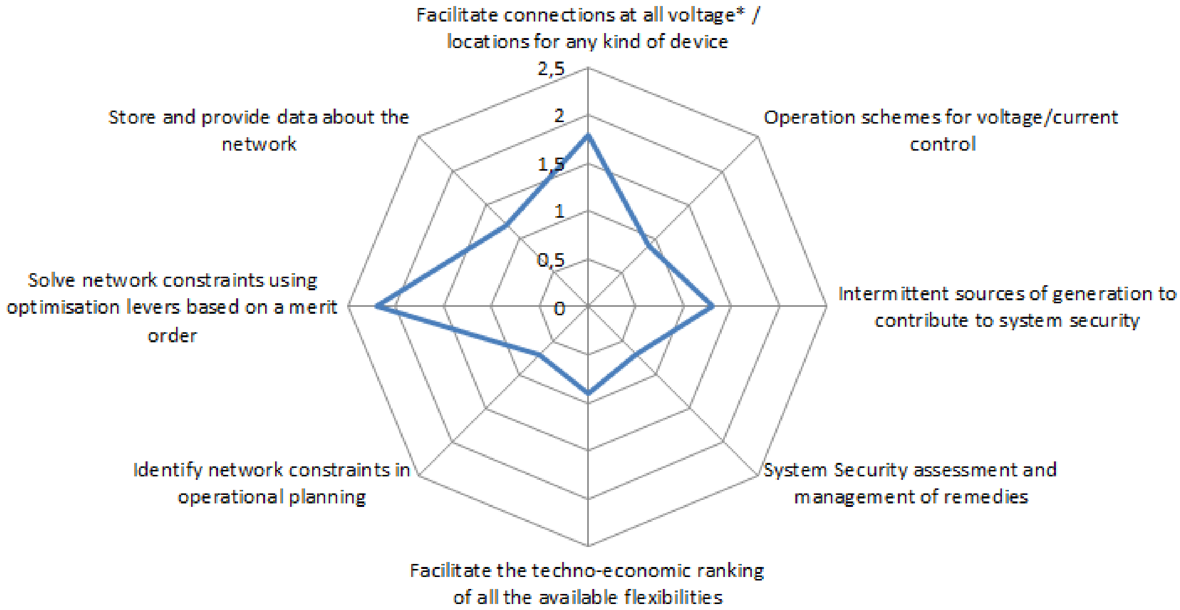



**Figure 31 – Impact across functionalities performed by Grenoble INP/RSE/VITO and checked by e-distribuzione**

In Figure 32, it can be observed how the tool allows DSOs to use flexible resources in a cost-efficient way for grid operation, guaranteeing quality of supply, which will than result in a higher hosting capacity of DRES in the grid.

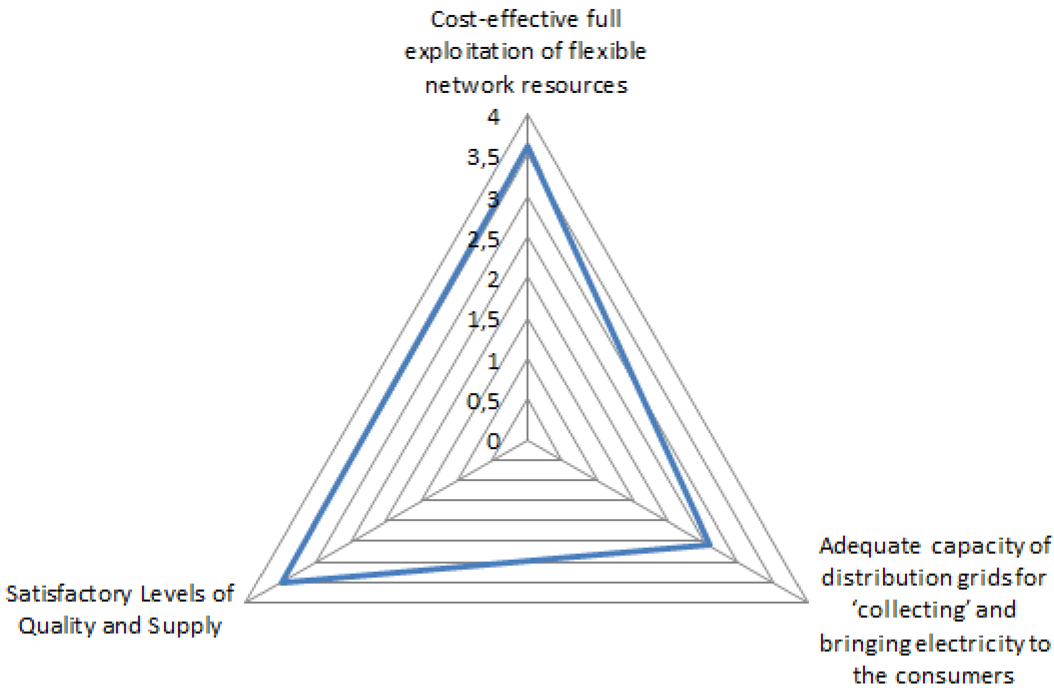



**Figure 32 – Impact across benefits performed by Grenoble INP/RSE/VITO and checked by e-distribuzione**

## 6.4.6. Identification and quantification of the costs

In order to properly identify the costs associated to the OP tool exploiting, it is necessary to consider the actual level of development and the efforts made so far, the additional efforts to reach the industrial readiness and the costs associated to the integration of the tool in the DSO environment.

The overall efforts needed to develop a complete industrial application can be summarized as follows:

1. Efforts to develop and simulate the tool (realized costs in the project).
2. Additional efforts to make the tool ready for industrial deployment, i.e.:
   - Standardization of the input/output data (i.e. adoption of CIM standards) and protocols;
   - Improvement of robustness of Economic Analysis module for industrial applications;
   - Extensive Tests on different sub-tools module with various scenarios and in multiple networks;
   - Development of market interface module to communicate directly with markets;
   - Operational testing: specific CP-specific debugging costs: cost of setting up and performing operational tests, evaluations and reporting may increase due to the use of Constraint Engines. the failure, even if the failure is genuine and not caused by a bug;
   - Commercial CP solver (to be purchased): to provide dedicated support for finding causes of infeasibility (in particular with additional support for debugging);
   - Code translation.

It should be stressed out that around 41% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 26 PM spent during the project (with a rough estimation of the average PM cost around 6750€) and 38 PM for the additional developments towards industrialization. The cost of the commercial CP solver is not included.

The cost for tool integration in a real operating environment cannot be estimate within the project because the tool was not tested in the field. The minimum technical requirements for its integration have been identified and are summarized in Table 82, Annex V.

# 7. Contingency Simulation Tool

## 7.1. Introduction

A more complex network management will characterize future grids, due to the increasing penetration of RES in distribution systems. Load and DRES temporal variability, the ageing process of the system elements/devices and, in general, uncertainties of various kinds should be taken in to account more and more accurately: this will necessarily require advanced solutions to pursue the goal of well-optimized networks, allowing a suitable voltage quality and an economically effective exploitation of active resources.
Furthermore, in the development of smart grid applications, specific tools for communications and ICT infrastructure simulation are needed. The electrical system will be operated and controlled with the help of a communication network, creating interdependencies between the electrical and the control/communication systems.
In the context of the evolvDSO project, the development of an innovative tool able to address the asset unavailability was required to fulfil the services *"Optimise network operations until market gate closure (in operational planning)"* and *"Simulate contingency analysis in Operational Planning"*. In such a tool contingencies can be derived from a reliability analysis of the network and then simulated, both from power and ICT sides, in order to investigate the availability and the effectiveness of countermeasures.
In Figure 33 the link between new DSO activities and roles, and their associated services is represented for the Contingency Co-Simulation (CCS) tool:

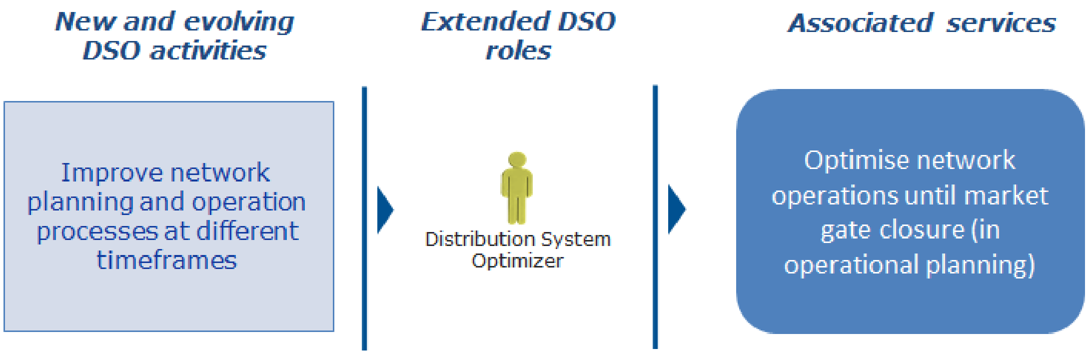



**Figure 33 – The impact of the CCS on the DSO roles**

## 7.2. Description of the tool and its elements

The main objective of the Contingency Co-Simulation tool is to select and simulate realistic contingencies in order to identify the suitable levers and, as a consequence, the corrective actions and policies to solve them in the most efficient and effective way. Besides the contingencies simulation, ICT performance analysis is carried out through an innovative co-simulation module. The proposed methodology provides a robust identification of network contingencies, by means of pseudo-sequential MCS, which can be then simulated and analysed taking into account both the Active Management and the ICT systems, through a specifically developed co-simulation algorithm based on freeware code. The outcome information of this

analysis can be used to define improved contingencies resolution actions and to ease the development of advanced network management policies. Since this tool is applied in the context of Operational Planning, the analysed time horizon spans from short-term to day ahead, i.e. from 72 to 24 hours before the considered period.
The functional scheme of the tool is presented in Figure 34; the modular structure of this tool allows the future integration of new functionalities and easy algorithms/modules updating.

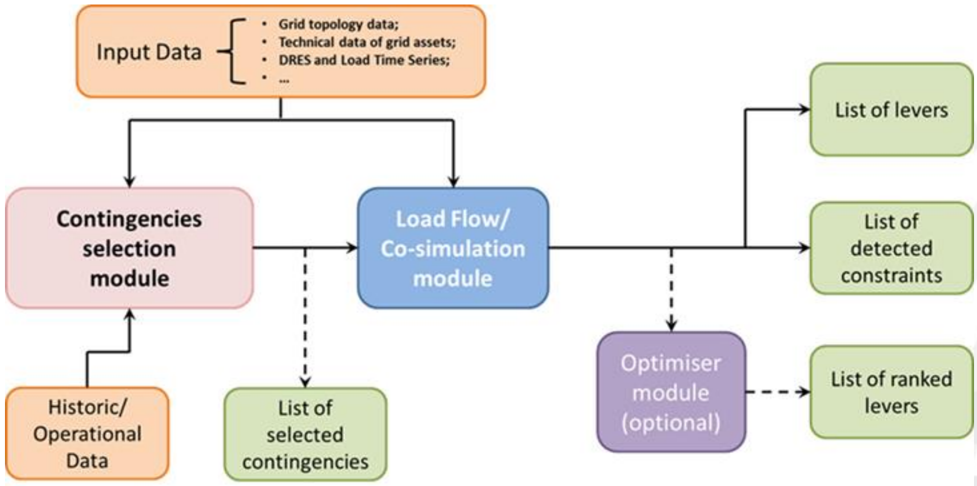



Figure 34 – Technical architecture of the CCS tool

The overall process of the tool is managed via a GUI, which allows the operator to easily follow all the process phases.
First, the process starts with the acquisition of input data; every other operation is disabled until all the relevant data are loaded. After this phase, the operator can start the Contingency Selection Module, which identifies the failure states of network assets through a statistical reliability analysis: the identified contingencies are displayed in the GUI where the operator can integrate/group them as well as add other relevant contingencies.
At this point, operators can choose three different ways to proceed: leave the contingencies list like it is and start the Co-simulation Module, delete/group some contingencies based on the specific analysis they want to perform, or integrate in the list of contingencies custom contingencies or contingencies retrieved from past event records. In the three cases, the operator can delete or group contingencies. The contingencies list can also be saved in a file or printed.

Once the contingencies list finalized, the Co-simulation process can be started. The Co-simulation Module takes the grid data and the selected contingencies as an input and analyses the grid: all the violations detected as well as the corresponding levers are displayed in the GUI. Beside this analysis, the ICT criticalities and constraints are also identified.
The detected constraints and the related levers are displayed on two different lists on the User Interface. They can be edited, saved in a file and printed

## 7.3. High-level technical assessment of the tool

### 7.3.1. Synthesis of tool evaluation in WP3 simulation tests

The tests performed in WP3 show the capability of the tool to define a set of realistic contingencies and to deal with voltage violations, which can originate in realistic networks of average size and complexity; since it is a novel application, only lab trials with simple test networks had been run before.

These simulations were also useful to demonstrate the effectiveness of the idea behind the tool and the functionalities of the basic framework of the code. The co-simulation sub-tool proved valuable to test the capability of the available active resources to face voltage violations and to analyse the most effective solutions to solve contingencies; furthermore, it allows verification of the effective exploitation of flexibilities, analysing ICT transmission behaviour in different operating conditions.

The simulations carried out in WP3 confirm the expectations on the tool behaviour but also indicate certain weaknesses of the present version of the tool, which can be the prompts for the next development work. Here are the most significant:

- A strong limit is represented by the high amount of computational resources, which are necessary to simulate ICT systems with more than 3-4 active nodes; even if this issue can be taken on with high performance processors, it limits the usage of this tool for real, complex networks.
- The list of ICT models implemented in the tool is limited to WiMax and Wi-Fi data transmission systems; while their operation can be easily affected by weather conditions and an accurate analysis is valuable, the capability to analyse also wired and other radio communications systems usually used by DSOs could improve the versatility of the overall tool.
- An accurate and versatile model of the networks, in order to evaluate reconfiguration options after contingencies, is necessary; in this sense, it is useful to have a reconfiguration module, which can be employed to define more realistic network reconfigurations in order to define reliable baseline scenarios and to adequately prepare the modified networks for co-simulation analysis.
- The DMS optimizer could be improved; it is up to the task for selecting the most effective active resources (from the technical point of view) but it does not allow an accurate techno-economic optimization like other tools.
- Sub-modules integration, Graphical User Interface and I/O data exchange need to be improved.

The tool is still in development, it was then not possible to exploit its full potential but these trials gave to the developers the required insights for the updates necessary for its improvement.

### 7.3.2. Synthesis of tool evaluation in WP4 field tests

As explained before, the WP3 tests were applied to two feeders for each of the two considered MV networks; in addition, various future scenarios of DRES penetration and demand growth based on a constant configuration of the distribution grids were considered.
In the WP4 tests, all the MV feeders of a primary substation (with only one HV/MV transformer), and its currently available flexible resources, were considered. In addition, the evolving configuration of the network topology as well as its active and reactive power forecasts were considered for the WP4 tests.
It was difficult to get relevant insight about the results provided by the contingency simulator strictly based on only field data. Assumptions had to be made to constraint the network under study since it was well designed and no constraint appeared either in its normal state, or in its reconfigured ones. Without such modifications the capability of the tool DMS to relieve voltage and transit problems could not be assessed.
The tool version tested was not ready to be interfaced with external systems and databases, so several adaptations were needed. Each part of the tool required a specific and very different data format. Therefore, two translation routines had to be developed to interface the tool with Enedis' databases. A configuration interface had to be developed to attribute load and active management profiles to each MV producer, MV customer and MV/LV substation. A post-processing routine was developed to calculate the tool KPIs.
The tool GUI is not very user friendly. Indeed, it does not have network representations that could help the user understand the results displayed by the interface. Only customer-by-customer results are available and no global overview of the results is provided. It makes the results difficult to apprehend without post-processing. Enedis considers that in its current state the GUI is still far from an industrial tool interface.

The tool DMS is able to solve the encountered network constraints when sufficient flexibility levers are available. It also successfully manages to overcome situations with planned ICT failures. However, when the available flexibility is not sufficient to solve the detected constraints, the tool cannot provide a solution solving partially the problem, i.e. the best solution improving the situation. Either the solution found solves all the operational constraints, or the tool does not provide any set points for the controllable assets.

The results from WP3 and WP4 tests are complementary since they allowed an evaluation of the effectiveness of the CCS tool on distribution grids with different characteristics. Insights on the tool capabilities regarding different timescales were thus obtained thanks to WP4 tests.

### 7.3.3. Results of the KPIs and PMs calculation in WP4 field tests

Some of the KPIs and PMs defined and applied in WP3 could not be applied to the field test for different reasons:

- Representative MTTF and MTTR values could not be computed only based on the list of events provided by the Contingency Selection module;
- The SAIDI, AUR and Energy Curtailment KPIs are all defined related to fault recovery operations. Since the Co-Simulation tool delivered is able to simulate neither fault events, nor the following self-healing reconfiguration operations, applying these KPIs to the field tests made little sense.

Two new KPIs and PMs were defined in order to evaluate the Co-Simulation module in WP4:

- *Voltage Quality improvement:* This KPI evaluates how the Co-Simulation module of the CCS is able to solve or mitigate voltage constraints appearing on the MV network by making use of the generation units / storage units / loads flexibilities available and taking into account potential telecommunication failures;
- *Energy curtailment reduction*: This KPI uses the following strict assumption: if an overvoltage constraint is detected, the power generated by the DG unit(s) responsible should be completely curtailed. The KPI evaluates thus how much of the power injected by the DG unit is preserved by the CCS when setting its control action.

It is important to note that the KPI and PM values provided are not illustrative of the added value of the CCS in real-life situations; in fact, only artificially constrained situations are considered in the tests since the network under study was well-designed. Some trends are highly overestimated in the scenarios simulated. This can potentially lead to an important bias in favour or at the expense of the tool depending on the situation.
The positive values presented here for the KPIs and the PMs rather illustrate the ability of the tool DMS to solve, at least partially, some network constraints and thus improve the overall quality of the power supply.

| ***KPI Name*** | ***KPI Value*** | ***Comment*** |
|---|---|---|
| ***Reduced energy curtailment of RES & DER*** | +14.1% of the total generated energy is preserved | This additional energy preservation is due either to the limited power curtailment defined by the CCS (in regards to full curtailment), or the none-curtailment because of communication losses. In the latter case, the network might remain constrained. |
| ***Power quality & quality of supply*** | 87% of the voltage constraints are relieved | The situations where the constraints could not be solved are either due to communication losses and/or to an insufficient availability of flexibility levers. |

| ***PM Name*** | ***PM Value*** | ***Comment*** |
|---|---|---|
| ***Energy curtailment reduction*** | +14.1% of the total generated energy is preserved | This additional energy preservation is due either to the limited power curtailment defined by the CCS (in regards to full curtailment), or the none-curtailment because of communication losses. In the latter case, the network might remain constrained. |
| ***Voltage Quality improvement*** | 87% of the voltage constraints are relieved | The situations where the constraints could not be solved are either due to communication losses and/or to an insufficient availability of flexibility levers. |

## 7.4. Evaluation of costs and benefits of the tool

### 7.4.1. Mapping the tool onto functionalities

The services and functionalities enabled by the CCS tool in the evolvDSO project framework are reported in Table 41. It has to be noted that the contingency analysis can be considered as a process parallel to the network optimisation (as represented also in the BUC and SUCs description in *Deliverable 2.1* and *2.2*); in addition, no service proposed in Annex III of the JRC methodology [1] is suitable to be applied to the CCS tool. For these reasons only the service *Optimise network operations until market gate closure based on a schedule (in operational planning)* is considered; it is based on the BUC with the same name, as defined in *Deliverable 2.1*. As a consequence, the corresponding functionalities are directly derived from the SUCs *Simulate contingency analysis in Operational Planning (asset unavailability analysis)* and *Identify and solve network constraints in operational planning*, defined in *Deliverable 2.2*. The third functionality is new and it is specific to the CCS tool.

| Services | Co-Sim Functionalities |
|---|---|
| **Optimise network operations until market gate closure based on a schedule (in operational planning)** | 1. Simulate contingency analysis in Operational Planning (asset unavailability analysis) |
| | 2. Identify and solve network constraints in operational planning |
| | 3. Integrate ICT unavailability in operational planning |

Table 41 – Mapping of the CCS tool into the functionalities it provides.

### 7.4.2. Mapping the functionalities onto benefits

Regarding the CCS tool there is no direct correlation with the benefits suggested in the *JRC methodology guidelines* [1]. For this reason, the benefits enabled by the CCS tool are specifically defined for this tool or they are derived from EEGI KPIs. This follows the assumptions reported both in section 7.3.3 and in the *Deliverable 4.3*. The mapping between the functionalities and the benefits provided by the CCS tool is shown in Table 42.

In the following, a brief explanation of how the referred benefits are provided by the CCS functionalities is presented.

- **Improved levels of security and quality of supply:** the CCS tool is able to identify potential contingencies and to simulate them in presence of planned/forecasted ICT unavailability: this facilitates the constraint solving process and allows a better voltage control, enhancing security and quality of supply management and the overall operational planning. This benefit is linked with the EEGI KPI "Power Quality and Quality of supply".
- **Reduced costs of activating flexible resources:** the simulation of contingencies and the consequent constraints resolution allows a better understanding of the amount and type of flexibilities needed; this could help to achieve a more cost-effective use of the

available flexibility levers. This objective can be fulfilled automatically through a proper setting of the DMS model.

- **Reduce RES and DER total energy curtailment:** towards the usage of the DMS function, when voltage violations occur, the CCS tool can solve the violations without disconnecting the RES/DER. Alongside this, the simulation of ICT unavailability can help to detect the actually available flexibilities and to optimize their exploiting in volume and cost. In this way, a controllable operation of the active resources is enabled, avoiding the total (or even none) curtailment of RES and DER while voltage is maintained within the admissible limits. This benefit is linked with the EEGI KPI "Reduced energy Curtailment of RES and DER".
- **Increase RES and DER hosting capacity:** the identification of contingencies might improve the network planning and the exploitation of DER and RES. From a long-term planning perspective, an efficient constraints resolution facilitates the connection of more new DER and RES units without causing voltage violations. This benefit can be achieved due to the DMS control actions simulated by the CCS tool, which considers all the available grid active resources. This benefit is linked with the EEGI KPI "Increased RES and DER Hosting Capacity"

| Benefits | Functionalities | | |
|---|---|---|---|
| | 1 | 2 | 3 |
| **Improved levels of security and quality of supply** | • | • | • |
| **Reduced costs of activating flexible resources** | | • | • |
| **Reduced energy curtailment of RES/DER** | | • | • |
| **Increased RES & DER hosting capacity** | • | • | |

Table 42 – Mapping of the functionalities on to a set of benefits (CCS tool) performed by Enedis.

### 7.4.3. Establishment of the baseline

The baseline and the project scenarios considered for the CCS tool tests are reported in the following:

- **Baseline scenario**: The CCS tool is not executed, so the potential voltage violations that may appear can be solved only through the disconnection of the asset/s responsible (curtailment of DGs/disconnection of loads)
- **Project scenario**: The CCS is executed and the DMS function manages the operations of all the available active resources in order to maintain the voltage within the admissible limits.

Table 43 summarizes the benefits, the scenarios and the metrics considered. Detailed description of the selected scenarios and the tests performed with CCS tool is reported in

*Deliverables 3.4* and *4.3*. When possible the metrics defined in *D3.4* and *D4.3* are used. The benefits for which is difficult to numerically quantify the impact, or it wasn't possible to define a suitable metric, a qualitative evaluation is considered.

| Benefits | Baseline Scenario | Project Scenario | Metrics Used |
|---|---|---|---|
| **Improved levels of security and quality of supply** | The CCS is not considered; reference scenarios are those defined in *Deliverables 3.4 and 4.3.* | The CCS is considered in the scenarios defined in *Deliverables 3.4 and 4.3* | ***Voltage Quality improvement:*** This metric evaluates how the Co-Simulation module of the CCS is able to solve or mitigate voltage constraints appearing on the MV network by making use of the generation units / storage units / loads flexibilities available and taking into account potential telecommunication failures.. |
| **Reduced costs of activating flexible resources** | | | Qualitative evaluation |
| **Reduced energy curtailment of RES/DER** | | | ***Energy curtailment reduction***: This metric uses the following strict assumption: if an overvoltage constraint is detected, the power generated by the DG unit(s) responsible should be completely curtailed. The metric evaluates thus how much of the power injected by the DG unit is preserved by the CCS when setting its control action. |
| **Increased RES & DER hosting capacity** | | | Qualitative evaluation |

Table 43 – Baseline and Project conditions for the CCS benefits

## 7.4.4. Demonstration of the benefits

The results achieved for the demonstration of the benefits, according to the metrics reported in last section, as well as the corresponding beneficiaries are presented in the following sections.

It is important to stress out that, in the baseline scenario, the CCS tool is not executed and then potential voltage violations can be solved only by full curtailment/disconnection of the entities connected to the nodes in which voltage values are outside the thresholds.
On the other side, in project scenario, all benefits are demonstrated considering that the CCS tool is executed and the DMS function manages all the available active resources.

### 7.4.4.1. Improved levels of security and quality of supply

This benefit is evaluated by assessing the capability of the CCS tool to solve all the voltage constraints violations arose during tests. The evaluation process consists in the comparison between the total number of detected violations (baseline scenario) and the number of violations solved by the CCS tool (project scenario), over the same time period and with the same network configuration. At the end, the percentage of the voltage violations solved is calculated. For the tests performed, the result is that the 87% of the voltage constraints are relieved. It is important to keep in mind that the situations where the constraints could not be solved are either due to communication losses and/or to an insufficient availability of flexibility levers.

The main beneficiaries of the improved level of security and quality of supply are the DSOs:

- From a technical point of view they can experience potential benefits in the planning and operation of their electric systems, such as avoid or postpone network reinforcements, improve voltage quality and reliability.
- From an economical point of view they can avoid/reduce penalties for customers interruptions and/or revenues for DGs curtailment.

### 7.4.4.2. Reduced costs of activating flexible resources

Since the CCS tool is not intended to act as a techno-economical optimization system, this benefit is not directly/numerically estimable. Anyway, the capability of the CCS tool to simulate the contingency resolution through the available active resources allow a better understanding of the resources exploited; the DMS function allows to simulate different resolution actions targeting to reach the minimum exploitation costs of the available resources. This benefit has been evaluated in a qualitative way during the WP4 tests and the corresponding results are reported in the section 7.4.5. The main recipients of this benefit are DSOs.

### 7.4.4.3. Reduce RES and DER total energy curtailment

This benefit is evaluated by measuring the reduction in energy curtailment of RES/DER generation due to voltage violations. This reduction is measured through the comparison between the total amount of energy curtailed for the baseline conditions and the total amount of energy curtailed in the case where the CCS tool is used to solve voltage violations. The evaluation is performed considering the same time period and network configuration both the baseline and the project scenario. At the end, the corresponding percentage of the difference of energy not curtailed is calculated. For the tests performed the final result is a saving of 14% of generated energy if the CCS tool is used. It is important to keep in mind that this additional energy preservation is due either to the limited power curtailment defined by the CCS (in regards to full curtailment), or the none-curtailment because of communication losses. In the latter case, the network might remain constrained.

The main beneficiaries of this benefit are the prosumers. The reduction of the energy curtailed in RES implies that they could still sell a reduced amount of the energy they produce, instead of not being paid at all if their units are completely disconnected in order to deal with voltage violations (CCS tool not used).

#### 7.4.4.4. Increase RES and DER hosting capacity

Regarding this benefit, the CCS tool can be considered a marginal contributor since it is not intended as a full network control tool. Anyway, in the long-term perspective, the contingency simulation could give valuable information about flexibility needs and their potential exploitation planning; these information could help to improve the network planning and, together with an efficient constraints resolution, to facilitate the connection of more new DER and RES units. This benefit has been evaluated in a qualitative way during the WP4 tests and the corresponding results are reported in the section 7.4.5. The main recipients of this benefit from the considered point of view are DSOs.

### 7.4.5. Qualitative impact analysis

As introduced in section 7.4.4, the benefits identified for the CCS tool in some cases cannot be univocally quantified in a numerical way; this raise the need to adopt the qualitative impact analysis approach to estimate the tool impact regarding their functionalities and benefits.

In this approach, the qualitative assessment of the CCS tool is done through the merit deployment matrix compilation (Table 86, Annex VI). In this matrix, a link between functionalities and each benefit is established and a numerical score (weight) is assigned. The sum of the values in columns and rows gives a numerical quantification of the impact of the CCS tool in terms of functionalities and benefits.
For the CCS tool the weights were assigned by the DSO which tested the tool in the WP4 framework (Enedis). So their values reflect also the specific integration efforts tackled and the general impressions of people who made the tests.

