MARKET ENABLING INTERFACE TO UNLOCK FLEXIBILITY SOLUTIONS FOR COST-EFFECTIVE MANAGEMENT OF SMARTER DISTRIBUTION GRIDS

Deliverable: D7.4

Portuguese Demonstrator — Demonstration of the UMEI concept in the management of market driven flexibility

Demonstration results assessment and conclusions

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List of Abbreviations

BUC	Business Use Case
DdVC	Data driven Voltage Control
DSO	Distribution System Operator
END	Energy Not Distributed
EV	Electric Vehicles
FMO	Flexibility Market Operator
FSP	Flexibility Service Provider
HEMS	Home Energy Management System
KPI	Key Performance Indicator
LV	Low Voltage
MV	Medium Voltage
MV FST	MV Flexibility Scheduling Tool
OCR	*Órgão de Corte e Religação* (Automatic reconnection switch)
OPF	Optimal Power Flow
OLTC	On-load Tap Changer
PV	Photovoltaic
REST API	RESTful application programming interface
SUC	System Use Case
UMEI	Universal Market Enabling Interface
VFR	Violation Frequency Reduction

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Executive Summary

This Deliverable has been drafted in the context of the EUniversal project. The EUniversal project aims to overcome existing limitations regarding the use of flexibility by DSOs for congestion and grid management. Considering the European approach as well as the need for harmonization and creation of standards, one objective of EUniversal is the establishment and integration of a Universal Market Enabling Interface (UMEI) to ensure system interoperability to facilitate access to multiple Flexibility Market Platforms and thus access to distributed flexibility. The UMEI is tested in three locations across Europe, i.e. Portugal, Germany and Poland, examining its use for market-based flexibility procurement in various use cases.

This report presents the main objectives, results, and findings from the Portuguese Demonstrator, aiming to demonstrate the Universal market Enabling Interface (UMEI) and the developed DSO toolbox as enablers for the implementation of local flexibility markets. This deliverable reports the main results obtained for four business use cases (PT1, PT2, PT3 and PT4), demonstrating long-term and short-term congestion management and voltage control considering the mobilization of market-based flexibility negotiated in NODES and N-SIDE Flexibility Market Platforms. The implementation of the four business use cases, involved the implementation and coordinated testing of 15 system use cases, divided within 3 domains: 7 within the smart grid operation, 3 in the flexibility markets, 5 in the flexibility aggregation and grid user's domain and finally 1 for data management.

The deployment and validation of the Portuguese demo was divided in two parts: 1) Individual tests of each smart grid tool, the market environment and aggregation platform 2) integrated testing of the three domains: DSO tools, Flexibility Markets and Aggregation Platform. The report presents the individual and integrated testing results obtained for relevant days and whenever relevant the associated Key Performance Indicators (KPIs) identified in WP6.

1 Introduction

1.1 Background

The European Union aims at transforming the energy system towards a sustainable, low-carbon and climate-friendly economy. The scope is to increase the energy share of electricity production in distribution grids to around 50% of renewable energy sources (RES) until 2030 while guaranteeing the security of supply and avoiding unnecessary network investments. For this purpose, load generation and consumption of prosumers across all grid levels shall serve as energy and flexibility resources making them active participants in the energy system. In such a scenario, prosumers become key enablers towards a more sustainable, low-carbon and climate-friendly electricity system by adapting their consumption and production behaviour to stabilize the grid when needed. Yet, flexibility will also add complexity and create unpredictable power flows in the distribution networks. Distribution System Operators (DSOs) need to integrate smart-grid solutions to cope with the new types of load patterns of diverse small-scale assets (e.g., electric vehicles and heat pumps) and to identify the required flexibility to safely host the increasing share of RES. Therefore, innovative technologies and solutions are required to transform the challenges of the energy transition into opportunities for the sector, and ultimately for the society.

The EUniversal project aims to overcome the existing challenges for DSOs concerning the use of flexibility. The primary project goal is to overcome barriers between multiple market agents and their internal systems through the Universal Market Enabling Interface (UMEI), described in detail in the project deliverables D2.4-D2.6. The UMEI has been developed to support distribution system operators and their active system management by facilitating access to distributed flexibility via multiple market platforms at different locations while limiting the DSO system changes to a minimum. The UMEI is tested in three different demonstrations in Germany, Poland, and Portugal. This deliverable describes the results obtained from the Portuguese demonstrator.

1.2 Scope and objectives of this document

This report is part of the seventh work package of the EUniversal project. The operative objective of WP7 is to validate the Universal market Enabling Interface (UMEI) and the developed tools in different contexts and scenarios made available in the Portuguese Demo. It assesses flexibility for distribution grids and the market capacity to provide new services to the DSO.

The main objective of the Portuguese DEMO was the demonstration of flexibility procurement to solve grid constraints, supporting operation and medium/long-term investment planning. Four operational objectives can be derived:

- Demonstrate day-ahead congestion management and integrated voltage control in MV and LV grids.
- Contracting flexibility services to avoid voltage and/or congestion issues during planned maintenance action in MV grids.
- Congestion Management for medium /long-term grid planning through market mechanisms.
- Demonstrate integrated and interoperable operation between DSO toolbox, Market and Aggregators Platforms through UMEI.

This report is using valuable information out of other WPs, namely:

- WP2, for the definition of use cases (both BUC and SUC) that will be demonstrated, as well as the UMEI, namely with the identification of the interactions between the DSO and Flexibility Market Platforms and data exchange.

* WP3, with the use of a flexibility toolbox, identifying the technologies and solutions most suitable to provide flexibility services to the distribution grid.
* WP4, for the development of the DSO smart grid tools and their alignment.
* WP5, the identification of relevant market mechanisms.
* WP6, with a common framework to harmonise, monitor and assess the validation of the results in the three demos.
* WP 8 (DE demo) and 9 (PL demo): harmonization and experience exchange.
* WP10: outputs for SRA (Scalability and Replicability Analysis).

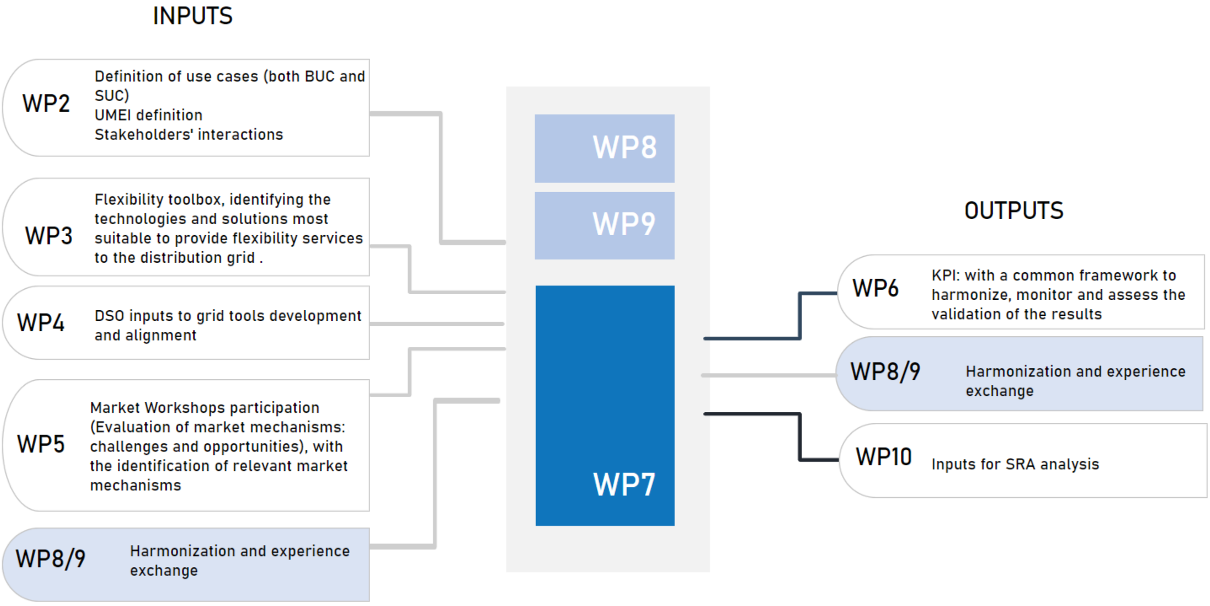


Figure 1-1– WP interactions.

1.3 Report structure

This document is organized as follows: chapter 2 provides an overview of the final characterization of the Portuguese demonstrator, considering the distribution grids involved, MV and LV consumers participating in flexibility provision, architecture implemented, and final testing plan implemented.

In chapter 3, the results of the demo tests are discussed and quantified. During the demonstration phase, a set of System Use Cases was tested, each of them dealing with a specific functional element within the overall demonstrator framework. In chapter 3, the demonstration results are given according to the system use cases and their associated KPIs that were previously defined within WP2 and WP6 of the project.

In the last chapter, the main conclusions concerning the Portuguese demo test results are presented. Also, a reflection on the overall flexibility value chain is given.

The knowledge gained in this demonstration was used to support WP10 in the development of business models for the exploitation of EUniversal's results and to provide recommendations for policy makers and regulatory authorities to set up a framework for flexibility markets.

2 Demonstrator activities

2.1 Demo site characteristics

The Portuguese demonstration consists of real 5 MV and 9 LV grids that supply approximately 200 MV/LV substations and 1189 LV consumers. The selected grids are in different regions of the country, ensuring a wide set of scenarios and contexts, namely:

- Valverde (a small village located in a suburban area of Évora district)
- West zone of Portugal (two urban areas: Mafra and Caldas da Rainha)
- Alcochete (near Lisbon - Tejo River south bank)

Figure 2-1 – Demonstration locations.

2.2 Clients enrolled - Final Figures

The Portuguese demo involves both MV and LV consumers that accepted to participate and provide flexibility services to the DSO. Initially a total of 43 participants have accepted to participate in the demonstrator tests. However, as shown in Table 2-1 only a total of 28 consumers have provided their actual consent for the tests. Table 2-1 presents a comparison between the number of clients that stated their will to participate in new projects, our client base for contact, and the number of clients that gave their actual consent. The numbers clearly present the result of the difficulties imposed by the GDPR implementation, already described in Deliverable 11.4 [7].

Table 2-2 presents the MV and LV consumers allocated by MV and LV network.

Table 2-1 – Set of Equipment - LV flexible assets.

Demo	Set of equipment	#LVClients
Alcochete	HEMS;	0(1)
	HEMS; PV; BT	1(1)
	HEMS; PV	1 (1)
	Total	2(3)
Caldas Da Rainha	HEMS;	1(4)
	HEMS; PV; Battery	11(15)
	HEMS; Water heater	1(2)
	HEMS; PV	4(6)
	Total	**17(27)**
Valverde	HEMS	7 (7)
	HEMS; PV; Battery	1(4)
	HEMS; Water heater	0(1)
	HEMS; PV	1(1)
	Total	**9 (13)**
	Total # LV Clients	**28 (43)**

Table 2-2 – Clients Enrolled - Final Figures.

DEMO	MEDIUM VOLTAGE			LOW VOLTAGE	
	MV Feeder	# MV Cons.	# MV Prod.	Sec. Subs.	# LV Clients
São Francisco	F1	2	-	SS1 SS2	1 1
Évora	F1	1	1	SS1 SS2	6 3
Sto. Onofre	F1	1	-	SS1 SS2	5 1
Caldas da Rainha	F1	-	-	SS1 SS2 SS3	2 4 5
Mafra	F1 F2 F3 F4 F5 F6	1 1 1 - - -	1 - - 1 1 1	-	
TOTAL	**-**	**7**	**5**	**-**	**28**

2.3 Portuguese Demonstration objectives and use cases

The main objective of the Portuguese DEMO was the demonstration of flexibility procurement to solve grid constraints, supporting operation and medium/long-term investment planning. Four operational objectives can be derived:

1. Demonstrate day-ahead congestion management and integrated voltage control in MV and LV grids.
2. Contracting flexibility services to avoid voltage and/or congestion issues during planned maintenance action in MV grids.
3. Congestion Management for medium /long-term grid planning through market mechanisms.
4. Demonstrate integrated and interoperable operation between DSO toolbox, Market and Aggregators Platforms through UMEI.

To achieve those goals, four Business Use Cases (BUC) were defined in Deliverable 2.2 [1], as described in Table 2-3, operationalized considering the implementation of the System Use Cases (SUC) described in Deliverable 2.3 and identified in Table 2-4.

Table 2-3 –Business Use Cases

BUC ID	BUC name	Service
PT1	Congestion management in MV grids for the day-ahead market (or between 1 to 3 days in advance)	• Congestion management
PT2	Integrated Voltage Control in MV and LV grids for the day-ahead market	• Voltage control
PT3	Contracting flexibility services for avoiding voltage and/or congestion issues during planned maintenance action in MV grids	• Congestion management • Voltage control
PT4	Congestion Management for medium and long-term grid planning through market mechanisms	• Predictive congestion management

Table 2-4 – System Use Cases

Domain	SUC ID	SUC name	BUC	OWNER
Smart Grid Operation	SUC 1	Grid expansion planning activities considering long-term flexibility services	PT 4	E-REDES
	SUC 2	Congestion management considering flexibility needs in MV network for planned maintenance	PT 3	E-REDES
	SUC 3	Coordinating flexibility need identification and mobilization between LV and MV network	PT 1, PT 2	INESCTEC
	SUC 4	Day-ahead congestion management considering flexibility needs in MV network	PT1, PT2	INESCTEC
	SUC 5	Estimating LV voltage magnitude based on historical data and load forecasts	PT2	INESCTEC
	SUC 7	Voltage control in LV networks based on limited observability and network topology characterization	PT2	INESCTEC
	SUC 13	Short-term flexibility procurement	PT 1, PT2	NODES

Domain	SUC ID	SUC name	BUC	OWNER
Flexibility Market	SUC 14	Long-term flexibility procurement	PT 3, PT4	NODES
	SUC 15	Flexibility procurement via N-SIDE market platform	PT1, PT2, PT3, PT4	N-SIDE
Flexibility Aggregation and grid users	SUC 16	DER registration and configuration	PT1, PT2	CENTRICA
	SUC 17	Bidding aggregation	PT1, PT2	CENTRICA
	SUC 18	Resources' dispatch and monitoring	PT1, PT2	CENTRICA
	SUC 19	Baselining	PT1, PT2	CENTRICA
	SUC 20	Collecting and publishing metering data	PT1, PT2	CENTRICA
Data management	SUC 22	DSO data management – Portuguese Demonstrator	PT1, PT2, PT3, PT4	E-REDES

2.4 Portuguese Demonstrator architecture

To achieve such ambitious goals, the demo framework represented in Figure 2-2 was implemented, ensuring seamless integration between the four main blocks of the Portuguese demo architecture: DSO Data Exchange and tools platform, Flexibility Market Platforms and Flexibility Aggregator Platform connecting to MV and LV consumers.

Both NODES and N-SIDE market platforms have been tested in parallel for day-ahead and long term flexibility procurement. In the case of NODES platform two markets with continuous trading named ShortFlex and LongFlex markets are provided, providing the flexibility offers that are then selected and validated by the DSO to achieve the most cost-efficient solution to solve the predicted grid congestion and postpone grid reinforcement investments.

N-SIDE's Local Flexibility Market Platform aims to help solving grid problems by offering an auction-based mechanism, that facilitates the matching of the DSO's flexibility needs with the FSPs/aggregators' offers, through an algorithm that maximizes the social welfare for all time frames. The algorithm considers the flexibility offers provided by the FSPs defined based on the asset location concerning the grid technical constraints. It yields the dispatch solution considering a pay-as-clear remuneration mechanism. The relationship between both MV and LV clients and the market is assured by an aggregator, Centrica, which operates on both platforms.

The DSO toolbox implemented forecasts grid constraints and quantifies the flexibility needed to solve them, assuring the coordination between LV and MV grids. The toolbox is composed of a MV multi-temporal OPF developed ENGIE that defines the grid assets control plan. If needed the MV Flexibility Scheduling Tool (MV FST) from INESC TEC determines MV flexibility needs or selects the bids (depending on market platform assigned). For the LV networks, a data-driven approach was successfully tested, considering smart metering historical data, namely LV forecast and DdVC (Data-driven Voltage Control) to forecast grid constraints at the LV network, define flexibility needs and select bids (when applicable).

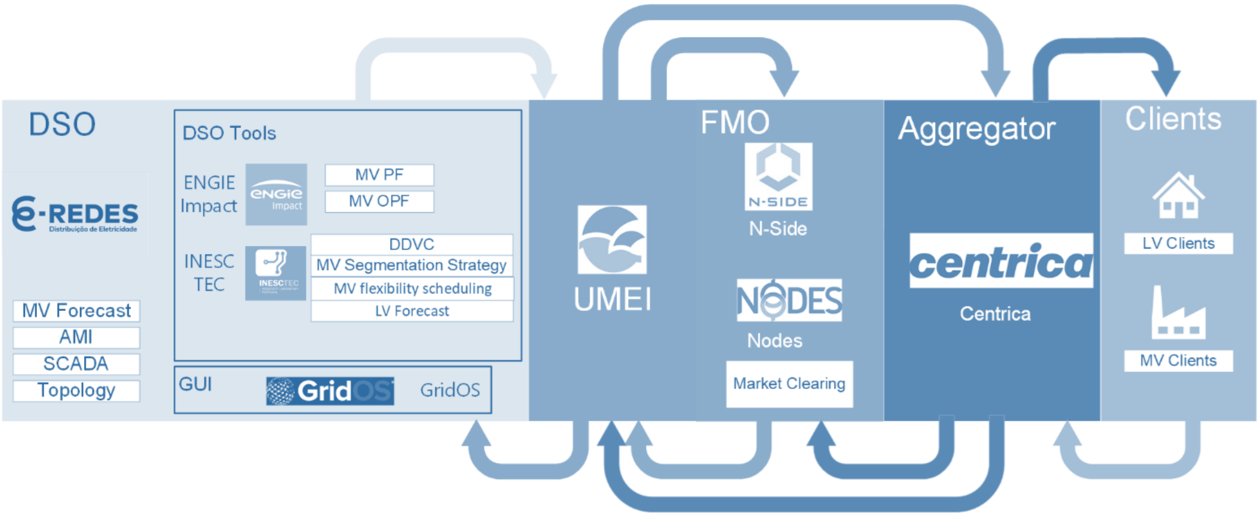


Figure 2-2 – General framework of the Portuguese demonstrator.

2.5 Implementation and test plan

The Portuguese demonstrator established very ambitious goals, involving the demonstration of new DSO tools developed within the project, two Flexibility Market Platforms, one Aggregation Platform connected through the UMEI.

The four defined BUCs from the Portuguese demo are supported by N-SIDE and NODES market platforms for day-ahead and long-term procurement of local flexibility (weeks to 3 year ahead), and with CENTRICA acting as the aggregator.

Table 2-5 presents the final distribution of demo areas per BUC and Market Platform. Considering the reduced number of clients enrolled, it was necessary to revise the mapping initially proposed in Deliverable D7.2 [5]. As described previously in section 2.2 (see

Table 2-2), due to the reduced number of participants in some of the networks (particularly in the LV networks), it was necessary to run the two markets in parallel. As presented in Table 2-5, the two platforms were tested in Évora network for BUC 1 and BUC 2.

Table 2-5 – Distribution of demo areas per BUC and Market Platform.

Demo	Market platform	BUC1	BUC2	BUC3	BUC4
Mafra	Nodes	x		x	
Alcochete	Nodes	x	x		x
Caldas da Rainha	N-Side	x	x		
Évora	N-Side /Nodes	x	x	x	x

The delays in the deployment and final testing of the Portuguese demo framework, led to the decision of testing the Long-term flexibility procurement only with NODES Long-Flex Platform foreseen in BUC 3 and BUC 4 (see results in section 3.2 and 3.3).

The demonstration activities performed under Task 7.3 were mainly focused on the validation of the framework developed and the implementation of the BUC. Two groups of testing activities could be derived:

- The most complex tests were focused on the validation of BUC 1 and BU2, involving testing of the full framework represented in Figure 2-2. Its implementation and tests revealed a complex and time-consuming process, considering that the success of all steps depend on obtaining adequate results and data from previous steps. Following initial integration tests performed in Task 7.2 (see Deliverable 7.2 [5]), the initial testing of the Data Exchange Platform , a middleware created for the project within the DSO environment that ensures data provision to the DSO tools, started around May 2023, being followed by the deployment of the DSO tools around June 2023 and finally testing of data exchange with Flexibility Market Platforms and Aggregation Platform. Automatically running BUC 1 and BUC 2 was only possible during November and were extended until the 19/12/2023.

- In the case of BUC 3 and BUC 4, a first set of simulation studies were derived to define long-term flexibility needs and then procurement on the Long-term Flexibility Markets were tested.

The results obtained are described in chapter 3.

3 Demonstration results

This chapter describes the main demonstration results obtained from the testing Portuguese demo BUC, namely:

- Testing of day-ahead congestion management and integrated voltage control as foreseen in BUC PT1 and PT2. This involves the procurement of short-term flexibility services in two distinct Flexibility Market Platforms, namely N-SIDE and NODES Flexiblity Market Platforms, involving the testing of two different timelines implemented. The tests and representative results obtained from individual and integrated testing are described in section 3.1 and 3.2 respectively.
- Testing of flexibility services to support network operation during maintenance actions, as foreseen in PT3. Section 3.3 describes the maintenance planning scenarios, identification of flexibility needs, and flexibility procurement results obtained.
- Testing of long-term flexibility services for support of grid investment planning, as in PT4. Section 3.4 presents the network investment planning scenarios defined and the results obtained for two planning horizons, namely 3 and 11 years.

Most of the results were obtained during November and December 2023, after successful configuration and testing of all tools and of the two timelines.

The KPIs obtained for the tools and demonstrator activities are also presented when applicable.

3.1 Day-ahead congestion management & Integrated Voltage Control in MV and LV grids (PT1 and PT2)

The main objective of PT1 and PT2 is to demonstrate the support of flexibility services for congestion management and voltage control. The BUCs were tested for two distinct Flexibility Market Platforms, involving two different timelines:

- The timeline represented in Figure 3-1 was implemented and tested for the procurement of flexibility using N-SIDE market platform. The distinctive features of this timeline are:
    - DSO tools first determine the necessary flexibility to solve the expected grid constraints for the next day without knowing the selling bids, represented as dynamic flexibility zones.
    - The needs are presented by the market platform, to allow aggregators to submit their offers considering the network areas and hours where grid constraints are expected.
    - Clearing is then provided by N-SIDE platform to implement the concept proposed of the **semi-dynamic flex zones**, adapting its market clearing process, to include the areas defined and the grid technical limits.
- The timeline represented in Figure 3-2 was implemented for the procurement of flexibility in NODES Short-Flex Flexibility Market. Flexibility offers are first presented and then selected by the DSO to solve the expected grid constraints. NODES, as independent market operator, provides the central environment for market-based procurement of flexibility ensuring correct and transparent transactions between buyers and sellers. Due to the limited market liquidity verified in the demo, NODES only applies a continuous market clearing via pay-as-bid. The flexibility offers are then selected by the DSO considering its location, volume and price that has been submitted to the market platform by the flexibility providers through the UMEI.