The impact of the CCS tool across the benefits is represented in Figure 35; as it can be seen, according to the considerations made in section 7.4.4, the lightest impacts are for the benefits *“increased RES & DER hosting capacity”* and *“reduced costs of activating flexible resources”* for which the tool outcome can only partially contribute. On the other side the highest impact is for benefit *“improved levels of security and quality of supply”* which is supported also by the high value of the related Performance Metric.

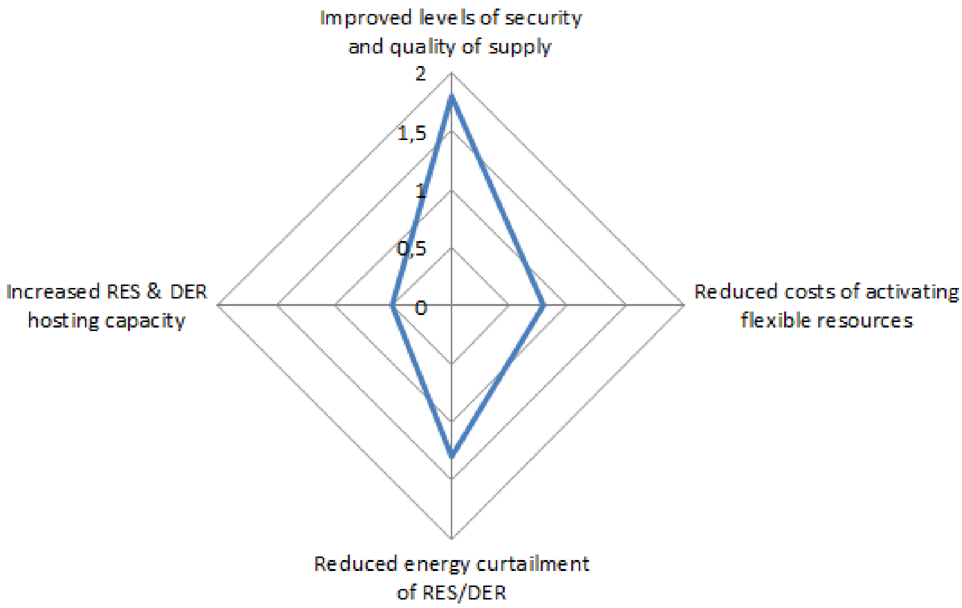



Figure 35 – CCS tool impact across benefits performed by Enedis.

Figure 36 illustrates the impact that each functionality has in the global performance of the CCS tool. It has to be noted that both *"simulate contingency analysis in operational planning (asset unavailability analysis"* and *"integrate ICT unavailability in operational planning"* pay the toll of the actual state of the tool development: these functionalities could be better supported once the planned improvements listed in section 7.4.6 will be fulfilled.

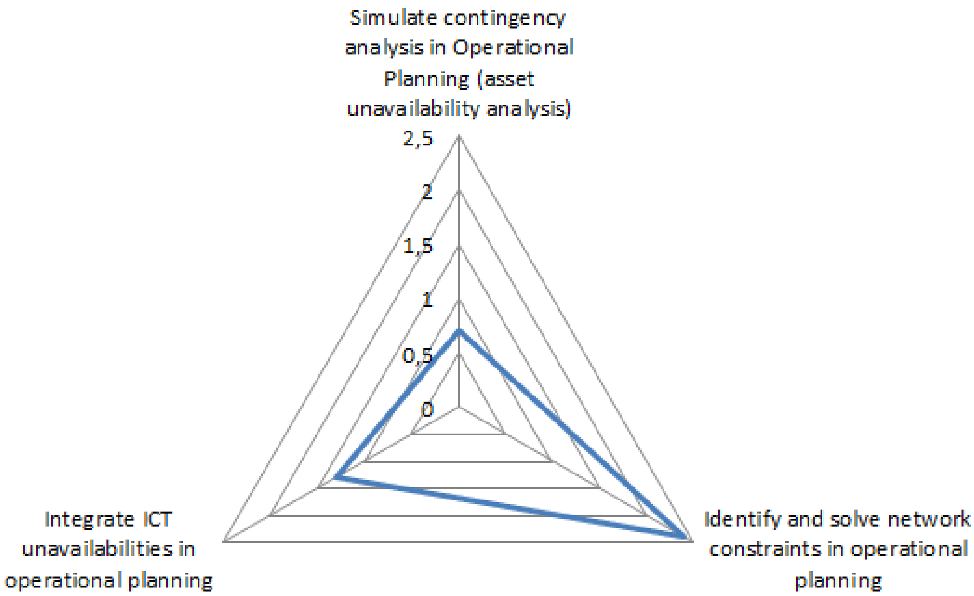



Figure 36 – CCS tool impact across functionalities performed by Enedis.

### 7.4.6. Identification and quantification of the costs

In order to properly identify the costs associated to the CCS tool exploiting, it is necessary to consider the actual level of development and the efforts made so far, the additional efforts to reach the industrial readiness and the costs associated to the integration of the tool in the DSO environment.

The overall efforts needed to develop a complete industrial application can be summarized as follows:

1. Actual version of the tool (early prototype)
2. Improvements to bring the tool to industrial tool:
   - Improvement of the grid elements model (upgrade of Primary Subs and Storage Systems models, local control of resources, etc..);
   - Improvement of the ICT systems models;
   - Improved interface for data exchange and standardization of data format (I/O);
   - Improved integration between the sub-tools/modules;
   - Improvement of the analysis capability of the tool (for scalability) and rationalization of the code (for performance);
   - Development of a grid reconfiguration functionality within the tool;
   - Development of an advanced optimization routine;
   - Translation of the code into an industrial language (C++, Java, Python, etc. …);

It should be stressed out that around 29% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 10 PM spent during the project (with a rough estimation of the average PM cost around 6500€) and 24 PM for the additional developments towards industrialization.

As described in detail in *Deliverable 3.3* and other project deliverables, the CCS tool is intended as a standalone tool for informative/analysis purposes and it is not designed to carry out any type of direct control inside the DSO systems. For this reason, it needs only a commercial PC, a data storage system and a data exchange interface for its basic exploiting.
The sum of the costs of these systems/devices represents the integration cost for the basic exploitation of the CCS tool in a DSO environment.
Some of these costs are strictly dependent on the specific background, which can be found in a DSO operation centre environment. While potential data interface issues can be overcome by completing the tool development, specifically by creating a data interface function suitable to accept the most widespread standardized data format, if a DSO uses a custom proprietary format or dedicated data pre-processing routines are needed, the integration costs become very difficult to quantify. Furthermore, if data interface and pre-processing have a deep impact on the DSO central control automation, the corresponding costs could also reach 2-3 orders of magnitude compared to the cost of a commercial PC necessary to run the tool. For these reasons, the full integration cost quantification is not possible at this phase.
Another issue for the CCS tool exploitation in a real DSO environment is related to the availability of input data, in particular asset reliability data and ICT parameters.
This issue arose during the WP4 tests; these data are not present in Enedis databases and it was necessary to use general data or to calculate them specifically for the test cases. Such an approach cannot be accepted for a full-scale exploitation of the tool so the creation of

dedicated databases should be taken in to account. Related costs can be very high and very difficult to estimate since the boundary of the application is not known at this phase.
Despite these remarks, a qualitative integration cost evaluation versus technical requirements and scale is presented, respectively, in Table 84 and Table 85 of Annex VI.

# 8. Network Reliability Tool – Replay

## 8.1. Introduction

The Replay tool operates within the short-term planning domain. It presents a didactical platform and it aims to support the SCADA operators in the network analysis. The aim of this first phase is to analyse the past, building the basis for preventing similar situations in the future and improving the network management in the near future. This analysis will lead to a decrease in the number of interruptions and their duration (SAIDI), as well as respecting the electrical parameters on the network with acceptable performances in terms of quality of service and power quality. Furthermore, because of the architecture of the system, the Replay system could become a test platform for new tools and software to be tested on the real SCADA system, without impacting the real operation on the network. Indeed the introduction of new cloud technology and virtualization architecture could allow easier sharing of the information available on different didactical platforms and so information among different control rooms and different areas.
In Figure 37 a schematic representation of the "concepts chain" is represented, from the evolvDSO roles supported by the Replay to the specific implemented services.

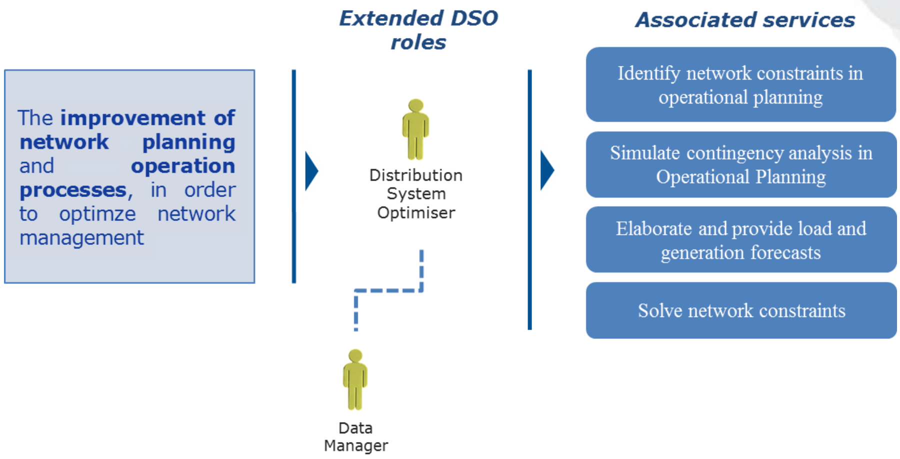



**Figure 37 – The impact of the Replay tool on the DSO roles**

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 (48 to 72 hours ahead) 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 supporting the SCADA operator in detecting constraints;
- 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 defined timeframes;

- Validate from a technical perspective the flexibility offers proposed or activated in the balancing market and/or flexibility market.

## 8.2. Description of the tool and its elements

The Replay is a real time system able to communicate with the real SCADA, exchanging with it network data related to the occurred events, electric schemes and measurements. In order to understand the basic idea of the replay a simple scheme of the system architecture system is represented in Figure 38.

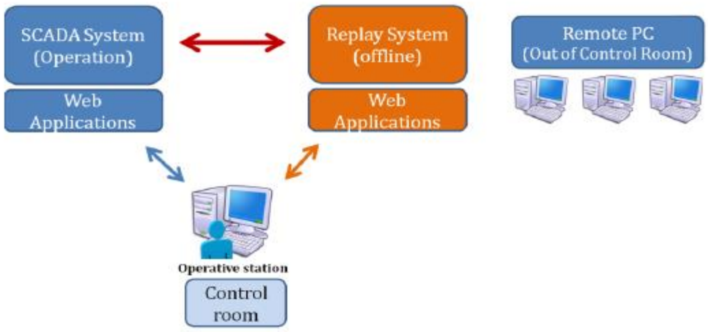



**Figure 38 – Replay tool functional architecture**

In common practice, mainly for security, the SCADA network real-time schemes can be accessed by external operators only for information. Consequently they can't act on the network through the tools and functionalities implemented in the control room.
Since the Replay tool is an independent platform, acting as a virtual SCADA system, it can communicate with remote PCs allowing the training of a large number of operators without restrictions .

In essence, the Replay tool takes into account the history of the network recording the most important events occurred on the network in the past and collecting data from the system, in particular:

- Network schemes from SCADA database.
- Quality of services data related to the interruptions by interaction with Web Applications to facilitate *ex post and predictive analysis*.
- Forecasting data for customers and producers (3 days forecast).
- SCADA Data: Actual position of grid's equipment.
- Technical data of grid assets and topology data.

As used in the real e-distribuzione control room, regarding the human machine interface of the control centre operators, a computer must be dedicated to the network operation (*ST-REPLAY*) and another one is dedicated to data elaboration (*ST-Web Application Replay*). Furthermore, this double interface (SCADA and Web interface) extends the access to network data to external units, avoiding the security risk of managing a SCADA station out of the control centre.

One of the key points of the methodology behind the Replay tool is that it is not strictly based on specific tools/functionalities of the e-distribuzione's SCADA: the concept of a smart didactical platform can be applied to several other systems, based on different software, allowing the replicability of the tool among other DSOs.

Furthermore, the use of an off-line system that replicates the real system in operation could give an opportunity to become a test platform to be used for testing new SCADA sub tools and software without perturbing the real system operation.

Another innovative point of the Replay tool, compared with the existing network analysis tools, is represented by the possibility that Replay provides the visualization of the network protocol events directly on the corresponding network scheme. This analysis method can help the operators on the training as well as the network expert in different kind of analysis.

## 8.3. High-level technical assessment of the tool

### 8.3.1. Synthesis of tool evaluation in WP3 simulation tests

Within the boundaries of WP3 simulation tests, reported in detail in the *Deliverable 3.4*, the basic functionalities of the Replay tool have been tested, in order to proof the effectiveness of the proposed methodology. The tests were carried out on a simple network consisting in a primary substation and an MV feeder. Different operating scenarios (grid configurations) and specific asset issues, based on past events, have been considered for this network.

For the first time it was also possible to model and exploit the active power modulation flexibility which, at present, is not allowed in Italy and therefore cannot be analysed with the SCADA system. The simulations were carried out by tool developers with the support of network experts.

The simulations consisted in:

- Accessing the network database of the SCADA system;
- Select a time interval in the past considering a long interruption (t>3min);
- Visualizing the list of events in the Replay System;
- Visualizing the network scheme in the Replay System corresponding to the event list;
- Visualizing the quality of service parameters related to the interruptions (ex-post analysis)
- Defining test scenarios to analyse parameters increase/decrease based on the specific network modifications (configuration changes and active power modulations).

The simulations confirm the expectations related to the potential advantages about the ex post analysis and the predictive analysis. The capability of investigating past events in the actual/real-time operating conditions proved its effectiveness; from their analysis it was possible to evaluate several set of operators actions and to identify those which can improve the network management. For each test the corresponding quality of service parameters have been evaluated: the Replay tool showed a high potential in reducing both the number and duration of interruptions (increase of SAIDI Reduction Index KPI till 20%).

From the operators point of view, the availability of a virtual fully operating SCADA system which doesn't affect the real operation system was highly appreciated: they were free to test and repeat realistic actions several times before finding the best ones without the urge (and the risks) of the real control-room.

### 8.3.2. Synthesis of tool evaluation in WP4 field tests

For the field tests carried out within WP4, a larger scale of analysis was considered: several networks characterized by a large number of MV feeders and up to 3 primary substations were modelled and analysed. Considering three basic kind of networks (urban, industrial and rural) more than 30 test scenarios were created and tested in the e-distribuzione's Smart Grid Lab in Milan. Besides e-distribuzione-owned flexibilities, also active power modulation and other new types of flexibilities have been considered.

For these tests the Replay tool architecture was installed in the control room of the Smart Grid Lab and connected with the SCADA databases, sub tools and utilities; furthermore interactive sessions with trained SCADA operators have been organized in order to collect feedbacks from the operating of the Replay prototype. These sessions helped the developers to identify critical points to be solved and relevant prompts for future improvements and large scale deployment.

The full integration of Replay tool in a real control room allowed to collect data directly from SCADA system: the network database (schemes and related historical evolution) for the ex-post analysis and the forecasting tool for loads and generators profiles for the predictive analysis. To complete the data set, a list of past events occurred in July 2015 in the analysed networks was considered.

One of the most important difficulties found in the test is the huge amount of data (events) necessary for the simulations. The first modification adapted in the tool is the selection of the list of events to be managed by Replay. In particular, to increase the quality of service parameters only specific signals from the network needs to be analysed. While the other can be stored in the database without processing finalized to the ex-post analysis. On the other hand, the introduction of specific engine calculators (to be evaluated) can improve the load flow computational time. Indeed, in the near future for the large-scale deployment the possibility of using an external engine could improve the behaviour of all the system as done for the real SCADA system in operation. In this perspective, the results of the WP4 help the developers to follow the line of a common integrated SCADA interface with the interactive connection to all the tools of the Operation domain. The Replay tool appears very useful as a didactical platform and as a tool for the back office support in the control room.

Alongside the quantitative outcomes, reported in the next paragraph, these tests confirmed that Replay can by deployed in a real environment in the short term without major modifications; this result is in favour with the full replicability concept. Also, through the interactive sessions with SCADA operators, the proof that Replay can positively support the current network management processes was achieved: the new versions of the Replay tool will support the change of approach of the operators, who will be asked more and more to integrate the back office know-how in the usual network management.

### 8.3.3. Results of the KPIs calculation in WP4 field tests

Both for simulation and field tests the same KPIs have been considered; anyway, as explained in the previous sections, for WP4 field tests they were calculated for several networks with a wider scale, compared to the simple network considered for simulation tests. This was reflected on the final results, which appears more heterogeneous compared with those obtained in WP3 simulation tests. In particular the SRI (SAIDI Reduction Index), which in WP3 tests showed fairly good average figures (20%), for the cases evaluated in field tests spread from 3% to 60%. This wide variability is mainly related to the specific operating conditions of each network, to the level of expertise of the SCADA operator and the level of automation and the remote control rate of the feeders. By the way, the overall results obtained through the Replay implementation are broadly positive, always showing a reduction in interruptions and their duration. Also the CRI (Criticalities Reduction Index) figures, even if currently the predictive analysis is not considered on the core context of the tool, confirms the potential support that the tool can create using new levers as active power modulation. The introduction of flexibility has been analysed in the perspective of the use of the prototype for a training platform. The present limits in the active power modulation have been exceeded for test purposes and this helped consistently the analysis of alternative actions to reduce criticalities occurrence. The correct network design with the fit-and-forget approach generally avoids the occurrence of critical situations but, on contingency situations, the possibility to modulate active power to solve network criticalities can represent an interesting lever.

In the following table the KPI results for field tests are summarized:

| ***KPI Name*** | ***KPI Value*** | ***Comment*** |
|---|---|---|
| ***SRI: SAIDI Reduction Index (potential)*** | **SRI values**<br><br>From 1% to 5% medium values, with peak of **60%** | It is possible to measure and appreciate the potential SAIDI reduction by the introduction of Replay tool. The values are referred to the standard current management approach compared with the results (SAIDI) obtained simulating new approaches by the use of the Replay. The peak is referred to situations managed in the training phase with a low level of expertise of the operator. |
| ***CRI: Criticalities Reduction Index*** | **CRI-Values**<br><br>From 2% to 60% (the range considers the possibility to apply active power modulation without the current regulatory limits). | It is possible to measure and appreciate the potential reduced number of criticalities based on power modulations verified by the Replay tool. The values are referred to the standard current management approach compared with the results obtained simulating the network by the use of the Replay tool and in particular by the introduction of flexibility contract (active power modulation). |

| | | |
|---|---|---|
| ***TTS/CTS: Training Time Saving/Training Cost Saving*** | **TTS/CTS: [Estimation]** From 60% to 80% of time saved compared with the current procedure. | Estimation of these values with and without the use of the Replay Tool. The current evaluation takes into account the possibility by a qualitative as well that quantitative component of the KPI. In particular, if the quantitative component is calculated with the hypothesis of the number of faults to be managed, the qualitative component is evaluated on the basis of the specific and unique contribution of Replay System (real events of the past, real network, real SCADA interface, etc...). |

## 8.4. Evaluation of costs and benefits of the tool

### 8.4.1. Mapping the tool on to functionalities

The services and functionalities enabled by the Replay tool are reported in Table 44. None of the services proposed in Annex III of the JRC methodology [1] is suitable to be applied to the Replay tool. On the other hand, a new service entitled *Simulate contingency analysis in Operational Planning (asset unavailability analysis)* was derived from the corresponding SUC (defined in *Deliverable 2.2*). All the functionalities identified are specific for the Replay tool.

| Service | Replay Functionalities |
|---|---|
| Simulate contingency analysis in Operational Planning (asset unavailability analysis) | 1. Ex-Post network analysis: Possibility to analyze the past and identify critical situations. |
| | 2. Predictive Analysis: Possibility to modify users active power, events and network configuration in a simulation to prevent future criticalities. |
| | 3. Analysis of Quality of Service parameters in real and simulated cases. |
| | 4. Short-Term validation of power flows and voltages: Calculation of current and voltages before and after the network modification. |

Table 44 – Mapping of the Replay tool into the functionalities it provides.

### 8.4.2. Mapping the functionalities on to benefits

The third step of the cost-benefit analysis has the purpose of identifying the benefits that are provided by each functionality. The EPRI methodology [2] provides a list of 22 Smart Grid Benefits. However, since the Replay tool is more related with a qualitative evaluation, three new non-quantifiable benefits were used to develop the functionalities-benefits matrix. A brief explanation of how the referred benefits are provided by the Replay tool functionalities is presented below. Whenever it exists, the link between the benefits and the correspondent operational KPIs is also presented.

- **Reduced service interruptions (quantitative):** the improvement of the SCADA operator directly influences the reduction of service interruptions. The ex-post analysis methodology allows the analysis of specific events occurred in the past, with the possibility to identify alternative actions to avoid or to reduce interruptions, resulting in a more effective network management. This innovative function is performed by monitoring SAIDI for each interruption with the possibility to modify some operations occurred in the past and recorded in a dedicated database. So, by the use of the Replay, it is not possible to modify the past but it possible to have a better operation for the future.

- **Reduction of Network Criticalities (Qualitative impact on Reduction of energy curtailment of RES and DER):** the Replay creates network scenarios and it allows the execution of tests elaborating load flow calculation. The Replay tool finds new solutions for electrical constraints as over voltages and overloads helping the SCADA operator to solve them. The Replay represents a didactical platform: even though to date many commercial tools can automatically elaborate the best network configurations, the Replay allows the SCADA operator to identify the solution by manual interventions on the real network condition. This approach lead operators to further investigate specific network configurations and network operations without the need of a different environment for simulations.
- **Enhanced training of control room operators (qualitative):**
  From the qualitative point of view, more training possibilities are available, without the support of senior colleagues.

The functionalities-benefits matrix is summarized in Table 45.

| Benefits | Functionalities | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| Reduced service interruptions (quantitative): | • | • | • | |
| Reduction of Network Criticalities (Qualitative impact on Reduction of energy curtailment of RES and DER): | | | | • |
| Enhanced training of control room operators (qualitative) | • | • | • | • |

Table 45 – Functionalities-Benefits matrix for the Replay tool performed by e-distribuzione

### 8.4.3. Establishment of the baseline

The definition of the “control state” which illustrates the used benchmark model is an important part of the cost-benefit analysis. The “control state” is commonly called “baseline scenario” and has the goal of enabling the comparison with the new developed tool. Considering the mentioned above, the scenarios to be tested in the Replay tool case are:

- **Baseline scenario:** it is based on the actual operating conditions, without the virtual duplication of SCADA functionalities achievable through the use the Replay tool.
- **Project scenario:** Evaluation of the applicability of the Replay tool and evaluation of the results based on the prototype installed in the Milano’s Smart Grid Lab.

For each one of the two scenarios above, the most relevant conditions regarding the analysed grids, the load growth and DRES scenarios, as well as the metrics used to evaluate the correspondent benefits are summarized in Table 46.

| Benefits | Baseline scenario | Project Scenario [use of Replay] | Metric |
|---|---|---|---|
| **Reduce service interruptions** | No use of Replay | Use of Replay<br>• Change of Network Configuration/Activation of flexibility<br>• New calculation of SAIDI | SAIDI Interruption duration * customers |
| **Reduction of network criticalities** | No use of Replay | Use of Replay:<br>• Identification of voltage and Current violations by LF calculation<br>• Propose new predictive network configurations based on elaboration of forecasted values (MAGO) and introduction of FLEXIBILITY | Number of criticalities identified |
| **Enhanced training of control room operators** | No Use of Replay | Use of Replay:<br>• Estimation of the time by the introduction of the REPLAY didactical simulator | Time estimation |

Table 46 – Baseline and Project conditions for the Replay tool benefits

It is important to state that the metrics described in Table 46 are based on the Operational KPIs. More information can be found in *Deliverable 3.3*.

### 8.4.4. Demonstration of the benefits

According to the metrics presented in Table 46, the results validating the benefits and the corresponding beneficiaries are shown in the next sections.

#### 8.4.4.1. Contributes to potentially decrease SAIDI in the network management.

As established in Table 46, the SAIDI is one of the parameters used to evaluate the contribution of the Replay tool to the improvement of network management.
The test consists in the comparison of SAIDI and other quality of service parameters calculated through the ex-post analysis carried out with the Replay tool, with the same parameters calculated for the "usual" network management (i.e. independently from the use of Replay tool). Ideally, the SCADA operator manages the outages in the best optimized way keeping the SAIDI value to the minimum; anyway, the off-line simulations carried out with Replay tool allow to find better solutions and helping in further reduction of the SAIDI figures.
This type of test proved also to be helpful in validating the potential of a didactical platform, by the evaluation of the positive contribution of the ex-post analysis.

In order to quantify the impact introduced by the use of the REPLAY, we use an operational KPI: the potential SAIDI reduction index.
The main beneficiaries of this benefits are the DSOs and the customers. The level of uncertainty related with this benefit can be classified as modest, since the accuracy of the information provided by the Replay tool was obtained using simulated fault.
The Replay accuracy is dependent on the quality of the input data: network events and related time, forecast and SCADA measures. It is essential to stress that this data is considerably influenced by the specific operating conditions.

| Primary Substation reference | MV Feeder | Number of Customers | Time Interval | SRI | NOTE |
|---|---|---|---|---|---|
| Cagliari Centro | Villaputzu | 2783 LV; 8 MV | 6 minutes | 1% | Light Optimization of the outage management |
| Cagliari Centro | SanPriamo | 863 LV; 8 MV | 6 minutes | 3,40% | Strong Optimization of the outage management |
| Cagliari Centro | FIERA | 1111 LV; 3 MV | 16 minutes | 60% | Training example |

**Table 47 - Operational KPI SAIDI Reduction Index for the Italian distribution network (Cagliari) with current level of RES penetration**

In Table 47, three specific examples of SRI calculation are considered. The first one is an example of small optimization in the outage management obtained by the use of the Replay tool. In particular, considering the SAIDI calculated for a specific fault occurred in a defined time interval, the potential reduction obtainable optimizing the process has been 1%. For the second example the potential reduction of a fault is 3.4%. Anyway the most interesting data about the potential SRI was achieved in the feeder "Fiera", where the outage management has been strongly optimized in the simulation compared with the real case: a more effective schedule for switches operation was defined based on the ex-post analysis outcomes. This allowed to save some time in network reconfiguration after the outage, reducing the corresponding SAIDI. In this specific case the SCADA operator had the opportunity to improve its behaviour.

### 8.4.4.2. Contributes to potentially decrease network criticalities

One of the main advantages of executing a load flow calculation on the network is the possibility of monitoring criticalities in terms of over current and overvoltage. Regarding the Italian network studied, two different context scenarios are considered in particular the current and the 2020 scenarios. It is important to highlight that specific network criticalities could be related to specific network configuration or contingency situations.

Specifically for the tests, a narrower voltage range has been considered (+/- 3% of the nominal value instead of +/-10%, as imposed by the Italian network rules). This preventive approach was necessary since in the normal operating conditions not enough criticalities for test purposes are observed.

| Test Case | Sub - Test Case | Station | MV Feeder | Data period | Actions on the network | Network criticalities | CRI |
|---|---|---|---|---|---|---|---|
| 2016 scenario (Current Real Complete network + adjustment to RES Penetration) | Predictive Analysis - No Flexibility allowed | SULCIS 2 | CARBO SULCIS | 8/07/15 | None - Standard Configuration | 5 | 0,6 |
| | Predictive Analysis - Flexibility allowed | SULCIS 2 | CARBO SULCIS | 8/07/15 | Power Reduction 20% | 2 | |
| | Predictive Analysis - No Flexibility allowed | SULCIS 2 | FLUMENTEC | 8/07/15 | None - Standard Configuration | 4 | 0,8 |
| | Predictive Analysis - Flexibility allowed | SULCIS 2 | FLUMENTEC | 8/07/15 | Changing network configuration and power reduction of 20% | 1 | |
| 2016 scenario (Current Real Complete network + adjustment to RES Penetration) | Predictive Analysis - No Flexibility allowed | SULCIS 2 | METALLOTEC | 8/07/15 | None - Standard Configuration | 5 | 0,2 |
| | Predictive Analysis - Flexibility allowed | SULCIS 2 | METALLOTEC | 8/07/15 | Power Reduction 20% | 4 | |
| | Predictive Analysis - No Flexibility allowed | SULCIS 2 | ZONA INDUSTRIALE P VESME | 8/07/15 | None - Standard Configuration | 6 | 0,8 |
| | Predictive Analysis - Flexibility allowed | SULCIS 2 | ZONA INDUSTRIALE P VESME | 8/07/15 | Changing network configuration and power reduction of 20% | 1 | |

Table 48 - Operational KPI Criticalities Reduction Index for the Italian distribution network (Cagliari) with current level of RES penetration (2016)

In Table 48 a list of the tests carried out is presented within the current scenario. The potential reduction of network criticalities is not homogeneous because of the small area considered. The specific network portions considered are industrial, rural and urban and it is possible to see that the results of the test are not dependent from the kind of network considered. The overall result, i.e. the number of solved criticalities, is not directly linked to the Replay tool exploiting due to the specific operating conditions of test cases networks; anyway, it has been observed that the use of Replay helped the operators in the network management: very often the best action was identified easier through the Replay tool comparing with the usual approach.

The same approach of the previous described tests has been used also to analyse a specific a situation of the next 2020 perspective, with a major level of RES penetration and a higher level of customers consumptions. These tests were based on the future scenarios identified in WP1; for this purpose, the contractual power of the generators and customers was increased by the 20%. Even if this type of analysis is usually carried out with long-term planning tools, in this case the Replay predictive analysis capability proved to be reliable and effective. The results of these tests are presented in Table 49.

| Test Case | Sub - Test Case | Station | MV Feeder | Data period | Actions on the network | Network criticalities | CRI |
|---|---|---|---|---|---|---|---|
| 2020scenario (Current Real Complete network + adjustment to RES Penetration) customers/producers power increased of 30% | Predictive Analysis - No Flexibility allowed | CA CENTRO | POETTO | 8/07/15 | None - Standard Configuration | 5 | 0,6 |
| | Predictive Analysis - Flexibility allowed | CA CENTRO | POETTO | 8/07/15 | Changing network configuration and power reduction of 20% | 2 | |
| | Predictive Analysis - No Flexibility allowed | MURAVERA | MURAVERA | 8/07/15 | None - Standard Configuration | 6 | 0,7 |
| | Predictive Analysis - Flexibility allowed | MURAVERA | MURAVERA | 8/07/15 | Changing network configuration and power reduction of 20% | 2 | |

**Table 49 - Operational KPI Criticalities Reduction Index for the Italian distribution network (Cagliari) with 2020 level of RES penetration**

### 8.4.4.3. Contributes to potentially decrease training time in the control room

The introduction of the didactical platform available in the Replay tool, can support the DSO in the training time saving and in particular it could be possible to save related costs.
The procedure adopted to verify this issue is articulated in three steps:

- Evaluation of a set of standard cases to be managed to become expert operator.

- Evaluation of time/costs to become expert for the set of selected activities by mean the current methodology.
- Comparison between the results obtained by the use of Replay.

First of all, the SCADA operators identifies a set of activities to be evaluated from the training point of view:

1. Detection of the specific fault (branch) with and without applying automation.
2. Detection of the specific fault (branch) with and without applying automation and using repowering method to be verified by specific LF calculation.
3. Simulations on the network providing LF calculation.
4. New network configuration elaborated on the basis of specific network constraints to allow the SCADA operator to get expertise.
5. New network calculation approach to verify voltage and current violations (criticalities) for planned works.

That kind of activities could be considered the most common to be learned by the SCADA operator. The next step has been the identification of the time necessary to learn this kind of activity on the basis of the occurrence/frequency of the events. In Table 50 a representation of the specific hypothesis is provided.

| Test Case Number | Cases to be managed to become expert | Hypothesis | Real [effective work hours] | Hypothesis | Replay [effective work hours] | TTS |
|---|---|---|---|---|---|---|
| 1 | 50 | 10 faults per week | 368 | 5 faults per day | 36.8 | 90% |
| 2 | 15 | 10 faults per week | 368 | 6 faults per day | 73.6 | 80% |
| 3 | 10 | 2 simulations per week | 36,8 | 2 simulation per day | 7.36 | 80% |
| 4 | 15 | 10 faults per week | 368 | 6 faults per day | 73.6 | 80% |
| 5 | 10 | 2 simulations per week | 36,8 | 2 simulation per day | 7.36 | 80% |

**Table 50 - Operational KPI TTS for the Italian distribution network and Replay used as didactical platform for training purpose**

Considering simplified activities and assuming that this event occur with a defined frequency it is possible to estimate the advantages in terms of time and related cost by the use of the Replay didactical platform.
Furthermore considering the average personnel cost for a DSO it is possible to evaluate the effective TCS (Training Cost Saving) on the basis of the training time saving parameters.

### 8.4.5. Qualitative impact analysis

Often a project assessment addresses both quantifiable and non-quantifiable benefits. However, certain benefits that are described in a cost-benefit analysis are difficult to monetize. In this case, the qualitative analysis has a very important role. This is the case of Replay since is an "informative tool". Considering the benefits that are presented in section 8.4.2, their quantification is not possible. For instance, the description in physical units of the separation of the contributions of different types of flexibilities or the increase of data exchange is impossible. Therefore, in these cases is very important to do a detailed description of the qualitative appraisal of these benefits. The assessment framework is based on a merit deployment matrix where benefits are given in the rows and functionalities are given in columns.

Table 89 shows the merit deployment matrix developed for the Replay tool. This table allows to identify the links between benefits and functionalities. Moreover, in each cell is explained how the links between benefits and functionalities were achieved. The weights assigned to each link tries to quantify their relevance. Through these weights, it is possible to quantify the project impact across functionalities and benefits.

Figure 39 illustrates the impact that each benefit has in the global performance of the Replay tool. Since the main goal of the Replay is related to the relevance of ex-post and predictive analysis of the network, the core impact of the tool is to enhance training of control room with possibility of optimizing the time and cost of the training.

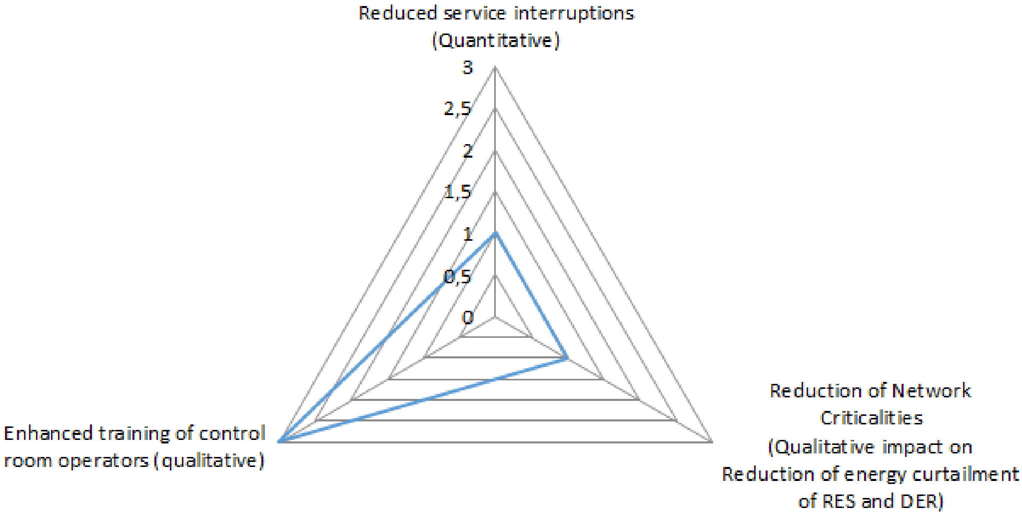



**Figure 39 – Project impact across benefits (Replay tool) performed by e-distribuzione**

Figure 40 shows the impact that each functionality provided by the Replay has upon the global assessment of the tool. As it can be observed in Figure 40 the possibility to execute ex-post analysis and more generally network analysis has a high weight and identifies the core purpose for the Replay. This higher impact represents the main goal of the replay tool: to provide network operators with a didactical platform to be used for network in-depth analysis. The *ex-post* analysis represents the most innovative and effective approach impacting the quality of service, whereas the predictive analysis could also be performed by the use of commercial platform available in the DSO centres. Obviously, the possibility to integrate the different approaches in a unique tool would represent a frontier of the SCADA evaluation.

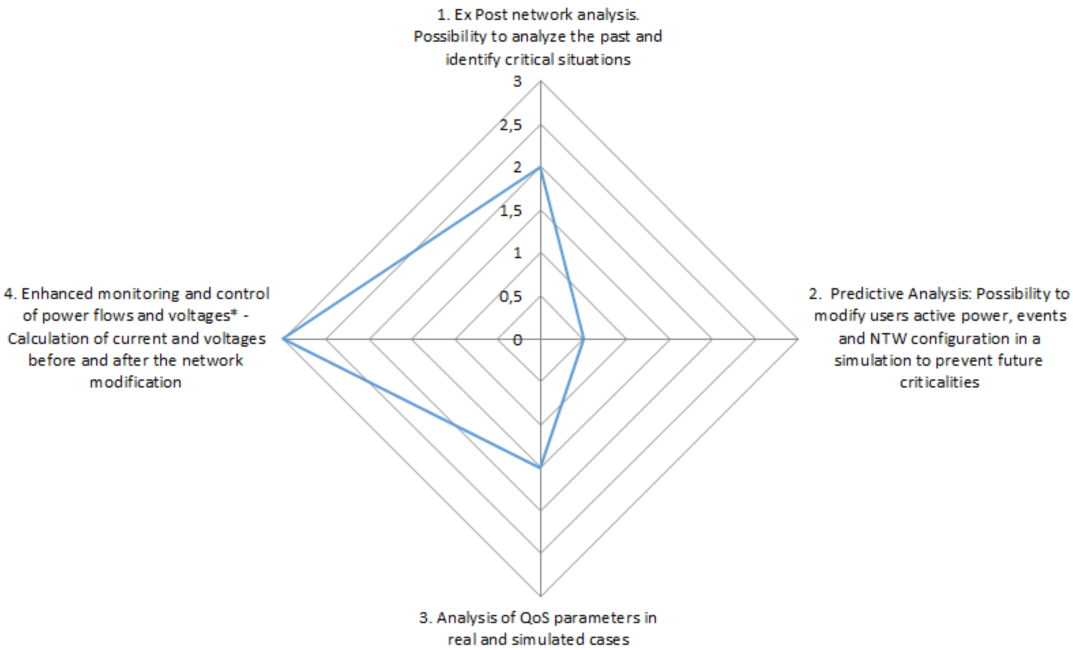



**Figure 40 – Project impact across functionalities (Replay tool) performed by e-distribuzione**

## 8.4.6. Identification and quantification of the costs

The costs associated to the Replay tool exploiting are mainly related to the development of the prototype code itself (and its installation in the control room systems), the development of a virtualized software infrastructure and its related hardware.
Within the evolvDSO project, the last two requirements cannot be accounted since the Milano Smart Grid Lab, in which Replay tool was tested, already allows to virtualize the SCADA functions for testing purposes and it is equipped with all the necessary hardware.
The development of the Replay tool was subcontracted by e-distribuzione to its service provider and then a single cost figure for the prototype instead of the person/month related figures is available; the costs within the evolvDSO project amount to 295k€ and they can be summarized as follows:

1. Software development for the prototype;
2. Installation of the prototype in the Smart Grid Lab for testing purpose including connection with real system in operation;
3. Licensing including the system in the Smart Grid Lab of Milano.

The installation costs are strictly related to the available technological level in the control room. All the implementation and installation efforts should be discussed directly with the SCADA provider: only in this way it is possible to accurately identify the corresponding costs.
A qualitative integration cost evaluation versus technical requirements is presented in Table 87 of Annex VII.
The costs presented in this paragraph are related only to the prototype solution installed in Milano Smart Grid Lab, so the cost scalability for the installation in other control centres was not carried out; anyway, a realistic example of cost versus scale analysis is provided in Table 88 of Annex VII.

# 9. Advanced Asset Management

## 9.1. Introduction

The Advanced Asset Management tool, developed by UCD, is a tool within the scope of an innovative Business Use Case *"Decide asset renewal priorities and optimise maintenance programmes"*. This tool functionality is illustrated in the Figure 41.

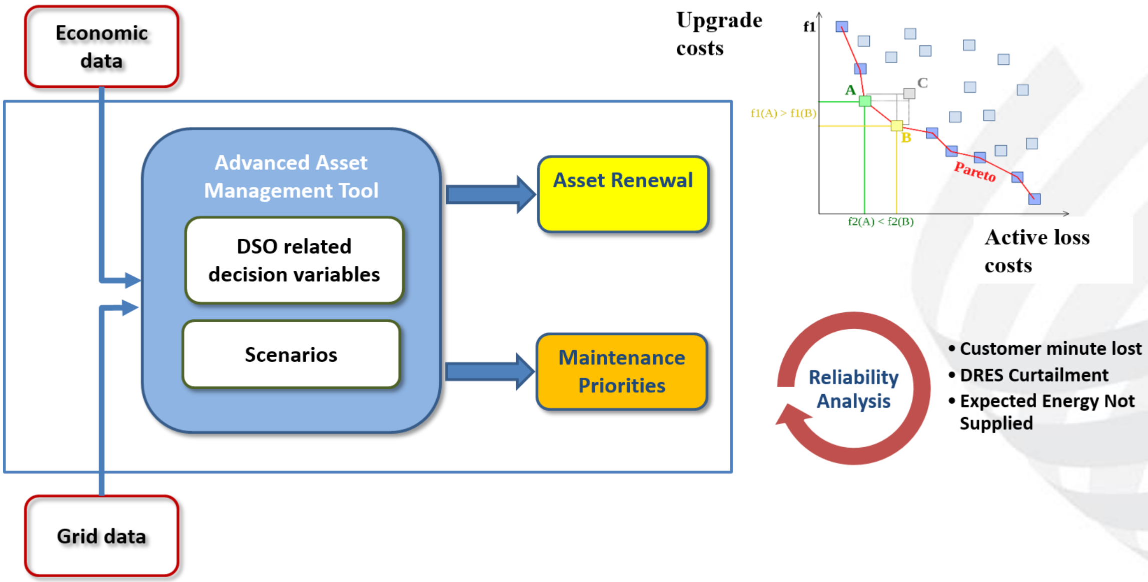



Figure 41 - A summary of the functional components of the AAM tool

In Figure 42 some of the new and evolving distribution system operator activities, as well as the associated tool-relevant services, are pointed out.

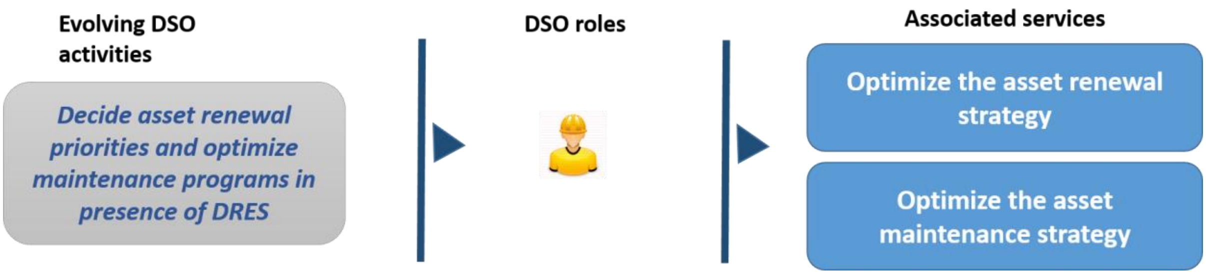



Figure 42 -New roles and services associated with the tool

## 9.2. Description of the tool and its elements

Asset management deals with the optimal assignment of maintenance/renewal priorities for each component in a given system considering component importance and failure/repair rates and their combined effects on overall system performance. The AAM tool embodies two subtools that try to improve the technical, financial and environmental performance of the distribution network. Each subtool offers actionable insights to the distribution system planner, to improve the quality of asset renewal and maintenance planning decisions. The asset renewal subtool optimizes within both a financial and a load flow framework, so that a potential upgrade's effect on network loss performance, and its discounted cost, is considered simultaneously. The maintenance priorities subtool determines which component outages in the network would be most critical, so that maintenance and inspection activities can be aligned appropriately.

The key inputs to the tool are the network description, component costings, and reliability data. Its key outputs are an enhanced asset renewal schedule, and a asset criticality listing.
This tool is designed to be used by *asset managers* within a distribution system operator.
Improvements are expected in:

- Customer minute lost.
- Expected energy not supplied.
- DRES energy curtailment.
- Active energy losses payments & Network upgrade costs

The tool's functionalities are accessed through a unified graphical user interface, as shown in Figure 43:

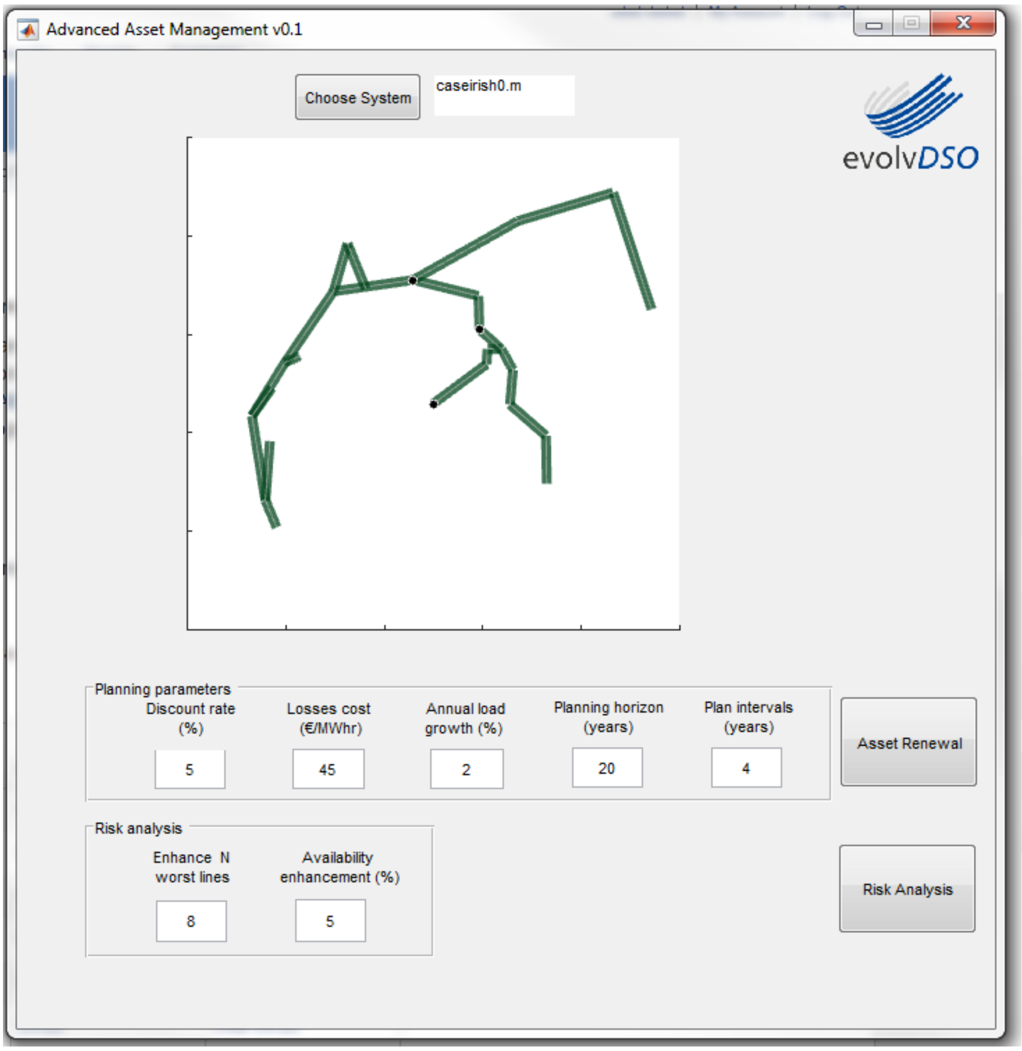



Figure 43 - A screenshot showing an example of the tool's graphical user interface in use

# 9.3. High-level technical assessment of the tool

## 9.3.1. Synthesis of tool evaluation in WP3 simulation tests

The test network used was an Irish 20 kV distribution network fed by a 38 kV substation. A one-line diagram of this network is depicted in Figure 44, where the location and distribution of the consumers and distributed generation units are marked (generation sites are shown with red circles). In keeping with Irish norms, the generating sites were taken to represent wind farms. The network contains 24 buses and 22 branches, and serves a maximal baseline load of around 16 MW. Bus 1 is the interface point with the 38 kV network.

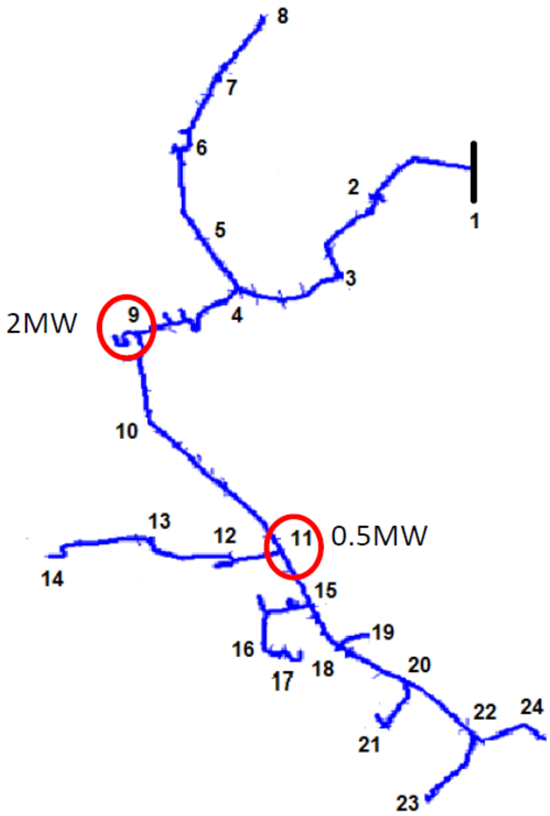



Figure 44 – The exemplary Irish rural network

The principal hypothesis to be tested was whether optimal asset renewal and maintenance decisions could realise substantial improvements in the network's reliability and financial efficiency.

In each scenario, the tool considered a twenty-year window over which to optimize the upgrading of conductors on the network. An investment pathway was calculated for each scenario, from which the KPIs could be derived. The financial efficiencies realised by this enhanced investment pathway is quantified with the first KPI, which considers the discounted network renewal and operation cost.

The comparative business-as-usual case for the asset renewal analysis is taken to be a naïve loss-minimization strategy without considering the upgrade costs. In these conditions, the planner just tries to minimize the cost of energy losses. The optimal strategy simultaneously considers the losses and the discounted upgrade costs. The various trade-offs between these objectives can be shown as a Pareto front for each asset renewal appraisal.

The KPIs tested in the WP3 are the same tested in the WP4. The KPI are described in Table 51:

| KPI Name | KPI Value | Comment |
|---|---|---|
| *Network Cost Improvement* | $1 - \frac{(C_{BaU} - C_{opt})}{C_{BaU}} = 10.79\%$ | Using the AAM tool shows that the optimal asset renewal sub-tool can improve the financial efficiency of distribution system investments. The optimal solution is compared with the business as usual case and nearly 11 % improvement in total costs is observed. |
| *Anticipated Network Risk Improvement* | $R_{enh}/R_{BaU} = 92.5\%$ | The DSO can identify the critical components that their failure may cause loss of load in the network. The optimal asset management tool can reduce approximately 7.5 % of this loss of load. in case of contingencies. |
| *Quality of Supply* | $CML_{enh}/CML_{BaU} = 92.5\%$ | The optimal asset management helps improving the power quality and quality of supply by reducing the customer minute lost around 7.5%. The customer minute lost is the average number of minutes per year that a customer does not receive any service. |
| *Reduced energy Curtailment of RES and DER* | $Curt_{enh}/Curt_{BaU} = 67.5\%$ | This showed how the DSO has used the clean and local energy resources in a more efficient way. This index arises when RES is available, but the grid operator does not allow it to inject power into the grid because of certain technical issues. In other words, the RES cannot be dispatched. These technical issues might be because of thermal limits of the networks, voltage constraints or islanding caused by line outage |

**Table 51 – KPIs defined and measured for the AAM tool**

## 9.3.2. Synthesis of tool evaluation in WP4 field tests

The WP4 trials were not aimed at validating the D3.4 simulations: rather, this *structured engagement* was seeking to assess how applicable the tool might be in a real distribution system asset management context. Over the course of various sessions, the tool's functionality was interactively demonstrated to asset management staff within ESB Networks. To gauge its likely real-world functionality, structured feedback forms were distributed to participating staff after each demonstration session. The results from WP3 and WP4 tests are complementary since they evaluate the theoretical and practical effectiveness of the tool, respectively.

Overall, the demonstration sessions were positive. The ability to automate asset planning decisions was welcomed by the professional staff in this ambit. However, there was a consensus that the tool should embrace a wider and more realistic gamut of potential asset maintenance/renewal actions. That is, the realism of how DSO actions were modelled was called into question. Likewise, it was proposed that a more refined focus on certain specific activities (e.g. pre-emptive timber cutting) would help the tool deliver more value.

### 9.3.3. Results of KPIs and PMs calculation in WP4 field tests

The KPIs defined and applied in WP3 could not fully be applied to the field test. Rather qualitative feedback was captured to see how smoothly the tool might integrate into a DSO asset management context: the WP3 KPIs capture how well it would perform once up-and-running in such an environment. WP3 and WP4 are fundamentally complementary as the numerical outputs for this tool in *D3.4* show its potential performance: the tool's *D4.3* qualitative feedback indicates its immediate usefulness in a real world asset management department.

This feedback is summarised below:

- **Tool User Interface**

Below are some quotes from the feedback comments received that were related to the user interface, which were solicited with the question "What functionalities could enhance the tool?"

1. *"Change GUI for asset intervention"*
2. *"Make output more explicit so that users could assess the components that go into each output"*

These answers indicate that the GUI has an appropriate approach but needs to provide more detail.

- **Planners' Needs**

A number of feedback questions solicited whether if the tool lived up to asset planners need and expectations: they are summarised in Table 54.

For *Actionable insights for loss-minimization*, the average answer was 5.75, indicating that the tool has some scope to assist in loss reduction efforts.
For *Actionable insights for asset renewal timing,* the average was 5.25, again a fairly neutral response, indicating that the tool may have useful value but not overwhelmingly so.
Under *Tool Realism*, the average was 4, indicating that it is neither realistic nor unrealistic, so seemingly the tool neither confounds nor exceeds expectations.
Finally, considering *Improvement over manual planning*, the average here of 6 shows that the automated optimizations of this tool represents a real advancement over manual and ad-hoc procedures.
With respect to *Insight Generation*, the average response was 5.25, suggesting that the loss reducing functionality of this tool might be its stronger point.

| Metric Name | Metric Value | Comment |
|---|---|---|
| ***Actionable insights for loss-minimization*** | 5.75 / 9 | Average of responses to question *"Overall, do you feel this tool can give actionable insights relating to loss-minimization on distribution networks?"* |
| ***Actionable insights for asset renewal timing*** | 5.25 / 9 | Average of responses to question *"Overall, do you feel this tool can give actionable insights relating to asset renewal timing on distribution networks?"* |
| ***Tool Realism*** | 4/9 | Average of responses to question *"Do you think the type of analysis this tool performs is: realistic/unrealistic"* |
| ***Improvement over manual planning*** | 6/9 | Average of responses to question *"Compared to manual network planning analysis in (…) this tool is a useful step forward"* |
| ***Insight Generation*** | 5.25 / 9 | Average of responses to question *"This tool revealed asset renewal pathways I may not otherwise have considered:"* |

Table 52 – Feedback metrics for the AAM tool

## 9.4. Evaluation of costs and benefits of the tool

### 9.4.1. Mapping the tool onto functionalities

An essential first step in a cost-benefit analysis is to determine which services/functionalities are enabled by each tool. This explicitly shows how different aspects of the tool's capabilities can drive value across different functionalities.
Table 52 shows the mapping of the AAM tool into functionalities. This explicitly identifies the services and functionalities for the evolvDSO project that are enabled by the AAM tool.

| Services | Tool Functionalities |
|---|---|
| Enhancing efficiency in network operation | **1.** Finds asset investment pathways that can optimise active power losses |
| Enhancing financial efficiencies in network operation | **2.** Finds asset investment pathways that take due account of the time value of money to find optimal trade-offs of imminent versus deferred investment |
| Enhancing reliability in network operation | **3.** Appraises component criticalities so that inspection and maintenance priorities can be appropriately aligned |
| Enhancing operator understanding of their networks | **4.** GUI facilitates user insights on factors affecting asset renewal scheduling |

Table 53 - A mapping of AAM tool services onto project functionalities

### 9.4.2. Mapping the functionalities onto benefits

The third step of the cost-benefit analysis identifies the benefits that are provided by each functionality. The mapping between the functionalities and the benefits provided by the AAM tool is shown as a matrix in Table 54.
Six specific potential benefits have been identified. The JRC guidelines [1] embrace a list of 22 Smart Grid Benefits stemming from an EPRI methodology [2]. However, since the AAM tool, as an insights engine, inherently requires a qualitative evaluation, six new non-quantitative benefits were used to develop the functionalities-benefits matrix.

| Benefit Category | Specific Benefits | Relevant Functionalities | | | |
|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 |
| Economic | Reduced active power losses | ● | | | |
| | Reduced reactive power losses | ● | | | |
| | Less risk of stranded assets | | ● | | |
| | Less regulatory penalties | ● | | ● | ● |
| Reliability | Reduced outage frequency | | | ● | |
| | Reduced outage severity | | | ● | |

Table 54 - A mapping of tool functionalities to specific benefits, drawing on the structured engagement between ESBN and UCD.