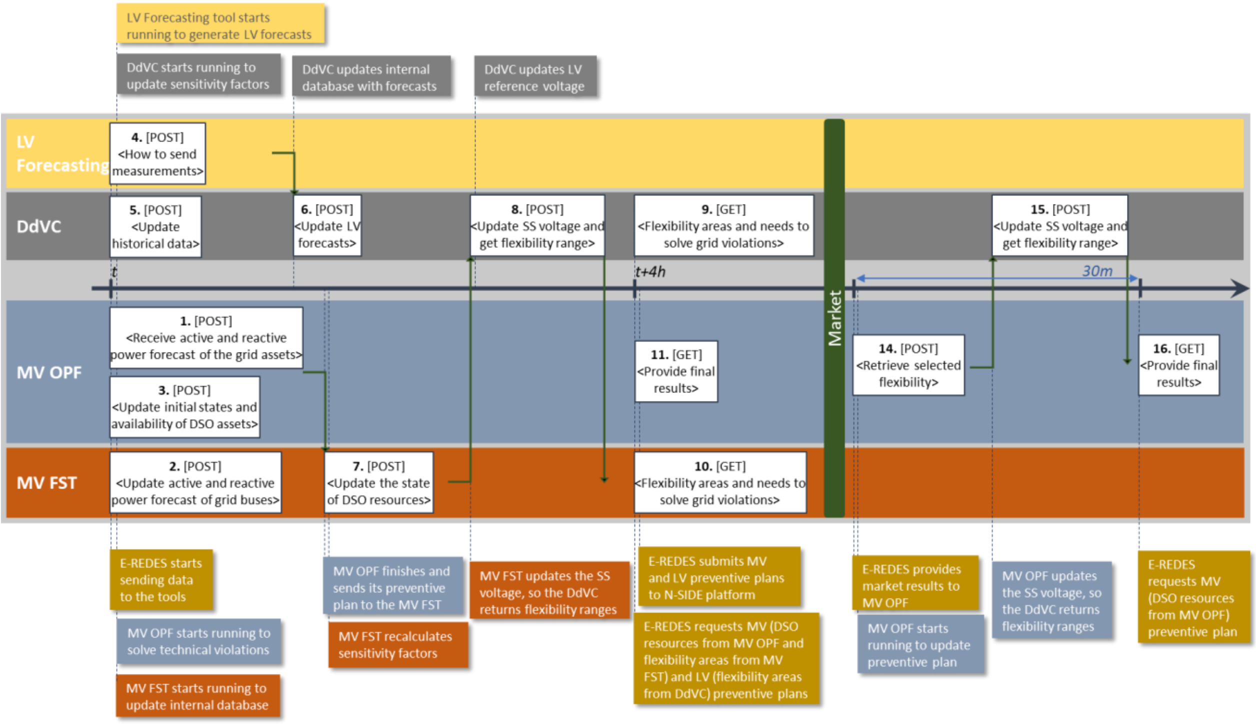


Figure 3-1 – Timeline of the interaction between the different tools till the final MV and LV preventive plans to submit to N-SIDE platform.

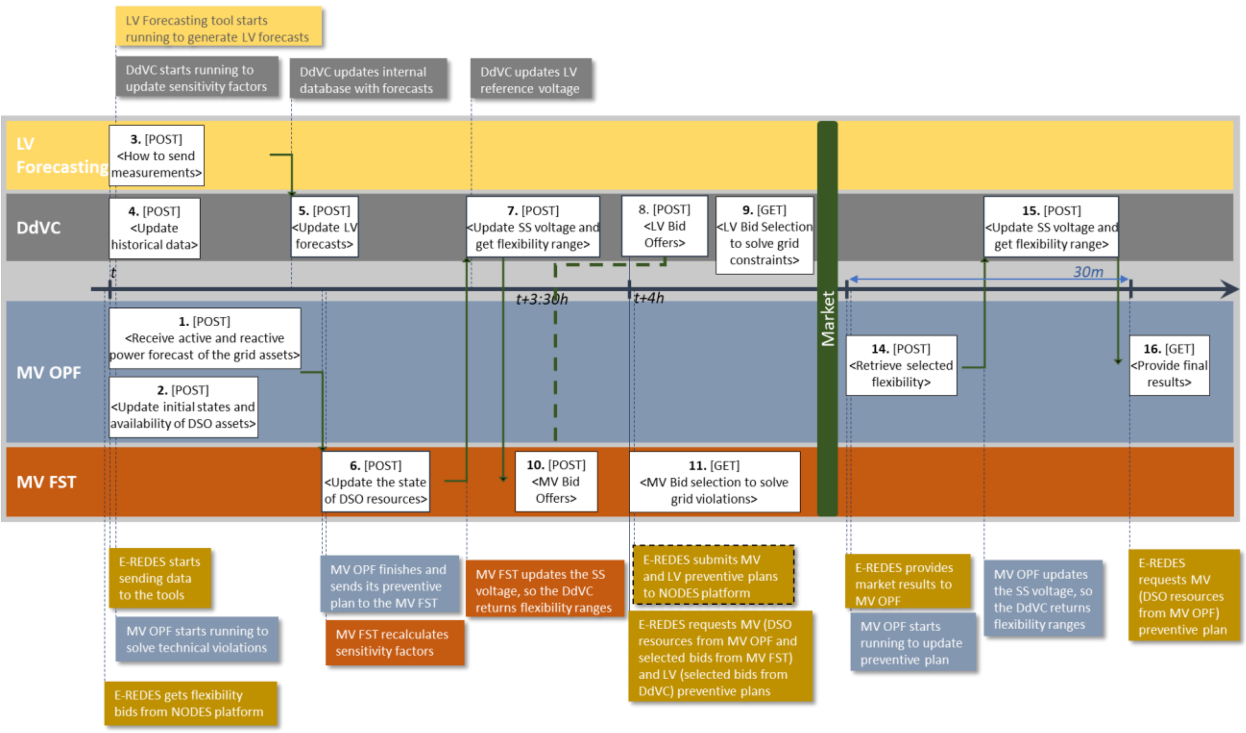


Figure 3-2 – Timeline of the interaction between the different tools till the final MV and LV flexibility bids selection to submit to NODES platform.

3.1.1 MV congestion management tool

The main objectives of the MV congestion management tool is to define the optimal operation plan of DSO controllable assets for the next day, and validate the final plan when flexibility is required. Two main tasks can then be derived:

- Its first task is to check if there are some voltage violations and contingencies in the MV network and to try to remove them using the DSO controllable assets. In order to identify voltage and congestion problems, the MV congestion management tool requires as inputs the MV load/generation forecasts for the next day. Additionally, it receives from the DSO the most recent status of each DSO resources. If the DSO controllable assets do not allow to solve all technical constraints, flexibility procurement will be considered. the market is asked to select some flexibility to try to solve them.
- The second task of the MV congestion management tool is then to check if the flexibility selected by the market platform allows to remove the voltage violations and contingencies in the MV network while not impacting the LV part of the network. To ensure that last point, the voltage limits of the MV/LV substations and the flexibility limits are requested to the Data-driven Voltage Control (DdVC) tool.

Finally, the MV congestion management tool sends to the DSO the final quantity of flexibility used, the state of DSO assets and the results (voltage and current).

It should be noted that this tool is independent of the type of market platform involved in the process. The exchanges with the market platform are indeed managed by the MV flexibility scheduling tool (for the sending of flexibility needs) and by the DSO (for the retrieve of the selected flexibility).

3.1.1.1 Search for a feasible state with DSO controllable assets

The results obtained for a representative day, specifically on November 28 2023 are described to demonstrate the results obtained by the tool during the demonstration period.

The results of the time-series load flow show a voltage violation at bus 836579285 from 13h30 to 14h00. The limit at this bus is 16.5 kV and a voltage of 16.523 kV is calculated. At this node a producer (MV_CLIENT_221) and a MV/LV substation are connected.

To solve this overvoltage, a Multi-period Optimal Power Flow is run using the DSO controllable assets as control variables. The control variables available are transformers' taps, switches, and a battery. However, these assets are not sufficient to solve this contingency.

The results of this simulation are sent to the MV flexibility scheduling tool.

3.1.1.2 Validation of the selected flexibility

Table 3-1summarize the results of the MV congestion management tool for the 28^{th} of November. The "quantity ordered" column refers to the amount of flexibility in kW ordered by the DSO for a period of 30 minutes. The "quantity used" column refers to the estimate of the amount of flexibility that the DSO should use to resolve the voltage violation.

Table 3-1– Flexibility ordered and used for the 28th of November.

Client ID	periodFrom_UTC	Quantity ordered (kW)	Quantity used (kW)
MV_CLIENT_221	2023-11-28T13:30:00Z	300	180

The DSO sends us the flexibility selected by the market to solve the contingency identified by the initial evaluation. This flexibility consists of 300 kW provided by the MV_CLIENT_221. Flexibility from MV/LV substation was not considered due to the limited number of LV flexibility providers.

This flexibility is activated within the Multi-period Optimal Power Flow and a run is done. The first goal of this OPF is to check if the bought flexibility can effectively solve the identified voltage violation. A second goal is to establish the precise amount of flexibility required. To that aim, we use the operational cost as objective function in the OPF problem. A cost is assigned to each kW of flexibility used while the cost of the DSO controllable assets is zero.

The OPF shows that the selected flexibility can solve the overvoltage at bus 836579285. Only 180 kW of the 300 kW offered are necessary to reach an acceptable state. Indeed, curtailing the production of MV_CLIENT_221 by 180 kW reduces the voltage at node 836579285 from 16.523 kV to 16.497 kV while the limit is 16.5 kV. Figure 3-3 shows the initial voltage on the feeder and the final voltage obtained when applying the flexibility computed by the OPF.

The final quantity of flexibility used, the state of DSO assets and the voltage and current are sent to the DSO.

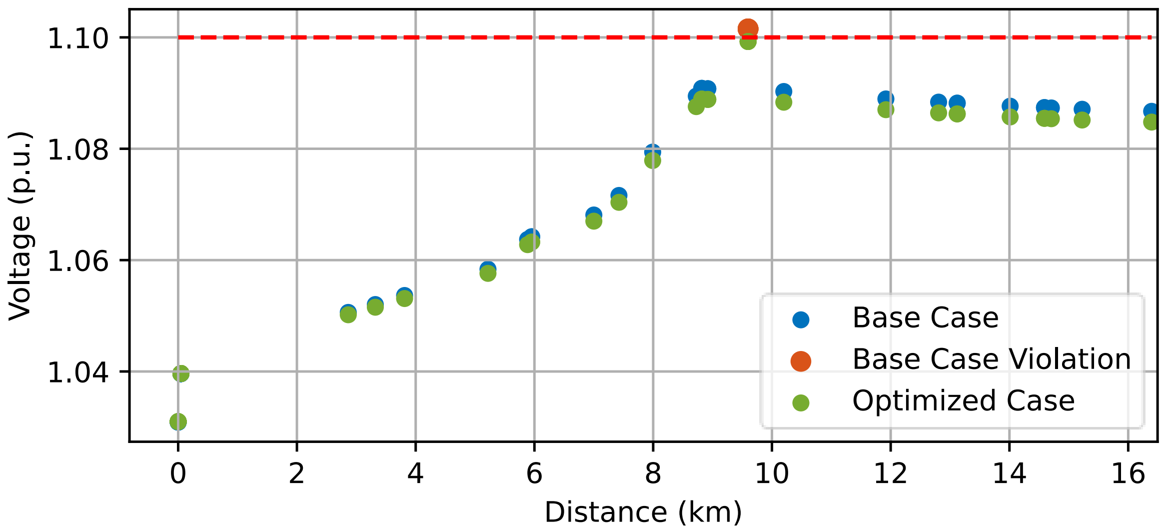


Figure 3-3 – Comparison between initial and final voltage values for some neighbouring nodes and one timestamp (2023-11-28 13:30:00) using the flexibility computed by the OPF.

3.1.2 MV flexibility scheduling tool

The main objective of the MV flexibility scheduling tool (MV FST) is to compute the flexibility needs required to avoid network constraints and select the flexibility bids offered in the market, depending on the market design.

As shown in Figure 3-4, the tool can run individually considering MV forecasts, or integrated with the multi-temporal OPF providing a pre-defined plan for MV grid assets such as OLTC and capacitor banks. The MV FST provides two main outputs:

- Computes flexibility areas and needs to solve grid violations, grouping the grid nodes that minimize the flexibility activation needed across all areas. This flexibility area computation is conducted for each timestamp where grid constraints are identified. The flexibility areas are then submitted to N-SIDE platform through the UMEI.
- Computes the optimal selection of flexibility offers that minimize the total cost of activation of flexibility. The flexibility offers are collected from NODES Short-Flex Platform. As output the MV FST provides the list of the selected bids with the corresponding quantity of active power required to tackle grid issues.

The main innovation of this tool is that runs based on a linear model of the distribution network, considering the computation of sensitivity coefficients V-P and I-P, having high computational performance when dealing with optimization problems with a high number of variables, namely the potential number of flexibility bids available to select.

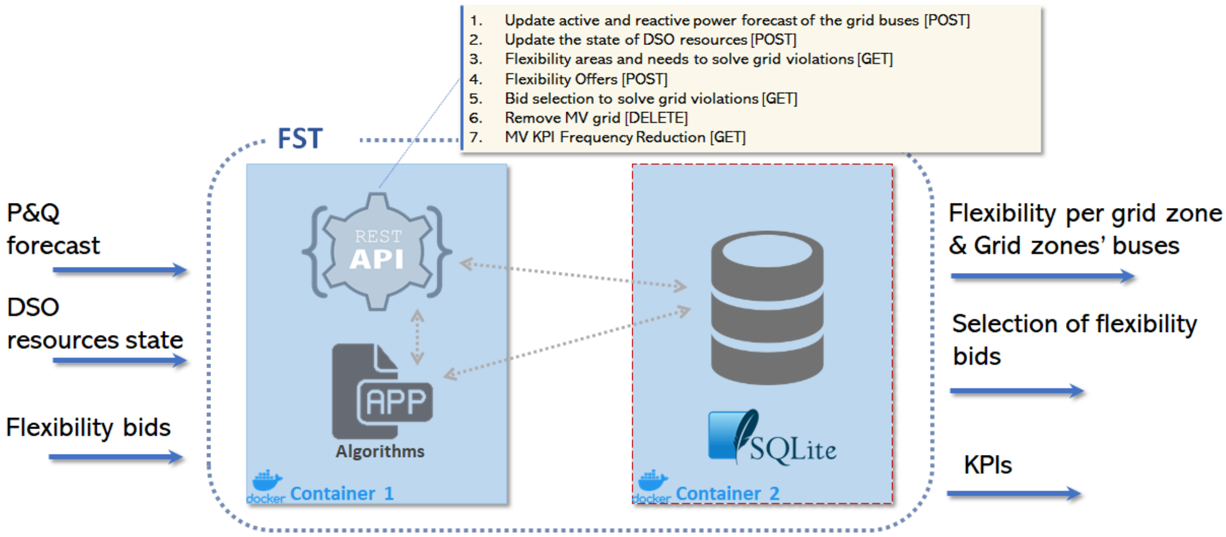


Figure 3-4 – MV Flexibility scheduling tools deployment framework.

The tool was deployed in E-REDES server together with the other DSO tools developed by INESC around June 2023. First integration tests were performed during September considering MV forecast inputs. Tests with the results from the OPF (so called DSO resource state) were also performed for Évora network. Full demonstration tests were performed during November and December. The results are described in the next section.

3.1.2.1 Identification of flexibility zones and quantification of needs to solve grid constraints

The identification of flexibility areas was tested for Évora network. A first set of tests was performed during September considering as inputs MV forecasts. During the initial testing period no grid constraints were identified by the tools, considering that the MV operates within limits and with adequate capacity to accommodate the loads and generation. To successfully demonstrate the procurement of flexibility, the voltage and lines current limits were adjusted.

The results obtained for a representative day, specifically on December 2, 2023 (2023-12-02) are described to demonstrate the results obtained by the tool during the demonstration period. Grid violation issues were identified at 8:30AM and 1:30PM. At 8:30 AM an undervoltage problem is identified considered a pre-defined minimum voltage limit for the grid nodes of the area where MV participants in (MV_CLIENT_407, MV_CLIENT_360, MV_CLIENT_81) are connected, as shown in Figure 3-5. In order to solve the grid constraint identified, downwards flexibility is required, obtained either from a load reduction or generation increase.

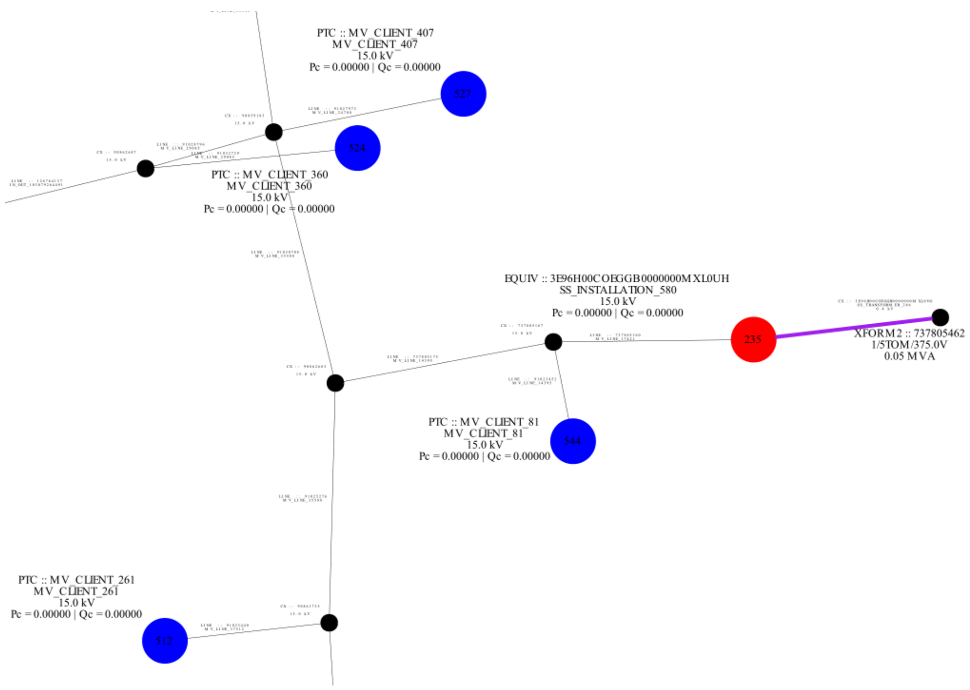


Figure 3-5 – Clients in which minimum voltage limit was changed.

At the second timestamp (1:30PM), the maximum voltage limit was altered to 1.07 p. u., causing overvoltage at bus 836579285, where participant client MV_CLIENT_221 is located (as can be seen in Figure 3-6). Here, the flexibility must either involve generation curtailment or increasing demand.

Taking into account these adjusted limits for undervoltage and overvoltage scenarios, the MV FST tool computed 48 areas for each case. Each area underwent an optimization process to determine its capability to address the grid constraints. In the undervoltage case, 17 areas were able to provide the needed flexibility involving participants MV_CLIENT_81, MV_CLIENT_407 and MV_CLIENT_360. Conversely, in the overvoltage case, 5 areas were able to provide the needed flexibility to address the issue concerning MV_CLIENT_221. Details regarding the optimum flexibility value at each timestamp, along with the number of buses within the chosen area, are outlined in Table 3-2.

Table 3-2, illustrates that at 08:30AM, the Area_15 contains 16 buses. A demand reduction of 77 kW resolves the undervoltage issues for MV_CLIENT_81, MV_CLIENT_407 and MV_CLIENT_360. Similarly, at 1:30PM, the Area_12 comprises 31 buses. A generation curtailment of -113 kW resolves the overvoltage issue for MV_CLIENT221. The "optimum flexibility" refers to the minimum requirement of flexibility within an area to address the identified issue(s), considering all areas that can provide such flexibility.

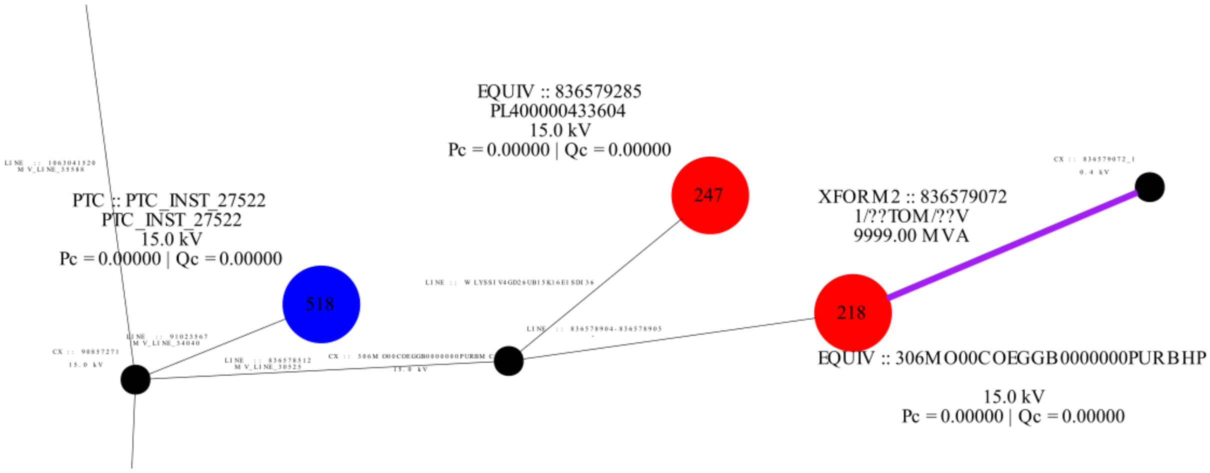


Figure 3-6 – Client in which maximum voltage limit was changed.

Table 3-2 – Results of the areas flexibility in Évora.

Timestamp	Optimum flexibility	Number of buses in the area
2023-12-02T08:30:00	77 kW	16
2023-12-02T13:30:00	-113 kW	31

3.1.2.2 Results of bids selection to solve grid violations

As referred previously, the MV FST tool was also responsible for selecting the MV flexibility offers submitted daily in NODES Short-Flex Market Platform. A first set of tests was performed during September considering as inputs MV forecasts and MV artificial flexibility offers. Compared to the results obtained previously, no grid constraints were identified by the tools, considering that the MV operates within limits and with adequate capacity to accommodate the loads and generation. To successfully demonstrate the procurement of flexibility, the voltage and lines current limits needed to be adjusted.

The results are shown for a representative day for both Évora and Mafra. For Évora, the analysis focused on the day of December 2, 2023, specifically addressing a voltage violation issue at 1:30PM (matching the previously mentioned timestamps for the areas), where MV participants are available to provide flexibility.

Concerning Mafra, the results correspond to the same day, however the grid violation issues were identified at 11:00AM, 11:30AM, 11:00PM, 11:30PM, coinciding with the availability of flexibility bids. In this case, maximum voltage limit was adjusted to emulate an overvoltage problem, as shown in Figure 3-7. Hence, in this case, the flexibility solutions must involve either increased demand or generation curtailment.

Table 3-3 displays the flexibility bids offered and selected for Évora and Mafra MV grids, for each timestamp under consideration. These bids involve offering generation curtailment, and the cleared amounts indicate the intended reduction in generation by the respective generators.

As shown in Table 3-3, Évora's cleared quantity is -128 kW closely aligns with the optimum value within the flexibility area, noted as -113 kW in Table 3-2. This suggests the efficiency of the flexibility area, demonstrating a discrepancy around 12% between values. Examining Mafra's results reveals two distinct patterns. Firstly, MV_CLIENT_208 and MV_CLIENT_71 consistently emerge as the primary flexibility contributors across all timestamps.

Secondly, there is a causality between the difference in voltage values and maximum voltage limits adjustments and the active power quantity in the cleared bids in Table 3-3. Essentially, the greater the disparity between voltage values and maximum voltage limits is, the higher the active power quantity of cleared bids.