The tool's first functionality, in finding loss optimized investment pathways, creates value in reducing active and reactive power losses, in turn potentially reducing regulatory penalties.
The second functionality, in considering the time value of money in investment decisions, directly delivers value in reducing the risk of stranded assets.
The third functionality, in appraising component criticalities towards a better maintenance and inspection regime, should reduce the frequency and severity of network outages, in turn reducing regulatory penalties.
The final functionality, in fostering network insights with an intuitive GUI, offers secondary value in informing network operations (e.g. in power restoration schemes), and such business intelligence may help reduce regulatory penalties.

### 9.4.3. Establishment of the baseline

In order to quantify or demonstrate any particular benefit, it is necessary to define and compare the baseline scenario and the scenario in which the tool is deployed (project scenario). In this sense, the scenarios that allow demonstrating the AAM benefits are defined as follows:

- **Baseline scenario:** It is assumed that asset renewal is performed based on a naive single objective strategy (e.g myopic loss minimization).
- **Project scenario:** Several scenarios are considered for demonstrating the benefits of AAM tool and its multi-objective analysis. Each scenario has its specific planning horizon and the penetration level of renewable energy resources varies with the scenarios defined in *Deliverable 3.4*.

#### 9.4.4. Demonstration of the benefits

In the next sections, the results regarding the demonstration of the benefits, according to the rubrics presented in last section are shown.
The technical insights the tool offers can potentially deliver benefits that can be quantified under a number of rubrics, which are recounted below. The weighting of these potential benefits remains somewhat subjective, but is informed by the feedback gathered from ESB Networks as part of the structured engagement activities in WP4.

As given in the High Level Assessment of the structured engagement period for this tool, various qualitative feedback was acquired, which gives a qualitative indication of the benefit the tool many deliver within a real world asset planning environment. The results of the feedback are summarized in Figure 45, which shows the strengths and potential applicability of the tool in different areas:

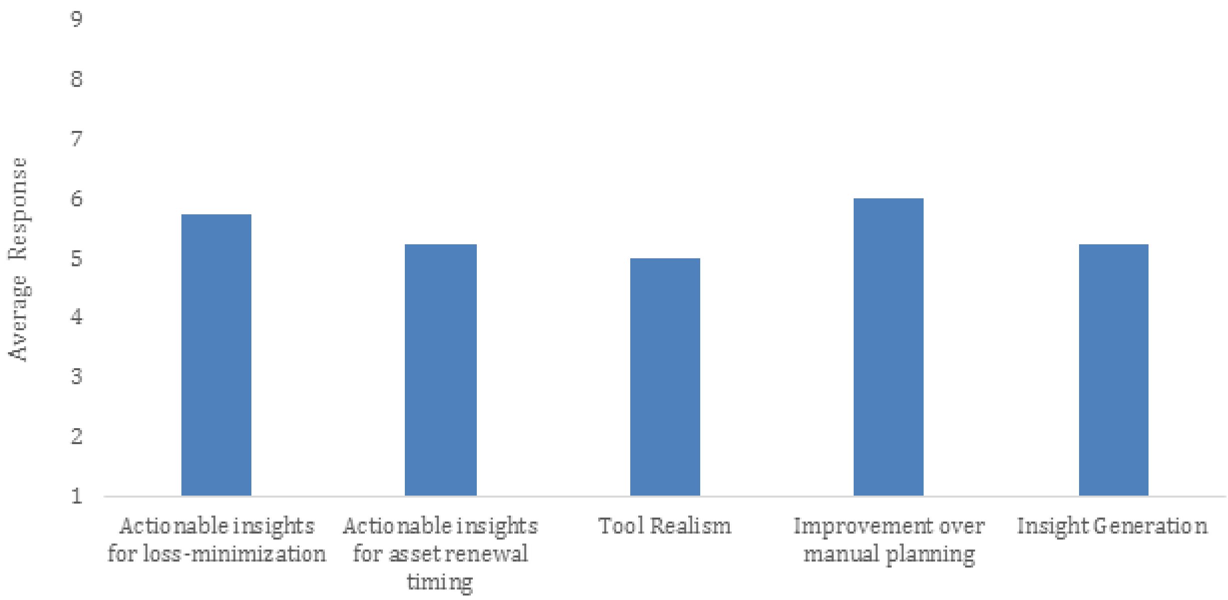



**Figure 45- Qualitative feedback of tool performance in different areas, using feedback from the structured engagement period**

The sources of these insights are given in Table 55, which also shows how they rank in the rightmost column

| | | |
|---|---|---|
| **Actionable insights for loss-minimization** | Average of responses to question *"Overall, do you feel this tool can give actionable insights relating to loss-minimization on distribution networks?"* | **2** |
| **Actionable insights for asset renewal timing** | Average of responses to question *"Overall, do you feel this tool can give actionable insights relating to asset renewal timing on distribution networks?"* | **3** |
| **Tool realism** | Average of responses to question *"Do you think the type of analysis this tool performs is: realistic/unrealistic"* | **4** |
| **Improvement over manual planning** | Average of responses to question *"Compared to manual network planning analysis in [incumbent software], this tool is a useful step forward"* | **1** |
| **Insight generation** | Average of responses to question *"This tool revealed asset renewal pathways I may not otherwise have considered:"* | **3** |

**Table 55 – Sources of qualitative feedback from the structured engagement feedback**

#### 9.4.4.1. Active power losses reduction & reactive power losses reduction

Reducing the active energy losses is a measure of efficient distribution network management. It will also reduce the need for transferring energy from generating point to the demand node. Additionally, this reduction would reduce the pressure on upstream network to supply the distribution network. The beneficiaries of this benefit is primarily the DSO since it will cause more efficient operation of the distribution network. Similar benefits accrue from the reduction of reactive power losses.

Based on the feedback rankings in Table 55 under the relevant headings of "Actionable insights for loss-minimization" (2) and "Improvement over manual planning" (1), we rank the loss reductions benefits of this tool in **first** place.

#### 9.4.4.2. Less risk of stranded assets & less regulatory penalties

Identifying the critical assets and optimal asset renewal decision-making may help the DSO to avoid unanticipated devaluations of assets. These assets are referred to those that are unable to recover their investment cost as intended, with a loss of value for DSO. The beneficiaries of this benefit is DSO. DSOs are usually encouraged/penalized by regulatory with rewards & penalties. The AAM tool will help the DSO to avoid regulatory penalties such as those related to active losses or renewable energy curtailments.

Based on the feedback rankings in Table 55, under the relevant headings of "Tool realism" (4) and "Insight generation" (3) we rank these benefits in **third** place.

#### 9.4.4.3. Reduced outage frequency & reduced outage severity

The DSO is responsible for providing the secure and reliable service to the customers in its territory. Outage frequency reduction is a way of increasing the service quality for the end users. The AAM tool will identify the critical assets to avoid/reduce component outages in distribution network. The beneficiaries of this benefit are the end users.

Based on the feedback rankings in Table 55, under the relevant headings of "Actionable insights for asset renewal timing" (3) and "Improvement over manual planning" (1) we rank these benefits in **second** place.

#### 9.4.4.4. Specific benefit weight ranking

Table 56 summarises how the feedback maps onto a ranking of which domains the tool can drive the most benefit in. The tool's automated approach to planning means it can drive value in operating loss reductions, but questions about how accurately it models DSO business decisions means it can drive less value in the reliability and financial domains.

| Benefit Category | Specific Benefits | Rank/ Weight |
|---|---|---|
| Economic | Reduced active power losses | 1 |
| | Reduced reactive power losses | 1 |
| | Less risk of stranded assets | 3 |
| | Less regulatory penalties | 3 |
| Reliability | Reduced outage frequency | 2 |
| | Reduced outage severity | 2 |

Table 56 – Sources of qualitative feedback

### 9.4.5. Qualitative impact analysis

Table 90 gives a subjective appraisal of how the tool can deliver benefits across the functionalities and benefits of AAM. This appraisal is informed by the feedback received during the structured engagement with ESB Networks, as detailed in the High Level Assessment.

In the merit deployment matrix (shown in the Annex), a weight was assigned to each cell that quantifies the relevance of each benefit/functionality link.

Through these weights, it is possible to quantify the project impact across benefits and across functionalities as in Figure 46, Figure 47, which draw on insights from ESB Networks and UCD as developed in the period of structured engagement.

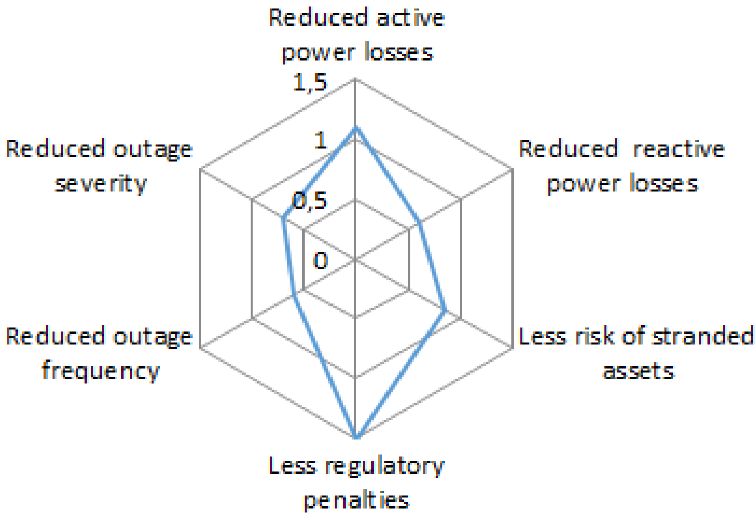



Figure 46- Spider chart of project impact across benefits

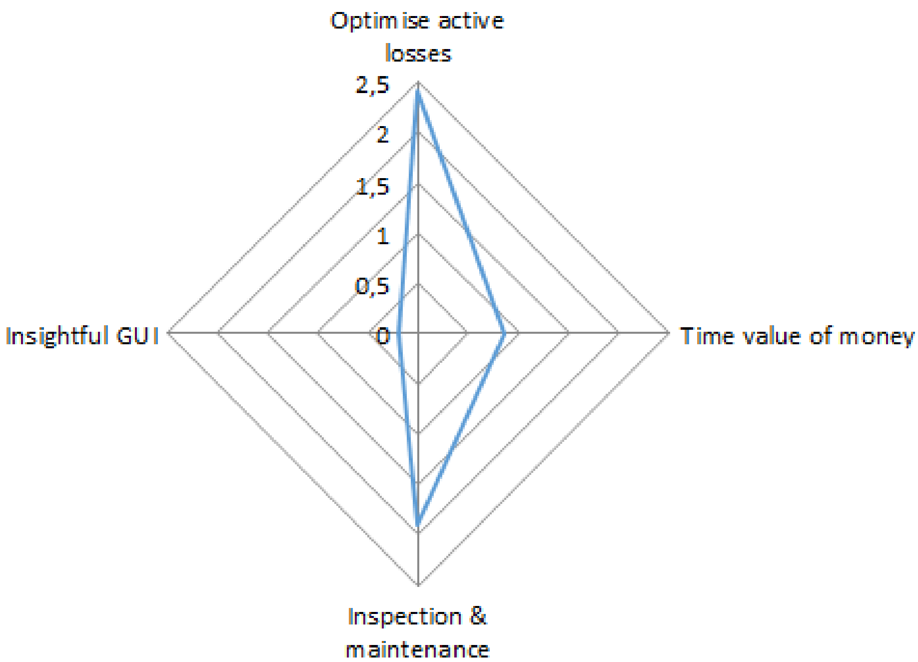



Figure 47- Spider chart of project impact across functionalities

### 9.4.6. Identification and quantification of the costs

The costs associated with the development AAM tool were divided into two categories:

a) Development of the algorithms/tools in WP3, which comprises the effort (in person-month cost of UCD) to create a tool that can perform the required analysis;
b) Subsequent integration costs of the tool into an industrial context.

The industrialization cost is nonrecurring, whether the tool it is applied one or more times. The development cost is the sum of the person-month spent during the project in WP3-4 to develop and improve the tool plus additional effort to complete the following developments:

- Standardisation of a suitable input/output data model;
- Development of data quality control and pre-processing functions for the input data;
- Development of Graphic User Interface (GUI) to facilitate the interaction of users and core software.

To deploy this tool within a DSO, it will require dynamic interfacing with the asset management database, rather than the once-off extractions used in the demonstration process. Once integrated, the tool can be applied to a multiplicity of networks at small marginal cost.

The costs of this integration are hard to assess, but are discussed below. For the case of Ireland, the following assumptions were made:

- Information acquisition and storage is part of ESB Networks business-as-usual processes, and thus is not considered as an additional cost.
- The same assumption applies to the development, maintenance, and operation of the smart grid infrastructure (assets, services, databases and AMI system).

The AAM was demonstrated in the framework of WP4 for ESB Networks (Ireland) and since it is planning tool only computer simulations were made in WP3. An accurate and quantitative identification of integration costs is not possible:

a. A high level of uncertainty exists in quantifying the costs associated to the AAM tool that will provide input data for the AAM and computational requirements' cost for a large-scale deployment of the tool;
b. The costs for data management and access to input data are expected to be low and easy to quantify since the majority of this information is already available in the SCADA, nevertheless communication costs should be considered.

As an estimate, perhaps a similar number of PMs would be needed to integrate this tool into a DSO as have so far been expended on its development.

# 10. Short-term network reinforcements considering flexibilities and ICT reliability – FLEXPLAN

## 10.1. Introduction

The increasing connection of new generation units and loads into distribution networks often leads to the need for expanding the networks. Due to increasing numbers of flexible customers being able to communicate via information and communication systems (ICT), alternative options to conventional network enforcement exist. These include the curtailment of generation or the use of flexible loads to reduce the network loading during periods with a high feed-in. Furthermore, DSOs have to cope with increasing uncertainties during the planning process, as neither the exact amount of distributed generation capacity nor the exact location of the generation units are available at the time of the planning. To deal with these new challenges, existing network planning tools and software have to be enhanced in order to enable the DSOs to find cost-optimal, secure and reliable network configurations considering uncertainties as well as the new degrees of freedom offered by flexible customers.
In Figure 48 the new and evolving DSO activities and the associated services related to the network planning domain are presented.

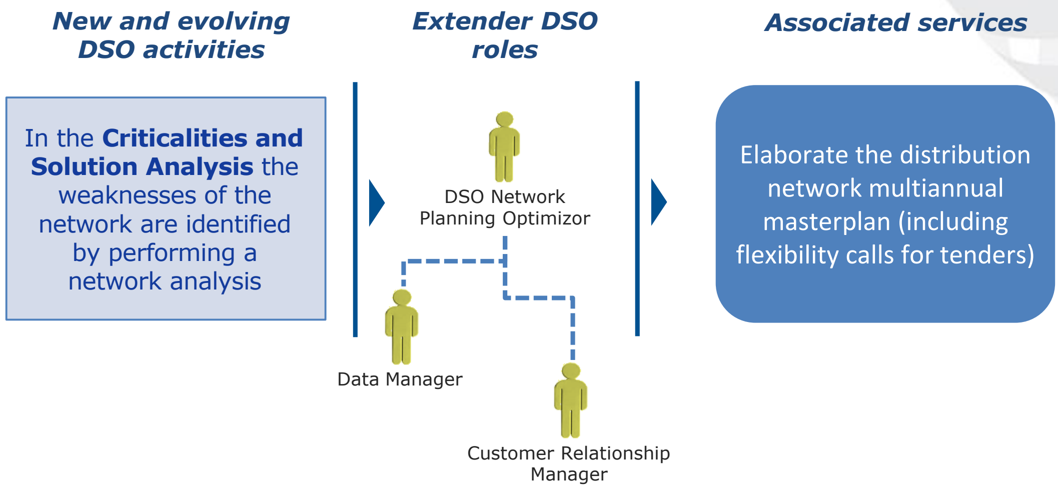



Figure 48 – DSO roles and services related to the planning domain

The tool "Short-term network reinforcements considering flexibilities and ICT reliability" (FLEXPLAN) covers a timeframe up to 10 years and considers scenarios for the modelling of uncertainties. The methodology demonstrates a new way of finding relevant network planning cases (NPC). Based on the NPC optimal combinations of network reinforcements such as new lines and the usage of flexibilities are determined. Further, the tool addresses the effect of an increasing influence of information and communication technology (ICT) systems, when planning future networks. The innovative functionalities covered by the tool are:

- Analysing the impact of network planning for multiple scenarios.
- Dimensioning the network closer to its technical limits by considering relevant planning cases.
- Assessing the changes in reliability of the network due to an increasing usage of ICT.
- Evaluating the influence of different flexibility prices on the result of network planning.

## 10.2. Description of the tool and its elements

The tool FLEXPLAN focuses on a timeframe up to 10 years in the future in order to find an optimal expansion solution for high and medium voltage grid structures Figure 49 shows a flow-chart representation of the five different sub-tools and their interaction within the tool.

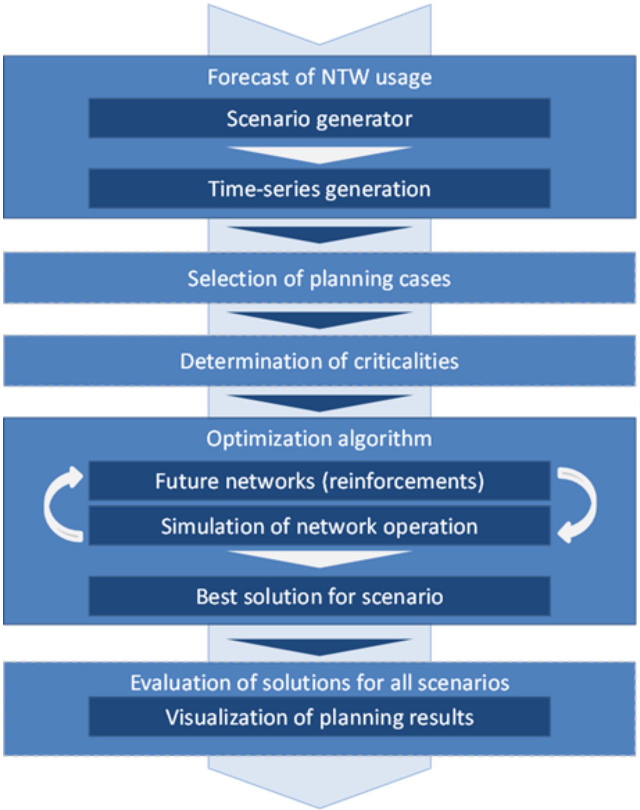



Figure 49 – Sub-Tool interaction within the tool FLEXPLAN

The sub-tool “Forecast the network usage” forecasts the generation and load situation of the considered network area. As the forecast is influenced by uncertainties, a set of various scenarios is generated. The scenarios consider the installed capacity and the location of DRES. Next, each DRES is linked with a corresponding feed-in or consumption profile to model realistic future feed-in and load situations.

The feed-in and load situations for each scenario result in a large amount of data. Relevant NPC are selected for the ongoing network expansion optimization. The sub-tool “Selection of planning cases” reduces the amount of NPC in order to reduce the computational effort. Traditionally, only a few NPC (e.g. maximum feed-in of renewables with minimum load, and no feed-in from renewables with maximum load) are used to assess the network. These worst-case considerations can lead to an over-dimensioning of the network. This sub-tool selects NPC based on feed-in and consumption time-series given by the forecast. The benefit of this procedure is the dimensioning of the network closer to its technical limits leading to a reduction of network expansion costs.

The selected NPC are used to identify criticalities (network constraints) in the existing network for the future network usage by performing load flow calculations, (N-1)-contingency analysis, short-circuit analysis or reliability-analysis. If future networks rely on ICT to handle criticalities in the network, these components have to be adequately modelled

to analyse the impact of ICT on network reliability. Therefore, the sub-tool "Determination of criticalities" includes a new tool for enhancement of reliability calculation of future networks in order to determine the impact of ICT.
The traditional way to resolve network constraints is the use of conventional network expansion measures. Today, alternatives such as voltage regulated distribution transformers or operational measures e.g. switching actions are also assessed. Nevertheless, as most congestions are currently driven by DRES, they only arise a limited number of times per year, in periods with a high feed-in. For this reason some network assets might only be necessary for short periods. Therefore, an alternative to conventional network expansion is the consideration of flexibility (e.g. curtailment of DRES) in the planning phase. The sub-tool "Optimization algorithm" elaborates cost-effective solutions considering both network reinforcements and the usage of flexibility resources. However, the use of flexibility in the planning phase is currently not allowed in most of the European countries regulatory regimes. As the tool can be applied to large networks, the planner needs to be able to analyse the optimization results in order to ensure the applicability of the computed solution. Therefore, the results are presented graphically. Further, the algorithm proposes an optimal solution for each scenario, which may differ for each scenario. The visualization enables the comparison of different solutions and is implemented in the sub-tool "Visualization of planning results".

## 10.3. High-level technical assessment of the tool

### 10.3.1. Synthesis of tool evaluation in WP3 simulation tests

The tools are tested using models of one medium-voltage (MV) and one high-voltage (HV) network both situated in a northern, rural part of Germany. The meshed HV-network includes the 110 kV and relevant 30 kV elements[5]. Any underlying network is modelled by its aggregated equivalent elements. For the forecast (10 years) three scenarios[6] $S_u$, $S_{ml}$, $S_o$ are derived based on *Deliverable 1.1*. One additional scenario has been given by the DSO, allowing a better regional specification (scenario $S_{bg}$). The radial MV-network includes the 10 kV voltages level and the primary substation.

Various test cases have been used for the assessments of the sub-tools. Table 57 provides information about the networks and scenarios used for each specific test case.

| # | Name | Network | Scenario |
|---|---|---|---|
| 1 | Identification of relevant network planning cases | High voltage network (HV), Medium voltage network (MV) | $S_{bg}$ (HV), $S_{ml}$ (MV) |
| 2 | Influence of ICT on the network reliability | High voltage network (HV), Medium voltage network (MV) | $S_{bg}$ (HV), $S_{ml}$ (MV) |

[5] In the considered network the 30-kV has a similar function as the 110-kV voltage level.
[6] u = under-expected scenario; ml = most-likely scenario; o = over-expected scenario.

| | | | |
|---|---|---|---|
| 3 | Analysis of flexibility prices on network expansion planning | High voltage network (HV) | $S_{bg}$ |
| 4 | Robust network planning to cover the future uncertainty | High voltage network (HV) | 10 scenarios generated by $S_u$, $S_{ml}$, $S_o$ and $S_{bg}$ |

**Table 57 – Relation of test cases and scenarios.**

The tests show the capability of the tool to generate scenarios covering a wide range of uncertainties and select relevant NPC. Furthermore, improvements in the assessment of network reliability, covering ICT-systems and in planning considering flexibilities and uncertainties have been reached. Since the network planning covers a timeframe up to 10 years, only lab trials using simulations have been performed. As each sub-tool overs different functionalities, the assessment results are individually discussed for each of the sub-tools.

The sub-tool for the NPC selection has been tested for the meshed HV-grid and the radial MV-grid. It is demonstrated to which extend time series can be reduced to a small number of relevant NPC. The usage of these NPC strongly reduces the calculation time in network planning methods and is a key factor for the proposed overall planning tool.
A cost comparison of a network planned using "business as usual" (BaU) NPC with a network planned using the selected NPC, demonstrates the benefit of this sub-tool.
For the HV-grid, 12 NPC representing the highest network loading have been determined. For the MV-grid, only 3 NPC are needed. The costs of a network planned with the selected NPC compared to the "business as usual"-NPC, show a cost reduction of 2% in the meshed grid and of 9% in the radial grid. For the estimation of time-dependent values about 100 NPC are needed in both cases. The simulations performed in *D3.4* show that a higher meshing of the grid will lead to higher numbers of required NPC. However, the selection method has to be further tested for different grids in order to confirm the results obtained so far.

Simulations were carried out for the MV and HV grid to show how smart-grid applications and a dependence of the grid on the ICT-system effect the grid's reliability. For comparison, simulations were carried out for reinforced grids without a dependence on the ICT-system as well as simulations for different ICT-system topologies. The simulation results show that the use of smart-grid applications and a dependence on the ICT-system may lead to a change of reliability. The overall effect on reliability is determined by the functionality of the applications, the degree of the grids dependence on the ICT-system and equipment reliability, and therefore may differ significantly between single grids, different applications and voltage levels. However, as today no long-term data for the reliability of smart grids exists, the simulation results have to be validated for real grids, ICT-systems and applications.

The usage of flexibilities alternative to network expansion is applied on the HV grid. The flexibilities considered in the simulations are the curtailment of DRES. Different prices for the curtailment have been investigated: A price of 35 €/MWh (average spot price at the electricity market) and a price of 100 €/MWh (used in various studies to reflect feed-in tariffs of DRES in Germany) have been chosen. The reduced costs for network planning, when considering flexibility usage, can be used to estimate the remaining expenditure to cover the ICT costs. Furthermore, the tool can be used to quantify the marginal costs of a grid expansion compared to flexibility utilization, if ICT costs are defined.

The results show that the inclusion of flexibilities in network planning can have a significant impact on network expansion costs. However, the value of a flexibility within the planning process varies in a case-specific way. The cost and technology of ICT will be a determining factor for the final cost savings.

For the robust planning approach, the tool “Forecast the network usage” has been used to derive a set of scenarios covering the uncertainty for the HV-grid. The network expansion costs when planning for one “most-likely” scenario are compared to the results of the planning for multiple scenarios. Flexibilities are not considered in this test case. The simulations show that considering a broader set of future scenarios leads to higher expansion costs depending on the spread of uncertainties. It is in line with prior expectations that a robust network is more expensive than a network optimized for only one scenario. The evaluation of the results shows, that this approach supports a kind of risk management to minimize stranded investments, but leads to higher costs than in cases of perfect foresight which is in reality never the case. It has to be kept in mind that the benefits of a robust network, which is suitable for a wider range of future developments, may outweigh the initially higher investment costs. This aspect has to be assessed in future tests.

The NPC used in network planning can have a significant impact on network expansion costs depending on BaU-NPC, especially for the considered MV network. Only a very limited number of NPC is necessary to represent the maximal network loading caused by a time-series simulation. For meshed networks, annual figures like network losses or curtailed energy can be determined using roughly 50 to 100 NPC.
The influence of smart grid applications and ICT systems on reliability in new grid structures is not negligible and should be considered in future network planning.
Including flexibilities in network planning shows a great impact on network expansion costs. The value of a flexibility varies case specific. However, some expansion measures are required in all cases to avoid a high uncertainty of flexibility prices. The cost and technology of ICT is a determining factor for the overall cost reduction.
Planning the network for a broader range of future scenarios leads to higher network expansion costs. Nevertheless, robust planning is necessary to optimize expansion costs respecting the uncertainties of the development.

The limitations and the needs for further research are therefore:

- The robustness (insensitivity against certain factors) of determined NPC needs to be evaluated in cases when the network topology is changed by reinforcements.
- The development of simple rules for the selection of network planning cases for the practical network planning should be continued.
- Further investigations of different ICT technologies and their individual failure rates as well as their influence on the reliability of distribution networks should be performed.
- Integrated approaches for all voltage levels of distribution network (LV/MV/HV) should be developed.
- A further enhancement of probabilistic planning methods (e.g. minimizing the expected value or a least regret approach) for multiple scenarios should be discussed
- User interfaces have to be improved and a better visualisation and aggregation of the results is crucial for the network planner to handle the increasing complexity of the planning process.