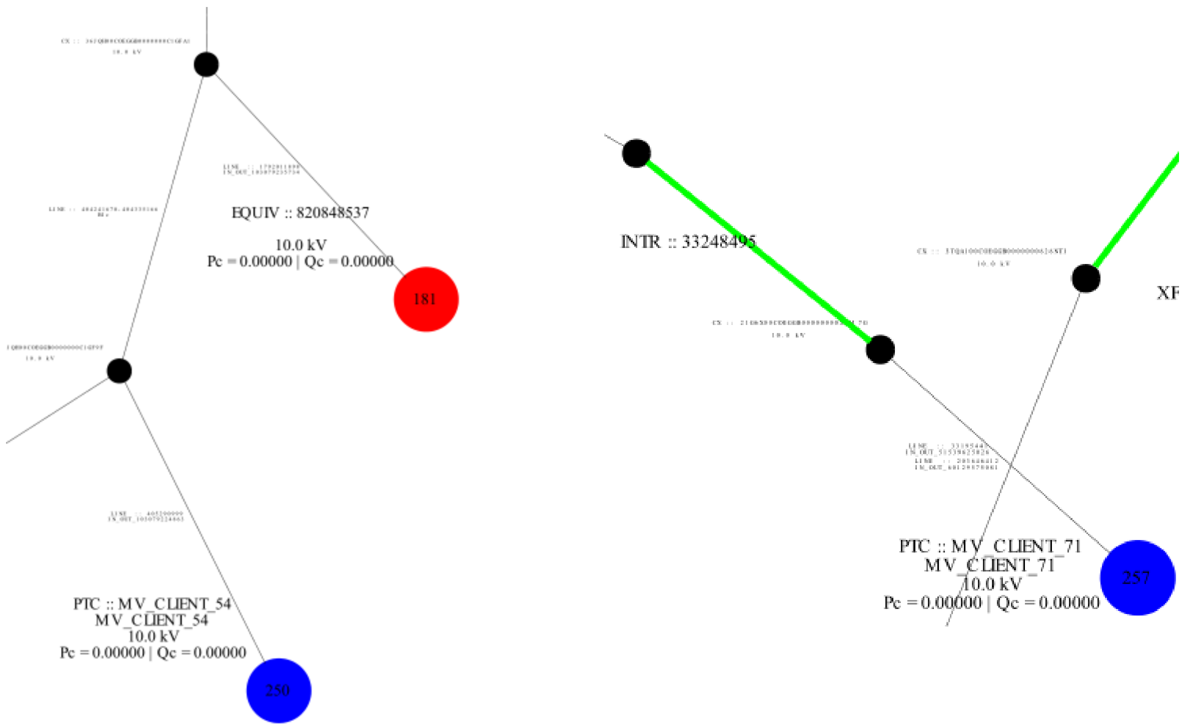


Figure 3-7 – Clients in which maximum voltage limit was changed.

Table 3-3 – Bid offers and cleared amount for each timestamp for Évora and Mafra.

Grid	Timestamp	CLIENT	Bid offer (kW)	Cleared bid quantity (kW)
Mafra	2023-12-02T11:00:00	MV_CLIENT_208	-1000	-440
Mafra	2023-12-02T11:00:00	MV_CLIENT_71	-2000	-1660
Mafra	2023-12-02T11:00:00	MV_CLIENT_451	-500	0
Mafra	2023-12-02T11:00:00	MV_CLIENT_465	-214	0
Mafra	2023-12-02T11:30:00	MV_CLIENT_208	-1000	-438
Mafra	2023-12-02T11:30:00	MV_CLIENT_71	-2000	-1650
Mafra	2023-12-02T11:30:00	MV_CLIENT_451	-500	0
Mafra	2023-12-02T11:30:00	MV_CLIENT_465	-214	0
Évora	2023-12-02T13:30:00	MV_CLIENT_221	-500	-128
Mafra	2023-12-02T23:00:00	MV_CLIENT_208	-1000	-198
Mafra	2023-12-02T23:00:00	MV_CLIENT_71	-2000	-750
Mafra	2023-12-02T23:00:00	MV_CLIENT_451	-500	0
Mafra	2023-12-02T23:00:00	MV_CLIENT_465	-214	0
Mafra	2023-12-02T23:30:00	MV_CLIENT_208	-1000	-173
Mafra	2023-12-02T23:30:00	MV_CLIENT_71	-2000	-652
Mafra	2023-12-02T23:30:00	MV_CLIENT_451	-500	0
Mafra	2023-12-02T23:30:00	MV_CLIENT_465	-214	0

3.1.2.3 Tool KPIs and conclusions

In the preceding sections, the results for a specific representative day (2023-12-02) in Évora and Mafra are outlined. The analysis of flexibility area computation for Évora revealed that multiple areas can meet the flexibility requirements for both timestamps. Among these areas, the optimum flexibility area, as detailed in Table 3-2, provides the minimum flexibility needed to address grid issues.

The optimal bid selection, as presented in Table 3-3, underscores notable observations. Firstly, in Évora, the cleared bid quantity closely aligns with the optimum flexibility area, indicating the reliability of the clustering method using sensitivity factors. Secondly, in Mafra, the selected client bids primarily offer higher flexibility curtailment quantities. Despite this, the bid selection prioritizes clients crucial for resolving grid issues due to their strategic location in the distribution grid.

Table 3-3 also reveals a consistent pattern in cleared bid quantities across timestamps for Mafra. From 11:00 AM to 11:30 PM, there is a reduction in cleared bids, indicating a correlation between timestamps with issues and the quantity of cleared bids. This pattern arises from adjusted voltage and current limits inducing greater violations during daytime compared to nighttime hours.

To measure bid selection performance, we utilize the Voltage Violation Frequency Reduction (VFR) Key Performance Indicator (KPI), which quantifies the decrease in the occurrence of voltage violations within a specific time interval. The VFR is defined as:

$$VFR = \frac{n_{\mathrm{vv}} - n_{rvv}}{n_{\mathrm{vv}}} \times 100\%$$

Where n_{vv} is the number of voltage violations in the grid (adjustments made) and n_{rvv} is the remaining number of voltage violations after the selection of bids. The VFR values regarding the bid selection method for all the grids for the representative day 2023-12-02 can be seen in Table 3-4.

Table 3-4 – VFR for all MV grids during 2023-12-02.

Grid	VFR (%)
Évora	100
Mafra	100
São Francisco	0

As shown in Table 3-4, both Évora and Mafra achieved a VFR of 100%. This indicates that all violations were successfully resolved using the selected bids for the respective day. However, in the case of São Francisco, the bid provided could not help solve the identified grid constraint, considering its location, resulting in a VFR of 0%. The VFR values regarding the bid selection method for all the grids from 2023-12-01 to 2023-12-10 can be seen in Table 3-5.

Table 3-5 – VFR for all MV grids for one week

Grid	VFR (%)
Évora	100
Mafra	55
São Francisco	0

According to Table 3-5, Évora attained a VFR of 100%. This signifies that throughout the observed period, the flexibility bids consistently provided sufficient active power to solve all the grid issues. In contrast, Mafra's VFR achieved 55%. This value represents that throughout the observed period, the flexibility bids were not enough to solve all grid issues, primarily due to a lack of liquidity. Regrettably, São Francisco faced persistent grid issues throughout the observed period. This was mainly due to the presence of only one flexibility bid, offering insufficient active power to solve any grid issues.

Overall, the demonstration yielded satisfactory results. However, throughout the testing and demonstration period, a few challenges were observed that impacted the effective operation of the MV FST tool. In particular, the primary issue encountered was the limited liquidity affecting bid selection since some resources considered during testing were unavailable for demonstration purposes. This challenge was not foreseen during the design of the optimization algorithm thus revealing convergence difficulties under such flexibility limitations.

As future work, the optimization algorithm behind the MV FST tool must include strategies (e.g., compensation variables) to relax the constraints and allow the convergence even when the resources available are not enough to solve the violations. Also, it has to be developed a method to find the optimal number of clusters (areas) and enable the ability to accommodate complex bids with interoperability constraints.

3.1.3 Low voltage forecasting service

Flexibility procurement requires first to identify technical problems. In LV networks, due to the poor characterization of the network, an alternative approach to conventional power flow-based tools was followed to quantify voltage constraints, namely forecasting both active power and voltage measurement for each consumer connected to the pilot LV grid, based on historical metering data.

The tool forecasts voltage and active power for each LV consumer for the next 24 hours (30-min resolution), using relevant statistical and machine learning models. It has been implemented as part of a larger RESTful API. This service was paired with an Apache Cassandra database instance, where all the metadata and data are stored and managed, supporting the forecast computation task and all related processes.

The main endpoint of this service implements the historical measurements injection method. By sending data over this endpoint, the service is updated with the most recent available data for the target grid, triggering a process that consists of the following steps:

1. After storing raw data in the database, this data is processed internally for the meters contained in the newly sent data and stored in the database (processing includes changing data time resolution to 30 minutes, checking for invalid measurements, and outlier detection to avoid contaminating the forecasting models with abnormal data).
2. Forecasts are computed for each of the meters listed in the method call (both active power and voltage).
3. Forecasts are stored in the service's database and made available through the forecast request method.
4. This output is processed and sent to the DdVC service using the appropriate method.

Three other tasks are carried out periodically using scheduled processes. These tasks are:

a. Retrieving Numerical Weather Predictions (NWP) from the MeteoGalicia THREDDS server (to be used as exogenous variables in the forecasting models).
b. Generating KPIs to be stored in the database and made available through the KPI request method.
c. Training the models for each meter. This optimizes (timewise) the forecast computation step described previously since it guarantees models have been pre-trained and only need to be loaded.

3.1.3.1 Deployment and testing

For the configuration and individual test of the LV forecast tool, firstly, metadata about the meters has been shared and loaded onto the service's database. This was an important step since this allows to control and validate the data being sent over the previously referred method.

The tool has been deployed in E-REDES server in May of 2023. Demonstration data has been sent to the API starting May of 2023. It is originating from consumers in 9 different grids, with a time resolution of 15 minutes, although the outputs use a 30-minute resolution for compatibility with market platforms. The first phase of data injection allowed functional tests of all stages of the forecasting generation, and some technical issues arising from the continuous interactions were addressed in the following months. Since the accuracy of forecasting models is improved with the availability of historical data, this first phase also allowed to accumulate raw observations which would help generate better forecasts in the long term. Until the end of September, most of the necessary adjustments in the models and the implementation were made.

Forecast generation is triggered each time the historical data injection method is invoked and the time horizon for the output is the 24 hours of the following day. Figure 3-8 shows an example of the output of the service, for a given meter that was included in the demonstration (meter "NLV_CLIENT_1030" for grid "SS_INSTALLATION_96"), over two consecutive days (18^{th} and 19^{th} of November 2023, computed on the 17^{th} and 18^{th} of November, respectively). The real (resampled to 30 minutes) measurements are also represented, for both active power and voltage.

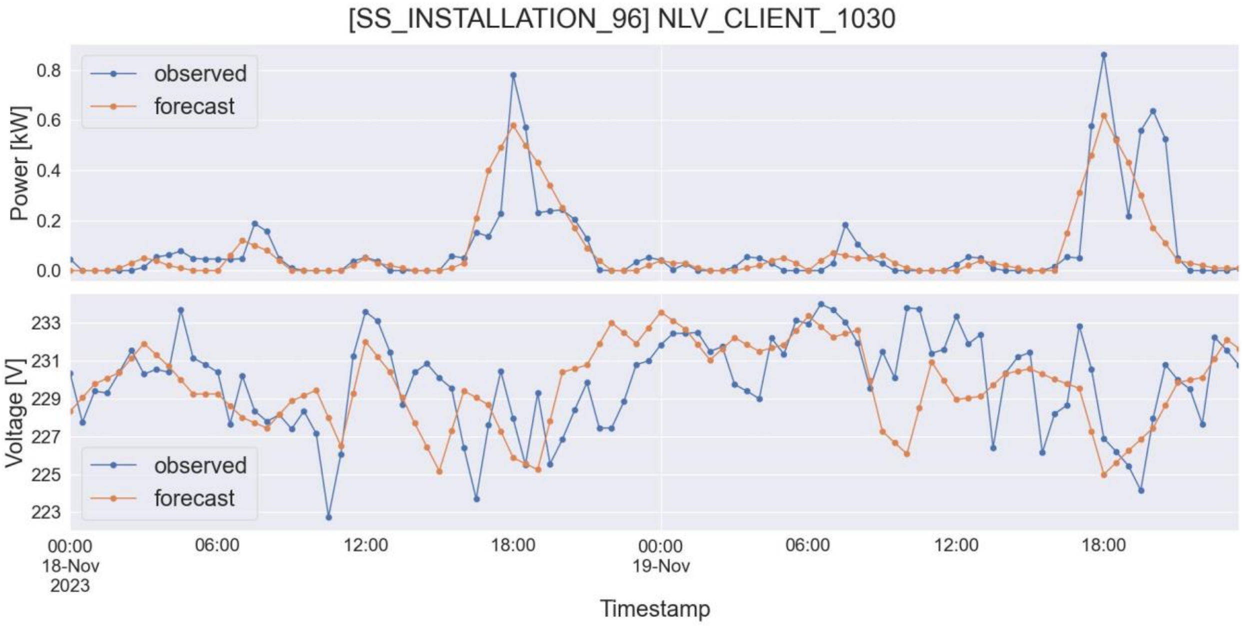


Figure 3-8 – Example of output of low voltage forecasting service.

3.1.3.2 Tool KPIs and conclusions

The Key Performance Indicators (KPIs) for the low voltage forecasting service were the following:

- **Mean Absolute Error (MAE)** – For each forecast generation, the average deviation from the observed measurement, in absolute terms. Considering instant 1 as the initial step in the forecast horizon, y_i as the observed measurement on instant *i*, $\widehat{y_i}$ the estimation for the same instant and *n* as the number of forecasts, it is given by the definition:

$$MAE = \sum_{i=1}^{n} \frac{|y_i - \widehat{y_i}|}{n}$$

- **Maximum Absolute Error (MAD)** – For the same forecasts generated, extract the maximum deviation observed, in absolute terms. Corresponds to the following formulation:

$$MAD = \max\{|y_i - \hat{y}_i|\}, 1 \leq i \leq n$$

Considering the last month of the demonstration (November of 2023), KPIs for each successful forecast (and for which real measurements were eventually sent) were computed, and a summary is presented in Table 3-6.

Table 3-6 – KPIs for the forecasts computed during the demonstration month of November 2023.

Active Power (kW)		Voltage (V)	
MAE	MAD	MAE	MAD
0.21	1.13	2.02	6.01

During the testing and demonstration period, some issues regarding the data were noted that affected the operation of the service and the quality of its output, namely:

- Gaps in the historical data (some caused by technical issues on the service side, others from the failure to deliver new historical data). This affected the availability of data and consequently the performance of the service.
- The quality of the data provided – In a great number of cases, especially in the voltage data, historical measurements were discarded as they were considered abnormal (i.e., outside of expected values, as was the case of a great number of meters' timeseries which are constantly zero). This was an impediment to the generation of forecasts for the affected meters.

3.1.4 Data-driven Voltage Control (DdVC) API architecture and main functions

The Data-driven Voltage Control (DdVC) tool main objectives are to quantify flexibility needs, flexibility technical envelopes and select optimal bid offers when applicable, based exclusively on the historical data of the installed smart meters. These results enable accurate voltage control within LV networks, optimized flexibility utilization, and informed decision-making for improved LV network performance.

It has been implemented as part of a larger RESTful API, as in Figure 3-9, running in parallel with other DSO tools in E-REDES server.

The core concept behind the DdVC is the calculation of sensitivity factors (i.e., $S_{i,j} = \Delta V_i / \Delta P_j$) that portray the voltage variation in node (or customer) i when the active power injection in node (or customer) j is affected. These relationships can be extracted via linear regression using historical data gathered from smart meters. In this sense, the DdVC expects to receive regular updates of historical data (every 24h) so it adapts the sensitivity factors to the time-varying consumption patterns, also using a sliding window to "forget" old behaviours.

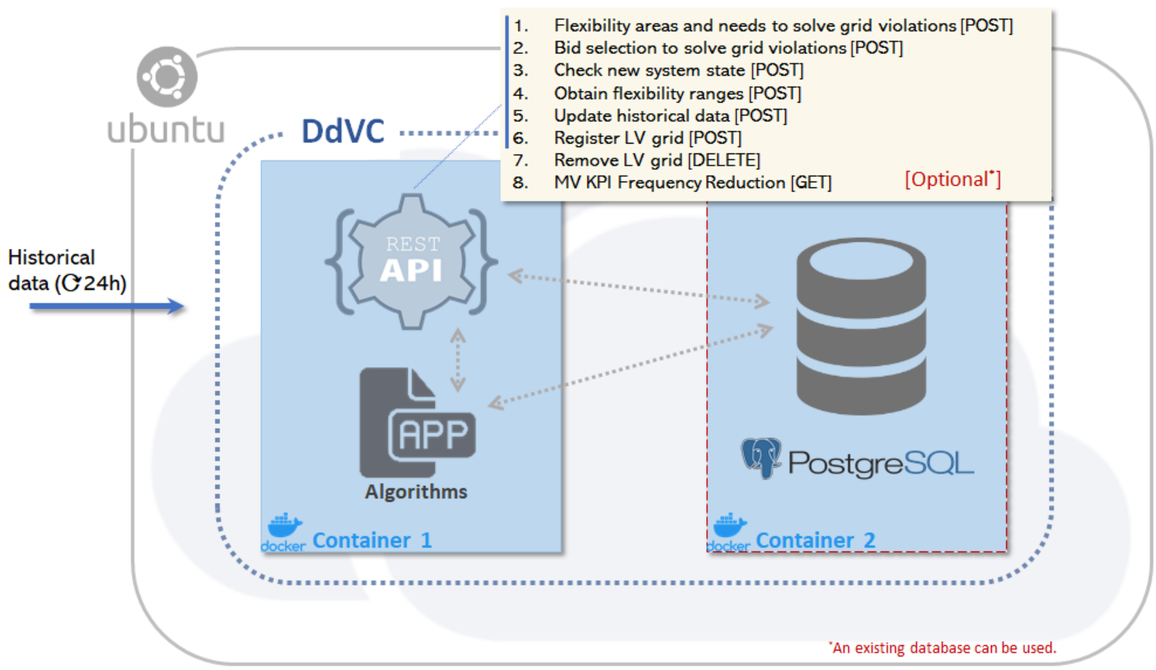


Figure 3-9 – The DdVC is deployed using docker images for Linux distributions.

To calculate the sensitivity factors, the following historical data is required (in ideal conditions):

- Voltage magnitude from all the smart meters (at least 2 months).
- Active power from all the smart meters (at least 2 months).
- Voltage magnitude, per phase, at the MV/LV substation (at least 2 months).
- Active power flow, per phase, at the MV/LV substation (at least 2 months).

The minimum historical size necessary to calculate the sensitivity factors is 15 days of synchronized data.

Regarding the functionalities available to the user, assuming there were conditions to calculate the sensitivity factors, it is possible to:

- Define flexibility perimeters: The forecasted state of the system is provided to the DdVC. If voltage violations are found, the DdVC will determine the amount of flexibility per flexibility perimeter required to solve those violations, while minimizing costs.
- Selection of flexibility bids offers: Solve technical constraints detected in LV networks, by selecting the most economical flexibility bid offers collected from the Flexibility Market Platforms.

In both these methods, if not all violations can be solved, the user also receives an information of the necessary voltage change in the substation to solve the rest of the problems.

This tool was tested for 8 months, during which some modifications were made. Because voltage range violations are not usual in these grids, the voltage limits were adjusted to allow for the occurrence of violations, that could then be solved. The final voltage limits are listed in Table 3-7. It was also found that there was a great deal of incorrect or missing values in the historical data, which led to the implementation of an algorithm to process and improve the input data.

Table 3-7 – Voltage limits for the low voltage grids.

Grid ID	Min Voltage (V)	Max Voltage (V)
SS_INSTALLATION_67	225	240
SS_INSTALLATION_96	228	240
SS_INSTALLATION_119	219	238
SS_INSTALLATION_325	221	237
SS_INSTALLATION_440	226	240
SS_INSTALLATION_496	222	237
SS_INSTALLATION_606	222	242
SS_INSTALLATION_682	223	234
SS_INSTALLATION_884	225	250
Others	220	255

3.1.4.1 Flexibility areas and needs to solve grid violations

The arrival of a new set of forecasted data triggers the DdVC to find voltage violations in the data, aggregate the clients into flexibility areas, and define what flexibility is necessary from each area to solve these violations. For illustration purposes, the selected flexibility areas and needs for one grid and one timestamp can be seen in Table 3-8.

Table 3-8 – Flexibility areas and needs selected to solve grid violations for one grid (id: SS_INSTALLATION_682) and one timestamp (2023-12-02 17:00:00).

Area	Clients	Need (kW)
SS_INSTALLATION_682_0_8	NLV_CLIENT_529	0.033
SS_INSTALLATION_682_16_3	NLV_CLIENT_1086	0.002
	NLV_CLIENT_1175	
SS_INSTALLATION_682_31_6	NLV_CLIENT_149	0.001
SS_INSTALLATION_682_33_3	NLV_CLIENT_45	0.009
	NLV_CLIENT_452	
SS_INSTALLATION_682_39_7	NLV_CLIENT_243	0.004
SS_INSTALLATION_682_51_4	NLV_CLIENT_259	0.014

The forecasted voltage and the voltage after applying the selected flexibility needs (calculated based on the sensitivities) for each client in the grid for that timestamp, as well as the voltage limits for that grid, are illustrated in Figure 3-10.

As shown in Figure 3-10, the selected flexibility needs were able to solve all the problems in the grid, without the need for a voltage adjustment in the secondary substation.

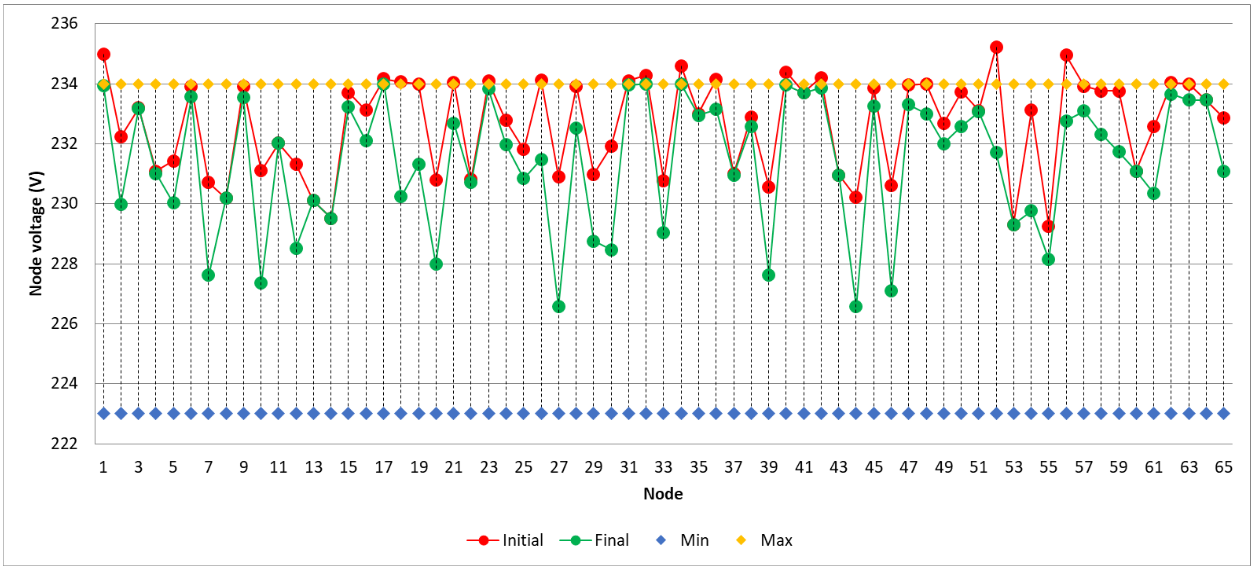


Figure 3-10 – Comparison between initial and final voltage for SS_INSTALLATION_682 and one timestamp (2023-12-02 17:00:00) using the flexibility areas.

3.1.4.2 Bid selection to solve voltage violations

The bids selected to solve voltage constraints are described in Table 3-9.

Table 3-9 – Bids selected to solve grid violations for: SS_INSTALLATION_682 and one timestamp (2023-12-02 17:00:00).

Client	Need (kW)
NLV_CLIENT_113	0.015

The forecasted voltage and the voltage after applying the selected bids (calculated based on the sensitivities) for each client in the grid for that timestamp, as well as the voltage limits for that grid, can be seen in Figure 3-11.

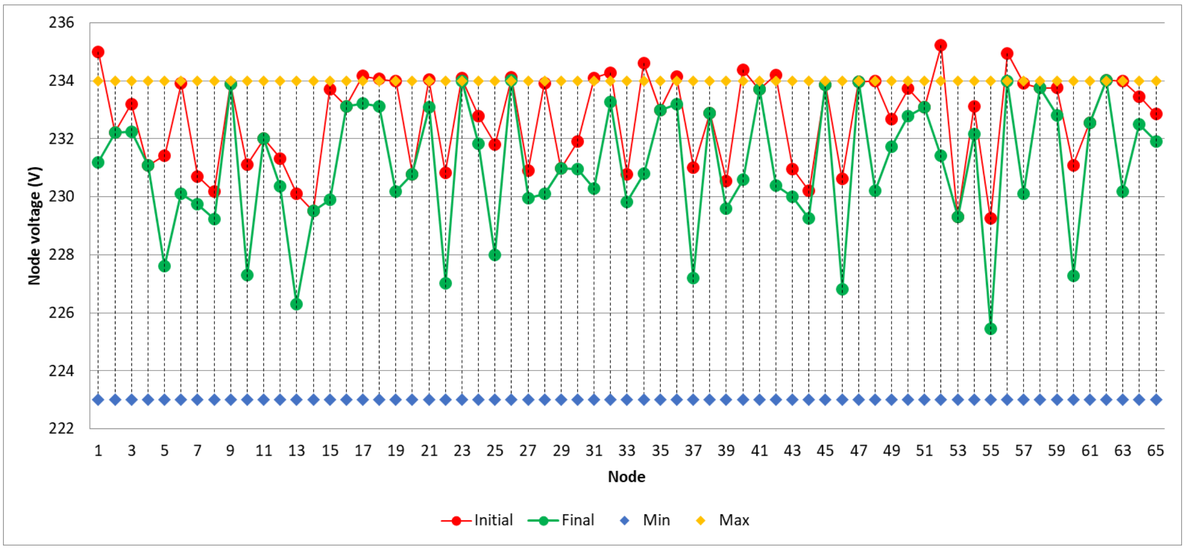


Figure 3-11 – Comparison between initial and final voltage for SS_INSTALLATION_682 and one timestamp (2023-12-02 17:00:00) using the bid selection method.

Examining the results shows that the selected bid was able to solve all the problems in the grid, keeping the new voltage values between limits. As with the flexibility areas method, the voltage adjustment in the secondary substation was, in this case, not necessary.

3.1.4.3 Tool KPIs and conclusions

The KPI used for this tool is the Voltage Violation Frequency Reduction (VFR), the reduction of the number of voltage violations in a time interval. It is defined as:

$$VFR = \frac{n_{\text{baseline}} - n_{LVC}}{n_{\text{baseline}}} \times 100\%$$

Where n_{baseline} is the number of violations (registered in each asset) in the baseline scenario and n_{LVC} is the number of violations (registered in each asset) with the tool application.

The VFR of the flexibility areas method for all the grids for eleven days are listed in Table 3-10. On one day (2023-12-08) there were no calculations. On some occasions, there are no violations found for a certain grid. In the remaining cases, the VFR values are generally high, meaning that, for those days, it was possible to solve most (and in some cases all) of the voltage violations in the grids by the utilization of the indicated flexibilities. It is, then, shown that the DdVC can be a useful tool for the prevention of problems in low voltage grids.

Table 3-10 – Violation frequency reduction for all LV grids for each day for the flexibility areas method

Grid ID	VFR (%)										
	02/12	03/12	04/12	05/12	06/12	07/2	09/12	10/12	11/12	12/12	13/12	VFR avr
SS_INSTALLATION_67	100	78,1	100	98	90,1	78,9	69,4	75	65,1	56,5	62	79,4
SS_INSTALLATION_96	81,3	67,9	66,2	65,4	67,4	66,9	65,3	65,3	74,8	73,5	71,1	69,6
SS_INSTALLATION_119	No viol	77,5	83	74,5	90,3	100	52	30,3	79,6	63,9	73,7	72,5
SS_INSTALLATION_325	100	100	100	100	100	100	100	100	100	100	100	100,0
SS_INSTALLATION_440	77,1	51,7	72,9	35,6	67,4	65,4	71,2	65,4	63,6	82	79,2	66,5
SS_INSTALLATION_496	76,6	98,5	100	100	100	100	100	100	100	100	100	97,7
SS_INSTALLATION_606	No viol	100	60	No viol	74,3	92,9	100	100	100	71,4	50	83,2
SS_INSTALLATION_682	99,6	100	94,8	86,3	95,9	92,8	100	100	92,7	83,8	83,4	93,6
SS_INSTALLATION_884	100	85	65,5	60,4	60,8	72,9	78,6	No viol	78	71,4	71,8	74,4
												81,9

As for the bids selection method, the results can be observed in Table 3-11. In some cases, the offered bids were used to successfully solve all problems in their timestamps. In others, however, the VFR value was lower. This is because, even though there were flexibility offers for those grids, these were not adequate to solve the problems that were found.

Table 3-11 – Violation frequency reduction for all LV grids for each day for the bid selection method

Grid ID							
	02/dez	07/dez	09/dez	10/dez	11/dez	12/dez	13/dez	VFR aver
SS_INSTALLATION_96	22,2	0	85	79	0	0	0	26,6
SS_INSTALLATION_440	-	100	100	100	77,1	76,1	63,2	86,06667
SS_INSTALLATION_682	100	-	-	-	-	-	-	100
								70,9

3.1.5 Flexibility Aggregation and grid users

3.1.5.1 Aggregation workflow

The aggregation algorithm was designed by Centrica to calculate the available flexibility (both quantity and price) that each device can offer to the DSO market. The optimal offer is determined by solving an optimization problem. The optimal bids are then submitted to the FMO via the UMEI. After market clearing, the results are processed by Centrica via the UMEI. To disaggregate the results and activate flexibility, there are different ways to send out the control signal to the flexible assets, depending on the type of end-users, namely:

- LV customers are provided with HEMS, through specific API connection to HEMS controller. HEMS are controlled centrally by Cleanwatts, a partner of former H2020 InteGrid project. This allowed Centrica to perform their previous analysis on flexibility potential and to activate/deactivate each participant's load/generation through direct automatic connection to Cleanwatts' system. Through Cleanwatts HEMS, Centrica had access to the consumption, generation and the states of flexible devices (such as state of charge of the battery), as well as send control signal to the assets. Electric water heater, PV, and battery are different types of assets available in PT demo.
- MV producers are activated manually by curtailing their power production. This activation is requested by Centrica and is communicated to the MV producers through E-REDES.
- MV consumers are also activated manually by shifting their starting time and their ending working time in the morning and in the afternoon. Similar to producers, this activation is requested by Centrica and is communicated to the MV consumers through E-REDES

Figure 3-12 shows how the aggregator, Centrica, communicates with the external partners and Figure 3-13 presents an overview of the architecture Centrica has developed as part of the EUniversal project.

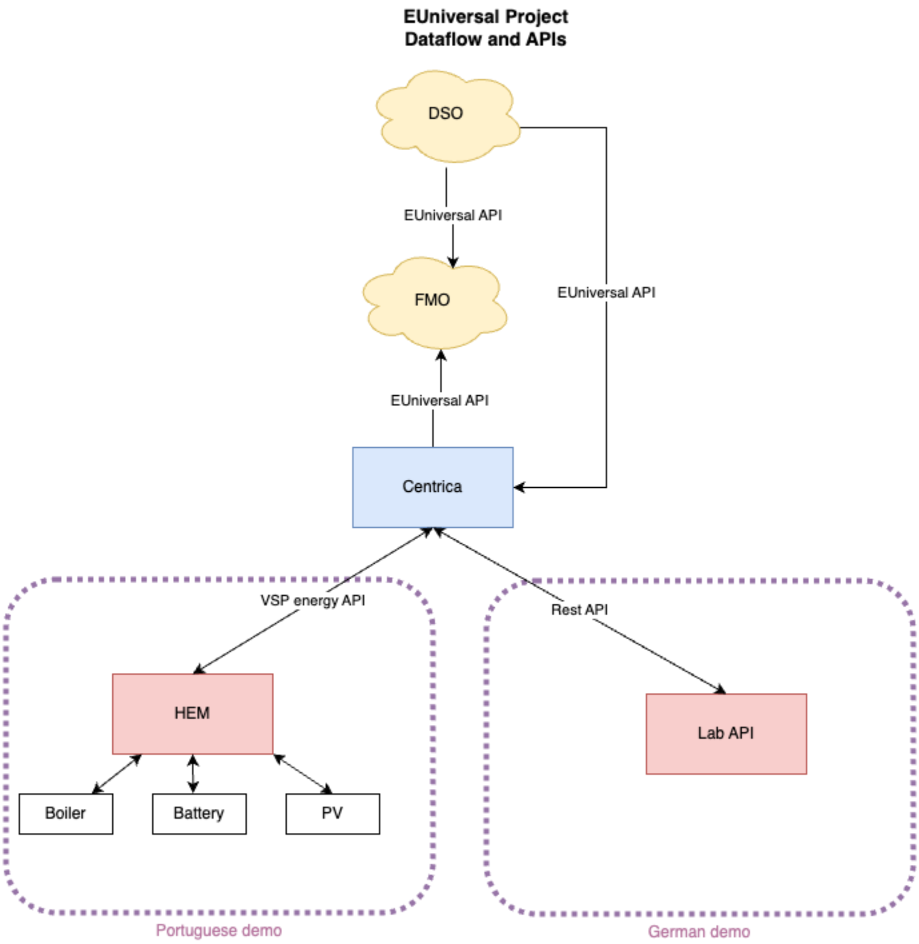


Figure 3-12 – Centrica communications with partners.

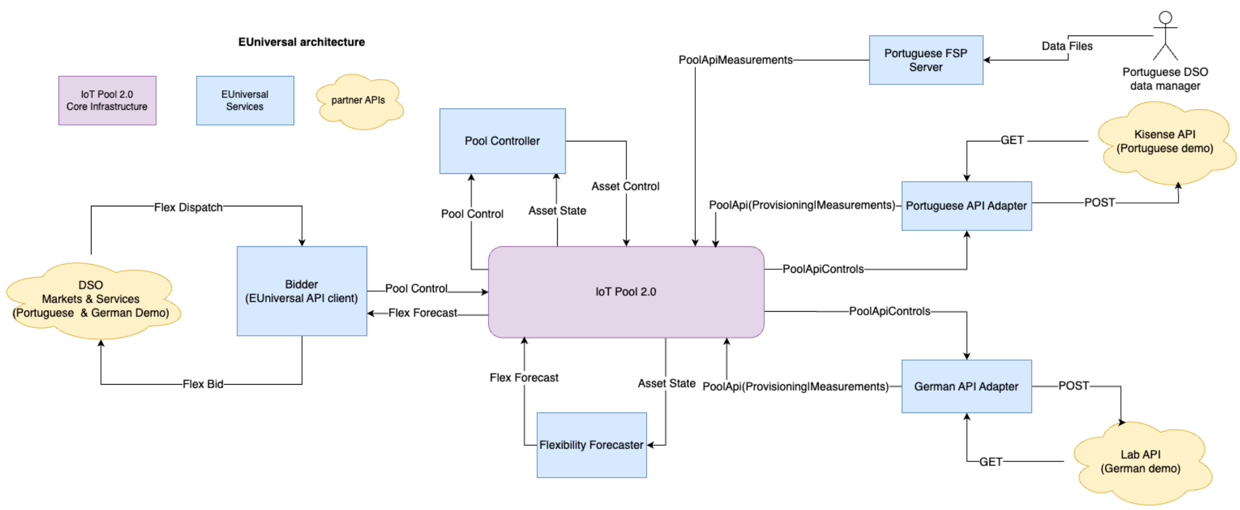


Figure 3-13 – Overview of the architecture developed.

3.1.5.2 Results

Figure 3-14 shows an example control schedule for the battery of customer NLV_CLIENT_301. The blue line is the day-ahead control schedule for the battery, optimised to minimise the electricity costs of the customer. In blue, it is shown a potential new control schedule that would be used to steer the customer's battery. The difference between the 2 control schedules is the flexibility that is offered to the Flexibility Market Operator (FMO).

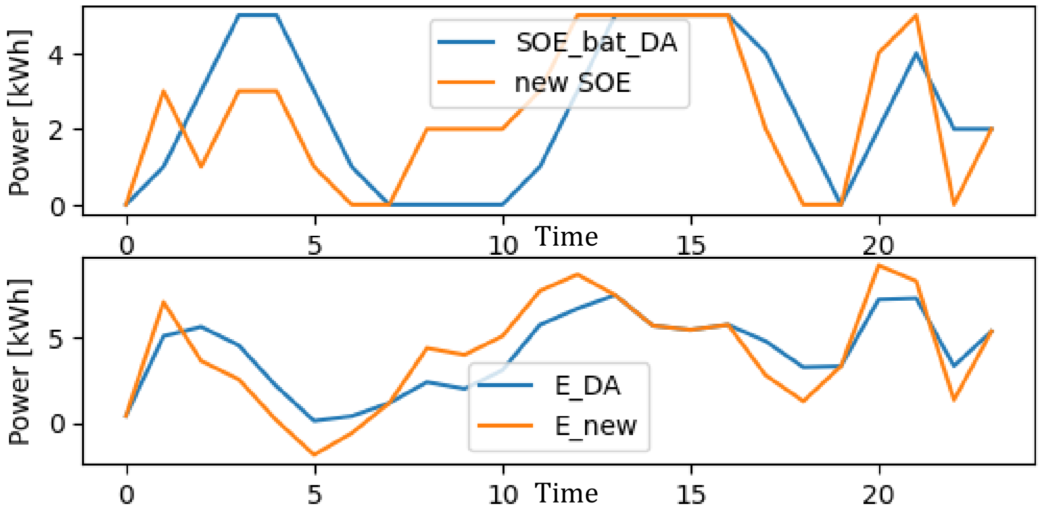


Figure 3-14 – Control schedule for Device ID 3160 (NLV_CLIENT_301).

Figure 3-15 shows a control schedule of a smart heater. The blue line shows the baseline operation by considering the temperature constraints and the day-ahead electricity prices. The orange line shows a potential new control schedule for the smart heater. The power differences between the 2 control schedules are used to make flexibility bids to the FMO.

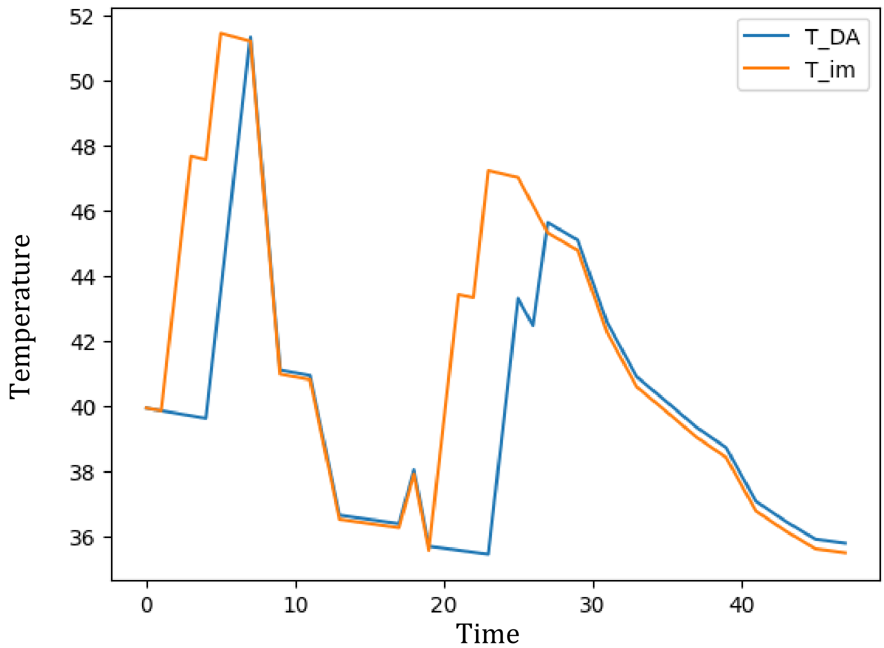


Figure 3-15 – Control schedule of the smart heater (device id 3157) for customer NLV_CLIENT_389.

Table 3-12 shows a snapshot of the database for bids made on the 11th of December. The "quantity_order" column refers to the amount of flexibility, in kW, that was offered for a period of 30 minutes. The "quantity_trade" column refers to the amount of flexibility that the FMO bought.

Table 3-12 – Snapshot of the database of flex orders and trades for the 11th of December.

Client ID	periodFrom_UTC	quantity_order	quantity_trade
NLV_CLIENT_1029	2023-12-11T01:00:00Z	1,5	0,632
NLV_CLIENT_387	2023-12-11T01:00:00Z	1	0
NLV_CLIENT_597	2023-12-11T01:00:00Z	1	0
NLV_CLIENT_1042	2023-12-11T01:00:00Z	1,5	0
NLV_CLIENT_301	2023-12-11T01:00:00Z	1	0
NLV_CLIENT_643	2023-12-11T01:00:00Z	2,5	0,042
NLV_CLIENT_389	2023-12-11T01:00:00Z	1,5	0,042
NLV_CLIENT_389	2023-12-11T01:30:00Z	1,5	0,041
NLV_CLIENT_643	2023-12-11T01:30:00Z	2,5	0,019

3.1.6 Integrated test results

This section presents the results for the day-ahead flexibility procurement, following the steps represented in Figure 3-16. In detail, these results consist in the operation plan for the 12-12-2023, considering the outputs from the market cleared in the previous day.

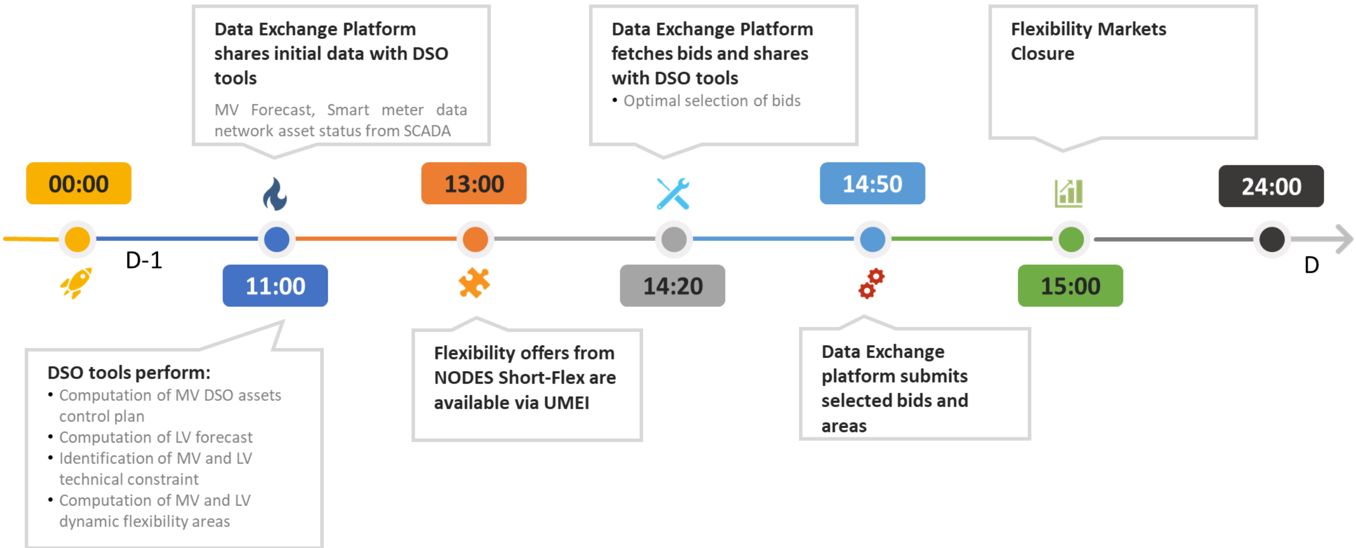


Figure 3-16 – Summarized timeline of PT demonstration for day-ahead procurement of flexibility services.

After receiving the required input data, namely MV forecasts, voltage and load diagrams from smart meters and the last known status of DSO assets such as OLTC, capacitor banks and network switches, the DSO tools run.

To compute the DSO needs in the MV network, forecast data or power flow results from the day-ahead are utilized across flexibility areas and flexibility bids computation. To illustrate the procurement of flexibility through these areas, adjustments were made to the voltage and line current limits in Évora, resulting in one MV bus experiencing overvoltage. Similarly, adjustments were made in Mafra and São Francisco, leading to two buses with undervoltage in each grid. However, in these periods, the procurement of flexibility did not occur within flexibility areas. Instead, the procurement of flexibility was achieved through flexibility bids. These adjustments were tailored for December 12th, and the forthcoming sections will present the detailed results.

Based on the data from the previous day, the LV forecast tools runs to compute load and voltage forecast for the next day

Figure 3-17 depicts illustrative results of the operation of the service on December 11th, generating forecasts for the following day (active power and voltage), namely for the 12/12/2023. Four random examples, each from a different grid (identified in square brackets in the figure's caption), were selected.

Considering the voltage limits defined in Table 3-7 for each LV network, the DdVC computed the flexibility areas and needs for all LV networks required to solve the simulated grid constraints. Table 3-13 shows the results obtained for one of the LV demo grids, namely SS_INSTALLATION_440. Figure 3-18 represents the voltage forecast for all the nodes of MV/LV substation 440 and the expected results after mobilization of flexibility.

Table 3-13 – Flexibility areas and needs selected to solve grid violations for one grid (id: SS_INSTALLATION_440) and one timestamp (2023-12-12 08:30:00).

Area	Clients	Need (kW)
SS_INSTALLATION_440_17_0	NLV_CLIENT_1174	-0,021
SS_INSTALLATION_440_33_0	NLV_CLIENT_643	-0,186
SS_INSTALLATION_440_37_0	NLV_CLIENT_183	-0,193

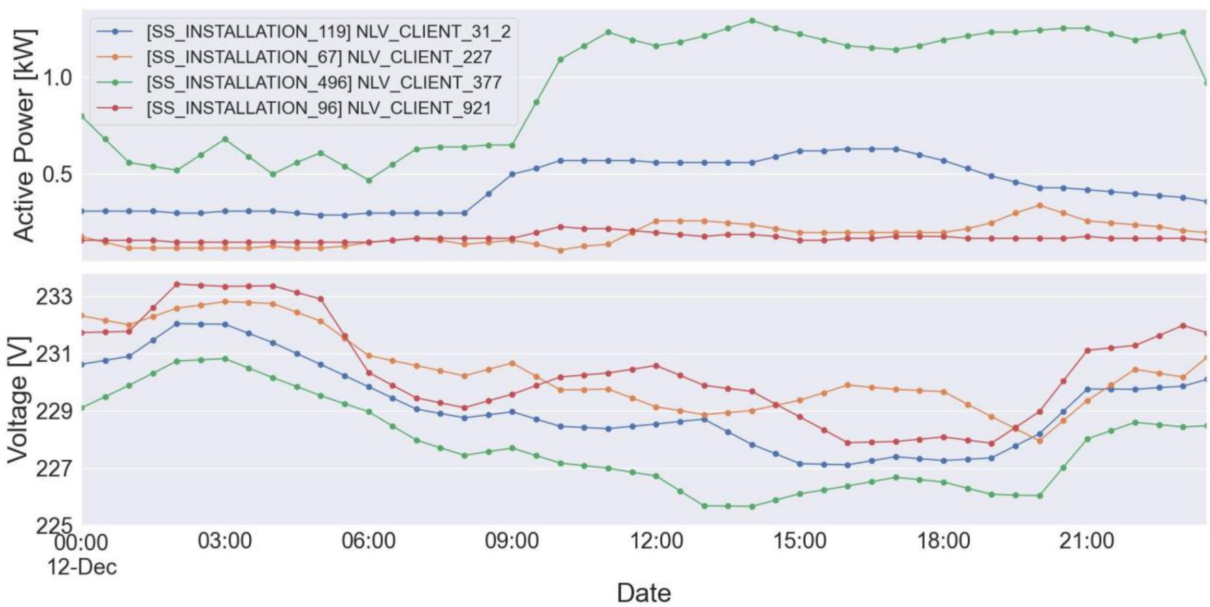


Figure 3-17 – Examples of low voltage power and voltage forecasts for demo day 2023-12-12.