## 10.4. Evaluation of costs and benefits of the tool

### 10.4.1. Mapping the tool onto functionalities

The mapping of FLEXPLAN into functionalities for the evolvDSO project and the services identified in [1] is presented in Table 58.

| Services | FLEXPLAN Functionalities |
|---|---|
| Enhancing the determination of losses in the planning process | Identification of technical and non-technical losses by power flow analysis *(JRC Guidelines[7], Nr. 9)* |
| Ensuring network security, system control and quality of supply | System security/quality of supply assessment and management of remedies *(JRC Guidelines, Nr. 14)* |
| Better planning of future network investment | Better models of Distributed Generation, storage, flexible loads, ancillary services *(JRC Guidelines, Nr. 17)* |
| | Improve asset management and replacement strategies *(JRC Guidelines, Nr. 18)* |
| | Additional information on grid quality and consumption by metering for planning *(JRC Guidelines, Nr. 19)* |

Table 58 – Mapping of the FLEXPLAN tool into services and functionalities

### 10.4.2. Mapping the functionalities onto benefits

In this section, a mapping between the functionalities identified in the previous section and the benefits they provide is presented. The functionalities provide the benefits defined below:

- **Deferred Distribution Capacity Investments (economic benefit):** Nowadays most European regulations do not allow the consideration of flexibilities (i.e. curtailment of DRES) in the network planning stage. Therefore, distribution networks are extended using primary technology until no congestions remain even in rare critical situations. With the new approach, improved planning decisions can be achieved by considering flexibilities in the planning stage as one possible action resolve network congestions. By considering the flexibility options, the dimensioning of the network can be improved in order to reduce expensive expansion measures that are required only for a few critical situations throughout the year. Furthermore, the tool enables a sensitivity analysis by varying the price of flexibilities in order to elaborate the best combination between the use of flexibilities and the expansion of the networks.
- **Reduced Electricity Costs[8] (economic benefit):** By deferring distribution capacity investments or by replacing the investments by the use of (less expensive) flexibility options, the electricity costs for customers can be reduced. The reduction of electricity costs at the wholesale market is not addressed by this tool.
- **Enhance Knowledge about Impact of Smart Grid Components on System Reliability (reliability benefit):** In currently applied analytic calculation methods for

[7] JRC Reference Reports "Guidelines for conducting a cost-benefit analysis of Smart Grid projects" - Annex III: Smart Grid Services and Functionalities (EC Task Force for Smart Grid 2010A)
[8] Electricity costs at the whole sale market are not addressed

the assessment of system reliability in distribution networks, failures of the ICT system are usually not taken into account. As future grid operation including the use of flexibilities will rely, to a greater extend, on the ICT-systems as today (e.g. for the activation of DRES curtailment). The influence of these systems on system reliability has to be taken into account. The explicit modelling of the ICT-system introduced in this tool enables the reliability calculation for grids influenced by smart grid components and the simulation of failures in the ICT-system.

- **Network Expansion is Suitable to Cover Future Uncertainties (security benefit):** In the current network planning process, the network is designed for a small set of predefined worst-case conditions ensuring a secure grid operation for the predicted future network usage. The future network usage is usually defined using a most-likely scenario for the future network usage. With the new FLEXPLAN tool, distribution networks can be planned for a wider set of future scenarios. The planning for a set of scenarios including the consideration of flexibilities to cope with extreme scenarios enables a better dimensioning of the network. In particular, for scenarios with a small probability of occurrence, the trade-off between the usage of flexibilities and the installation of new network equipment can be determined. However, the correct definition of scenarios remains a challenge for the application.
- **Level of Total Losses in Distribution Networks (efficiency benefit):** When planning the networks only for a very limited set of worst case conditions, an estimation is used to calculate the network losses in the planning stage without performing a high number of power flow calculations (e.g. based on the expected hours of full-load usage of the network). By evaluating the network usage and network loading for a wider set of network planning cases, the network losses can be calculated in a more detailed way. Furthermore, the effect of a higher utilisation of network elements due to the dimensioning including the consideration of flexibilities can be analysed.
- **Percentage Utilisation (i.e. Average Loading) of Electricity Grid Elements (efficiency benefit):** Currently, some network investments are only required for very few critical situations, leading to a low utilisation of some (expensive) network expansions. When flexibilities can be considered in the planning stage, some of these network investments can be replaced by the use of flexibilities. On average, this leads to a higher utilisation of the remaining network elements.

Table 59 summarises the mapping between the benefits.

| | **Benefits** | **Functionalities** *(Number according to JRC-Guidelines)* | | | | |
|---|---|---|---|---|---|---|
| | | **9** | **14** | **17** | **18** | **19** |
| Economic | Deferred Distribution Capacity Investments | | | ● | ● | |
| | Reduced Electricity Costs* | ● | | ● | ● | |
| Reliability | Enhance Knowledge about Impact of Smart Grid Components on System Reliability | | ● | ● | | ● |
| Security | Network Expansion is Suitable to Cover Future Uncertainties | | | ● | ● | |
| Efficiency | Level of Total Losses in Distribution Networks | | ● | | | |
| | Percentage Utilisation (i.e. Average Loading) of Electricity Grid Elements | | | ● | ● | |

● Relevant functionalities

* Electricity costs at the whole sale market are not addressed

Table 59 – Mapping between the functionalities and benefits performed by RWTH and checked by Innogy

### 10.4.3. Establishment of the baseline

In order to demonstrate or quantify the benefits of the developed tool, it is necessary to define and compare a baseline scenario and a scenario in which the tool is deployed. As the tool consists of different sub-tools providing different benefits, the baseline is given individually for the respective sub-tool. In this sense, the scenarios allowing the demonstration of the FLEXPLAN benefits can be defined as follows:

**Forecast of the Network Usage and Selection of Planning Cases**

- **Baseline Scenario:** Nowadays, the network planning cases used to dimension the network typically are based on the worst-case conditions for the most-likely prediction of the future installed capacities in the network (regarding the total installed capacity and the regional allocation of DRES). Furthermore, the dimensioning only takes place for a very limited number of worst-case situations, such as maximum feed-in from renewables or maximum load without feed-in from renewables. Therefore only very few extreme network usage cases are used for dimensioning the networks. The forecast of the network usage and the relevant planning cases according to these procedures define the baseline scenario, which is used for planning a future network.
- **Project scenario:** The project scenario in contrast to the baseline scenario uses multiple forecasts for the future network usage. Additionally a wider set of network planning cases is selected using the implemented sub-tool. This set of planning cases incorporates a wider set of scenarios for the future network usage and simultaneously consists of simple worst-case assumptions from a more complex selection of planning cases based on historic time series and respective scenarios. Using this project scenario, the dimensioning of the network takes place according to the changed assumptions and planning cases.

**Determination of Criticalities (Including ICT impact on system reliability)**

- **Baseline scenario**: The determination of criticalities not only includes the calculation of power flows to check current and voltage limits for future network usage scenarios, but also the calculation of the degree of system reliability under future conditions. As the verification of technical limits in the tool does not change compared to the tests performed in tools currently used for network planning, the baseline scenario focuses on the system reliability calculation. The baseline scenario represents the calculation of system reliability parameters without taking into account future ICT-systems, which might be required for system operation.
- **Project scenario:** In the project scenario, the explicit modelling of the ICT-system introduced in the developed tool is used for reliability calculations of grids influenced by smart grid components and the simulation of failures in the ICT-system. Therefore, in the project scenario the effects of a stronger dependency on ICT-systems are considered during the network planning process.

**Optimization Algorithm and Visualization of planning results**

- **Baseline scenario:** In the current planning praxis, flexibilities (i.e. the curtailment of DRES) are usually not considered in the network planning stage. Therefore, the distribution networks are extended using primary technology until all congestions are resolved for all critical network planning cases. This procedure represents the baseline scenario, which may lead to networks that have a relatively low utilization of some investments that only build a few critical situations.

- **Project scenario:** The new approach allows the consideration of flexibilities in the planning stage as one possible solution to resolve network congestions in critical situations to improve planning decisions. The project scenario covers a network planning regime whereby the use of flexibilities is considered in the planning process. This may result in a reduced investment in primary technology for network expansion in case flexibility options are available to resolve network congestions in critical situations.

| Benefits | Baseline scenario | Project scenario |
|---|---|---|
| **Deferred Distribution Capacity Investments**<br>**Reduced Electricity Costs** | • No consideration of flexibilities in the planning process<br>• Planning for one best-guess scenario<br>• Planning for worst-case network planning cases | • Flexibilities can be used in the planning process<br>• Planning can be performed for multiple scenarios<br>• A wider set of network planning cases is used to dimension the network |
| **Enhance Knowledge about impact of Smart Grid Components on System Reliability** | • Faults of the ICT-systems are not considered in the system reliability analysis | • The system reliability analysis also considers faults in the ICT-systems required for network operation |
| **Network Expansion is Suitable to Cover Future Uncertainties** | • Planning for one best-guess scenario | • Planning is performed considering multiple scenarios |
| **Level of Total Losses in Distribution Networks** | • Planning for a small set of worst-case network planning cases<br>• Usage of simple rules to estimate losses | • A wider set of network planning cases is used to dimension the network<br>• More calculations are performed which allow a better estimation of network losses |
| **Percentage Utilisation (i.e. Average Loading) of Electricity Grid Elements** | • No consideration of flexibilities in the planning process<br>• Planning for worst-case network planning cases | • Flexibilities can be used in the planning process<br>• A wider set of network planning cases is used to dimension the network |

**Table 60 – Baseline and project conditions for the FLEXPLAN benefits**

### 10.4.4. Demonstration of the benefits

Simulation results demonstrate the benefits of the FLEXPLAN tool. Comparative values are not available for all computations performed by the new tool. The benefits of the improved calculation of system reliability for future networks depending on ICT-systems can nowadays not be compared to historic values, which for statistical reasons have to be collected over a long period. The results regarding the total losses in distribution networks are not discussed in detail, as the influence of losses is included in the results regarding the reduction of network costs and electricity costs (see *D3.4*).

**Deferred Distribution Capacity Investments and Reduced Electricity Costs**

Forecast of the Network Usage and Selection of Planning Cases: The beneficiaries of this tool are the DSOs, since a better (closer to reality) estimation of the network loading without large over-estimations is obtained. This is achieved while still performing simulations only for a small set of network usage cases. On the other hand, the beneficiaries of this approach are the customers as network costs reduce. However, the network is designed closer to the technical limits; this leaves the DSO less of a buffer for unexpected network exigencies.
Optimization Algorithm including use of flexibilities: The beneficiaries of this approach are the customers and the DSOs because network costs can be reduced. Once the required ICT-systems are installed, the DSO furthermore benefits from a rising number of flexibility options during network operation to cope with unexpected events.

**Enhance knowledge about impact of Smart Grid Components on system reliability**

The beneficiaries of this tool are the DSOs as they can achieve a better understanding of the impact of ICT-components on their system reliability. Further, customers relying on high system reliability benefit from enhanced simulations, as counteractions can be implemented in case the use of smart-grid components affects the system reliability (e.g. due to a lower reliability of the existing ICT-systems).

**Network expansion is suitable to cover future uncertainties and Percentage utilisation of electricity grid elements**

By designing the network for a wider set of scenarios, the beneficiaries of this approach are the DSOs. Using the FLEXPLAN tool a DSO is better prepared for uncertain future developments. However, the network costs may rise due to the consideration of more unlikely scenarios.

### 10.4.5. Qualitative impact analysis

The evaluation of cost and benefit presented in these pages shows that the benefits provided by the FLEXPLAN functionalities are complex to quantify. Therefore, a qualitative analysis is taken into account.

To conduct the qualitative assessment, the common approach consists of identifying links relating benefits and the respective indicators (KPIs/metrics) with functionalities. For each one of the identified links an explanation of how such links were established is performed, together with the assignment of a weight to quantify how strong and relevant the link is.
The results of the qualitative analysis are presented in form of the impact across functionalities (Figure 50) and the impact across benefits (Figure 51).

Regarding the impact of the tool across functionalities, the impact of the developed tools is strongest on the functionality *"Better models of Distributed Generation, storage, flexible loads, ancillary services"*. Furthermore, the functionality *"Improve asset management and replacement strategies"* is supported strongly by the developed tool, as the management and replacement of assets is strongly connected to the planning principles used by the DSO.

Regarding the impact of the tool across benefits, the impact on the benefits *"Deferred Distribution Capacity Investments"*, *"Reduced Electricity Costs"*, *"Enhance knowledge about* *impact of Smart Grid Components on system reliability" and "Network expansion is suitable to cover future uncertainties"* is comparable. This has been expected, since different sub-tools have been specifically implemented to achieve these benefits. The impact on the two remaining benefits is weaker, as the losses (or the utilization of network equipment) are influenced by the network planning, but not the main goal of the optimization procedure.

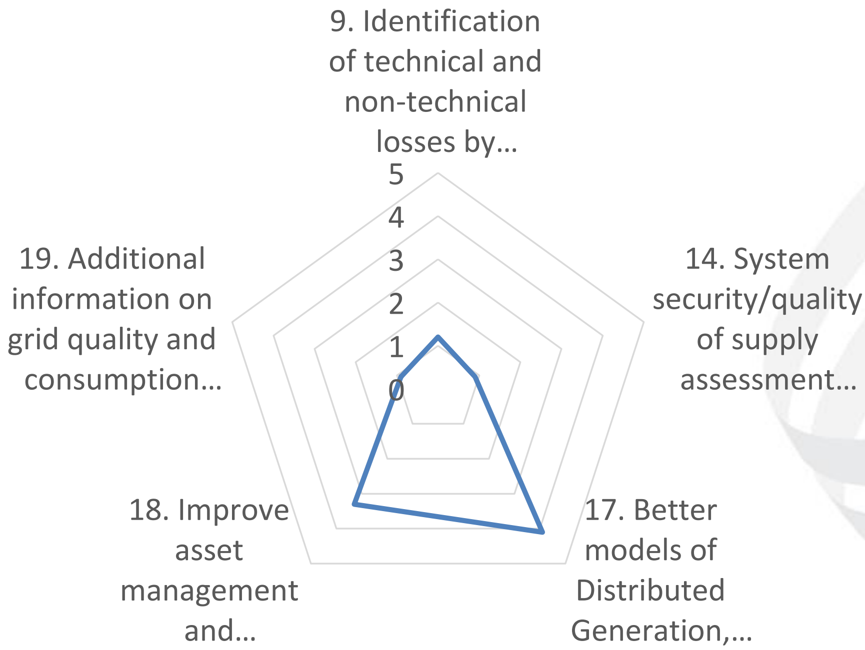



Figure 50 – FLEXPLAN tool impact across functionalities (performed by RWTH and checked by Innogy)

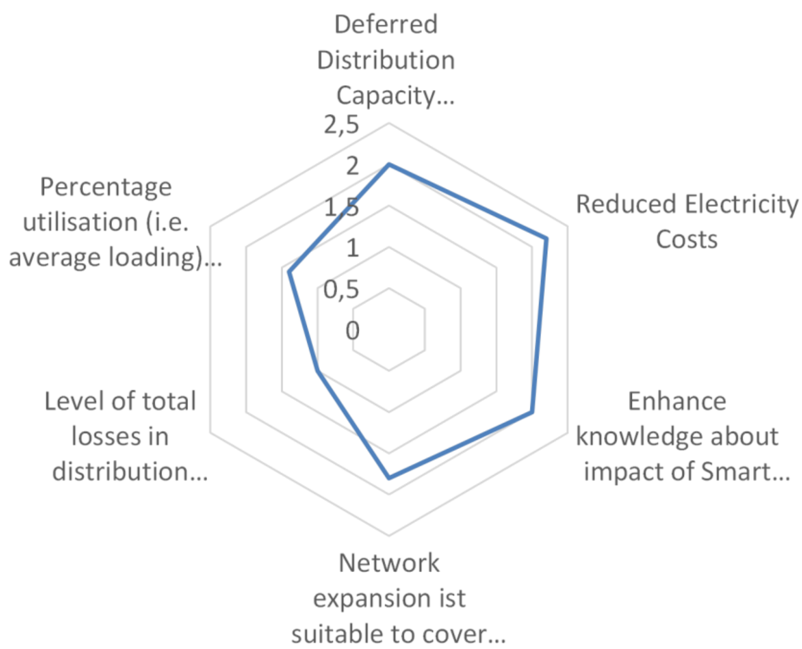



Figure 51 – FLEXPLAN tool impact across benefits (performed by RWTH and checked by Innogy)

### 10.4.6. Identification and quantification of the costs

The costs associated to the FLEXPLAN tool can be divided into the categories

a. industrialisation of the algorithms/tools developed, which comprises all the effort (in person-month) to create a tool ready to be integrated in the business processes of a DSO and
b. the application of the finished tool by the DSOs within the planning process.

As the development/ industrialisation costs only occur once, they do not scale with the number of software instances. The costs for using the software within the planning process include the hardware to run the databases and the optimization software as well as further software licenses (e.g. for database-servers or commercial solvers for optimization problems). The time used within the evolvDSO project to implement prototypes of the sub-tools included 46 Person/Month (PM). In terms of the TRL, the current status of the tool refers to stage 4 ("Proof of Concept"). As the tools were not integrated and tested in a DSO environment in WP4, the gap for the installation into the daily DSO business is quite large and hard to quantify. A rough estimation of the remaining time and costs to develop a stable software for the DSOs out of the prototypes is given as by the following estimated additional person month needed for the industrialization summing up to another 40 PM being about 83% of the time and costs invested so far in the development of the tools:

- Adoption to companies scenario process (8 PM)
- Integration of software in the current planning environment of the DSO (18 PM)
- Improvement of planner decisions in the simulation software (8 PM)
- Enhancement of visualisation and inclusion in existing systems (6 PM)

The technical (hardware and software) requirements for using the software are as follows (all minimum technical requirements are listed in Annex I):

Software:

- In order to perform optimization tasks, the commercial solver "CPLEX" is used within the simulation of the optimal use of flexibilities in network operation. Therefore, a licence for CPLEX or another, comparable solver for liner optimization problems in required.
- Power flow software to validate the technical requirements of the network is used in the planning process. Therefore, a licence for network calculation software is required. In the prototype, the software INTEGRAL has been used.
- The visualization of the planning results uses MATLAB for visualisation purposes. Also for this software, a licence is required.

Hardware:

- As the simulation of network operation and the optimization tasks handle large amounts of data and perform a high number of time consuming computation steps (load flow calculations, optimal power flow calculations, etc. for a high number of network usage cases), one high performance computer for running the optimization/simulation is required.
- As the network data and the results are stored in a database a computer to run the database-server is required. In case the performance is sufficient, it can be the same computer being used for the simulations.

- Normal desktop computers or notebooks are sufficient for the visualization of the simulation results.

Data Storage & Management:

- A SQL-database-server is required to store multiple databases for
    - the network model
    - network equipment data including reliability data
    - the scenario data
    - the planning results

Maintenance and Upgrades:

- Training of the network planner with the new software
- The simulation software may require maintenance or upgrades. These include:
    - Maintenance of the database-server, commercial solver and network calculation software
    - Updates of the developed tool in case of one of the above mentioned third-party software changes its interface.
    - Upgrades of the software tool, especially of the visualisation software in order to facilitate the planning according to feedback from the network planners

Other:

- The determination of scenarios for the considered network area may require additional data from third parties (e.g. historic weather data or georeferenced data of potential areas for new generation units) which have to be adapted to the existing software and databases.

# 11. Long-term planning tool using stochastic modelling - TopPlan

## 11.1. Introduction

Long term planning studies are usually carried out considering only loads in the worst case (maximal consumption) with a deterministic approach. The evolution of the distribution network (DRES, flexibilities) can raise the following question: is the current planning methods still adapted for this evolution? Do current planning methods consider the high uncertainties of the future? In the literature, many papers try to answer this question but without considering uncertainties. This tool proposes stochastic planning by integrating some uncertainties regarding DRES and flexibilities. The TopPlan tool is an additional toolbox that could be integrated to the DSO planning software in order to plan their network considering flexibility levers and DRES taking into account the uncertainties. Figure 52 shows some of the new and evolving DSO activities, as well as the main associated services related with the TopPlan-tool.


Figure 52– The TopPlan goals in the DSO roles.

## 11.2. Description of the tool and its elements

The System Use Case “Analyse flexibilities and reinforcement needs” is the scope of the tool described in this section. The TopPlan tool proposes and compares two master plans (in a 40 year horizon) obtained from automatic methods: network reinforcement and new topology configuration. The aim is to solve voltage and current constraints that could appear with high penetration of DRES. In the tool, flexibility of generation (curtailment) and the On-Load Tap Changer (OLTC) settings control is considered as stochastic inputs. Figure 53 depicts the four main steps of this algorithm.

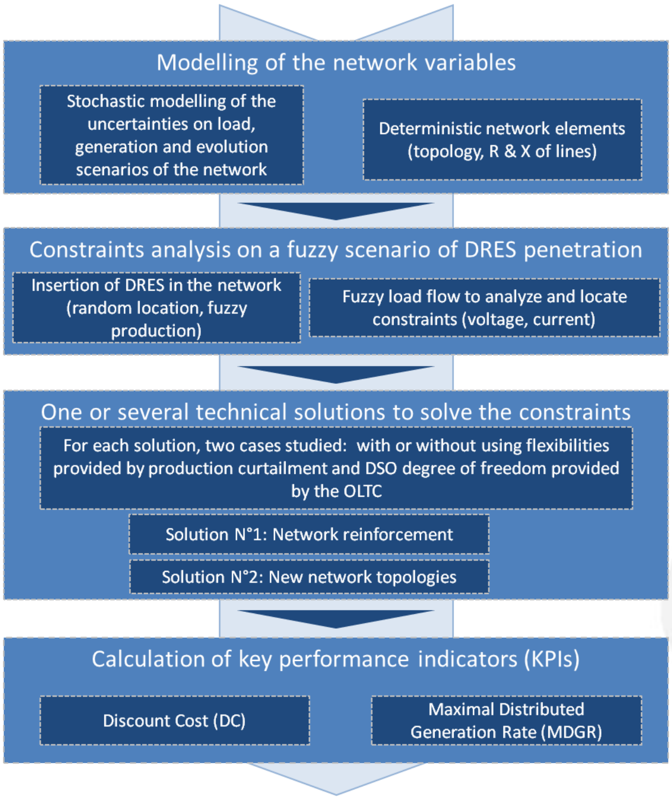



**Figure 53 – Long term Distribution Network Expansion Planning proposed methodology.**

In the step "**Modelling of the network variables**", the classical hypotheses made on load growth by fuzzy logic modelling to model the uncertainties is replaced. Distributed Renewable Energy Ressources (DRES) and flexibilities not accounted for in traditional planning are also taken into consideration using fuzzy logic modelling.
In the step "**Constraints analysis on a fuzzy scenario of DRES penetration**", several Monte Carlo simulations enable randomly distributed DRES in the network; providing a random location and randomly installed capacitites. A fuzzy loadflow is used to compute the voltage at each node and currents in lines. If voltages and/or currents limits are violated, the information is stored in a constraint matrix for a further analysis.
In the step "**One or several technical solutions to solve the constraints**", two different solutions are studied: reinforcement or building new architectures considering or not flexibilities and some degrees of freedom in the network.
In the step "**Calculation of key performance indicators (KPIs)**", the discount cost and the estimation of the maximal amount of DRES that can be connected to the distribution network without making technical violations are computed in order to compare the different solutions.

## 11.3. High-level technical assessment of the tool

### 11.3.1. Synthesis of tool evaluation in WP3 simulation tests

The planning tool is tested on one medium-voltage (MV) network situated in a northern rural part of Germany. The radial MV-network includes the 10 -kV voltage level and the primary substation (22 nodes, 92 km of lines of which 73 % are cables). All underlying customers are modelled by their equivalent elements. Time series of 8760 daily profiles for load and productions were used as input data provided by Innogy.

Three scenarios "$S_u$, $S_{ml}$, $S_o$" (for under-expected, most likely and over-expected) are defined using the annual growth rates of the scenarios of *Deliverable 1.1*. These scenarios are detailed for both short-term and long-term simulations in the *Deliverable 3.4*.

The test case that has been defined for the TopPlan tool is a comparison between the construction of a new topology and the reinforcement of the existing topology. Designing the new architectures (new topologies) with new operation modes for integrating the high amount of production and reinforcement of the constrained areas solution with or without flexibility is then the key decision that can be taken through that tool.

The performance of each solution obtained for the three scenarios on the MV network is measured through two KPIs which are the discount cost and the maximal amount of DERs that can be connected to the distribution network without violating technical constraints called "MDGR" for Maximal Distributed Generation Rate.

The flexibilities brought by the production curtailment, and also the degrees of freedom of the DSO brought by the on-load tap changer, were modelled as trapezoidal fuzzy numbers. It should be noticed that the flexibility deployment cost was not taken into account.

In the solution "Network reinforcement" the random locations of new generators were considered. In the solution "New topology", the new production location is supposed to be the same as the one already installed in the network.

For each given scenario of applied flexibilities, the sub tool "Network reinforcement" contains three main steps (algorithms):

1. All the conductors are reinforced considering 4 cases:
    - 1 cable of 240 $mm^2$.
    - 2 cables of 240 $mm^2$.
    - 3 cables of 240 $mm^2$.
    - 4 cables of 240 $mm^2$.
2. The maximal amount of DRES (MDGR) that can be connected to the network is evaluated. Constraint analysis aiming at defining the set of constrained lines and nodes (see *D3.1-3.1.2*) are evaluated following:
    - A Monte Carlo approach: DRES are randomly located in the network.
    - The worst case studied (minimal consumption and maximal production).
3. The DRES penetration rate algorithm is used to check if the needed penetration rate is achieved on the reinforced network.

For developing the new topologies, an optimization tool called automated optimal design of distribution network architecture described in *D3.1-3.1.3* was used.

The first step of the algorithm is the construction of a potential network graph having the same location of loads and substations.

The objective function of the algorithm is to minimize the operating costs (OPEX) which depend on the technical losses and investment costs (CAPEX) which depends on network's length. A set of electrical constraints ($I_{max}$, $V_{min}$) were taken into account in the problem as well as topological constraints (double connectivity for all load/production buses).

The topologies of the constructed networks are meshed. For ensuring the radial topology of the distribution network, the second step of the algorithm deals with the optimal placement of normally open switches, where the power losses are being minimized.

To measure the performance of the obtained solutions, a KPI MDGR was used. This KPI enables to estimate the amount of generation that can be connected to the distribution network without violating the technical constraints. This is done without any assumptions on their numbers, postitions and installed power.

**"New topology" solutions analysis**

Flexibility N°1: Production curtailment

The best DRES insertion rate provides 344% MDGR and covers the over expected scenario ($S_O$). Moreover, it improves the Discount Cost of 10% comparing with the case without using flexibilities. It has to be noticed that the cost of flexibilities have not been taken into account in this study. The optimality gap of obtained solutions varies from 34% to 45%, the number of switches from 67 to 91 and the total length of radial configuration from 161km to 178km.

Flexibility N°2: On-load tap changer transformer

In distribution network, the OLTC is currently used to regulate the voltage in distribution network. The voltage at the secondary of the transformer is continuously and automatically changed independently from the voltage at the primary side to meet a given voltage target. Regarding the type of network, the DSO estimates the value of this voltage target so that no constraint appears in the network. In case of high penetration of DRES, this target may have to be changed.
This possible degree of freedom of the DSO has been studied in this sub case. The best setting of the OLTC is 1.05 pu and leads to an increase of the MDGR of 2% and a decrease of the discount cost of 0.1%. For smaller settings of the OLTC, the MDGR and the discount cost are worse. The conclusion is that changing the settings of the OLTC seems not to improve a lot both the MDGR and the discount cost in this case. Only the method that leads to this conclusion (and not the conclusion itself) can be generalized. The concrete impact of the OLTC transformer is highly dependent on the specific supply task of the grid.

**Reinforcement Vs New topologies analysis**

Discount Cost
In general, greenfield planning leads to lower costs than grid reinforcement but it does not consider the presence of productions. In the case of the "New Topology" algorithm, productions are taken into consideration so it could have been possible that the final topology has more cables with bigger sections leading to higher costs. All the network solutions obtained by the "New topologies" method contain two cables and so provide a better KPI 'Discount Cost' compared to the solutions with the 'Reinforcement' method. The last one provides the solutions which solve the under expected scenario ($S_U$) beginning from a three cables topology.

MDGR

The "New topologies" and the "Reinforcement" methods give similar results on the same flexibility test cases. Results are presented in Section 11.4.4.

## 11.4. Evaluation of costs and benefits of the tool

### 11.4.1. Mapping the tool onto functionalities

Table 61 – Mapping of the TopPlan tool into the functionalities it provides. illustrates the mapping of the TopPlan tool into functionalities.

| Services | Functionalities |
|---|---|
| Increasing DRES penetration | *Considering reinforcement*: the tool finds the statistical reinforcement to do and its location to reach a given targets of DRES penetration (without knowing the DRES amount & location in the network) with and without flexibilities<br>*Considering new topology*: DRES are considered when the algorithm is run |
| Decreasing network costs | The algorithm minimizes the reinforcement so the global costs.<br>For the new topology, the optimization algorithm aims at minimizing the CAPEX and OPEX (flexibilities cost and communication costs are not taken into account) |

Table 61 – Mapping of the TopPlan tool into the functionalities it provides.