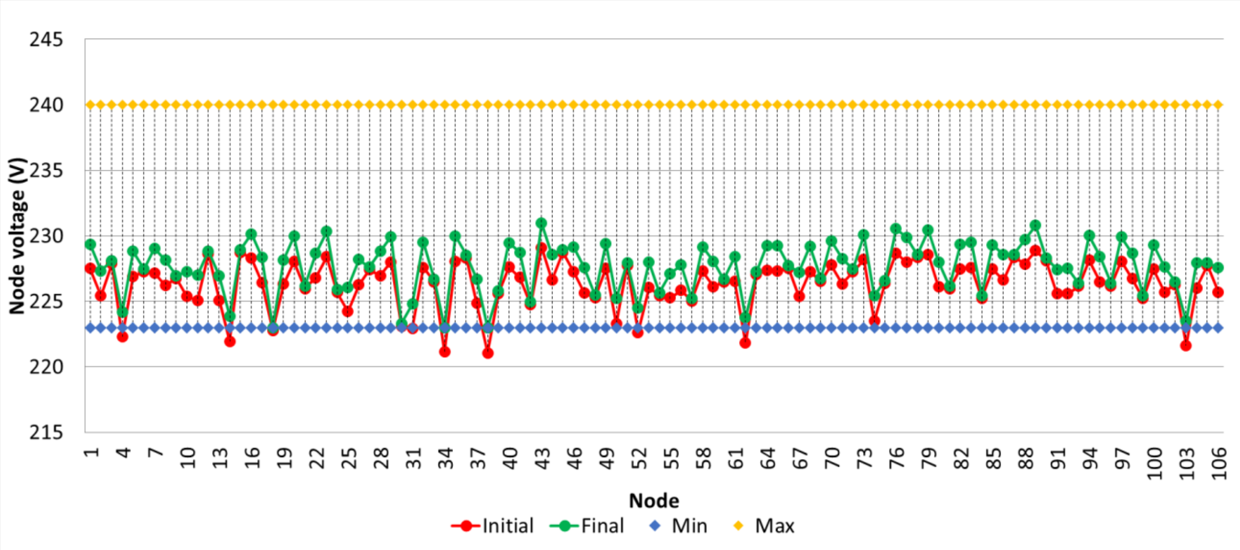


Figure 3-18 – Comparison between initial and final voltage values for one grid (id: SS_INSTALLATION_440) and one timestamp (2023-12-12 08:30:00) using the flexibility areas and needs method.

3.1.6.1 N-SIDE Flexibility Market Results

Considering the flexibility needs determined, the flexibility areas were submitted to N-SIDE Flexibility Market and CENTRICA submitted the flexibility offers. The total offers submitted and cleared in N-SIDE market for the 12/12/2023 are presented in Table 3-14.

Table 3-14 – Aggregated flexibility bids submitted and cleared by N-SIDE Flexibility Market Platform for the 12-12-2023.

Client ID	Orders_Nside (kW)	Trades_Nside (kW)
MV_CLIENT_221	250	95
MV_CLIENT_261	12,5	0
NLV_CLIENT_1029	7,5	2,074
NLV_CLIENT_1042	7,5	0
NLV_CLIENT_301	14	0,822
NLV_CLIENT_387	14	0
NLV_CLIENT_389	7,5	0,193
NLV_CLIENT_597	14	2,438
NLV_CLIENT_643	10	1,107
Sum Low Voltage	74,5	6,634
Sum Medium Voltage	262,5	0,095

Regarding the flexibility areas submitted for SS_INSTALLATION_440, Table 3-15 summarizes the flexibility offers and trades for the identified areas.

Table 3-15 – Flexibility offers and cleared bids on N-SIDE Market Platform for the 12-12-2023 08:30:00.

Area	Clients	Need (kW)	Orders_Nside (kWh)	Order Price (€/kW)	Trades_Nside (kWh)	Trade Price (€/kW)
17	NLV_CLIENT_1174	-0,021	-	-	-	-
33	NLV_CLIENT_643	-0,186	1	1,17	0,0853	1,17
37	NLV_CLIENT_183	-0,193	-	-	-	-

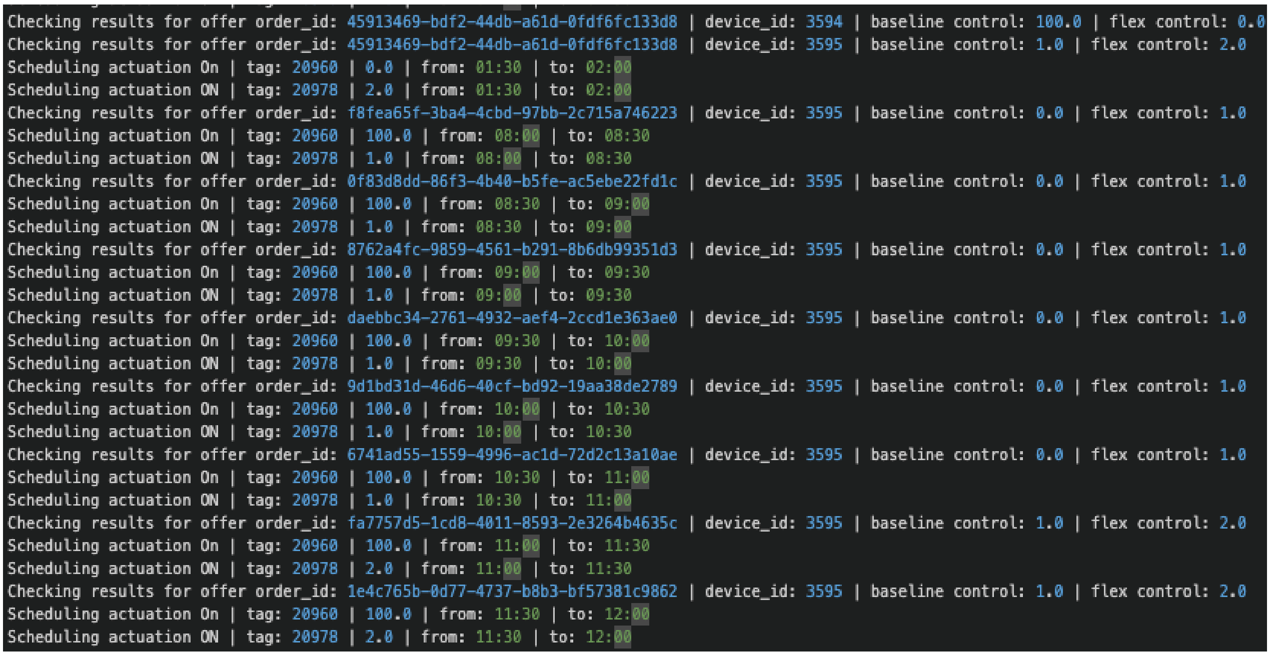
In Évora, flexibility areas within the MV network were calculated. Table 3-16 presents a summary of the required flexibility, whether it's demand response or increased generation, to address the grid issue mentioned in the preceding section.

Table 3-16 - Flexibility area needs for the 12-12-2023 13:30:00.

Area	Grid	Need (kW)
30	Évora	31

For the N-SIDE market, on the 11th of December, the total amount of flexibility offered was 337 kWh. 6.7 kWh were accepted, which is about 2% of the offered flexibility. Due to the low amount of flexibility requested, it was decided not to activate the flexibility from LV consumers.

The logs of the disaggregation service are shown in Figure 3-19 for a given device of the participants. This service compares the schedules stored in the database with the results from the market clearing and creates new actuations for each device accordingly. The steering of the actuations was successfully tested between Cleanwatts and Centrica.



```
Checking results for offer order_id: 45913469-bdf2-44db-a61d-0fdf6fc133d8 | device_id: 3594 | baseline control: 100.0 | flex control: 0.0
Checking results for offer order_id: 45913469-bdf2-44db-a61d-0fdf6fc133d8 | device_id: 3595 | baseline control: 1.0 | flex control: 2.0
Scheduling actuation On | tag: 20960 | 0.0 | from: 01:30 | to: 02:00
Scheduling actuation ON | tag: 20978 | 2.0 | from: 01:30 | to: 02:00
Checking results for offer order_id: f8fea65f-3ba4-4cbd-97bb-2c715a746223 | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 08:00 | to: 08:30
Scheduling actuation ON | tag: 20978 | 1.0 | from: 08:00 | to: 08:30
Checking results for offer order_id: 0f83d8dd-86f3-4b40-b5fe-ac5ebe22fd1c | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 08:30 | to: 09:00
Scheduling actuation ON | tag: 20978 | 1.0 | from: 08:30 | to: 09:00
Checking results for offer order_id: 8762a4fc-9859-4561-b291-8b6db99351d3 | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 09:00 | to: 09:30
Scheduling actuation ON | tag: 20978 | 1.0 | from: 09:00 | to: 09:30
Checking results for offer order_id: daebbc34-2761-4932-aef4-2ccd1e363ae0 | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 09:30 | to: 10:00
Scheduling actuation ON | tag: 20978 | 1.0 | from: 09:30 | to: 10:00
Checking results for offer order_id: 9d1bd31d-46d6-40cf-bd92-19aa38de2789 | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 10:00 | to: 10:30
Scheduling actuation ON | tag: 20978 | 1.0 | from: 10:00 | to: 10:30
Checking results for offer order_id: 6741ad55-1559-4996-ac1d-72d2c13a10ae | device_id: 3595 | baseline control: 0.0 | flex control: 1.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 10:30 | to: 11:00
Scheduling actuation ON | tag: 20978 | 1.0 | from: 10:30 | to: 11:00
Checking results for offer order_id: fa7757d5-1cd8-4011-8593-2e3264b4635c | device_id: 3595 | baseline control: 1.0 | flex control: 2.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 11:00 | to: 11:30
Scheduling actuation ON | tag: 20978 | 2.0 | from: 11:00 | to: 11:30
Checking results for offer order_id: 1e4c765b-0d77-4737-b8b3-bf57381c9862 | device_id: 3595 | baseline control: 1.0 | flex control: 2.0
Scheduling actuation On | tag: 20960 | 100.0 | from: 11:30 | to: 12:00
Scheduling actuation ON | tag: 20978 | 2.0 | from: 11:30 | to: 12:00
```

Figure 3-19 – Snapshot of the logs of the disaggregation thread.

3.1.6.2 Trading results from Nodes Short-Flex Flexibility Market

At 14:20 DSO tools, namely the DdVC and the MV Flexibility Scheduling Tool receive the bids submitted to NODES Flexibility Market and compute the optimal selection.

As an example, from the bids received for the 12/12/2023, the DdVC selected for the voltage constraints detected at MV/LV substation 440 at 17:00 the flexibility provided by NLV_CLIENT_643, as described in Table 3-17.

Table 3-17 – Bids selected to solve grid violations for one grid (id: SS_INSTALLATION_440) and one timestamp (2023-12-12 08:30)

Client	Flexibility bid selected (kW)	Orders_Nodes (kW)	Order Price (€/kW)	Trades_Nodes (kW)	Trade Price (€/kW)
NLV_CLIENT_643	-0,193	-	-	1	1.17

In the case of Mafra, concerning the bids received for 12/12/2023, the MV FST opted to utilize the flexibility offered by MV_CLIENT_208 and MV_CLIENT_71 (generation curtailment) at 11:00 AM due to identified voltage constraints at MV buses. Detailed information is provided in Table 3-18.

Table 3-18 – Bids selected to solve grid violations within Mafra grid at the timestamp (2023-12-12 11:00 AM)

Client	Flexibility bid selected (kW)	Orders_Nodes (kW)	Order Price (€/kW)	Trades_Nodes (kW)	Trade Price (€/kW)
MV_CLIENT_208	-151	500 (Down)	1	117 (Down)	1
MV_CLIENT_71	-570	1000 (Down)	1	442 (Down)	1

The total offers submitted and cleared in NODES market platform for the 12/12/2023 are presented in Table 3-19.

Table 3-19 – Aggregated flexibility bids made and bought flexibility by Nodes on 11/12/2023 for the next day 12-12-2023.

Client ID	Orders_Nodes (kW)	Trades_Nodes (kW)	Trade Price (€/kW)	Order Price (€/kW)
MV_CLIENT_414	50			1,000
MV_CLIENT_221	500	75	1,000	1,000
MV_CLIENT_465	430			1,000
MV_CLIENT_208	2000	117	1,000	1,000
MV_CLIENT_451	1000			1,000
MV_CLIENT_71	4000	442	1,000	1,000
NLV_CLIENT_387	14			1,174
NLV_CLIENT_1042	7,5			0,429
NLV_CLIENT_1029	7,5			0,429
NLV_CLIENT_643	19,5	1	1,17	1,602
NLV_CLIENT_301	14			1,174
NLV_CLIENT_597	14			1,174

3.1.7 Portuguese demo main results

As shown by the results presented in section 3.1, the BUC related with the day-ahead congestion and voltage management in MV and LV networks were successfully tested. However, the implementation and test of full timeline revealed a complex and time-consuming process, considering that the success of all steps depend on obtaining adequate results and data from previous steps. The initial testing of the Data Exchange Platform started around May 2023, being followed by the deployment of the DSO tools around June 2023 and finally testing of data exchange with Flexibility Market Platforms and Aggregation Platform. End-to-end testing of BUC was only possible during November, and were extended until the 19/12/2023.

Table 3-20 and Table 3-21 summarize the results obtained from 11-12-2023 to 19-12-2023, where it was possible to run the full timeline for the Portuguese pilot, from technical constraint identification to market clearing and activation, using the two Flexibility Market Platforms. Table 3-20 presents the total flexibility orders submitted to N-SIDE and NODES platform as well as the flexibility cleared. As described previously (see

Table 2-2), in the case of the MV and LV networks connected to Évora HV/MV substation the flexibility resources are common to both market platforms.

Table 3-20 – Portuguese demo results obtained for a reference demo week from 11-12-2023 to 19-12-2023.

	N-SIDE Flexibility Market Platform		NODES Flexibility Market Platform	
	Total flexibility orders (kW)	Total flexibility traded (kW)	Total flexibility offered (kW)	Total flexibility traded (kW)
MV_CLIENT_208			14000	387
MV_CLIENT_221	3500	385	3500	436
MV_CLIENT_261	175			
MV_CLIENT_414			350	
MV_CLIENT_451			7000	
MV_CLIENT_465			3010	
MV_CLIENT_71			28000	1.462
NLV_CLIENT_1029	52.5	9.157	52.5	
NLV_CLIENT_1042	52.5		52.5	
NLV_CLIENT_301	98	3.972	98	
NLV_CLIENT_387	98		98	
NLV_CLIENT_389	52.5	0.657		
NLV_CLIENT_597	98	14.772	98	
NLV_CLIENT_643	136.5	5.947	136.5	

Table 3-21 – Summary of the flexibility trades obtained in the Portuguese demo for a reference demo week.

	N-SIDE Flexibility Market Platform			NODES Flexibility Market Platform		
	Total flexibility offered (kW)	Total flexibility traded (kW)	Flex Traded/Flex Offered	Total flexibility offered (kW)	Total flexibility traded (kW)	Flex Traded/Flex Offered

LV networks	588,00	34,51	5,868%	535,50	0,00	0,000%
MV networks	3675,00	390	9.3%	3262.5	450	13.8%

3.1.8 CM_KPI_1 Flexible capacity vs. flexible volume offered ratio

The main objective of CM_KPI_1 is to quantify the ratio between total registered flexibility capacity and the amount of flexibility that FSP offers via the market platform. The total flexibility capacity provided by the MV and LV participants is described in Table 3-21. Considering that the flexibility offers correspond to the flexibility capacity, the KPI_1 obtained is 100%. This is not expected in a real life scenario, considering that technical capacity of consumers flexible resources (e.g. energy storage units, electric water heaters, heat pumps, EVs) may not be available due to consumer preferences and energy consumption forecast.

Table 3-22 – Summary of the total flexibility capacity of MV and LV participants.

	Flexibility capacity (kWh)
MV total	56035
LV total	294
Total	56329

3.1.9 CM_KPI_2 Volume of mobilised flexibility

This KPI aims to quantify to which extent the market has been able to cover the flexibility requests from the grid operators with flexibility offers from the FSPs. The ratio of delivered flexibility and flexibility bid accepted by DSO. Table 3-23 summarizes the results obtained for a week, where it was possible to run the full timeline for the Portuguese pilot, from technical constraint identification to market clearing and activation.

Table 3-23 – CM_KPI_2 results obtained for a reference demo week.

	N-SIDE Flexibility Market Platform			NODES Flexibility Market Platform		
	Total flexibility offered (kWh)	Total flexibility traded (kWh)	KPI	Total flexibility offered (kWh)	Total flexibility traded (kWh)	KPI
LV networks	588,00	34,51	1704%	535,50	0,00	0
MV networks	3675,00	385,3	954%	55860	2285	24,4%

The results obtained show that flexibility offers covered all flexibility needs. In the case of NODES platform, as flexibility needs are not known prior to the submission of the bids, the total flexibility offered is typically higher than the cleared, leading to a lower KPI. As expected, this results from the low number of flexibility constraints simulated considering the demo networks have sufficient capacity to meet the loads. In some specific cases it was also observed a mismatch between the offers and needs, considering that offers are presented for periods of the day where there aren't grid constraints. Therefore, conclusions on the flexibility adequacy should not be taken by the results of this KPI, but also looking to the obtained results per hour of the day and the number of constraints forecasted.

3.1.10 CM_KPI_3 Flex volume delivered by FSP vs. Flex bids accepted by DSO

This KPI aim is to quantify is FSP can deliver the amount of flexibility which was offered on the market platform. The KPI measures the ratio of delivered flexibility and flexibility bid accepted by DSO. Within the Portuguese demonstrator, the calculation method of CM_KPI_3 was maintained as initially defined. However, due to the limited results obtained for the LV networks, no significant results were obtained for calculating the KPI for LV network flexibility procurement. As described in Table 3-24, all MV flexibility cleared in the market was activated. In fact, the capacity offered by the participants exceed the flexibility contracted and activated.

Table 3-24 – Portuguese demo results of CM_KPI_3.

FSP	Flexibility capacity (kW)	KPI
MV_CLIENT_208	387	100%
MV_CLIENT_221	385.3	100%
MV_CLIENT_71	1462	100%
MV total	2234,3	100%

The results obtained are limited by the reduced number of flexibility providers, supplying in some cases insufficient flexibility to solve the detected constraints, or in periods of the day that do not coincide with the forecasted grid constraints. Further testing of BUC 1 and BUC 2 beyond the project timeline would be required to be able to derive more solid conclusions.

3.2 Contracting flexibility services to avoid voltage and/or congestion issues during planned maintenance action in MV grids (PT3)

The main objective BUC PT3 was to demonstrate the participation of market-based flexibility services for the support of maintenance activities. The network operator's traditional approach consists in scheduling the maintenance actions to periods in which the network can be reconfigured without congestions while minimizing the Energy Not Distributed (END). This often implies scheduling the work during weekends or off-peak hours when the maintenance crew's costs are higher. However, this can compromise the service quality.

A methodology was proposed in WP4, to help the DSO to select the most adequate days/hours to perform maintenance, considering first DSO network assets and if necessary available flexibility. The network operator can benefit from the flexibility offered in local flexible markets, to help manage congestion and voltage grid constraints, while increasing the number of viable periods where it's possible to perform maintenance actions, with lower costs and reducing load curtailment. A more detailed description of the tool is provided in deliverable *D4.3* [3].

As shown in Figure 3-20, the use case demonstration involves first the identification of the flexibility needs determined by the tool, that are then submitted to the long-term Flexibility Market. Based on the flexibility requests Centrica submits the offers that are then selected by the DSO. The flexibility is reserved and automatically submitted to the Short-term Flexibility Market.

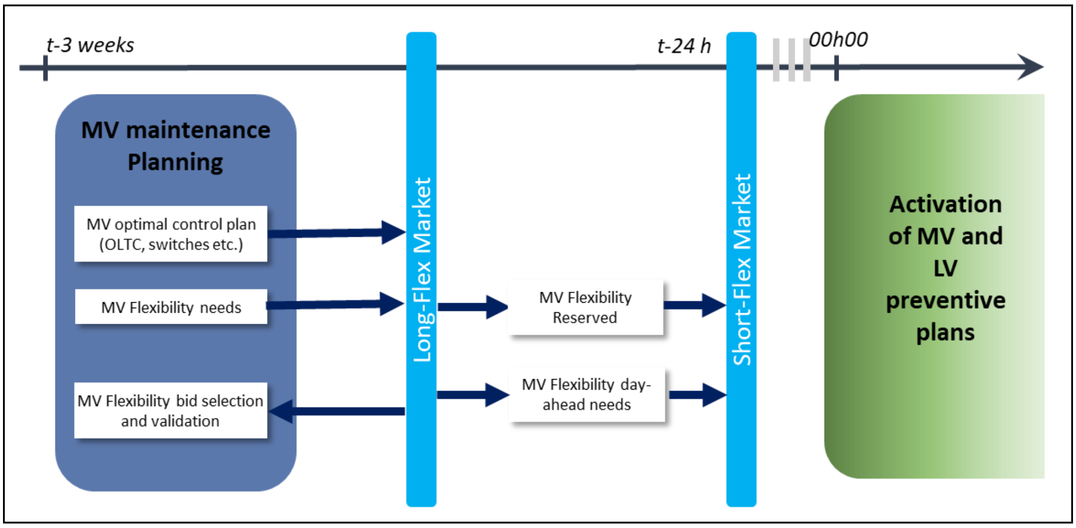


Figure 3-20 – Coordination between long-term and short-term flexibility markets for flexibility procurement.

The following steps were followed to test BUC3:

1. Definition of the maintenance scenario, with the identification of the devices under maintenance and the network reconfiguration plan, following DSO business as usual. Identification of the relevant period for maintenance. In this case the month of November was considered.
2. Identification of maintenance planning options with identification of flexibility needs, considering load and generation historical data from previous year. Ideally forecast should be considered.
3. Submission of flexibility requests in the Long-Term Flexibility Market Platforms from NODES for the viable periods identified by the tool. The tool provides more than one possible period for performing maintenance.
4. In the case of NODES platform, the flexibility offers will be collected and selected considering cost and network technical constraints.
5. The cleared bids are collected from the Market Platforms for technical validation.

To support the demonstration of the BUC, the maintenance planning tool was run offline to define the flexibility needs for a set of defined planned maintenance actions. As outputs the tool provides:

- Switches opened to isolate the maintenance area.
- Deactivated area.
- Schedule- staring time.
- Energy not Distributed (END): Loads that were not energized with new topology.
- Contracted flexibility –by nodes (as in the case of Flexibility Market Platform)
- Flexibility cost.

The results obtained during demonstration are described below.

3.2.1 Identification of Long-term flexibility needs for network maintenance support

3.2.1.1 Definition of maintenance plan

For the demonstration of this use case, two MV networks, namely Évora and Mafra, were considered. The scenario considered involved a maintenance operation with a projected duration of 5 hours for components across both networks. The analysis focused on the timeframe spanning from the 12th to the 25th of November.