### 11.4.2. Mapping the functionalities onto benefits

In the next section, the mapping between the functionalities and the benefits provided by the TopPlan tool is presented. Table 62maps the benefits of TopPlan to the functionalities.

| Benefits | Functionalities | |
|---|---|---|
| | 1 | 2 |
| Increase DRES penetration | ● | |
| Decrease network costs | ● | ● |

Table 62 – Mapping of benefits and functionalities performed Grenoble INP and checked by Innogy.

A more detailed explanation of the benefits delivered by the TopPlan tool follows:

- **Increase DRES penetration:** DRES penetration is limited as voltage violations, current violations or considerable investment may occur. The tool proposes planning choice to alleviate these violations.
- **Decrease network costs:** The objective function of the tool is to minimize CAPEX and OPEX so the benefit "Decrease network costs" is fully integrated in the optimization functions. Without the tool, costs of the network could increase a lot if the DRES target was high or the network was weak.

### 11.4.3. Establishment of the baseline

Regarding the TopPlan tool, the baseline and the project scenarios to be tested are the following:

- **Baseline scenario**: Reinforcement to enable the DRES penetration target is used while minimizing the total length of additional conductors. Reinforcements up to four cables per trench are possible. Considering three scenarios of DRES penetration, a constraint algorithm locates weak area of the network where reinforcement is required to reach the three DRES penetrations' rates.

- **Project scenario**: The flexibility is integrated to the reinforcement procedure for the three scenarios of DRES penetration. The possibility to change the topology is also investigated.

The most relevant conditions regarding grid topology, load growth and DRES scenarios, as well as the metrics used to evaluate the corresponding benefits are summarised in Table 63, both for the baseline and project scenarios. The metrics described in Table 63 are based on the Operational and EEGI KPIs (see respectively *Deliverable 3.2* and *Deliverable 5.1* of the project).

| Benefits | Baseline Scenario | Project Scenario | Metrics Used |
|---|---|---|---|
| Increase DRES penetration | The German distribution network and the loads and DRES scenarios described in D3.4 are simulated using load flows. The reinforcement algorithm enables to assign cost for each DRES scenario if they are reachable. | Flexibility is added and the reinforcement procedure is run again. An optimization algorithm sets the optimal topology (regarding length of conductor and power losses). The associated cost and DRES penetration are then estimated. | KPI MDGR (Maximal amount of DRES that can be connected to the distribution network without making technical constraints violation) |
| Decrease network cost | | | KPI discount cost |

Table 63 – Baseline and Project conditions for the TopPlan benefits

### 11.4.4. Demonstration of the benefits

The full results of the test of the TopPlan tool are described in *Deliverable 3.4*. The main results are summarized below and demonstrate the benefits as described in previous section.

The case studied by simulation was a German distribution network. This is not a classical distribution network as there is more installed production than consumption. The maximal amount of distributed generation that can be connected without violating technical constraints is 142% of the maximal consumption. Three scenarios have been studied: under expected (263%), most likely (300%) and over expected (342%).

The main conclusions are the followings:

- Results are very dependent on the type of network, and the chosen scenarios and hypotheses;
- Reinforcement enables to satisfy all the DRES scenarios. If the entire network is reinforced using four conductors, the maximal amount of DRES that can be connected without violating technical constraints will be 411% of the maximal consumption. If three conductors are used, this amount decreases to 291%.
- Depending on the scenario, curtailment and OLTC can reduce the cost of network reinforcements. To satisfy the most likely scenario (300%), reinforcement with four

conductors is necessary. By using curtailment of existing generators or the OLTC, this figure decreases to three. This reduction of one conductor reduces the discount cost by 33%.

Building a new topology can be less expensive than reinforcing the network. The new topology using two cables enables to reach a MDGR of 311% that represents almost the half of the reinforcement cost required to satisfy the most likely scenario.

### 11.4.5. Qualitative impact analysis

The figures below assess in a qualitative way the impact of the tool across functionalities on the one hand and across benefits on the other hand. Table 76 shows the merit deployment matrix, which results from the qualitative assessment done for the TopPlan tool. In this table, the description of the links between benefits (and the respective indicators) and functionalities, as well as the weights assigned to each link are presented.
Figure 54 illustrates the impact that each functionality has in the global performance of the TopPlan tool. For this particular case, the *"statistical reinforcement"* is the functionality, which has a greater impact because it has been done considering the two benefits as targets. The "minimization of the total length" functionality is not directly linked to the DRES integration benefit that is why the impact is not relevant.

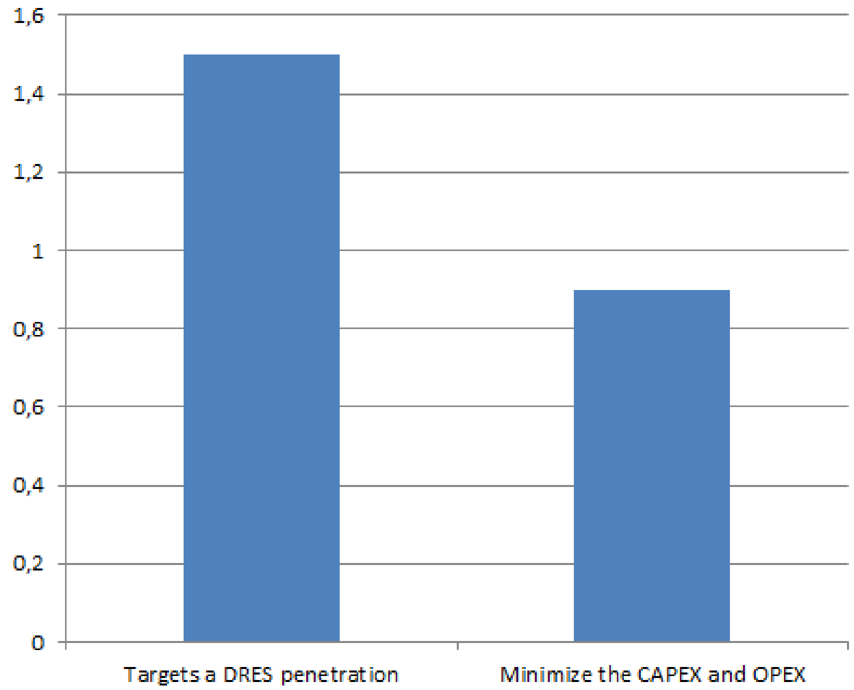



**Figure 54 – TopPlan tool impact across functionalities performed by Grenoble INP and checked by Innogy.**

Regarding the tool impact across the benefits, the benefit of decreasing costs is higher as the DRES integration is not an input of the optimization function (Figure 55).

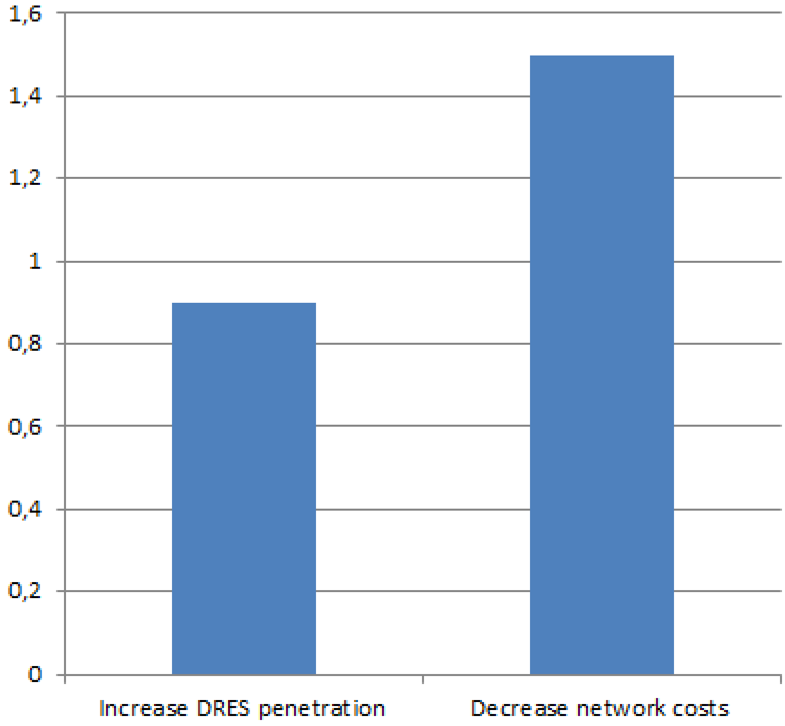



**Figure 55 – TopPlan tool impact across benefits performed Grenoble INP and checked by Innogy**

### 11.4.6. Identification and quantification of the costs

In order to properly identify the costs associated to the TopPlan tool exploiting, it is necessary to consider the actual level of development and the efforts made so far, the additional efforts to reach the industrial readiness and the costs associated to the integration of the tool in the DSO environment.

The overall efforts needed to develop a complete industrial application can be summarized as follows:

- To check the economic and technical parameters used and planning decisions rules;
- To validate on other test networks and other DRES scenarios;
- To adapt the tool(to adapt the inputs data for interfacing with the other software used by DSO or to translate the code).

It should be stressed out that 50% of the total cost estimated to have an industrial tool was already covered by the project. This corresponds to 12 PM spent during the project (with a rough estimation of the average PM cost around 4600€) and 12 PM for the additional developments towards industrialization.

The cost for tool integration in a real operating environment cannot be estimate within the project because the tool was not tested in the field. The minimum technical requirements for its integration have been identified and are summarized in Table 94, Annex X.

# 12. Summary and Conclusions

In this section a short recap of the analysis presented in the previous sections is reported, divided by tool.

**ICPF**

The ICPF estimates the flexibility ranges of active and reactive power at the TSO/DSO boundary nodes for the upcoming hours considering the network constraints and the available flexibility resources in the distribution grid. Therefore, the ICPF should be considered as an "informative tool" which makes the quantitative analysis of its benefits impact difficult. Within this scope, the development of a merit deployment matrix is crucial since it allows to quantify the tool impact across the functionalities and benefits.

Regarding the High Level Assessments of WP3 and WP4 tests, the computed KPIs proved the effectiveness of the ICPF tool in increasing the estimated flexibility area when comparing with the baseline scenario (Monte Carlo Simulations). In the case of WP4 French field-test, it increases between 6 and 197 %, while in the Portuguese case, the ICPF captures flexibility areas not searched by the MCS. A decrease of the computational time was also reported when compared to the baseline. Decreased values near 100% (e.g., from 220s using MCS to 110 seconds using the ICPF) were achieved for all the tests in WP3 and WP4. Considering the end-user feedback from the field-test, it could be relevant to reduce even more this computational time.

**SOPF**

The SOPF tool searches for the optimal values through network reconfiguration and voltage and reactive power control. Considering consecutive periods of analysis using a slide window approach, it proposes to derive a set of control actions that keep the active and reactive power flow within pre-agreed limits at the primary substations level.

The evaluation of costs and benefits performed in this document allows to map the SOPF tool into functionalities. Then, these functionalities are mapped into benefits. The DSOs involved in WP3 and WP4 tests addressed different weights to the links between functionalities and benefits in order to evaluate the tool impact across them. Both French and Portuguese DSOs assigned to the functionality "Enhance monitoring of power flows and voltages" the highest weight. In fact, voltage and reactive power control present a significant impact for electricity losses reduction, contributing also to reduce the costs associated with the activation of flexible resources plus penalisations of power out of limits at TSO/DSO boundaries. Regarding the benefits, the French and Portuguese DSOs performed a similar evaluation. Reduced total electric power losses and reduced costs of activating flexible resources plus the penalizations of power out of limits at TSO/DSO boundaries are the benefits with greatest impact. These benefits are not surprising since they are directly in the scope of the tool objectives.

Concerning the High Level Assessments of WP3 and WP4 tests, the SOPF proved its effectiveness through the calculation of the EEGI KPI's. The output of the SOPF provided a reduction in terms of active power losses and overall network operational costs. Moreover, this tool was able to maintain the active and reactive power within their minimum/maximum technical limits.

**LVSE**

The Low Voltage State Estimator (LVSE tool) provides to the DSOs a complete and reliable view of their LV networks in real-time and, at the same time, the solution can be used as an input for other power system related modules (e.g. voltage control).

Since the benefits provided by the LVSE functionalities are complex to quantify, their evaluation is mostly qualitative. The impact assessment of benefits and functionalities performed by the French and Portuguese DSOs were quite similar. Regarding, the functionalities, "Update network performance data on voltage quality" and "Enhance monitoring and observability of grids down to low voltage levels" were the ones with the highest impact. This was not a surprise since the main goal of the LVSE tool is to fulfil these functionalities. By providing a complete view of the LV networks in real-time, namely in terms of voltage magnitudes, the LVSE contributes to the observability of such networks.

In the High Level Assessments of WP3 and WP4 tests, the LVSE provided an accurate estimation of the network voltage magnitude while the error estimation index was only 1.0% of the nominal voltage. However it is important to highlight that the LV networks considered in the study were well designed, i.e. they did not have large voltage drops/increases in regards to their consumption.

**LVC**

The LVC is able to keep the voltage profile within the admissible limits through appropriate control actions sent to the available assets connected to the LV level. Therefore, the LVC searches to meet all regulatory limits while improving the operational efficiency and reliability.

The Cost and Benefits analysis follows a qualitative impact analysis to estimate the tool impact regarding their functionalities and benefits since they are difficult to quantify. The assessment performed by the French and Portuguese DSOs followed the same path. The highest weight was assigned to the functionality "solve network constraints using optimization levers based on merit order". This is in accordance with the expectations since the LVC is a contingency focused tool to solve voltage problems through operation management of the grid controllable assets. The benefit with the highest impact can be derived from this functionality. By solving voltage problems, the LVC allows an increase of DRES hosting capacity.

The High Level Assessment of WP3 tests are in accordance with the analysis made in the Cost and Benefits evaluation. For the Portuguese test cases, the LVC allowed a maximum increase of 7.5% of the hosting capacity while an increase of 3% was observed in the French ones.

**OP tool**

The Cost and Benefits evaluation performed for the OP-tool allows proving the efficiency of the tool for Operational Planning purposes. The tool supports DSOs in an efficient short-term management of their grid by providing them the possibility to solve network constraints at a minimum cost by contracting and integrating flexibility in the operational scheduling, respecting the necessary voltage limits.

The benefits presented and quantified by KPIs, show important improvements when the tool is utilized. In addition, the tool does not only provide benefits for DSOs, but also enables an increase in the hosting capacity of DRES, which is beneficial for end-consumers, flexibility providers and the entire system. Nevertheless, in order to integrate the tool, additional costs will be present to further industrialize and integrate the tool in existing systems. The main additional industrialisation costs are linked to extensive testing of the tool, standardisation of the data and the potential purchase of a commercial CP-solver. In terms of integration of the tool with existing DSO-tools, no real issues are expected. The main important element is that

the OP-tool has only value in case the necessary forecasts for load and DRES are available with a 15' granularity. In addition, the effectiveness of the tool depends also on the evolution of the local market for flexibilities, the availability of flexibilities and the cost of these flexibilities. In case it will be more cost-efficient for DSOs to reinforce their grid, compared to using flexibility, the tool will obviously have less value.
In conclusion, the OP-tool is a promising tool to be used by DSOs in the future to solve network constraints at a minimal cost.

**CCS tool**
The Contingency Co-Simulation tool is suitable for analysing distribution networks and Smart Grid case studies, based on active management of the network, with regulation of power flows and remote control of DRES. The capability to compile lists of contingencies to be simulated in these environments allows the DSOs to perform preventive studies of the active grids reliability. This would result in more efficient and effective actions and policies to manage undesired events. The co-simulation sub-tool allows testing the capability of the available active resources to face voltage violations and to evaluate the most effective solutions to solve the contingencies; it is valuable also to verify if flexibilities could be fully exploited and to analyse the impact of ICT transmission behaviour in different operating conditions.
The High-Level Assessment has generally confirmed these capabilities and has given the prompts for next development stages of the tool. Also the qualitative analysis performed in the Cost and Benefits evaluation has highlighted the strong and weak points of the actual version of the CCS tool.
The most valuable result of this assessment, from the developers perspective, is the confirmation that the idea behind this application is good and the work done so far is in accordance with the expectations; furthermore it has given the prompts for focused improvements in order to completely fulfil the envisioned performances.

**Replay**
The Replay is a smart didactical simulation platform that could be used for back office analysis in the control room (ex-post and predictive analysis) as well as a SCADA simulator in the short term planning to evaluate specific network configurations in the short-term period. For this reason, some specific KPIs could be measured (potential SAIDI reduction index, criticality reduction index and time training saving) even though this evaluation is highly dependent on the specific network and technical situation of the grid.
The tool is intended to bridge the gap between the usual operational procedures performed by network operators and innovative approaches the evolving scenario can offer. Regardless of the way market and regulatory framework can change in short/long term future, the tool demonstrates its usefulness also in the as-is scenario.
In particular, it is necessary to highlight the importance of the Replay within the current regulatory context. The ex-post analysis and all its available procedures represent the frontier for the creation of a smart didactical platform even though the procurement of flexibility could be a future perspective. In this framework, the more efficient is the interface for the operator, the more effective is the tool in supporting the operator in future procedures.
The Cost and Benefits evaluation presented in this document follows a qualitative approach. In this scope, the development of a merit deployment matrix allows to quantify the project impact across functionalities and benefits.

**AAM**

The developed tool proposes a method for finding the optimal asset management in a given planning horizon. It also identifies the most critical assets in a distribution network in terms of DRES curtailment and load shedding in case of component failure. The feedback from the High Level Assessment of the tool demonstration activities indicates that tools such of this have some ability to improve asset management and investment decisions for DSOs. However, integration of such tools with existing asset management databases appears costly and difficult. Likewise, some of the feedback gathered showed concerns about the realism of the model, and the real-world applicability of its outputs. This indicates that more sophisticated investment planning models (that consider, e.g. maintenance decisions in a more granular way) may be necessary to deliver sufficient value to the DSO to justify the cost of their integration with extant databases.

**FLEXPLAN**
The developed tool covers a method for finding relevant network planning cases based on time-series values and a planning algorithm combining network reinforcements and the use of flexibilities. Furthermore, the impact of ICT on the network reliability for future networks can be assessed. The assessment of the tools shows, that the inclusion of flexibilities into the network planning process has a significant impact on network expansion costs. However, the value of a flexibility within the planning process is case specific. Especially the costs and available technology of ICT will be determining factors for the cost savings that can be achieved. Furthermore, the simulation results lead to the conclusion, that the influence of ICT systems on grid-reliability is not negligible and depends on the specific power system topology and redundancy. Planning a distribution grid for a broader set of future scenarios leads to higher expansion costs depending on the spread of the considered uncertainties. In order to adequately model the maximum network usage within the planning process, a small set of representative network planning cases (NPC) (3 to 12 NPC in exemplary simulations) are sufficient. Yearly network losses as well as the yearly-curtailed energy from renewables can be determined by 50 to 100 network planning cases depending on the required accuracy.
As all assessments are solely based on simulations, further tests within the DSO environment are necessary for the industrialization of the tools and the proof of applicability within the DSO environment.

**TopPlan**
The tool for the long-term network planning TopPlan was assessed on two test cases. A real medium voltage network was studied according to defined scenario with high penetration of DRES for a long-term perspective of 40 years. In the study, the possible flexibility was considered as a stochastic input to choose between reinforcement and building new architectures. Thus the technical choice in the network depends on this flexibility.
Two proposed methods of TopPlan tool are able to solve all the network constraint violations in different scenarios of the defined targets. The test case presents a comparison between reinforcement of the existing network and new topology (building the network from scratch). Two flexibilities are also studied: production curtailment and different OLTC settings.
The performance of each solution obtained on the scenarios was measured by two KPIs: Discount cost and Maximal amount of DER that can be connected (MDGR). The best solutions were obtained using the production curtailment flexibility's lever.

# REFERENCES

[1] JRC, "Guidelines for conducting a cost-benefit analysis of Smart Grid projects," 2012.

[2] EPRI, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects", 2010.

# Annex I - ICPF tool

| Req. Type | Details | Level of Uncertainty | Costs Considered | Justification/comments |
|---|---|---|---|---|
| **ICT** | Collect information from the forecasting tool | LOW | YES | Assumption: the ICPF only receives information from the forecasting tool → No need to upgrade Enedis forecasting tool. All the adaptation costs (formats, protocols, etc.) are supposed to be on the development costs of the ICPF. |
| | Monitoring of switching gear, OLTC and capacitor banks actual status when the tool is activated, e.g. two times per day | NA | NO | For the switching gear and capacitor, cost are not supported by ICPF.<br>For the OLTC update costs could occurred but are not mandatory. No costs are considered for the OLTC transformer at Venteea. |
| **Data Storage & Management** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance for the next day tasks that require network reconfiguration | MEDIUM | YES | The cost includes study, specification and prototype.<br>This cost is also related to the communication of the data to the ICPF (ICT costs). |
| **Other Software Functions** | Data from a forecasting tool composed by 24h day-ahead forecasts for load and DRES | NA | None | We already have a forecasting tool so no costs. The only cost comes from the communication costs to collect the data as mentioned in the ICT costs. |
| | Data from network topology and network planned maintenance | NA | None | No costs because data already available |
| | Costs associated to processing all the input data required for ICPF | NA | NO | It is not possible to evaluate this cost. A complete functional analysis should be carried out to determine this cost. The costs might be consequent and should mostly be paid by the RI. |
| **Maint. / Upgrade** | Maintenance of the computer server that supports the required software infrastructure and data processing | NA | NO | Should be included in the hardware costs<br>[already included in the hardware] |

| | | | | |
|---|---|---|---|---|
| **Hardware** | The computational requirement to run the tool is quite low in terms of CPU and memory (i.e. regular computer) | HIGH | YES | The cost is highly dependent on the architectural structure chosen (centralised or de-centralised). |
| **Metering Data Structure** | No costs associated | NA | None | |

**Table 64 – Minimum technical requirements of the ICPF tool for France.**

| Req. Type | Details | Level of Uncertainty | Costs Considered | Justification/comments |
|---|---|---|---|---|
| **ICT** | Collect information from the forecasting tool | MEDIUM | YES | This cost might be available<br>Only adaptation costs are considered. |
| | Monitoring of switching gear, OLTC and capacitor banks actual status when the tool is activated, e.g. two times per day | LOW | YES | Only interface costs are considered. |
| **Data Storage & Management** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance for the next day tasks that require network reconfiguration | HIGH | YES | This cost might be available<br>Should go in ICT costs. The costs are more related to the communication of the data to the ICPF |
| **Other Software Functions** | Data from a forecasting tool composed by 24h day-ahead forecasts for load and DRES | LOW | YES | The only costs comes from the communication costs to collect the data as mentioned in the ICT costs. |
| | Data from network topology and network planned maintenance | MEDUIM | YES | Interface development between GIS and SAP PM |
| | Costs associated to processing all the input data required for ICPF | MEDIUM | YES | This cost might be available |
| **Hardware** | The computational requirement to run the tool is quite low in terms of CPU and memory (i.e. regular computer) | HIGH | YES | The cost is highly dependent on the architectural structure chosen (centralised or de-centralised). |
| **Metering Data Structure** | *No costs associated* | - | NO | |

Table 65 – Minimum technical requirements of the ICPF tool for Portugal.

| Req. Type | Details | Level of Uncertainty | Comments |
|---|---|---|---|
| **ICT** | Collect information from the forecasting tool | LOW | If forecasting tool is running, data is available. Only communication costs should be considered. |
| | Monitoring of switching gear, OLTC and capacitor banks actual status when the tool is activated, e.g. two times per day | LOW | This data is already available for operational purposes, so no additional costs are foreseen. |
| **Data Storage & Management** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance for the next day tasks that require network reconfiguration | LOW | This data is already available (e.g. Workforce management), only communication costs |
| **Other Software Functions** | Data from a forecasting tool composed by 24h day-ahead forecasts for load and DRES | HIGH | Tool for 24h day-ahead forecasts for load and DRES is not implemented and development cost have to be considered |
| | Data from network topology and network planned maintenance | LOW | This data is already available, only communication costs |
| | Costs associated to processing all the input data required for ICPF | MEDIUM | Same as above |
| **Hardware** | The computational requirement to run the tool is quite low in terms of CPU and memory (i.e. regular computer) | HIGH | Should be considered if one computer is needed for every second substation |

**Table 66 - Minimum technical requirements of the ICPF tool for Germany.**

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Support to the decision-maker regarding TSO-DSO interface monitoring** | **2. Estimate Flexibility Range of the Primary Substations** | **3. Frequent information exchange on actual active/reactive generation/consumption flexibilities** | **4. Manage TSO's requests and support decision-making near to real time at different timeframes** | **Total Sum for Benefit** |
| **Benefits** | **Contributes to increase the information exchange between TSO and DSO** | No relevant for contribute to increase the information exchange between TSO and DSO | Allows to find area not explored by the Monte Carlo Simulation (benchmark model) - identify the high and the low cost zones | The ICPF gives information about the range of variation for active/reactive generation/consumption due to the flexibility assets installed in the distribution network | This is one of the main tool objectives. | **2.7** |
| | **Weights** | 0 | 0.9 | 0.8 | 1 | |
| | **Enhancing the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO** | The decision-maker through the ICPF outcome (flexibility cost maps) is able to enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO | The Flexibility map cost allows the analysis of the possibility to move from a predicted point to another giving also the information concerning the relative cost | With post analytics it is possible to get extra information (improve accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO) | By managing correctly the TSO's requests it is possible not spending unnecessary costs by activating expensive flexibility assets with lower impact in the flexibility at TSO connection node.<br>The decision-making through the ICPF outcome (flexibility cost maps) is able to enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO | **2.8** |
| | **Weights** | 0.8 | 0.8 | 0.4 | 0.8 | |
| | **Separate the contributions of different type of flexibilities and flexibilities with different costs** | No relevant for separate the contributions of different types of flexibility | The different impacts of flexibilities and the maximum operating point as shown in the cost map allowed to separate different flexibilities and to decide which one to use when | No relevant for separate the contributions of different types of flexibility | No relevant for separate the contributions of different types of flexibility | **0.7** |
| | **Weights** | 0 | 0.7 | 0 | 0 | |
| | **Provide more data for the future planning of distribution network** | The ICPF tool allows simulating future scenarios, for example with different RES penetration levels or with loads that are more flexible. This gives an idea to the decision maker about potential future technologies for the distribution network | Accurate Flexibility Cost Maps lead to more realistic data about future scenarios. For example, in order to test the impact in terms of flexibility available in a scenario with high RES penetration.<br>ICPF is an operational tool, not a planning tool. Another tool is required to do the post analysis of the information. | Useful for post analysis. The frequency is not very relevant only the fact of having this information matter. | ICPF is an operational tool, not a planning tool. Another tool is required to do the post analysis of the information | **1.9** |
| | **Weights** | 0.9 | 0.2 | 0.5 | 0.3 | |
| | **Sum Total** | **1.7** | **2.6** | **1.7** | **2.3** | |

Table 67 - Merit deployment matrix of the ICPF tool (compiled by Innogy).

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Support to the decision-maker regarding TSO-DSO interface monitoring** | **2. Estimate Flexibility Range of the Primary Substations** | **3. Frequent information exchange on actual active/reactive generation/consumption flexibilities** | **4. Manage TSO's requests and support decision-making near to real time at different timeframes** | **Total Sum for Benefit** |
| **Benefits** | **Contributes to increase the information exchange between TSO and DSO** | No relevant for contribute to increase the information exchange between TSO and DSO | Allows to find area not explored by the Monte Carlo Simulation (benchmark model) - identify the high and the low cost zones | The ICPF gives information about the range of variation for active/reactive generation/consumption due to the flexibility assets installed in the distribution network | The ICPF tool enables the DSO to estimate the P and Q flexibility ranges, hence giving information about the boundaries of the available support that the DSO is able to offer to the TSO, when requested. This is one of the main objective of the tool. | **2.9** |
| | **Weights** | 0 | 0.9 | 1 | 1 | |
| | **Enhancing the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO** | The decision-maker through the ICPF outcome (flexibility cost maps) is able to enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO. The contractual values are not modified in real time; a post analysis would be required for a more relevant value. | The Flexibility map cost allows the analysis of the possibility to move from a predicted point to another giving also the information concerning the relative cost | With post analytics it is possible to get extra information (improve accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO) | By managing correctly, the TSO's requests it is possible not spending unnecessary costs thanks to the flexibility costs map. | **2.3** |
| | **Weights** | 0.5 | 0.8 | 0.4 | 0.6 | |
| | **Separate the contributions of different type of flexibilities and flexibilities with different costs** | No relevant for separate the contributions of different types of flexibility | Not relevant for the French case | Not relevant for the French case | Not relevant to separate the contributions of different types of flexibility | **0** |
| | **Weights** | 0 | 0 | 0 | 0 | |
| | **Provide more data for the future planning of distribution network** | A post analysis of the ICPF outputs could enable to build future scenarios based on passed flexibilities activated. These scenarios could be integrated in future operational planning. Another tool is required to do the post analysis of the information. | A post analysis of the ICPF outputs (Flexibility Cost Maps) could lead to more realistic data about future scenarios. For example, in order to test the impact in terms of flexibility available of high RES penetration. Another tool is required to do the post analysis of the information. | Useful for post analysis. The frequency is not very relevant, only the fact of having this information matters. | ICPF is an operational tool, not a planning tool; but another required tool could do the post analysis of the information. | **1.4** |
| | **Weights** | 0.3 | 0.3 | 0.5 | 0.3 | |
| | **Sum Total** | **0.8** | **2** | **1.9** | **1.9** | |

**Table 68 - Merit deployment matrix of the ICPF tool (compiled by Enedis)**

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Support to the decision-maker regarding TSO-DSO interface monitoring** | **2. Estimate Flexibility Range of the Primary Substations** | **3. Frequent information exchange on actual active/reactive generation/consumption flexibilities** | **4. Manage TSO's requests and support decision-making near to real time at different timeframes** | **Total Sum for Benefit** |
| **Benefits** | **Contributes to increase the information exchange between TSO and DSO** | The DSO through the ICPF outcome (flexibility cost maps) is able to enhance the information exchange with the TSO for each primary substation<br>**Very Relevant Benefit** | Allows to estimate the P and Q flexibility range in each primary substation<br>**Very Relevant Benefit** | The ICPF gives information about the range of variation of active/reactive generation/consumption related with the flexibility assets installed in the distribution network;<br>**Very Relevant Benefit** | The ICPF tool enables the DSO to estimate the P and Q flexibility ranges, hence giving information about the boundaries of the available support that the DSO is able to offer to the TSO, when needed;<br>**Very Relevant Benefit** | **3.4** |
| | **Weights** | 0.9 | 0.9 | 0.8 | 0.8 | |
| | **Enhancing the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO** | The decision-maker through the ICPF outcome (flexibility cost maps) is able to enhance the accuracy of the definition of contractual values of electrical energy exchange between TSO and DSO<br>**Very Relevant Benefit** | The Flexibility map cost allows the analysis of the possibility to move from a predicted point to another giving also the information concerning the relative cost<br>**Very Relevant Benefit** | By increasing the real-time available information regarding flexibilities of P and Q ranges, is possible to enhance the contractual values of electrical energy exchange between TSO and DSO;<br>**Relevant Benefit** | By managing correctly the TSO's requests it is possible to not spend unnecessary costs by activating expensive flexibility assets with lower impact in the flexibility at TSO connection node;<br>**Relevant Benefit** | **3** |
| | **Weights** | 0.8 | 0.9 | 0.6 | 0.7 | |
| | **Separate the contributions of different type of flexibilities and flexibilities with different costs** | The ICPF allows the decision maker to choose which type of flexibility to activate, anticipating its influence in the network operation point and cost;<br>**Relevant Benefit** | More accurate Flexibility Cost Maps lead to a more realistic understanding about the impact of the different types of flexibilities<br>**Very Relevant Benefit** | No relevant for separate the contributions of different types of flexibility | More accurate Flexibility Cost Maps enables an optimized reply to the TSO's requests, minimizing the flexibility costs;<br>**Very Relevant Benefit** | **2.2** |
| | **Weights** | 0.6 | 0.8 | 0 | 0.8 | |
| | **Provide more data for the future planning of distribution network** | The ICPF tool allows simulating future scenarios, for example with different RES penetration levels or with loads that are more flexible. This helps the decision maker to plan future investments on the distribution network;<br>**Relevant Benefit** | Accurate Flexibility Cost Maps lead to more realistic data about future scenarios. For example, allow to evaluate the impact in terms of flexibility available of a scenario with high RES penetration<br>**Relevant Benefit** | Useful to define future rules for providing reactive power support from the distribution network side<br>**Relevant Benefit** | No relevant for future network planning | **1.4** |
| | **Weights** | 0.4 | 0.4 | 0.6 | 0 | |
| | **Sum Total** | **2.7** | **3** | **2** | **2.3** | |

Table 69 - Merit deployment matrix of the ICPF tool (compiled by EDP Distribuição)

# Annex II - SOPF tool

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comment |
|---|---|---|---|---|
| **ICT** | Monitoring and control of switching gear, OLTC and capacitor banks actual status, flexible generators and flexible loads when the tool is activated, e.g. two times per day | NA | NO | For the switching gear and capacitor, cost are not supported by SOPF.<br>For the OLTC update costs could occur but are not mandatory.<br>→ No costs are considered for the OLTC transformer at Venteea. |
| **Data Storage & Management** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance tasks that require network reconfiguration | MEDIUM | YES | The cost includes study, specification and prototype<br>This cost is also related to the communication of the data to the ICPF (ICT costs) |
| **Other Software Functions** | A forecasting tool is needed for producing load/generation units active power forecasts for an expected time horizon of, at least, 24 hours | NA | None | We already have a forecasting tool so no costs. The only costs comes from the communication costs to collect the data as mentioned in the ICT costs. |
| | Data from network topology and network planned maintenance | NA | None | No costs because data already available |
| | A system for sending and recording the set points defined by the SOPF to the flexibility levers considered | NA | NO | Cost cannot be evaluated |
| | Costs associated to processing all the input data required for SOPF, but also its output data (flexibility assets set points) | NA | NO | It is not possible to evaluate this cost. A complete functional analysis should be carried out to determine this cost. The costs might be consequent and should mostly be paid by the RI. |
| **Hardware** | The computational requirement to run the tool is quite low in terms of CPU and memory (i.e. regular computer) | HIGH | YES | The cost is highly dependent on the architectural structure chosen (centralised or de-centralised). |
| **Metering Data Structure** | *No cost associated* | NA | None | |

Table 70 - Minimum technical requirements of the SOPF tool for France.

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comment |
|---|---|---|---|---|
| **ICT** | Monitoring of switching gear, OLTC and capacitor banks actual status when the tool is activated, e.g. two times per day | LOW | YES | Only interface costs are considered. |
| | Monitoring and control of switching gear, OLTC and capacitor banks actual status, flexible generators and flexible loads when the tool is activated, e.g. two times per day | NA | NO | For the switching gear and capacitor, cost are not supported by SOPF. |
| **Data Storage & Management** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance tasks that require network reconfiguration | HIGH | YES | This cost might be available<br>Should go in ICT costs. The costs are more related to the communication of the data to the SOPF |
| **Other Software Functions** | A forecasting tool is needed for producing load/generation units active power forecasts for an expected time horizon of, at least, 24 hours | LOW | YES | The only costs comes from the communication costs to collect the data as mentioned in the ICT costs. |
| | Data from network topology and network planned maintenance | MEDIUM | YES | Interface development between GIS and SAP PM |
| | A system for sending and recording the set points defined by the SOPF to the flexibility levers considered | HIGH | YES | Cost are difficult to be evaluated |
| | Costs associated to processing all the input data required for SOPF, but also its output data (flexibility assets set points) | MEDIUM | YES | This cost might be available |
| **Hardware** | The computational requirement to run the tool is quite low in terms of CPU and memory (i.e. regular computer) | HIGH | YES | The cost is highly dependent on the architectural structure chosen (centralised or de-centralised). |
| **Metering Data Structure** | *No cost associated* | | NO | |

**Table 71 – Minimum technical requirements of the SOPF tool for Portugal.**

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Enhance monitoring and control of power flows and voltages** | **2. Identification of technical power losses by power flow analysis** | **3. Frequent information exchange on actual active/reactive generation/consumption flexibilities** | **4. Optimise the network by providing active and reactive power profiles to the TSO** | **Total Sum for Benefits** |
| **Benefits** | **Reduced electricity losses Indicators: Total power losses improvement (%) (EEGI KPI - Power quality & quality of supply)** | The SOPF can control power flow and voltages that allow reducing the electricity losses by managing transformer and capacitor bank taps and by looking for different topological configurations. **Very Relevant Benefit** | By identifying the technical power losses for each solution the SOPF can find, iteratively, a solution with reduced power losses **Very Relevant Benefit** | **Not Relevant for Reduced electricity losses** | The power profiles provided to the TSO are obtained considering, among other, the total power losses of the found solution (using the SOPF tool, an improvement on power losses can be achieved). **Very Relevant Benefit** | **2.6** |
| | **Weights** | 0.9 | 0.9 | 0 | 0.8 | |
| | **Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries Indicators: Total costs improvement (operational KPI)** | By controlling the power flow and voltages, the SOPF can avoid high penalizations for surpassing power limits and control tan ϕ, as well as control the amount of activated flexible resources that can lead to costs reduction. **Very Relevant Benefit** | The power losses usually have direct link to the costs of activating flexible resources and to the costs of surpassing power limits. Reducing the power losses, such costs may be reduced too. **Relevant Benefit** | The information about the actual active/reactive generation/consumption constitutes a solution of the SOPF tool algorithm that can lead to the costs improvement, iteratively. **Relevant Benefit** | Using the SOPF tool, an improvement on flexibility costs can be achieved **Very Relevant Benefit** | **2.4** |
| | **Weights** | 0.9 | 0.5 | 0.3 | 0.7 | |
| | **Reduced energy curtailment of RES/DER Indicators:(EEGI KPI)** | The SOPF can reduce the energy curtailment by managing devices such as capacitor banks and transformer taps. **Relevant Benefit** | **Not relevant for the energy curtailment assessment** | The information exchange about the actual active/reactive generation/consumption can help to realize the levels of RES/DER used in the network and, therefore, avoid its curtailment **Relevant Benefit** | The solution achieved by the SOPF tool, and then provided to the TSO, can lead to the reduction of RES/DER energy curtailment **Relevant Benefit** | **1.5** |
| | **Weights** | 0.4 | 0 | 0.5 | 0.6 | |
| | **Increase RES & DER hosting capacity Indicators:(EEGI KPI)** | By controlling power flows and voltages, the SOPF can allow increasing RES & DER hosting capacity without violations of the power flows and voltages technical limits. **Relevant Benefit** | By controlling power flows and voltages, the SOPF can allow increasing RES & DER hosting hence minimizing the electrical power losses. **Very Relevant Benefit** | **Not Relevant for the increase of RES & DER hosting capacity** | **The SOPF tool will not improve the information already known related to the capability to increase the hosting capacity.** | **1.4** |
| | **Weights** | 0.6 | 0.8 | 0 | 0 | |
| | **Sum Total** | **2.8** | **2.2** | **0.8** | **2.1** | |

Table 72 - Merit deployment matrix to assess functionalities and benefits for SOPF tool (compiled by EDP Distribuição)

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Enhance monitoring and control of power flows and voltages** | **2. Identification of technical power losses by power flow analysis** | **3. Frequent information exchange on actual active/reactive generation/consumption flexibilities** | **4. Optimize the network by providing active and reactive power profiles to the TSO** | **Total Sum for Benefits** |
| **Benefits** | **Reduced electricity losses Indicators: Total power losses improvement (%) (EEGI KPI - Power quality & quality of supply)** | The SOPF can control power flow and voltages that allow to reduce the electricity losses by managing transformer and capacitor bank taps and by looking for different topological configurations. | By identifying the technical power losses for each solution the SOPF can find, iteratively, a solution with reduced power losses. | Not relevant | The reduction of electricity losses of the DSO is achieved through functionalities 1 and 2. This functionality is more related to data exchange and may reduce the TSO losses. | **2** |
| | **Weights** | 0.9 | 1 | 0 | 0.1 | |
| | **Reduced costs of activating flexible resources plus penalisations of power out of limits at TSO/DSO boundaries Indicators: Total costs improvement (operational KPI)** | By controlling the power flow and voltages, the SOPF can avoid high penalizations for surpassing power limits and control tan ϕ, as well as control the amount of activated flexible resources that can lead to costs reduction. | The power losses usually have direct link to the costs of activating flexible resources and to the costs of surpassing power limits. Reducing the power losses, such costs may be reduced too. | The information about the actual active/reactive generation/consumption constitutes a solution of the SOPF tool algorithm that can lead to the costs improvement, iteratively. | The reduction of electricity costs of activating flexible resources is achieved through functionalities 1 and 2. This functionality is more related to data exchange. | **2.2** |
| | **Weights** | 1 | 0.4 | 0.7 | 0.1 | |
| | **Reduced energy curtailment of RES/DER Indicators:(EEGI KPI)** | The SOPF can reduce the energy curtailment by managing devices such as capacitor banks and transformer taps. | Not relevant | The information exchange about the actual active/reactive generation/consumption can help to realize the levels of RES/DER used in the network and, therefore, avoid its curtailment. | The reduction of energy curtailment of RES/DER is achieved through functionalities 1 and 2. This functionality is more related to data exchange. | **1.8** |
| | **Weights** | 0.9 | 0 | 0.8 | 0.1 | |
| | **Increase RES & DER hosting capacity Indicators:(EEGI KPI)** | More related to planning: by controlling power flows and voltages, the SOPF can allow increasing RES/DER hosting capacity without violations of the power flows and voltages technical limits but could increase network losses | Not relevant | Not relevant | Not relevant | **0.4** |
| | **Weights** | 0.4 | 0 | 0 | 0 | |
| | **Sum Total** | **3.2** | **1.4** | **1.5** | **0.3** | |

Table 73 - Merit deployment matrix to assess functionalities and benefits for SOPF tool (compiled by Enedis).

# Annex III - LVSE tool

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **ICT** | "Real-time" communication (10 or 15 min) with a subset of LV smart meters. The size of this subset was estimated in the simulation tests of D3.4 (Portugal) and in WP4 (only for France) | HIGH | Partially | The costs depend on the architecture (centralised /decentralised). The costs considered cover only the real time communication between the data concentrator and the computer. The costs considered are annual. |
| | "Batch" communication of V, P, Q historical data with 10 or 15 min time steps for a large number of SMs to train the tool on network topological changes | NA | NO | Not possible to provide this cost. Only a limited period of time would be considered during a year for this collection (a few weeks at most) |
| | RT and batch communication between the DC and the control centre. | NA | NO | Not possible to provide a cost because it depends on the communication target architecture (centralised or decentralised).<br>RT (alarms), batch (load curve, indices…) and configuration communication are already implemented in a DC. Additional data would be needed: if LVSE is decentralised, only Power Quality information will be sent (LVSE derived results), while if not, it would be the measurements (LVSE inputs).<br>The additional costs come from the frequency of these new exchanges and the volume of data exchanged, but also of the chosen communication media (GPRS, PLC…). |
| **Data Storage & Management** | Data management and storage infrastructure capable of handling at least 6 months of smart meter historical data (active power and voltage) | NA | NO | Not possible to provide a cost because it depends on the communication target architecture (centralized or decentralized). This requirement has different impact depending on the target architecture: centralized training means more storage capability in a server of the control centre, while decentralized training means more storage capability in the DC performing the LVSE |

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **Hardware** | Additional cost to adapt the Smart meters in LV consumers/prosumers with VPQ real-time communication capability (e.g. PLC PRIME, PLC G3, GPRS) and to have VQ batch communication capabilities | HIGH | YES | The costs provided are for a prototype. The VQ batch communication capabilities are not considered. |
| | Data concentrator or any decentralized control unit (DCU) in the secondary substation for collecting both batch and RT data with sufficient memory to store the historical VPQ data of an adequate number of SMs. In a fully or partially decentralized application, the LVSE could be computed by the DCU. Sufficient computational power should also be available in this case. The computational requirement to run the tool is low in terms of CPU and memory | NA | NO | Not possible to provide a cost because it depends on target architecture.<br>The tool can be either implemented within the DC in a full distributed implementation, in a control centre in a centralized implementation, or even training performed at the control centre and the SE performed by the DC |
| **Metering Data Structure** | The smart meters (and DTC – if possible) should be able to collect active/reactive power and voltage measurements in each LV consumer/prosumer both in RT but in a scheduled collect (e.g. once a day) | HIGH | YES | The costs provided are for a prototype |

Table 74 – Minimum technical requirements of the LVSE tool for France.

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| ICT | "Real-time" communication (10 or 15 min) with a subset of LV smart meters. The size of this subset was estimated in the simulation tests of D3.4 (Portugal) and in WP4 (only for France) | MEDIUM | YES | -Considered the additional cost of using GPRS instead of PLC PRIME smart meter + scalability effect of a greater volume<br>-Considered the SIM Card cost + scalability effect of a greater volume<br>-Considered the cost of replacing the subset of $SM_r$ for GPRS smart meters<br>-Considered the cost of necessary additional configuration (HR effort) |
| | "Batch" communication of V, P, Q historical data with 10 or 15 min time steps for a large number of SMs to train the tool on network topological changes | NA | NO | Already available within the existing infrastructure. |
| | RT and batch communication between the DC and the control centre. | NA | NO | Already available within the existing infrastructure. |
| Data Storage & Management | Data management and storage infrastructure capable of handling at least 6 months of smart meter historical data (active power and voltage) | NA | NO | Already available within the existing infrastructure. |
| Hardware | Additional cost to adapt the smart meters in LV consumers/prosumers with VPQ real-time communication capability (e.g. PLC PRIME, PLC G3, GPRS) and to have VQ batch communication capabilities | MEDIUM | YES | -Considered the additional cost of using GPRS instead of PLC PRIME smart meter + scalability effect of a greater volume<br>-Considered the SIM Card cost + scalability effect of a greater volume<br>-Considered the cost of replacing the subset of $SM_r$ for GPRS smart meters<br>-Considered the cost of necessary additional configuration (HR effort) |

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| | Data concentrator or DTC any decentralized control unit (DCU) in the secondary substation for collecting both batch and RT data with sufficient memory to store the historical VPQ data of an adequate number of SMs. In a fully or partially decentralized application, the LVSE could be computed by the DCU. Sufficient computational power should also be available in this case. The computational requirement to run the tool is low in terms of CPU and memory | HIGH | YES | Considered the cost to deploy a new firmware version in the DTC located at secondary substation level, including licensing |
| **Metering Data Structure** | The smart meters (and DTC – if possible) should be able to collect active/reactive power and voltage measurements in each LV consumer/prosumer both in RT but in a scheduled collect (e.g. once a day) | NA | NO | Already available within the existing infrastructure. |

Table 75 – Minimum technical requirements of the LVSE tool for Portugal.

| Benefits | Functionalities | | | Total sum |
|---|---|---|---|---|
| | **1. Update network performance data on voltage quality** | **2. Enhance monitoring and observability of grids down to low voltage levels** | **3. Improve monitoring of network assets** | |
| **Contribute to the increase of information about the network operating conditions in real-time (increase situation awareness)**<br>Indicators: Absolute error and MAE | The information from the LVSE helps to the real time network operation (LV level). | The information from the LVSE helps to the real time network operation (LV level). | The LVSE improves the efficiency of the network operation through its real-time monitoring (and its assets) with a reduced number of $SM_r$. | 2.6 |
| Weights | 1.0 | 0.8 | 0.8 | |
| **Identification/correction erroneous data gathered from SM**<br>Indicators: MAE and Accuracy of voltage magnitude (operational KPI) | The updated information on voltage can help to identify bad data. | The identification and correction of erroneous data gathered from SM allows the LVSE enhances the monitoring and the observability of the network. | - | 1.6 |
| Weights | 0.8 | 0.8 | 0 | |
| **Detection of network technical constraints violation**<br>Indicators: Percentage of under/overvoltage false alarms and correct detections | The detection of network technical constraints violations allows that control actions are taken (by a control tool) in order to fix them, improving the voltage quality. | The LVSE enhances the monitoring of the network through the detection of network technical constraints violation. | - | 1.6 |
| Weights | 0.8 | 0.8 | 0 | |
| **Total sum** | 2.6 | 2.4 | 0.8 | |

**Table 76 – Merit deployment matrix to assess functionalities and benefits of the LVSE tool (compiled by EDP Distribuição)**

| Benefits | Functionalities | | | Total sum |
|---|---|---|---|---|
| | **1. Update network performance data on voltage quality** | **2. Enhance monitoring and observability of grids down to low voltage levels** | **3. Improve monitoring of network assets** | |
| **Contribute to the increase of information about the network operating conditions in real-time (increase situation awareness)**<br>Indicators: Absolute error and MAE | This functionality is related to operational planning so it does not contribute the real time increase of information about the network operating conditions. | The LVSE enables a reliable monitoring of the network, contributing to help in the real-time network operation (LV level). | The LVSE improves the monitoring of network assets by estimating their associated electrical quantities. This contributes to a better knowledge about the network operating conditions. | 1.9 |
| Weights | 0 | 1.0 | 0.9 | |
| **Identification/correction erroneous data gathered from SM**<br>Indicators: MAE and Accuracy of voltage magnitude (operational KPI) | The updated information on voltage enabled by the LVSE can help to identify bad data or the SM that requires maintenance. | The LVSE enhances the real-time monitoring of the network, which can also be useful to identify erroneous data. | The updated information on voltage enabled by the LVSE can help to identify SM that requires maintenance. | 1.8 |
| Weights | 0.6 | 1.0 | 0.2 | |
| **Detection of network technical constraints violation**<br>Indicators: Percentage of under/overvoltage false alarms and correct detections | The updated voltage information from the LVSE allows planning reinforcement to solve the identified technical constraints violations. | The enhanced real-time monitoring performed by the LVSE can be useful for the detection of violations of the network technical constraints. | - | 1.8 |
| Weights | 0.8 | 1.0 | 0 | |
| **Total sum** | 1.4 | 3.0 | 1.1 | |

Table 77 – Merit deployment matrix to assess functionalities and benefits of the LVSE tool (compiled by Enedis)

# Annex IV - LVC tool

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **ICT** | "Real-time" communication (10- 15 minutes) with Home Energy Management Systems (HEMS) and/or advanced power electronic interfaces | NA | NO | Not possible to evaluate. The costs will depend on the target architecture, the considered communication media and the requirements of the control system of the appliances |
| | RT and batch communication between the DC and the control center. | NA | NO | Not possible to provide a cost because it depends on the communication target architecture (centralized or decentralized).<br>Additional information might transit on this link because of this new feature. Highly dependent on the target architecture (centralized / decentralized) |
| **Data Storage & Management** | *No cost associated* | NA | None | |
| **Other Software Functions** | Need for a database of controllable resources with their characteristics (location, rated power, availability for control, periods in which the resources are unavailable, etc.) | NA | NO | Not possible to evaluate this costs for LV.<br>Level of detail available will depend on the architecture (centralized / decentralized) , the legislation… |
| **Hardware** | Additional cost to install a new device (e.g. energy box - EB) or to adapt the Smart meters in LV consumers/prosumers with RT (10 / 15 min) control capability | HIGH | YES | Costs depend if SMs are part of the control system.<br>Assumption: adaption of smart meter<br>The costs provided are for a prototype. |
| | Data concentrator or any decentralized control unit (DCU) in the secondary substation . In a decentralized application, the LVC would be computed by the DCU. Sufficient computational power should also be available in this case. Otherwise PCs at the control center should be required. The computational requirement to run the tool is low in terms of CPU and memory | NA | NO | Not possible to have this cost because it depends on the target architecture |
| **Smart Meter Data Structure** | The SMs/EB could be used to control remotely some appliances or could constitute a part of a control | NA | NO | Not possible to have this cost because it depends on the target architecture |

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| | architecture | | | |

Table 78 – Minimum technical requirements of the LV control tool for France.

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **ICT** | "Real-time" communication (10- 15 minutes) with Home Energy Management Systems (HEMS) and/or advanced power electronic interfaces | MEDIUM | YES | Note: we consider the communication is not directly with the HEM, instead this HEM is connected to the smart meter.<br>Given that the LVDSE is an input for the DSO, the following costs were considered for the SMr:<br>• Considered the additional cost of using GPRS instead of PLC PRIME smart meter + scalability effect of a greater volume<br>• Considered the SIM Card cost + scalability effect of a greater volume<br>• Considered the cost of replacing the subset of SMr for GPRS smart meters<br>• Considered the cost of necessary additional configuration (HR effort)<br>For the DER controlled by the SM, it is assumed an SMr is necessary but the meter cost is supported by the prosumer. However, the communication cost is supported by the DSO as it is one of its role to collect generation meter data. |
| | RT and batch communication between the DC and the control centre. | NA | NO | Already available with the existing infrastructure. |
| **Data Storage & Management** | *No cost associated* | NA | NO | Already available with the existing infrastructure. |

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **Other Software Functions** | Need for a database of controllable resources with their characteristics (location, rated power, availability for control, periods in which the resources are unavailable, etc.) | NA | NO | Not considered for this analysis. |
| **Hardware** | Additional cost to install a new device (e.g. energy box - EB) or to adapt the Smart meters in LV consumers/prosumers with RT (10 / 15 min) control capability | MEDIUM | YES | Given that the LVSE is an input for the DSO, the following costs were considered for the SMr:<br>• Considered the additional cost of using GPRS instead of PLC PRIME smart meter + scalability effect of a greater volume<br>• Considered the SIM Card cost + scalability effect of a greater volume<br>• Considered the cost of replacing the subset of SMr for GPRS smart meters<br>• Considered the cost of necessary additional configuration (HR effort)<br>For the DER controlled by the SM, it is assumed that the SMr is necessary but also that the HW cost is supported by the prosumer. However, the DSO supports the communication cost, as it is one of its roles to collect generation meter data. |
| | Data concentrator or any decentralized control unit (DCU) in the secondary substation. In a decentralized application, the LVC would be computed by the DCU. Sufficient computational power should also be available in this case. Otherwise, PCs at the control centre should be required. The computational requirement to run the tool is low in terms of CPU and memory | HIGH | YES | Considered the cost to deploy a new firmware version in the DTC located at secondary substation level, including licensing. |
| **Smart Meter Data Structure** | The SMs/EB could be used to control remotely some appliances or could constitute a part of a control architecture | NA | NO | Already available with the existing infrastructure. |

Table 79 – Minimum technical requirements of the LV control tool for Portugal.

| | | Functionalities | | | | | |
|---|---|---|---|---|---|---|---|
| | | 1. Facilitate connections at all voltages/locations for any kind of devices | 2. Facilitate the use of the grid for the users at all voltages/locations | 3. Enhance control of power flows and voltages | 4. Solve network constraints using optimization levers based on a merit order | 5. Minimizes the cost of the voltage deviation control | Total Sum for Benefit |
| Benefits | Increase RES and DER hosting capacity | Facilitating the connections to the network will help the connection of RES/DER, increasing indirectly the hosting capacity | Allows more integration of distributed generation (users). | With the LVC, more RES and DER devices can be connected maintaining an efficient management of the resources | The LVC allows to solve possible voltage constraints, thus can allow to increase DRES hosting capacity | Not relevant | **2.8** |
| | Weights | 0.6 | 0.6 | 0.7 | 0.9 | 0 | |
| | Reduce RES and DER total energy curtailment | Not relevant | Facilitating the use of the grid could decrease the energy curtailed by the impact is not direct | With the LVC, voltage can be maintained within the admissible limits by control actions sent to RES/DER or other equipment (e.g. transformers with OLTC), thus the total curtailment of RES/DER can be reduced or even totally avoided | The LVC allows to solve possible voltage constraints by controlling the RES/DER or other equipment (e.g. transformers with OLTC), thus the total curtailment of RES/DER can be reduced or even totally avoided | The LVC uses a merit order to control the grid assets based on their actuation costs. Since RES/DER are likely to have higher costs associated, they are usually the last ones to be actuated. Thus, by using other assets to solve the voltage deviation problems, RES/DER total energy curtailment can be reduced | **2.5** |
| | Weights | 0 | 0.4 | 0.8 | 1 | 0.3 | |
| | Limit voltage deviations | Not relevant | Not relevant | The LVC can control and operate the grid assets in order to maintain the voltage within the admissible limits. In case there is a voltage violation, the LVC can properly manage the grid assets available to correct / limit it. | Using optimization levers based on a merit order to solve network constraints, the LVC can correct / limit voltage deviations in order to maintain voltage within the regulated limits | The control actions of each grid asset has an associated cost. The LVC methodology uses a merit order of actuation of the grid resources to correct / limit voltage deviations while minimizing the total control action costs | **2.4** |
| | Weights | 0 | 0 | 0.9 | 1 | 0.5 | |
| | **Sum Total** | **0.6** | **1** | **2.4** | **2.9** | **0.8** | |

Table 80 - Merit deployment matrix to assess functionalities and benefits for LVC tool (France).