Given the specific nature of the maintenance task, it was deemed imperative that it be conducted during daylight hours. Consequently, the maintenance window was confined to the period between 9 a.m. and 7 p.m. to ensure optimal visibility and operational conditions, as well as weekdays, when maintenance crew has more availability and lower costs.

The details of the maintenance and network reconfiguration plan during the work are described in Table 3-25.

Table 3-25 – Maintenance plan details for Évora and Mafra MV networks.

Network	Maintenance item	Opened devices for isolation	Reconfiguration	
Évora	Extract circuit breaker	circuit breaker 842373	Closed	SECC 90991033, INTR 90942355, INTR 90945839, INTR 90946087, INTR 90946623, INTR 398754759, INTR 778412668
			Opened	INTR 90942563, INTR 90947175, INTR 192144606, SECC 90996425, SECC 90998153, DISJ 796865351
Mafra	LINE 225351537	OCR2 N01658	Closed	INTR 24849398, INTR 62147860, INTR 249294460, INTR 404241791, DISJ 33273913
		OCR2 N01659	Opened	INTR 33251815, INTR 249425269, INTR 227316329, INTR 1115369620

A simplified diagram of the relevant MV feeders of Évora network before and during maintenance is represented in Figure 3-21 and Figure 3-22. In the Évora network, it was assumed that the circuit breaker 842373 needed to be taken out for repair. When isolating this device, a feeder of the network becomes disconnected, impacting several MV and LV clients, including flexibility providers (see Figure 3-21). The network can be reconfigured through line 16214, by switching on SECC 90991033, resulting in the reconnection of all previously mentioned clients (see Figure 3-22). To reconnect all clients without voltage problems and lines overflows some clients must be allocated to other feeders of the same substation.

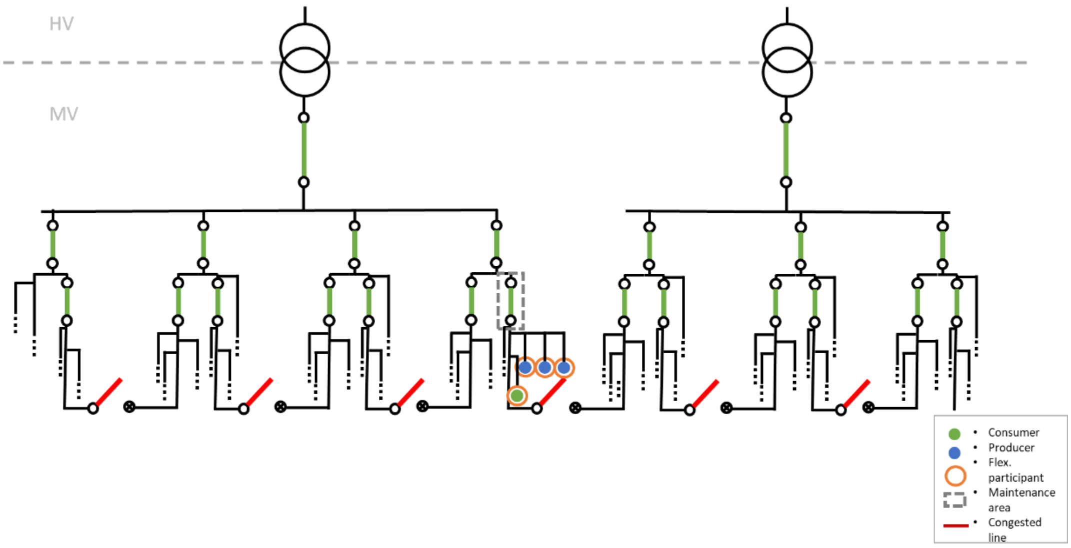


Figure 3-21 – Évora network diagram during normal operation.

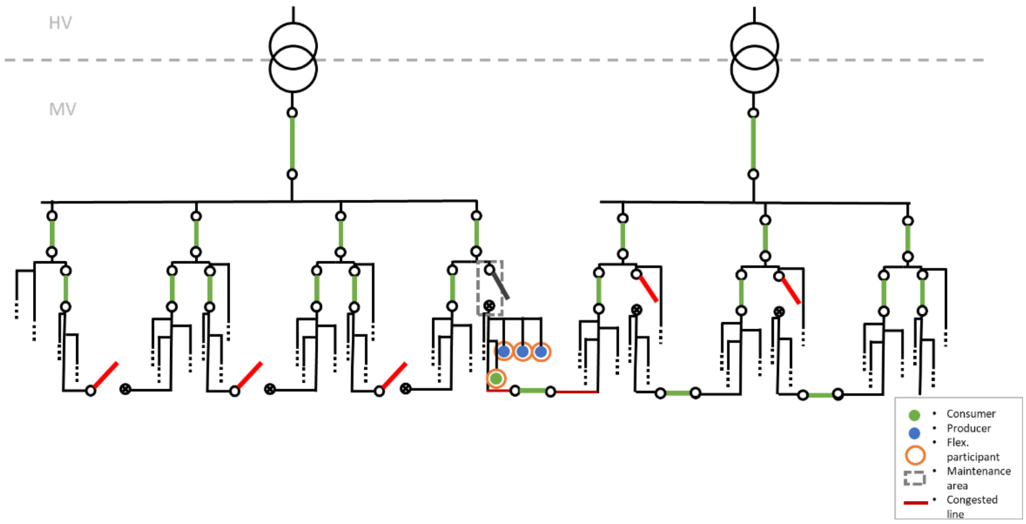


Figure 3-22 – Évora network diagram during maintenance actions.

In the Mafra network, a maintenance action on line 225351537 implies the opening of both N01659 and N01658 OCRs. The simplified diagrams of the relevant MV feeders of Mafra network before and during maintenance are represented in Figure 3-23 and Figure 3-24. To avoid congestion, some clients had to be moved to adjacent feeders, implying a reconfiguration of all the network.

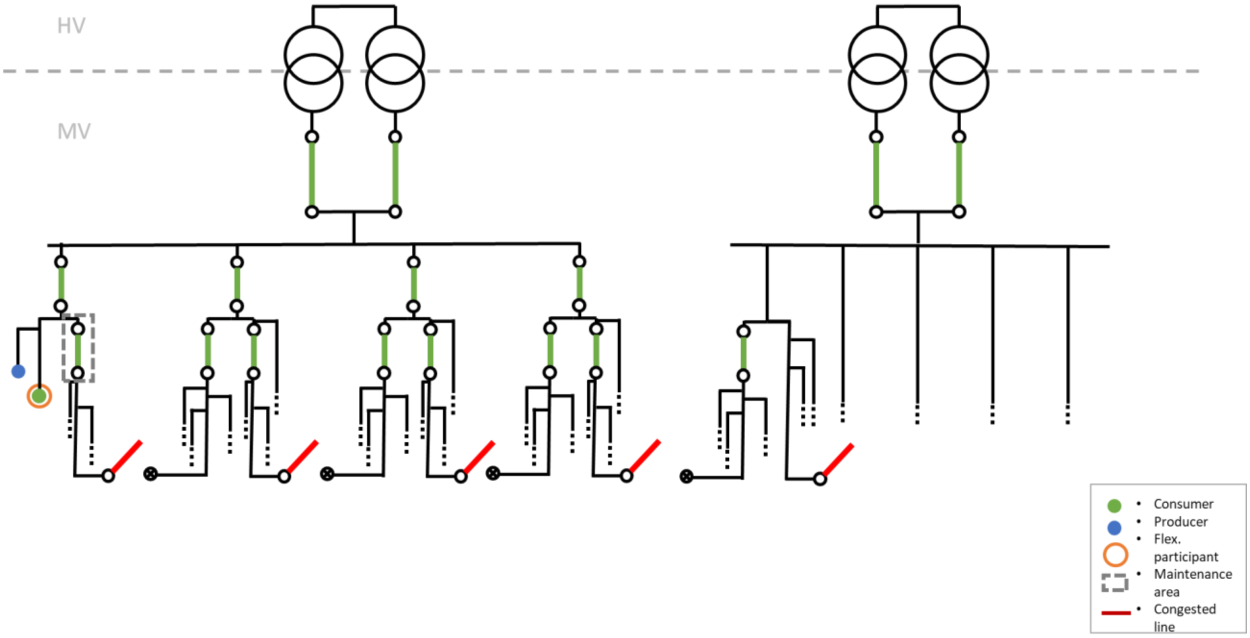


Figure 3-23 – Mafra network diagram during normal operation

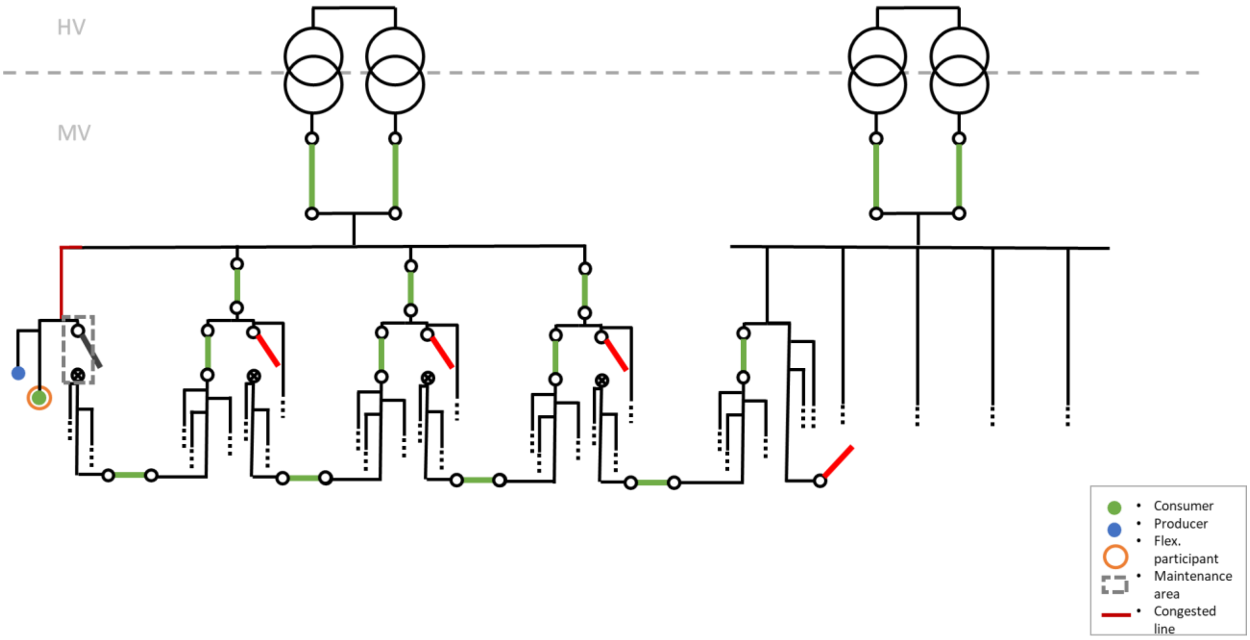


Figure 3-24 – Mafra network diagram during maintenance actions.

An assessment confirmed that both networks exhibited ample redundancy. Consequently, they demonstrated an ability to reconfigure and operate without any technical limit's violations during the maintenance actions. To illustrate the proposed methodology, the capacity of one line in each network was reduced, so that the networks would present overloads in some periods of the studied days, as in Table 3-26.

Table 3-26 – Network changes for demonstration purposes.

Network	Line	Original capacity (MW)	Diminished capacity (MW)
Évora	MV_LINE_16214	5.689787	1.079787
Mafra	MV_LINE_3436	6.270024	4.489

The modified line in Évora is open during normal operations but serves as a connection for clients during maintenance activities. In the Mafra network, the line with reduced capacity is upstream of the maintenance area. During maintenance, this line will remain connected to certain clients, including a producer that also functions as a flexibility provider, and the power injected by this producer will flow upstream, contrary to its usual downstream direction in normal operation.

3.2.1.2 Schedule of maintenance activities and flexibility services

Following the methodology outlined in Deliverable 4.3 [3], the first step involves identifying at least two time slots for conducting maintenance actions, from the 5 working days. The analysis focused on the timeframe spanning from the 12th to the 25th of November, considering a 5-hour maintenance period for both networks.

Figure 3-25 and Figure 3-26 illustrate the END throughout the studied week. Notably, in both networks, the time slots with the lowest END (sustained for five consecutive hours) are observed on Thursdays (Figure and Figure).

In Évora the first time slot starts at 9 a.m. and lasts until 1.59 p.m., and the second starts at 10 a.m. and lasts until 2.59 p.m. In Mafra the first time slot starts at 10, and lasts until 2.59, and the second is from 11 a.m. to 3.59 p.m.

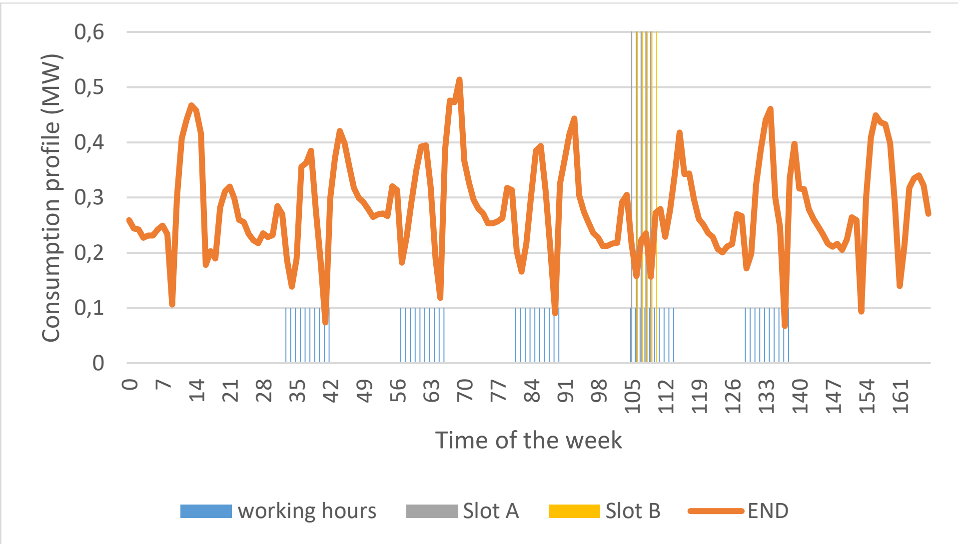


Figure 3-25 – Évora END

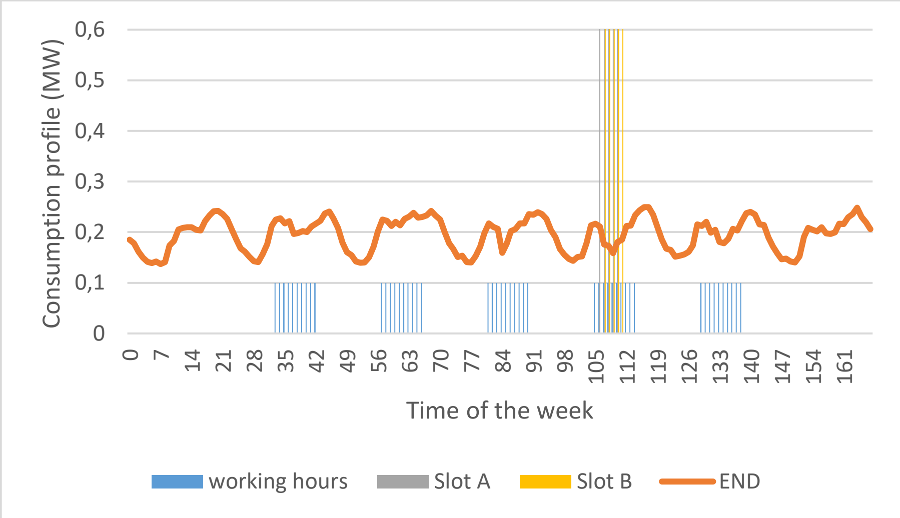


Figure 3-26 – Mafra END

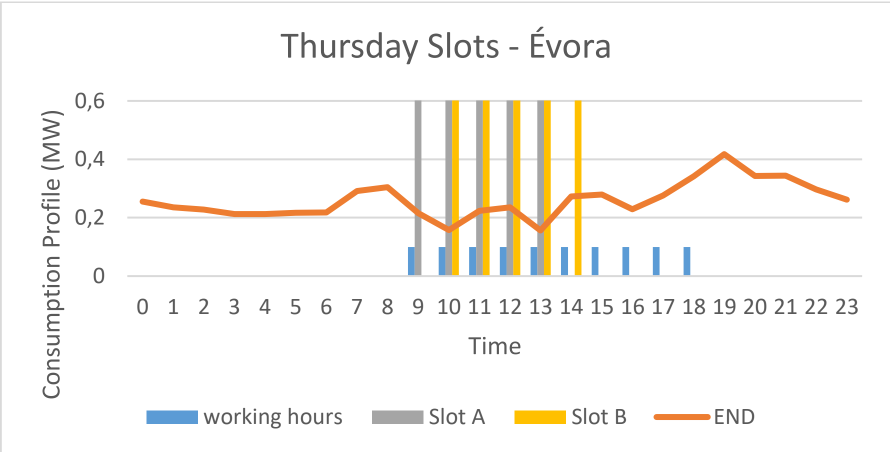


Figure 3-27 – Évora time slots selected on Thursday.

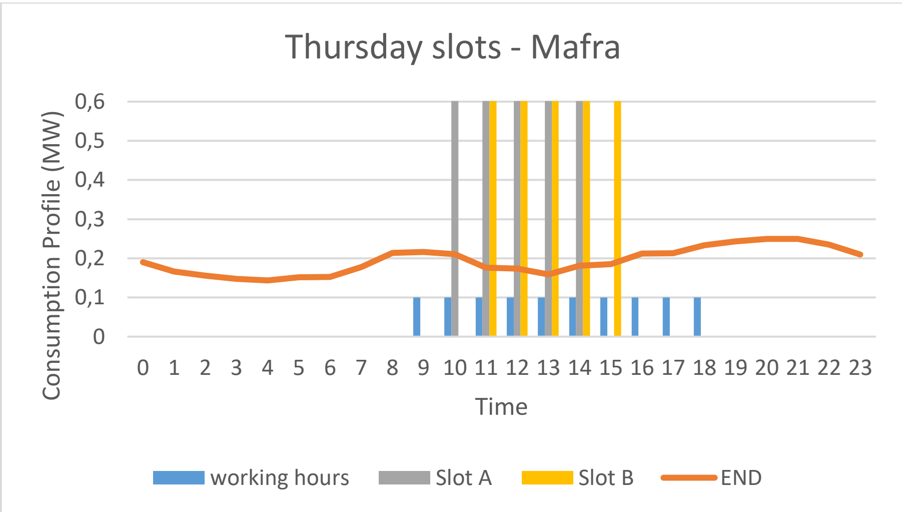


Figure 3-28 – Mafra time slots selected on Thursday.

Upon the selection of initial suitable time slots for conducting maintenance activities, the network reconfiguration solutions were determined. Both networks exhibit congestion in specific lines, mentioned in Table 3-26, during certain periods, necessitating the procurement of flexibility.

In Évora, congestions are foreseen at 11 a.m. and 12 p.m., which means that despite the time slot we choose (starting at 9 a.m. or 10 a.m.), it will always be necessary flexibility in two periods (11 a.m. and 12 a.m.).

In Mafra, overflows occur at 10 a.m., 11 a.m., 12 p.m., 2 p.m., and 3 p.m. Figure 3-28 visually represents the time slots chosen for Mafra network, with one starting at 10 a.m. until 1:59 p.m. and another from 11 a.m. to 2:59 p.m. Notably, flexibility contracting is required only at 10 a.m. or 2 p.m, once these periods don't belong to the same time slot.

Table 3-27 and Table 3-28 outline the flexibility necessary to solve congestions during the identified periods. In Évora it is required that the producer MV_CLIENT_221 reduces its injection in the node, in which the consumer MV_CLIENT_42 is also connected. For Mafra the flexibility is required from the producer with the code PTC MV_CLIENT_71, by reducing its injection on the node, noting that the node balance depends also on the consumer MV_CLIENT_357.

Table 3-27 – Évora flexibility needs.

Time	11:00	12:00
Node injection	1618	1311
Reduction	68	331
Max. Inj. (kW)	1550	980

Table 3-28 – Mafra flexibility needs.

Time	10:00	11:00	12:00	14:00	15:00
Node injection	4170	4960	4490	4350	4060
Reduction	468	588	89	828	678
Max. Inj. (kW)	3702	4372	4401	3522	3382

3.2.2 Procurement of long-term flexibility for network maintenance support – LongFlex - Nodes Platform

Based on the flexibility needs identified, the DSO submitted the flexibility request on NODES Long-Flex platform on the 13th of November for the procurement of flexibility in two alternative dates, the 16th and the 23rd of November. Centrica submitted the flexibility offers on the 15th of November.

3.2.2.1 Évora Long-Flex market results

Table 3-29 summarizes the flexibility requests submitted to NODES Long-Flex Market for Évora network.

In this given scenario, both time slots, commencing at 9 a.m. and 10 a.m., exhibit identical flexibility requirements of 399 kW, incurring a cost of €71.42. Consequently, the economic implications of opting for either time slot are equivalent. However, selecting the 9 a.m. slot offers the advantage of a possibility for maintenance period extension, allowing it to extend beyond the initial 5 hours until 2:59 p.m. – the conclusion of the second time slot – without introducing further impacts on the network.

Considering the uniformity in costs and flexibility needs across both time slots on both days, the decision between them holds inconsequential significance.

Table 3-29 – Summary of Flexibility requests submitted to NODES Long-Flex Market for Évora network.

NODES LongFlex Request	DAY	Start	Duration	Production Power Down	Cost/MW	Centrica's BID
BUC3 EVORA	16th and 23rd nov/23	11h	1h	68 kW	179 € activation 0€ availability	Received and Accepted
		12h	1h	331 kW		

3.2.2.2 Mafra Long-Flex market results

Table 3-30 summarizes the flexibility requests submitted to NODES Long-Flex Market for Mafra network. In this specified network, for both November 16th and 23rd, the time slot starting at 10 a.m. demands a total flexibility of 1976 kW, incurring a combined cost of €2170.

Notably, on November 23rd, there was no correspondence for the required flexibility within the 11 a.m. time slot, indicating its availability solely on November 16th. This specific time slot on the 16th necessitates a total flexibility of 2185 kW, with associated costs €2934.

Considering the cost differentials, the time slots starting at 10 a.m. emerge as the more economical choice. Opting for the 10 a.m. slot on November 16th is particularly advantageous since, in the event of unforeseen circumstances prolonging the maintenance, subsequent time slots on the same day remain available. This approach ensures flexibility and adaptability in managing the maintenance schedule.

Table 3-30 – Summary of Flexibility requests submitted.

NODES LongFlex Request	DAY	Start	Duration	Production Power Down	Cost/MW	Centrica's BID
BUC3 MAFRA 16 NOV 10h	16/nov/23	10h	1h	469 kW	1098 € activation	Received and Accepted
		11h	1h	588 kW	0€ availability	
		12h	1h	90 kW		
		14h	1h	829 kW		
BUC3 MAFRA 16 NOV 11h	16/nov/23	11h	1h	588 kW	1343 € activation	Received and Accepted
		12h	1h	90 kW	0€ availability	
		14h	1h	829 kW		
		15h	1h	678 kW		
BUC3 MAFRA 23 NOV 10h	23/nov/23	10h	1h	469 kW	1098 € activation	Received and Accepted
		11h	1h	588 kW	0€ availability	
		12h	1h	90 kW		
		14h	1h	829 kW		
BUC3 MAFRA 23 NOV 11h	23/nov/23	11h	1h	588 kW	1343 € activation	Received but starts and ends earlier
		12h	1h	90 kW	0€ availability	
		14h	1h	829 kW		
		15h	1h	678 kW		

3.3 Congestion Management for medium and long-term grid planning through market mechanisms (PT4)

The main objective of BUC 4 is to demonstrate the participation of market-based flexibility services to support network investment planning and evaluate if it can be considered an alternative to grid reinforcement. The following steps were followed to test BUC4:

1. Defining long-term flexibility needs for investment deferral.
2. Quantification of maximum flexibility bid cost, that DSO is willing to pay.
3. Submission of flexibility requests in the Long-Term Flexibility Market Platforms from NODES.
4. Selection of flexibility offers by the DSO.
5. The bids cleared are then automatically submitted to the Short-term Flexibility market.

For the identification of flexibility needs the methodology described in Figure was followed. Two different analyses were performed:

- First analysis for defining the demonstration scenarios, considering a 3 year ahead horizon. The results obtained were the flexibility needs quantification for submitting to the Flexibility market. Results obtained are described in section 3.4.1.1.
- A second analysis was performed considering an 11-year period, typically used to plan network reinforcement investments. The main objective was to analyse the impact of flexibility procurement in investment postponement and determining related KPI. Results obtained are described in section 3.4.1.2 and resulting KPIs explained in 3.4.3.

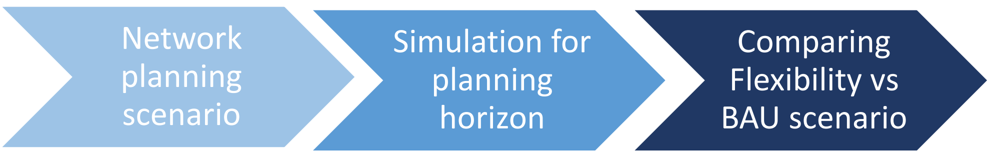


Figure 3-29 – Methodology for the identification of long-term flexibility needs.

To determine flexibility needs, first it was necessary to define network planning scenarios, considering historical information from loads and defining rate of load and generation increase. To test the BUC, the load increase rate was defined to force grid constraints, as explained in more detail below. For the planning scenarios defined grid constraints are identified per year and flexibility needs are computed.

The flexibility requests submitted and clearing results for the Long-term Flexibility market are described in section 3.4.2.

3.3.1 Identification of Long-term flexibility needs

The applicable demo cases are Évora and São Francisco (Alcochete) MV networks, in accordance with

Table 2-2. These are two 15 kV distribution networks operated in radial mode. In both cases, the existing grids were operating below their nominal capacity and the grid's buses operating well within acceptable voltage limits. Thus, to investigate the way in which flexibility could assist each system, it was necessary to worsen the operating conditions considerably.

In the case of Évora, this was done by increasing the system's total load until technical voltage violations (undervoltages) started to occur. This corresponded to an increase of 1.34 times the original load. In the case of São Francisco, increasing the system's load was not practicable, as the flexibility providers were located too far away from the buses with voltage magnitude problems and, therefore, could not help restoring their normal values. In alternative, a distribution cable was chosen to be downgraded, i.e. to have its loading limits reduced, so that an artificial congestion problem could be simulated, as well as quantify the flexibility needed to help solve the grid constraint.

To determine the flexibility needs, a full AC Optimal Power Flow (AC-OPF) was adopted, so that the methodology shown in Figure 3-29 could be implemented. In each node where flexibility is available, the existing flexibility is modelled through an equivalent generator that can either provide or absorb both active and reactive power. Thus, for each considered operation time-period, the generation capability of any of these "flexible generators" is limited by the amount of flexibility offered in the market by all the flexibility providers connected to that generator's corresponding node. The number of equivalent generators in the grid will therefore depend on the number of existing flexibility providers, as well as their geographical location within the grid, with the maximum number of equivalent generators equaling the number of grid nodes.

The equivalent generators will only operate if flexibility is required to maintain the system operating within safe limits. Otherwise, they will not operate, as their generation cost is much higher than supplying the load directly from the primary HV/MV substation. For example, if several undervoltages occur, the equivalent generators will inject power into the grid, to emulate load curtailment. However, if the available flexibility within the grid is not enough to eliminate the existing technical violations, then it will be necessary to reinforce the grid, either by replacing existing lines/cables or by building new circuits.

3.3.1.1 Flexibility needs for the demo cases

In this first analysis a 3-year period was considered. Results obtained for Évora and Alcochete MV networks are presented below.

3.3.1.1.1 Évora grid

Table 3-31 shows the results that were obtained for the Évora grid in the first two years of the planning horizon. Only actual flexibility providers, i.e. only the ones that indeed participated in the demonstration, were included.

Table 3-32 also includes the fractions $P_{curtailed}/P_{load}$ and $Q_{curtailed}/Q_{load}$, corresponding to the portion of the total flexible load that was curtailed in each *bus*. In each simulation *hour*, there is a certain number of flexibility providers that are required to reduce their loads at their respective connection *bus*. While some providers only contribute with a fraction of their total dispatchable load, others have to deliver 100% of their flexibility.

As the planning horizon advances, the system load increases, and more hours start presenting technical violations, with more flexibility providers being called to curtail their active and reactive power. Eventually, a situation is reached in which the flexibility can no longer eliminate the grid's problems (red colored values). At this point, the only way to eliminate the existing technical violations is by reinforcing the distribution grid.

Table 3-31 – Évora flexibility needs for year n-1 and year n.

	date	time	bus	$P_{curtailed}$ (MW)	$Q_{curtailed}$ (Mvar)	P_{load} (MW)	Q_{load} (Mvar)	$P_{curtailed}$ /P_{load}	$Q_{curtailed}$ /Q_{load}
Year 0	14/jul	17 h	512	0	0.2221	0.2774	0.2814	0%	78.9%
			1451	0.0090	0.0040	0.0090	0.0040	100.0%	100.0%
			1452	0.0052	0.0023	0.0053	0.0023	100.0%	100.0%
	15/jul	16 h	1452	0.0052	0	0.0118	0.0023	44.6%	0%
Year 1	14/jul	16 h	1451	0.0002	0.0003	0.0091	0.0041	1.7%	8.5%
			1452	0.0053	0.0024	0.0053	0.0024	100.0%	100.0%
	14/jul	17 h	512	0.1450	0.2842	0.2802	0.2842	51.7%	100.0%
			1451	0.0091	0.0041	0.0091	0.0041	99.9%	100.0%
			1452	0.0053	0.0024	0.0053	0.0024	99.9%	100.0%
	15/jul	16 h	512	0.1450	0.0486	0.3235	0.2274	44.8%	21.4%
			1451	0.0091	0.0041	0.0091	0.0041	100.0%	100.0%
			1452	0.0053	0.0024	0.0053	0.0024	100.0%	100.0%

Table 3-32 – Évora flexibility needs for year n+1.

	date	time	bus	$P_{curtailed}$ (MW)	$Q_{curtailed}$ (Mvar)	P_{load} (MW)	Q_{load} (Mvar)	$P_{curtailed}$ /P_{load}	$Q_{curtailed}$ /Q_{load}
Year 2	13/jul	20 h	1451	0.0076	0.0000	0.0092	0.0041	83.2%	0.5%
			1452	0.0054	0.0024	0.0054	0.0024	100.0%	99.7%
	14/jul	16 h	512	0.3067	0	0.3144	0.2515	97.5%	0%
			1451	0.0092	0	0.0184	0.0092	49.9%	0%
			1452	0.0053	0	0.0120	0.0054	44.5%	0%
	14/jul	17 h	512	0.2822	0.2874	0.2830	0.2871	99.7%	100.1%
			1451	0.0096	0.0045	0.0092	0.0041	104.4%	110.5%
			1452	0.0058	0.0028	0.0054	0.0024	107.4%	118.0%
	14/jul	19 h	512	0	0.0215	0.3158	0.2980	0%	7.2%
			1451	0.0092	0.0041	0.0092	0.0041	100.0%	100.0%
			1452	0.0054	0.0024	0.0054	0.0024	100.0%	100.0%
	15/jul	16 h	512	0	0.1180	0.3267	0.2296	0%	51.4%
			1451	0.0092	0.0041	0.0092	0.0041	100.0%	100.0%
			1452	0.0054	0.0024	0.0054	0.0024	100.0%	100.0%
	15/jul	19 h	512	0	0.0322	0.2871	0.2119	0%	15.2%
			1451	0.0092	0.0041	0.0092	0.0041	100.0%	100.0%
			1452	0.0054	0.0024	0.0054	0.0024	100.0%	100.0%

date the date to which the *hour* corresponds;
time of day the time, within the given *date*, at which the violation occurred;
bus the bus where the flexibility was mobilized;
$P_{curtailed}$ the amount of flexibility (active power) that was required at *bus*
$Q_{curtailed}$ the amount of flexibility (reactive power) that was required at *bus*
P_{load}, Q_{load} the total load available for flexibility (active and reactive power) at *bus*

3.3.1.1.2 São Francisco (Alcochete) grid

Table 3-33 shows the results that were obtained for the São Francisco grid in the first three years of the planning horizon. Since this grid has no undervoltage problems, only congestion problems, an additional column was added to the table showing the ratio S_{line}/S_{line_max}, which is the loading level of the overloaded line (>100%) before the activation of the flexibility.

Table 3-33 – Alcochete flexibility needs for years n-1 to n+1.

	hour	date	time of day	S_{line}/S_{line_max}	bus	$P_{curtailed}$ (MW)	$Q_{curtailed}$ (Mvar)	P_{load} (MW)	Q_{load} (Mvar)	$P_{curtailed}/P_{load}$	$Q_{curtailed}/Q_{load}$
Year 0	453	19/jan	21 h	100,2%	575	0	0	0.0650	0.0240	0%	0%
					598	0.0053	0	0.0248	0.0091	21.6%	0%
	477	20/jan	21 h	100,5%	575	0	0	0.0700	0.0250	0%	0%
					598	0.0149	0	0.0267	0.0095	55.7%	0%
Year 1	429	18/jan	21 h	100,5%	575	0	0	0.0737	0.0192	0%	0%
					598	0.0144	0	0.0281	0.0073	51.3%	0%
	453	19/jan	21 h	101,2%	575	0.0086	0	0.0657	0.0242	13.0%	0%
					598	0.0250	0	0.0250	0.0092	99.9%	0%
	477	20/jan	21 h	101,6%	575	0.0163	0	0.0707	0.0253	23.1%	0%
					598	0.0269	0	0.0269	0.0096	100.0%	0%
Year 2	429	18/jan	21 h	101,6%	575	0.0144	0	0.0745	0.0194	19.3%	0%
					598	0.0284	0	0.0284	0.0074	100.0%	0%
	453	19/jan	21 h	102,3%	575	0.0370	0	0.0663	0.0245	55.8%	0%
					598	0.0253	0	0.0253	0.0093	100.0%	0%
	477	20/jan	21 h	102,6%	575	0.0449	0	0.0714	0.0255	62.8%	0%
					598	0.0272	0	0.0272	0.0097	100.0%	0%
	621	26/jan	21 h	100,7%	575	0	0	0.0816	0.0235	0%	0%
					598	0.0194	0	0.0311	0.0089	62.5%	0%

As shown in Table 3-33 the planning horizon progresses (and the system's load increases), larger overloads tend to occur more frequently (increasing the nodes and hours where constraints are detected), thus requiring greater flexibility contributions from the providers. Like in the case of Évora, there is a point at which the available flexibility becomes insufficient to meet the system's needs.

Table 3-34 – Alcochete flexibility needs for year n+2.

	hour	date	time of day	S_{line} / S_{line_max}	bus	$P_{curtailed}$ (MW)	$Q_{curtailed}$ (Mvar)	P_{load} (MW)	Q_{load} (Mvar)	$P_{curtailed}$ / P_{load}	$Q_{curtailed}$ / Q_{load}
Year 3	429	18/jan	21 h	102,6%	575	0,0428	0	0,0752	0,0196	56,9%	0%
					598	0,0286	0	0,0286	0,0075	100,0%	0%
	453	19/jan	21 h	103,3%	575	0,0657	0	0,0670	0,0247	98,1%	0%
					598	0,0255	0	0,0255	0,0094	100,0%	0%
	454		22 h	100,7%	575	0	0	0,0598	0,0206	0,0%	0%
					598	0,0187	0	0,0228	0,0078	82,1%	0%
	477	20/jan	21 h	103,7%	575	0,0722	0,0258	0,0721	0,0258	100,1%	100,0%
					598	0,0275	0,0097	0,0275	0,0098	100,2%	99,1%
	478		22 h	100,5%	575	0	0	0,0690	0,0278	0,0%	0%
					598	0,0138	0	0,0263	0,0106	52,5%	0%
	597	25/jan	21 h	100,9%	575	0	0	0,0690	0,0299	0,0%	0%
					598	0,0249	0	0,0263	0,0114	94,6%	0%
	598		22 h	101,0%	575	0	0	0,0752	0,0278	0,0%	0%
					598	0,0281	0	0,0286	0,0106	98,2%	0%
	621	26/jan	21 h	101,7%	575	0,0164	0	0,0824	0,0237	20,0%	0%
					598	0,0314	0	0,0314	0,0090	100,0%	0%

It is important to highlight that the results obtained are strongly dependent on the technical problem detected. In the case of the Évora grid, the issue detected was the occurrence of undervoltages at several of the grid's nodes due to a large increase in the system's load. Eliminating these undervoltages required the participation of several flexibility providers around the affected area.

However, in the case of São Francisco, only the flexibility providers downstream of the congestion could participate in alleviating the overload, as the other participants have no effect on the issue at hand. This is because reducing the load on the buses upstream of the congestion does not reduce the power flow in the overloaded line. Such reduction can only be achieved by acting on the load downstream of the congestion.

3.3.1.2 Distribution planning with flexibility

To determine the benefits of long-term flexibility for the entire planning horizon (11 years), two different planning scenarios have been created: business-as-usual (BAU) and operating with flexibility (EUniversal).

BAU does not include flexibility, which corresponds to a conventional distribution system planning approach. In this case, the technical problems that may arise in the grid, such as undervoltages and branch overloads, can only be solved by reinforcing the network, i.e. by replacing lines/cables or building alternative pathways for supplying the load.

EUniversal, in contrast, includes the possibility of using flexibility to eliminate technical violations occurring at critical hours. This can lead to the postponement of reinforcement investments that would otherwise (i.e. in BAU conditions) must take place for guaranteeing the continuity of the grid's operation in the future. In EUniversal's case, the identification of the distribution network's long-term flexibility needs followed the planning methodology shown in Figure 3-29.

The complete planning exercise also assumes a longer list of flexibility providers. The reason why this extended list was used for the complete planning exercise is twofold: (1) there was an original list of providers for the demonstration, but some of them eventually did not participate; and (2) depending on the problem to be solved and the providers' location in the grid, more participants can sometimes result in an enhanced ability to solve technical problems.

3.3.1.2.1 Évora grid

Table 3-35 shows the results of the reformulated planning exercise for the Évora grid (first two years). These results are not the same as the ones that were previously presented on Table 3-35 because there are now more flexibility providers, scattered through more areas (buses) of the grid.

Table 3-35 – Évora flexibility needs for planning years n-1 and n (EUniversal)

	hour	date	time of day	bus	$P_{curtailed}$ (kW)	$Q_{curtailed}$ (kvar)	P_{load} (kW)	Q_{load} (kvar)	$P_{curtailed}/P_{load}$	$Q_{curtailed}/Q_{load}$
Ano 0	4674	14/jul	17 h	512	122,07	122,07	277,38	281,40	44,0%	43,4%
				520	8,75	0	379,22	0	2,3%	-
				1451	9,00	4,01	9,00	4,01	100,0%	100,0%
				1452	5,25	2,34	5,25	2,34	100,0%	100,0%
	4697	15/jul	16 h	1451	0,01	0	9,00	4,01	0,1%	0,0%
				1452	5,23	0,75	5,25	2,34	99,7%	32,0%
Ano 1	4673	14/jul	16 h	512	0,02	0,02	311,28	249,03	0,0%	0,0%
				520	0,02	0	372,19	0	0,0%	-
				1451	0,38	0,08	9,09	4,05	4,2%	2,0%
				1452	5,30	2,36	5,30	2,37	100,0%	99,8%
	4674	14/jul	17 h	512	262,17	262,17	280,15	284,21	93,6%	92,2%
				1451	0,01	0	9,09	4,05	0,1%	0
				1452	0,01	0	5,30	2,37	0,1%	0
	4697	15/jul	16 h	520	38,85	0	361,36	0	10,8%	-
				1451	9,09	4,05	9,09	4,05	100,0%	99,9%
				1452	5,30	2,36	5,30	2,37	100,0%	99,9%

As a result, it is now possible to delay reinforcement investments for an additional two years (Table 3-32 vs. Table 3-36). This suggests that, in grids having voltage problems, it may be advantageous to have more flexibility providers spread through the grid, as acting on many buses seems to lead to a greater benefit than only acting on a few. However, it should be pointed out that this is not always the case, as there needs to be a relative proximity, in electrical terms, from the providers to the buses with voltage problems. For example, as expected flexibility providers located on a given feeder seem to have no effect on the voltage problems observed in another feeder.

Table 3-36 – Évora flexibility needs for year n+3 (EUniversal)

	hour	date	time of day	bus	$P_{curtailed}$ (kW)	$Q_{curtailed}$ (kvar)	P_{load} (kW)	Q_{load} (kvar)	$P_{curtailed}/P_{load}$	$Q_{curtailed}/Q_{load}$
Ano 4	4650	13/jul	17 h	520	40,53	0	407,17	0	10,0%	-
				1451	9,36	4,17	9,37	4,18	100,0%	99,7%
				452	5,46	2,43	5,46	2,44	100,0%	99,8%
	4652	13/jul	19 h	520	45,22	0	345,81	0	13,1%	-
				1451	9,36	4,16	9,37	4,18	100,0%	99,6%
				1452	5,46	2,43	5,46	2,44	100,0%	99,8%
	4653	13/jul	20 h	520	100,00	0	297,01	0	33,7%	-
				1451	9,36	4,17	9,37	4,18	100,0%	99,8%
				1452	5,46	2,43	5,46	2,44	100,0%	99,8%
	4654	13/jul	21 h	520	54,93	0	302,59	0	18,2%	-
				1451	9,36	4,16	9,37	4,18	100,0%	99,5%
				1452	5,46	2,43	5,46	2,44	100,0%	99,8%
	4673	14/jul	16 h	512	256,57	256,57	320,71	256,57	80,0%	100,0%
				559	162,41	44,26	557,76	151,99	29,1%	29,1%
				1451	9,36	4,18	9,37	4,18	100,0%	100,0%
				1452	5,46	2,44	5,46	2,44	100,0%	100,0%
	4674	14/jul	17 h	512	288,91	289,35	288,64	292,83	100,1%	98,8%
				520	394,80	0	394,62	0	100,0%	-
				559	559,38	157,86	559,16	157,57	100,0%	100,2%
				1451	9,58	4,45	9,37	4,18	102,3%	106,5%
				1452	5,58	2,64	5,46	2,44	102,2%	108,4%
	4676	14/jul	19 h	520	126,29	0	315,14	0	40,1%	-
				1451	9,36	4,17	9,37	4,18	100,0%	99,7%
				1452	5,46	2,43	5,46	2,44	100,0%	99,8%
	4697	15/jul	16 h	512	1,87	1,87	333,26	234,26	0,6%	0,8%
				520	206,19	0	372,31	0	55,4%	-
				1451	9,36	4,18	9,37	4,18	100,0%	100,0%
				1452	5,46	2,44	5,46	2,44	100,0%	100,0%
	4698	15/jul	17 h	520	34,13	0	372,31	0	9,2%	-
				1451	9,36	4,17	9,37	4,18	100,0%	99,8%
				1452	5,46	2,43	5,46	2,44	100,0%	99,9%
	4699	15/jul	18 h	1451	1,84	0,01	9,37	4,18	19,7%	0,2%
				1452	5,46	2,44	5,46	2,44	100,0%	100,0%
	4700	15/jul	19 h	520	134,08	0	308,16	0	43,5%	-
				1451	9,36	4,16	9,37	4,18	100,0%	99,7%
				1452	5,46	2,43	5,46	2,44	100,0%	99,8%

3.3.1.2.2 São Francisco (Alcochete) grid

In the case of São Francisco, extending the list of possible flexibility providers did not produce any effect on the results already shown in Table 3-33 and in Table 3-34. This is because the additional flexibility providers are not positioned downstream of the congestion and, therefore, cannot help improving the overload. This is in stark contrast with the results obtained for Évora: voltage problems can sometimes benefit from additional flexibility providers, but congestion problems can only by further minimized if the additional providers are located downstream of the affected line/cable.

3.3.2 Procurement of long-term flexibility – LongFlex NODES Platform

Considering the results presented in section 3.4.1.1, E-REDES formulated the flexibility requests to submit to the platform. In addition to the flexibility quantity required, the request should also include a maximum activation price. This cost was determined considering the energy losses reduction cost resulting from the conventional investment scenario involving the overhead line replacement to increase its capacity. This was adopted in alternative of the total cost of investment, considering that the implementation of Flexibility Market Platform and related infrastructure was not quantified in this project.

A summary of the flexibility requests submitted are shown in Table 3-37.

Table 3-37 – Summary of flexibility requests submitted to Long-Flex NODES Platform.

MV network	Days	Start	Duration	Power (Down)	Cost/MW
Évora	Nov/2023 – Business Days	16h	1h	140 kW	**1496 €** activation + 0€ availability
Alcochete	Nov/2023 – Business Days	21h	1h	44 kW	**654 € activation +** 0€ availability
	Oct/2024 – Business Days	21h	1h	73 kW	

The needs identified above were manually submitted in NODES platform by creating two LongFlex requests – one per network – as described in Figure 3-30 and Figure 3-31.

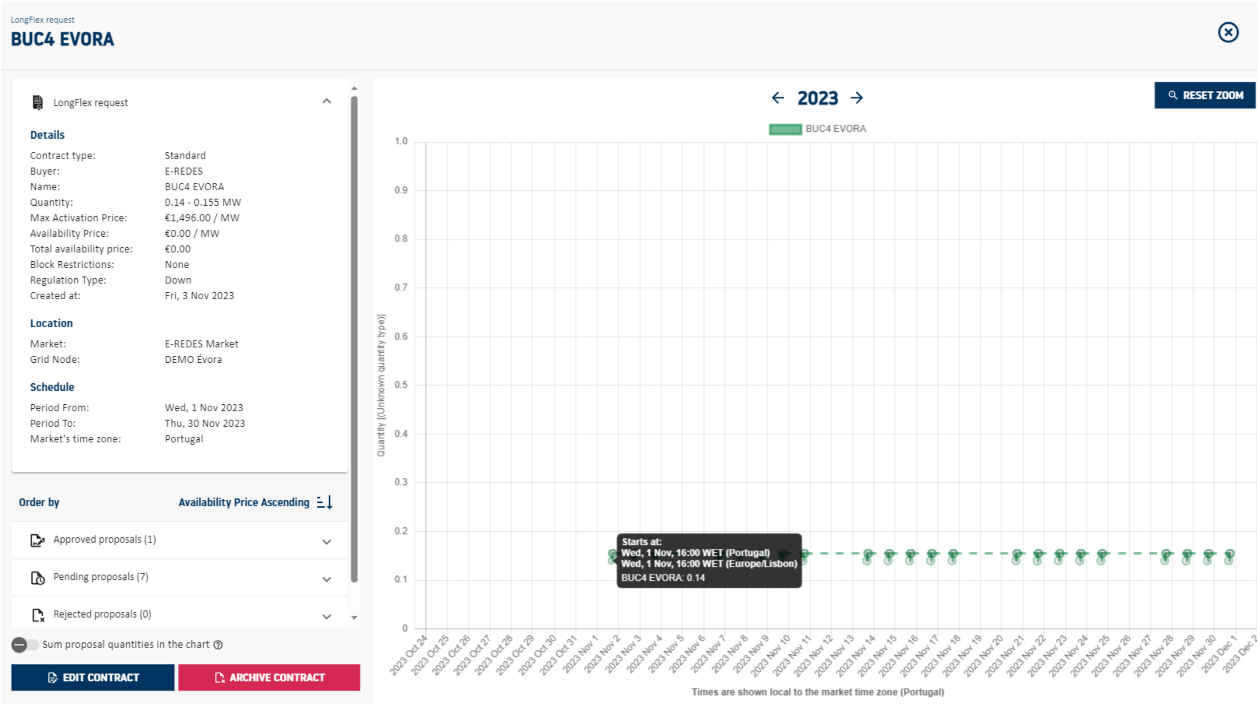


Figure 3-30 – BUC4 long-term (LongFlex request) need submission for Évora Network.