| | | Functionalities | | | | | |
|---|---|---|---|---|---|---|---|
| | | 1. Facilitate connections at all voltages/locations for any kind of devices | 2. Facilitate the use of the grid for the users at all voltages/locations | 3. Enhance control of power flows and voltages | 4. Solve network constraints using optimisation levers based on a merit order | 5. Minimizes the cost of the voltage deviation control | Total Sum for Benefit |
| Benefits | Increase RES and DER hosting capacity | With the LVC, more RES and DER devices can be connected without compromising the voltage values. An efficient management of the resources can be executed. | Allows more integration of distributed generation (users). | With LVC more RES are able to be integrated into the network, while maintaining voltage limits. | The LVC allows to solve possible voltage constraints, thus can allow to increase RES and DER hosting capacity | | 3.4 |
| | Weights | 0.8 | 0.8 | 0.8 | 1 | 0 | |
| | Reduce RES and DER total energy curtailment | | | With the LVC voltage can be maintained within the admissible limits by control actions sent to RES/DER or other equipment, thus the total curtailment of RES/DER can be reduced or even totally avoided | The LVC allows to solve possible voltage constraints by controlling the RES/DER or other equipment (e.g. transforms with OLTC), thus the total curtailment of RES/DER can be reduced or even totally avoided | | 1.8 |
| | Weights | 0 | 0 | 0.8 | 1 | 0 | |
| | Limit voltage deviations | | | In case of voltage violation, the LVC can manage the grid assets available to correct it. | Using optimization levers based on a merit order to solve network constraints, the LVC can correct voltage deviations in order maintain voltage within the regulated limits | Using optimization levers based on a merit order to solve network constraints, the LVC can correct voltage deviations in order maintain voltage within the established limits | 4.2 |
| | Weights | 0 | **0** | **0.8** | 1 | 0.8 | |
| | Sum Total | 1.6 | 1.6 | 2.4 | 3 | 0.8 | |

Table 81 - Merit deployment matrix to assess functionalities and benefits for LVC tool (Portugal)

# Annex V - OP tool

| Requirement type | Detail |
|---|---|
| Software functions | 1. Advanced 24-hour Forecasting Module for Loads and DRES with a resolution of 15’<br>2. SCADA system with network data and characteristics of controllable resources<br>3. Interface to translate offers on the day-ahead flexibilities market<br>4. Data pre-processing module with error correction and clean-up for all input data |
| Hardware | 1. Standard Windows PC to run load flows<br>2. Aggregated consumption data at secondary sub-station (smart meter or otherwise)<br>3. Controllability of OLTC, DER, and other flexibilities<br>4. Additional, more powerful computer for scaled-up tool |
| ICT | 1. Communication with DRES to record actual production and weather conditions with 15’ resolution<br>2. Communication with day-ahead flexibilities market platform once a day |
| Data Storage & Management | 1. Storage facility for historical weather, production and consumption data, to be used by the advanced forecasting module<br>2. Data management and storage for long-term flexibilities contracts and for flexibilities purchased from short-term market<br>3. Input / Output data type: JSON / CIM<br>4. Total data storage requirement: Gigabytes for daily storage, Terabytes for yearly storage |
| Maintenance/upgrade | 1. Maintenance contract for tool<br>2. Smart Meter upgrade / maintenance to provide 15’ data<br>3. Tool upgrades for addition of new types of flexibilities |
| Other | Operator training for proper utilization of the tool and its features |

Table 82 – Minimum technical requirements of the OP tool

| | | Functionalities | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Facilitate connections at all voltage* / locations for any kind of device** | **Operation schemes for voltage/current control** | **Intermittent sources of generation to contribute to system security** | **System Security assessment and management of remedies** | **Facilitate the techno-economic ranking of all the available flexibilities** | **Identify network constraints in operational planning** | **Solve network constraints using optimisation levers based on a merit order** | **Store and provide data about the network** | **Sum Total (Benefits)** |
| **Benefits** | **Cost-effective full exploitation of flexible network resources** | The use of flexibilities in the operational planning will allow for device connections at any location. **Very Relevant Benefit** | Not Relevant | The use of flexibilities contributes to the safe and secure integration of renewable energies. **Relevant Benefit** | Not Relevant | The merit-order generated to exploit flexible resources in a cost-effective manner allows for the techno-economic ranking of available flexibilities. **Very Relevant Benefit** | Not Relevant | The merit-order generated to exploit flexible resources in a cost-effective manner can be used for operational planning. **Relevant Benefit** | The generated merit orders can be stored for future use, statistical analysis, providing more information about the networks. **Relevant Benefit** | 3,6 |
| | **Weights** | 0,9 | 0 | 0,7 | 0 | 0,9 | 0 | 0,7 | 0,4 | |
| | **Adequate capacity of distribution grids for 'collecting' and bringing electricity to the consumers** | Thanks to the use of the tool, the network has adequate capacity to perform its functions, even when new devices are connected at new locations. **Very Relevant Benefit** | Not Relevant | Not Relevant | Not Relevant | Not Relevant | The assessment of the capacity of the network allows us to identify the various constraint violations. **Relevant Benefit** | The assessment of the capacity of the network allows us to search for methods to solve the constraint violations. **Relevant Benefit** | Capacity information can be stored for future use, statistical analysis, providing more information about the networks. **Relevant Benefit** | 2,6 |
| | **Weights** | 0,9 | 0 | 0 | 0 | 0 | 0,7 | 0,6 | 0,4 | |
| | **Satisfactory Levels of Quality and Supply** | Not Relevant | The benefit of satisfactory levels arises out of the functionality that provides operation schemes for voltage/current control. **Very Relevant Benefit** | The assurance of QoS contributes to the safe and secure integration of renewable energies. **Relevant Benefit** | The assurance of QoS provides a means to assess system security. **Relevant Benefit** | Not Relevant | Not Relevant | The assurance of QoS is provided by solving network constraints. **Very Relevant Benefit** | Capacity information can be stored for future use, statistical analysis, providing more information about the networks. **Relevant Benefit** | 3,5 |
| | **Weights** | 0 | 0,9 | 0,6 | 0,7 | 0 | 0 | 0,9 | 0,4 | |
| | **Sum Total (Functionalities)** | 1,8 | 0,9 | 1,3 | 0,7 | 0,9 | 0,7 | 2,2 | 1,2 | |

**Table 83 - Merit deployment matrix to assess functionalities and benefits for OP tool (compiled by Grenoble INP/RSE/VITO, validated by e-distribuzione)**

# Annex VI - CCS tool

| Req. type | Details | Cost |
|---|---|---|
| Software functions | Softwares/codes for proprietary data format conversion; | Difficult to estimate; it is application specific |
| | Software/codes for evaluation/calculation of input data which are not available, or they are available in aggregate format (asset reliability calculation, ICT parameters, etc..) | Difficult to estimate; it is application specific |
| Hardware | Standard PC for networks up to 300 nodes (64 bit OS, 8Gb RAM, Quad-Core CPU); for network over 300 nodes an higher performance PC is recommended; | 800€ |
| ICT | No ICT communication is provided within this tool; it is a standalone desktop product. | - |
| Data Storage & Management | The CCS tool needs the following data to run:<br>-Technical and reliability (MTBF, MTTR) data of the network devices;<br>-Load/Generation forecasts with a 15min time step;<br>-AD forecasts with a 15min time step<br>-General ICT system data (status: availability of the data link for the communication media used, power, frequency, topology, etc..);<br>If this data must be collected automatically from external sources (ex: databases) or must be calculated, the cost for data conversion or processing modules should be quantified (see «Software functions»).<br>Data storage requirements depend on the amount of data to be stored. Usually a standard 300Gb HDD or a central server partition is adequate for an average use of the tool (weekly/monthly period). | Difficult to estimate;<br>This requirement can be complementary to "Software functions" and it is application specific |
| Maint. / upgrade | Evolutionnary maintenance driven by the DSO. | Difficult to estimate; it depends on the specific evolutionary plan by the DSO |
| Other | - | - |

Table 84 – Minimum technical requirements for the CCS tool

| **Req. type** | **Basic Framework to Exploit the tool (TRL9)** | | **Specific DSOs Adaptations (pilot scale)** | | **Specific DSOs Adaptations (full scale)** | |
|---|---|---|---|---|---|---|
| | Description | Costs | Description | Costs | Description | Costs |
| Software functions | Software/codes for proprietary data format conversion; | Difficult to estimate; it is application specific | Software/codes for proprietary data format conversion; | Difficult to estimate; it is application specific | Software/codes for proprietary data format conversion; | Difficult to estimate; it is application specific |
| | Codes for estimating the asset reliability data based on country level information (asset reliability calculation, ICT parameters, etc..) | Difficult to estimate; it is application specific | Software/codes for evaluation/calculation of input data which are not available, or they are available in aggregate format for the pilot site (asset reliability calculation, ICT parameters, etc..) | Difficult to estimate; it is application specific | Software/codes for evaluation/calculation of input data which are not available, or they are available in aggregate format (asset reliability calculation, ICT parameters, etc..) | Difficult to estimate; it is application specific |
| Hardware | Standard PC for networks up to 300 nodes and one transformer (64 bit OS, 8Gb RAM, Quad-Core CPU) | 800€ | 1 PC able to handle networks from 300 to over 3000 and more than one primary substations at time | 3500€ | A least one PC for each control centre (60 max) able to handle networks with over 3000 nodes and several primary substations with several transformers for each | 210k€ (3,5k€ x 60) |
| ICT | No ICT communication is provided within this tool; it is a standalone desktop product. | - | No ICT communication is provided within this tool; it is a standalone desktop product. | - | No ICT communication is provided within this tool; it is a standalone desktop product. | - |

| Req. type | Basic Framework to Exploit the tool (TRL9) | | Specific DSOs Adaptations (pilot scale) | | Specific DSOs Adaptations (full scale) | |
|---|---|---|---|---|---|---|
| | Description | Costs | Description | Costs | Description | Costs |
| Data Storage & Management | Data storage requirements depends on the amount of data to be stored. Usually a standard 300Gb HDD or a central server partition is adequate for an average use of the tool (weekly/monthly period).<br>We need to develop a database for :<br>- Technical and reliability (MTBF, MTTR) data of the network devices;<br>- General ICT system data (status: availability of the data link for the communication media used, power, frequency, topology, etc..); | Difficult to estimate; This requirement can be complementary to "Software functions" and it is application specific | No visibility about the size of the storage requirements | - | No visibility about the size of the storage requirements | - |
| Maint. / upgrade | Evolutionary maintenance driven by the DSO | Difficult to estimate; it depends on the specific evolutionary plan by the DSO | Support and corrective maintenance | Difficult to estimate; it depends on the specific evolutionary plan by the DSO | Support and corrective maintenance | Difficult to estimate; it depends on the specific evolutionary plan by the DSO |

Table 85 – Minimum technical requirements versus deployment scale - CCS tool

| | | Simulate contingency analysis in Operational Planning (asset unavailability analysis) | Identify and solve network constraints in operational planning | Integrate ICT unavailability in operational planning | Total Sum for Benefit |
|---|---|---|---|---|---|
| Benefits | Improved levels of security and quality of supply | The identification of potential contingencies leads to a better operational planning | The analysis of network and ICT contingencies facilitate the identification of constraints and allows a better voltage control, enhancing security and quality of supply management | Taking into account planned ICT unavailability would help the constraint solving process, improving the overall quality of supply. This use case is however not usual. | 1,8 |
| | Weights | 0,4 | 0,8 | 0,6 | |
| | Reduced costs of activating flexible resources | - | The solving of constraints in operational planning helps to better use the flexibly levers available in volume and costs | Taking into account planned ICT unavailability would help the constraint solving process, improving the overall quality of supply. This use case is however not usual. | 0,8 |
| | Weights | 0 | 0,6 | 0,2 | |
| | Reduced energy curtailment of RES/DER | - | The solving of constraints in operational planning helps to better use the flexibly levers available in volume and costs | Taking into account planned ICT unavailability would help the constraint solving process, improving the overall quality of supply. This use case is however not usual. | 1,3 |
| | Weights | 0 | 0,8 | 0,5 | |
| | Increased RES & DER hosting capacity | The identification of contingencies might improve the network planning and allow a more effective exploitation of the active resources | This is more related to long-term planning : if constraints are better solved, more DER might be introduced | - | 0,5 |
| | Weights | 0,3 | 0,2 | 0 | |
| | Sum Total | 0,7 | 2,4 | 1,3 | |

**Table 86 – Merit deployment matrix to assess functionalities and benefits of the CCS tool (compiled by Enedis)**

# Annex VII - Replay tool

| Req. Type | Details | Cost [Virtual machine] | Cost [Physical machine] |
|---|---|---|---|
| Software functions | ❑ Optimization of DB processing<br>❑ Events recorder<br>❑ Events reproducer able to recreate the events configuration<br>❑ Load Flow calculation engine<br>❑ Integrated didactical platform (simulator/scenario definitions)<br>❑ Forecasting SW (MAGO) | **295 k€** Licenses for 1 system + developments on the SCADA System for the first system | **295 k€** Licenses for 1 system + developments on the SCADA System for the first system |
| Hardware | ❑ SCADA System in Operation (ST - or other)<br>❑ DB server to storage data<br>❑ Replay System representing a copy of the real time system in operation (physical or virtual machine)<br>❑ SCADA operator stations<br>❑ Dedicated machine to execute Load Flow calculation | No added costs foreseen. | Hardware cost for each installation (non-computable within the project boundaries) |
| ICT | ❑ The whole basic ICT infrastructure already used for the real operation System. | No added costs foreseen. | No added costs are foreseen. |
| Data Storage & Management | ❑ Storage network events on the DB Storage | No added costs foreseen. | Hardware cost for each installation (non-computable within the project boundaries) |
| Maintenance/ upgrade | ❑ Periodic maintenance/upgrade needs for the system as well as done for the real system in operation and hardware/software systems directly involved in its operations | No added costs foreseen. | No added costs foreseen. |

Table 87 – Minimum technical requirements for Replay tool

| Req. type | Basic Framework to Exploit the tool | | Specific e-distribuzione Adaptations (test scale Milano Smart Grid Lab) | | Specific e-distribuzione Adaptations (full scale 11 – Control Room) | |
|---|---|---|---|---|---|---|
| | Description | Costs | Description | Costs | Description | Costs |
| Software functions | BASIC SCADA available | TBD | Events recorder<br>Events reproducer<br>Load Flow calculation engine<br>Simulator/scenario definitions<br>Forecasting SW | 295k€ | **Optimization of DB processing (1° step)**<br>Integrated didactical platform (2° step) (simulator/scenario definitions) (2° step) | To be evaluated with the SCADA provider in 2 steps. |
| Hardware | SCADA System infrastructure with available station + dedicated industrial PC to realize the parallel system | TDB | Virtual ARCHITECTURE already existent for the ST system in operation in the Smart grid Lab | No added costs foreseen. | Virtual ARCHITECTURE already existent for the ST system in operation in the Smart grid Lab | No added costs foreseen. |
| ICT | Not specific infrastructures are needed | No added costs foreseen. | The whole basic ICT infrastructure already used for the real operation System. | No added costs foreseen. | The whole basic ICT infrastructure already used for the real operation System. | No added costs foreseen. |
| Data Storage & Manageme nt | For the prototype the same data storage of the system in operation is used. | No added costs foreseen. | For the prototype the same data storage of the system in operation is used. | No added costs foreseen. | A specific physical machine to store all the events data could be evaluated on the basis of specific control room needs. | Hardware cost for each installation (non-computable within the project boundaries) |
| Maint. / upgrade | At the first level no specific maintenance activities are planned/needed. | No added costs foreseen. | At the first level no specific maintenance activities are planned/needed. | No added costs foreseen. | An addiction of the already existing maintenance contract of the SCADA will be necessary | To be evaluated with the SCADA provider |

**Table 88 – Minimum technical requirements versus deployment scale** for Italy **- Replay tool**

| | | Functionalities | | | | |
|---|---|---|---|---|---|---|
| | | **1. Ex Post network analysis. Possibility to analyze the past and identify critical situations** | **2. Predictive Analysis: Possibility to modify users active power, eventsand NTW configuration in a simulation to prevent future criticalities** | **3. Analysis of QoS parameters in real and simulated cases** | **4. Enhanced monitoring and control of power flows and voltages- Calculation of current and voltages before and after the network modification** | **Total** |
| **Benefits** | **Reduced service interruptions (Quantitative)** | **Not relevant** the increase of quality of service is an indirect advantages of the training improvement | **Not relevant** the increase of quality of service is an indirect advantages of the training improvement | **Very relevant** the REPLAY Operation is the core session that allows the protocol analysis to increase the quality of service. | **Not relevant** the Replay LF calculation does not affect the quality of service | 1 |
| | **Weights** | 0 | 0 | 1 | **0** | |
| | **Reduction of Network Criticalities (Qualitative impact on Reduction of energy curtailment of RES and DER)** | **Not relevant** The Session "Replay Operation" does not impact the solution of existing NTW criticalities | **Not relevant** The Session "Replay Operation" does not impact the solution of existing NTW criticalities | **Not relevant** The Session "Replay Operation" does not impact the solution of existing NTW criticalities | **Very relevant** the Replay LF calculation influences the solution of the network criticalities and a correct use could support the SCADA operator | 1 |
| | **Weights** | 0 | 0 | 0 | **1** | |
| | **Enhanced training of control room operators (qualitative)** | **Very relevant** the REPLAY Operation is the core session that allows the protocol analysis to increase the quality of service. | **Relevant** the Replay LF calculation could support the solution of the network criticalities | **Relevant** the Replay LF calculation could support the solution of the network criticalities | **Very relevant** the Replay LF calculation could support the SCADA operator to understand the Smart Grid flexibility levers | 3 |
| | **Weights** | 1 | 0,5 | 0,5 | 1 | |
| | **Total** | 1 | 0,5 | 1,5 | 3 | |

**Table 89 - Merit deployment matrix to assess functionalities and benefits for Replay tool (compiled by e-distribuzione)**

# Annex VIII - AAM tool

| Benefits | Functionalities | | | | Sum |
|---|---|---|---|---|---|
| | 1. Optimise active losses | 2. Time value of money | 3. Inspection & maintenance | 4. Insightful GUI | |
| **Reduced active power losses** | Enhanced asset renewal pathways directly reduces energy waste Relevance: 1 | Relevance: 0 | Relevance: 0 | Relevance: 0.1 | **1.1** |
| **Reduced reactive power losses** | Enhanced asset renewal pathways directly reduce reactive losses Relevance: 0.6 | Relevance: 0 | Relevance: 0 | Relevance: 0 | **0.6** |
| **Less risk of stranded assets** | Relevance: 0 | NPV analysis ensures asset renewals are timed optimally with respect to their potential future benefits Relevance: 0.85 | Relevance: 0 | Relevance: 0 | **0.85** |
| **Less regulatory penalties** | Enhanced asset renewal pathways directly reduces energy waste, which is generally penalised Relevance: 0.7 | Relevance: 0 | Enhanced maintenance priorities enhances the security of supply, so that less regulatory penalties are faced Relevance: 0.7 | A better intuitive understanding of network risk improves on-the-fly decisions Relevance: 0.1 | **1.5** |
| **Reduced outage frequency** | Relevance: 0 | Relevance: 0 | Enhanced maintenance priorities directly enhances the security of supply Relevance: 0.6 | Relevance: 0 | **0.6** |
| **Reduced outage severity** | Asset renewals will results in newer conductors less prone to failure Relevance: 0.1 | Relevance: 0 | Enhanced maintenance priorities directly enhances the security of supply Relevance: 0.6 | Relevance: 0 | **0.7** |
| **Sum** | **2.4** | **0.85** | **1.9** | **0.2** | |

**Table 90- A qualitative weighting matrix for the benefits and functionalities of AAM (compiled by UCD, validated by ESB Networks)**

| Req. Type | Details | Level of Uncertainty | Costs Considered | Comments |
|---|---|---|---|---|
| **ICT** | Collect information from the network including demand, renewable generation | Low | No | It is not considered since this activity is already undertaken by ESB Networks |
| **Other Software Functions** | Data management structure capable of handling information about the network topology, e.g. information about planned maintenance strategy, timber cutting | High | No | This data is already available by ESB Networks |
| **Data Storage & Management** | Data management and storage infrastructure capable of handling historical data (active/reactive power, network configuration, renewable energy generation) | Low | No | Already available within the existing infrastructure. |
| **Dynamic data interfacing** | Allows the AAM tool to extract the relevant data for a particular network-under-study | High | No | Such work is beyond the scope of this project. Such interfacing costs could be expected to run quite high. |
| **Hardware** | Sufficient computational power should also be available in this case. The computational requirement to run the tool is low in terms of CPU and memory | Low | Yes | Standard desktop computing hardware is needed to run each instance of the tool |

**Table 91- Minimum requirements for developed AAM tool**

# Annex IX - FLEXPLAN tool

| Req. Type | Details | Comments |
|---|---|---|
| Software functions | CPLEX optimisation software (or comparable solver for liner optimization problems) | In order to perform optimization tasks, the commercial solver "CPLEX" is used within the simulation of the optimal use of flexibilities in network operation.<br>Therefore, a licence for CPLEX or another, comparable solver for liner optimization problems is required. |
| | Load flow simulation software | A load flow software to validate the technical requirements of the network is used in the planning process. Therefore, a licence for a network calculation software is required. In the prototype, the software INTEGRAL has been used. |
| | MATLAB | The visualization of the planning results uses MATLAB for visualisation purposes. Also for this software, a licence is required. |
| | C++ environment | In case the software has to be extended or upgraded, a C++ environment for developing the software is required. |
| Hardware | High performance computer for running the simulations | As the simulation of network operation and the optimization tasks handle large amounts of data and perform a high number of time consuming computation steps (load flow calculations, optimal power flow calculations, etc. for a high number of network usage cases), one high performance computer for running the optimization/simulation is required. |
| | SQL database-server | As the network data and results are stored in a database a computer to run the database-server is required. In case the performance is sufficient, the can be the same computer being used for the simulations. |
| | Normal desktop computer or notebook | Normal desktop computers or notebooks are sufficient for the visualization of the simulation results. |
| Data Storage & Management | Data-Management and storage of simulation input and output data | A SQL-database-server is required to store multiple databases for the network model, network equipment data including reliability data, the scenario data, the planning and simulation results. |
| Maintenance / upgrade | Maintenance and Updates of software, Training of network planner and software-support | Training of the network planner with the new software.<br>The simulation software may require maintenance or upgrades. These include:<br>• Maintenance of the database-server, commercial solver and network calculation software.<br>• Updates of the developed tool in case of one of the above mentioned third-party software changes its interface.<br>• Upgrades of the software tool, especially of the visualisation software in order to facilitate the planning according to feedback from the network planners. |
| Other | Determination of a scenario for the considered network area | The determination of scenarios for the considered network area may require additional data from third parties (e.g. historic weather data or geo-referenced data of potential areas for new generation units) which have to be adopted to the existing software and databases. |

**Table 92 – Minimum technical requirements of the FLEXPLAN tool**

| | | Functionalities | | | | | |
|---|---|---|---|---|---|---|---|
| | | 9. Identification of technical and non-technical losses by power flow analysis | 14. System security/quality of supply assessment and management of remedies | 17. Better models of Distributed Generation, storage, flexible loads, ancillary services | 18. Improve asset management and replacement strategies | 19. Additional information on grid quality and consumption by metering for planning | Sum Total (Benefits) |
| Benefits | Deferred Distribution Capacity Investments | Not Relevant | Not Relevant | **Very Relevant Benefit** | **Very Relevant Benefit** | Not Relevant | 2 |
| | Weights | 0 | 0 | 1 | 1 | 0 | |
| | Reduced Electricity Costs | **Relevant Benefit** | **Relevant Benefit** | **Very Relevant Benefit** | **Very Relevant Benefit** | **Relevant Benefit** | 2,2 |
| | Weights | 0,2 | 0,2 | 0,8 | 0,8 | 0,2 | |
| | Enhance knowledge about impact of Smart Grid Components on system reliability | Not Relevant | **Relevant Benefit** | **Relevant Benefit** | Not Relevant | **Relevant Benefit** | 2 |
| | Weights | 0 | 0,7 | 0,6 | 0 | 0,7 | |
| | Network expansion ist suitable to cover future uncertainties | Not Relevant | Not Relevant | **Very Relevant Benefit** | **Very Relevant Benefit** | Not Relevant | 1,8 |
| | Weights | 0 | 0 | 1 | 0,8 | 0 | |
| | Level of total losses in distribution networks | **Very Relevant Benefit** | Not Relevant | Not Relevant | Not Relevant | Not Relevant | 1 |
| | Weights | 1 | 0 | 0 | 0 | 0 | |
| | Percentage utilisation (i.e. average loading) of electricity grid elements | Not Relevant | Not Relevant | **Relevant Benefit** | **Relevant Benefit** | Not Relevant | 1,4 |
| | Weights | 0 | 0 | 0,7 | 0,7 | 0 | |
| | Sum Total (Functionalities) | **1,2** | **0,9** | **4,1** | **3,3** | **0,9** | |

Table 93 – Merit Deployment Matrix of the FLEXPLAN tool (compiled by RWTH, validated by Innogy)

# Annex X – TopPlan tool

| Requirements type | Detail |
|---|---|
| Software functions | 1. Interface to translate the data of the software used by the DSO to the TopPlan tool (if TopPlan is not integrated to the existing software) or code translation and integration to the existing software |
| Hardware | 1. Standard Windows PC to run the optimization algorithm |
| ICT | 1. Data are potentially coming from different softwares and departments (loads and production s profiles, network topologies…). Then a communication protocol is required to import all the required data automatically. |
| Data Storage & Management | 1. Low storage facilities will be enough to save topologies and associated KPIs for future comparison by the DSO. It depends on how the date are currently saved by the DSO |
| Maintenance/upgrade | 1. Tool upgrades by taking into account other flexibilities<br>2. If smart meters and other measurements devices are developed, the data will have to be taken into account in the tool. |

Table 94 – Minimum technical requirements of the TopPlan tool

| | | Functionalities | | |
|---|---|---|---|---|
| | | Targets a DRES penetration | Minimize CAPEX and OPEX | Sum Total (Benefits) |
| Benefits | Increase DRES penetration | Planning decision are provided to increase the DREs penetration **Very Relevant Benefit** | Not relevant | 0,9 |
| | Weights | 0,8 | 0,1 | |
| | Decrease network costs | 1.2. Trying to take into account the DRES scenarios may lead to solutions less expensive as if production is not considered and reinforcement are used when needed. **Relevant Benefit** | Cost included in the optimization function **Very Relevant Benefit** | 1,5 |
| | Weights | 0,7 | 0,8 | |
| | Sum Total (Functionalities) | 1,5 | 0,9 | |

Table 95 - Merit Deployment Matrix of the TopPlan tool (compiled by Grenoble INP, validated by Innogy)

# Annex XI – High-Level Technical Assessment template

This template aims to capture a summary-level description of the tool's functionalities, to draw out the value added and to emphasise its merits. Concise, pithy answers which summarise previous work are ideal here. The envisioned output of this survey should be devoted to raise the differences between the lab tests and field tests and to highlight the added value of the latter

**Name of tool:**

**Provide a brief (2-3 sentences) summary of the tool's functionality and of the test grid in which it is applied:**

**Provide some context for this tool's development, with brief reference to the prior literature:**

**Provide a high-level description of the validating simulations run in D3.4, emphasising how they demonstrate the tool's merits:**

**Provide an overall summary of what was learned by undertaking these simulations:**

**Did the simulations confound prior expectations?**

**Briefly describe major differences between D3.4 and D4.3 test networks, highlighting which had influenced the trials and their outcome and had led to unexpected results compared to those presented in D3.4.**

**Did the tool can be easily interface with other software/systems? Did it require specific input data pre-processing or output data post-processing? Please describe briefly the difficulties experienced (if any) during the trials and how the data exchange and the tool interface can be improved from your perspective.**

**Is the tool's user interface clear to understand and to operate? Please describe shortly the impressions gained from the trials.**

**Provide a description of the quality (compared to the needs of field application) of the tool output. Does it live up to your expectations? Does it appear accurate? Did you find it useful?**

**Provide a summary description about how the KPIs and PMs reported in D4.2 are calculated for D4.3 tests, emphasizing the differences in respect to D3.4 tests:**

**Describe how the KPIs results from D3.4 tests and D4.3 tests are complementary and summarize the overall impact of the tool:**

**Complete the below table for the EEGI KPI's relevant to this tool in relation to D4.3 tests, commenting as appropriate on the significance of the KPI values:**

| *KPI Name* | *KPI Value* | *Comment* |
|---|---|---|
| *Increased RES & DER hosting capacity* | | |
| *Reduced energy curtailment of RES & DER* | | |
| *Power quality & quality of supply* | | |
| *Extended asset lifetime* | | |
| *Increased flexibility from energy players* | | |
| *Increased hosting capacity for electric vehicles and other loads* | | |

**Complete the below table, with appropriate comments, for the tool's Performance Metrics calculated for D4.3 tests, expanding the table as necessary:**

| *KPI Name* | *KPI Value* | *Comment* |
|---|---|---|
| *[PM 1]* | | |
| *[PM 2]* | | |