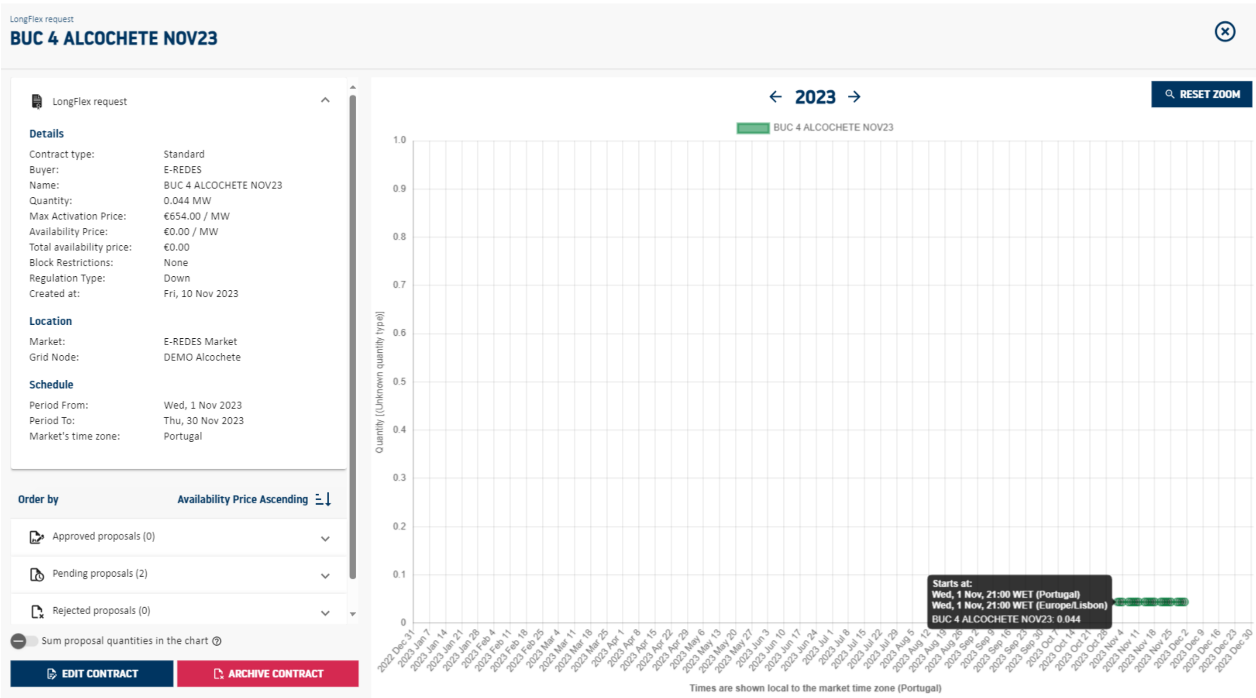


Figure 3-31 – BUC4 long-term (LongFlex request) need submission for Alcochete Network.

In response to the LongFlex requested for EVORA network, CENTRICA submitted 7 bids with different time periods and costs (Figure 3-32). E-REDES selected the 2 bids highlighted with a green box in Figure 3-32, that together matches the entire request for EVORA respecting the activation period, cost and power. More details on the selected bids can be seen in see Figure 3-33.

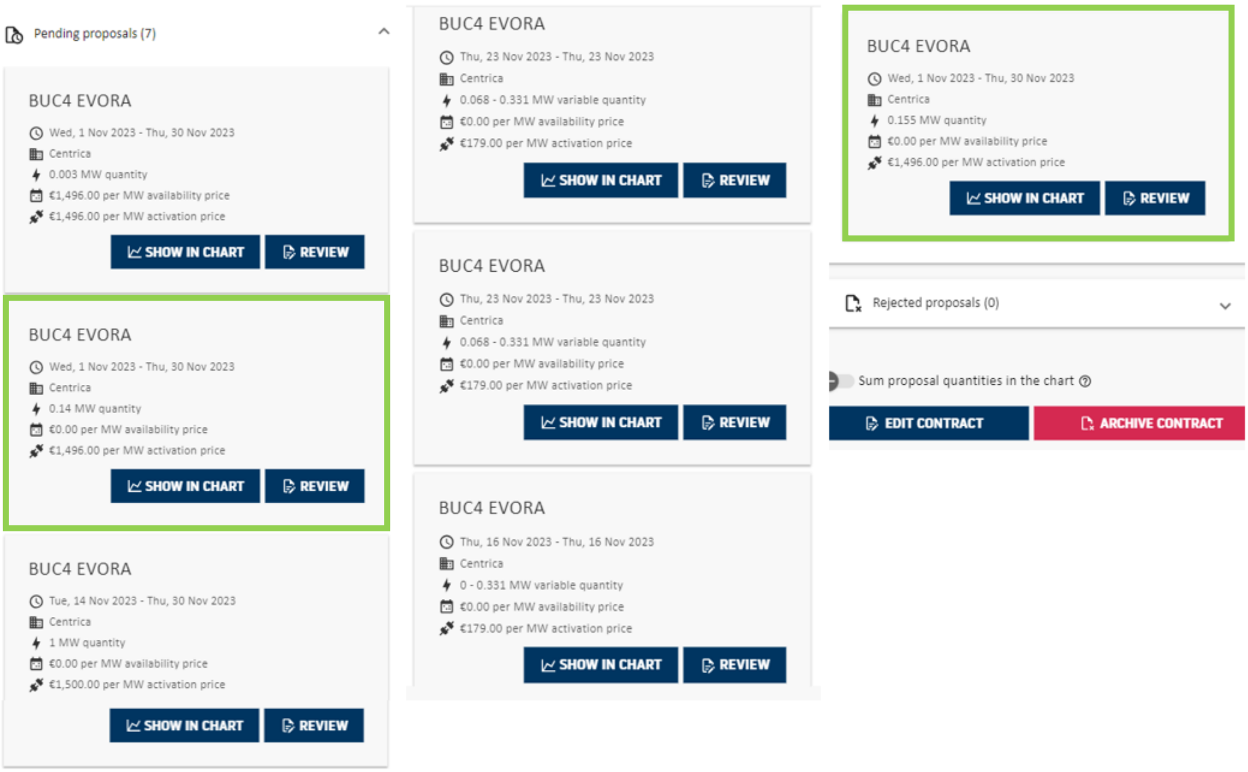


Figure 3-32 – BUC4 long-term bids received for Évora Network.

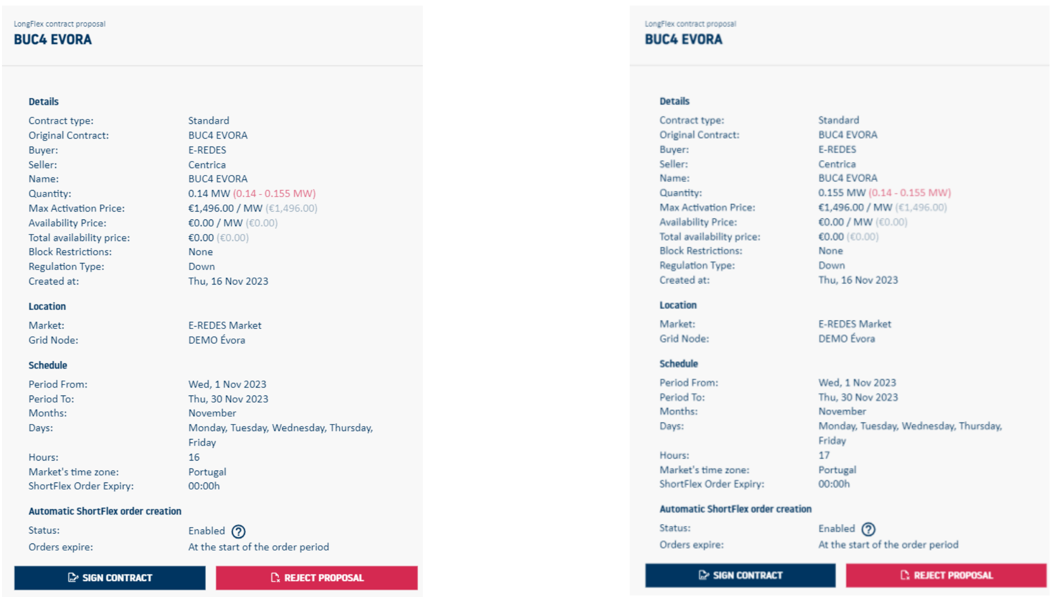


Figure 3-33 – BUC4 long-term selected bids for Évora Network.

The LongFlex requested for ALCOCHETE network received 2 bids from CENTRICA as shown in Figure 3-34. E-REDES selected the bid (green box in Figure 3-34) that fully answers the requested. Detail of the selected bid is represented in Figure 3-35.

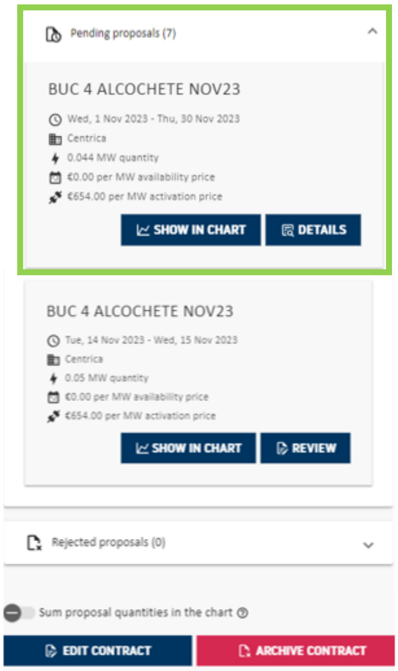


Figure 3-34 – BUC4 long-term bids received for Alcochete Network.

Figure 3-35 – BUC4 long-term selected bid for Alcochete Network.

After signed/selected the 3 long-term contracts, bids were automatically submitted in short-term (ShortFlex) for all business days in November 2023. This allows the activation by the dispatch teams and also to consider new potential bids with lower cost. In Figure 3-36 an example for the ALCOCHETE grid is shown, where the bid is available for activation.

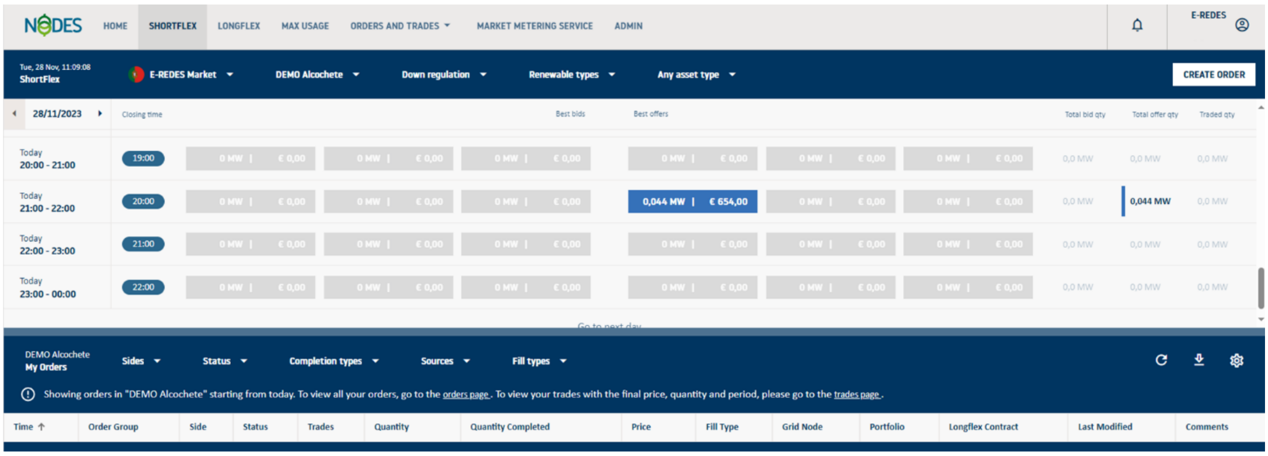


Figure 3-36 – BUC4 on NODES market: Short-term bid that automatically transitioned from the long-term market.

3.3.3 Deferred Distribution Capacity Investment KPI

With the aim of comparing the two scenarios, BAU and EUniversal, as well as quantifying the economic benefit resulting from operating the flexibility, the following network planning KPI, named as *Deferred Distribution Capacity Investment*, was calculated:

$$DDCI = \frac{NRC_{BAU} - NRC_{EUniversal}}{NRC_{BAU}}$$

with NRC_{BAU} being the net present value of the network reinforcement cost for the BAU scenario, and $NRC_{EUniversal}$ being the net present value of the network reinforcement cost for the EUniversal scenario.

Table 3-38 shows the net present value (NPV) analysis leading to the calculation of the cost of each plan, BAU and EUniversal, for the case of the Évora grid. The interest rate considered was 6.5 %, the cost of active power losses is 0.1013 €/kWh and the cost of flexibility is 3 €/kWh. The system's load increases at a rate of 1 %/year. These parameters have been provided by E-REDES.

In BAU, there is an initial investment cost (364.6 k€) due to the immediate necessity of replacing several distribution lines to eliminate the existing undervoltages ('Investment' column). In EUniversal, there is no need for such initial investment, as the available flexibility is enough to correct the technical problems. However, replacing the distribution lines has an important effect on active power losses, as a larger line cross section translates into a lower value of the line's electrical resistance, leading to a smaller level of active power losses ('Losses' column). Consequently, the cost of active power losses is smaller in BAU than in EUniversal. This effect only lasts through the first years of the planning horizon, as the flexibility can only eliminate the undervoltages until year 4.

On the other hand, there is a cost associated with mobilizing the flexibility (EUniversal), which increases rapidly until the cables are replaced ('Flex' column). This is because more flexibility providers have to be called – and paid – as the yearly load increases, and there are also more technical violations to deal with.

Table 3-38 – Net present value analysis for Évora (values in k€)

	Business-as-usual			EUniversal		
year	Investment	Losses	Flex	Investment	Losses	Flex
0	364.6			0		
1	0	-7.14	0	0	0	0.84
2	0	-7.19	0	0	0	1.78
3	0	-7.29	0	364.6	0	3.75
4	0	0	0	0	0	0
5	0	0	0	0	0	0
6	0	0	0	0	0	0
7	0	0	0	0	0	0
8	0	0	0	0	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
NPV→			345.5			307.3

The final cost of the EUniversal plan is, nonetheless, lower than the final cost of the BAU plan. The corresponding Deferred Distribution Capacity Investment KPI is:

$$DDCI_{Evora} = \frac{345.5 - 307.3}{345.5} \approx 11.1\%$$

Table 3-39 shows the net present value (NPV) analysis leading to the calculation of the cost of each plan, BAU and EUniversal, for the case of the Alcochete grid. The parameters of the analysis (interest rate, cost of active power losses, cost of flexibility and system yearly load increase) remain the same as the ones that were used in the Évora grid analysis.

Table 3-39 – Net present value analysis for Alcochete (values in k€)

	Business-as-usual			EUniversal		
year	Investment	Losses	Flex	Investment	Losses	Flex
0	33.6			0		
1	0	-3.65	0	0	0	0.06
2	0	-3.75	0	33.6	0	0.27
3	0	0	0	0	0	0
4	0	0	0	0	0	0
5	0	0	0	0	0	0
6	0	0	0	0	0	0
7	0	0	0	0	0	0
8	0	0	0	0	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
NPV→			26.8			29.9

Once again, there is an initial investment (BAU) at year n-1 (33.6 k€). This consists of replacing the distribution line that became overloaded. In EUniversal, the available flexibility can be used to correct the technical problem, thus postponing the network reinforcement until the end of year 2.

However, the final cost of the EUniversal plan is higher than the final cost of the BAU plan. The reason for this is twofold: (1) on one hand, installing the new cable in BAU leads to a considerable reduction in active power losses; the corresponding economic benefit of this reduction is higher, in relative terms, than the corresponding reduction in the Évora case; (2) on the other hand, and in comparison with the Évora case, the cost of reinforcement is not only significantly lower, but it also has a shorter deferment time (the closer the investment, in chronological terms, the higher its impact on the final cost of the plan). Consequently, the corresponding Deferred Distribution Capacity Investment KPI is negative:

$$DDCI_{Alcochete} = \frac{26.8-29.9}{26.8} \approx -11.4\%$$

This striking difference between the values of $DDCI_{Évora}$ and $DDCI_{Alcochete}$ is explained by the combination of several circumstances, namely:

- The distinct nature of the technical problem being solved in each case: several undervoltages in Évora vs. a single branch congestion in Alcochete;
- The fact that the load was increased by 1.34 times in Évora, but not in Alcochete, which means that the Évora grid was operating in a more stressed condition than the Alcochete grid.
- It was necessary to replace several lines in Évora, but only one line in Alcochete, leading to a much higher investment cost in the former case;
- The timespan of the investment postponement was also lengthier in the Évora case (year 3), in comparison with Alcochete (year 2);
- The number of "useful" flexibility providers was higher in Évora than in São Francisco (five providers in Évora vs. two in Alcochete).

These results suggest that the economic reasonableness of operating the flexibility is strongly dependent on the state of the grid, the nature of its technical problems, the investments required (number, type and overall cost), the number of flexibility providers and the practicality of using their flexibility to solve the problems at hand.

4 Conclusions

The Portuguese demonstrator was able to successfully demonstrate the procurement flexibility to solve grid constraints, supporting predictive network operation and medium/long-term investment planning. This was enabled by the successful implementation and test of a complete chain involving the demonstration of new DSO tools developed within the project, two Flexibility Market Platforms, one Aggregation Platform connected through the UMEI.

Demonstration was implemented in different regions of the country, involving 5 MV networks and 9 LV networks that supply approximately 200 MV/LV substations and 1189 LV consumers, from which 40 accepted to participate in the project. This resulted in the processing of a high volume of data performed by the data exchange platform and tools, enabling both the functional validation of the use cases and the identification of the challenges related with their replicability.

Different challenges needed to be overcome along the project, starting from the pilot architecture specification and data requirements identification, discussion of GDPR issues and preparing the guidelines to share sensitive smart metering data, implementation and deployment of tools and finally integrated testing of all demo components. Some specific conclusions can then be derived:

- The UMEI was successfully demonstrated, enabling communication and data exchange between DSO, Flexibility Markets and Flexibility Aggregation Platform. The APIs specification development benefit from collaboration of the different platforms involved, incorporating their internal specifications and experience from other projects.
- Pilot implementation involved the deployment of a data exchange platform interlinking internal DSO systems, as AMI, SCADA and MV load and generation forecast, that provide the input data for the DSO toolbox. At the same time, it also ensures the interaction with external platforms, through the UMEI. All data exchange processes are GDPR compliant. Daily collection of smart metering and MV consumer metering data is a time-consuming process that need to be considered in the specification of the final tool and market interaction timeline. Tools need to be able to deal with incomplete datasets while ensuring the quality of results, such as forecasts and day-ahead network operation planning and flexibility needs estimation. Longer demonstration period would be needed to derive more relevant conclusions on the impact of forecast errors in the flexibility mobilization solution.
- The data-driven approach implemented to improve LV network observability and control, based on the LV voltage forecast and Data-Driven Voltage Control (DdVC) tools was successfully demonstrated. This approach is based on smart metering data with the potential to reduce monitoring requirements, without requiring full characterization of network. This is a competitive advantage against some commercial solutions offered today in the market for LV networks. However, further developments need to consider increased robustness against gaps in the historical data or poor-quality data, particularly for the DdVC tool. This could be achieved by including other sources of data, also enabling tools deployment when smart metering infrastructures are not fully deployed.
- Two different timelines for the short-term flexibility procurement were successfully demonstrated. Timeline definition depended on the computation time of data inputs and DSO tools and market processing. Replicability will probably require adjusting to market size, participants and network area involved.
- When using N-SIDE market platform, the tools first determine the necessary flexibility to solve the expected grid constraints without knowing the selling bids. The needs are presented by the market platform, to allow aggregators to submit their offers considering the network areas and hours where grid constraints are expected. The concept was successfully tested for both

MV and LV networks, from their definition provided by the DSO tools to their implementation in N-SIDE clearing process. Demonstration shows that this approach allows aggregation of bids per area even in LV networks and market clearing considering abstract grid knowledge and avoiding further constraints. However, in a market with low liquidity, due to reduced number of participants, the areas may not include a significant number of bids, or even remain without bids. This approach is therefore only representative in network areas with a higher number of participants and should scale well with thousands of actors interacting since relying on the same software as the one used for several wholesale DAM and balancing market worldwide. In the case of these local markets with possibly less liquidity in some zones, issues such as the risk of market manipulation when compared to other market designs need to be further assessed.

- When using NODES market platform, flexibility offers are first submitted to the platform and then selected by the DSO to solve the expected grid constraints, while minimizing the cost of operation for the next day. Demonstration results show effective procurement of flexibility for the next day, with similar clearing results to N-SIDE market platform. This approach provides a process giving the DSO with full control over flexibility offers selection. In a grid where the number of participants is small, the optimization problem tractability is manageable. However, as the number of participants increase, the optimization problem needs to adopt adequate strategies to produce viable solutions. In this case the tools demonstrated within the pilot, namely MV flexibility scheduling and DdVC that use a linear model based in current and voltage sensitivity matrixes can deal with a high number of control variables.
- The main objective of BUC 3 was to demonstrate the participation of market-based flexibility services for the support of maintenance activities. A new approach to maintenance planning was evaluated in the demo, showing that the participation of flexibility offered in local flexible markets may allow to move field work during periods where the maintenance crew prices are lower, in weekdays, reducing load curtailment requirements. To do so, the DSO with the MV maintenance planning tool defines a viable set of alternative periods to perform maintenance, identifying the network reconfiguration solution that minimizes the Energy Not Distributed (END) and the flexibility needs for each period. The flexibility needs were then submitted to NODES LongFlex market and finally selected by the DSO for the maintenance period. This approach allowed for considering more realistic load profiles, based in historical data, and consequently of more accurate network reconfiguration plan. As expected from the demo results, flexibility reservation had higher bidding prices for longer maintenance actions, leading to higher END. The offers selected are reserved and renegotiated in the Short-flex market, allowing the DSO to procure the most economical flexibility bids.
- Long-term flexibility procurement was successfully demonstrated. As foreseen, the mobilization of flexibility in NODES long-term flexibility market was tested for Évora and Alcochete MV networks. The maximum cost for flexibility determined was based on the energy losses reduction cost resulting from the increase of line capacity. This was determined in alternative of the total cost of investment, considering that the implementation of Flexibility Market Platform and related infrastructure was not quantified in this project. The long-term flexibility needs were submitted in the market for the month of November. A maximum participation of 42h per year were requested for both MV networks, with a maximum request of 155kW during one hour in Évora network.

  Analysis for a planning horizon of 11 years has shown that the economic reasonableness of operating the flexibility is strongly dependent on the state of the grid, the nature of its technical problems, the investments required (number, type and overall cost), the number of flexibility providers and the practicality of using their flexibility to solve the problems at hand. A cost benefit analysis between conventional grid reinforcement solutions and alternative flexibility services needs to be considered to ensure the most economically efficient investment solution.

- Consumer engagement is key for future large-scale demonstration of the framework developed and tested in the PT demo. Longer demonstration period with higher number of participants is recommended for future projects to consolidate the results and conclusions drawn from the demonstration results.

5 Internal Documents

[1] EUniversal deliverable D2.1, "Grid flexibility services definition", April 2021.
[2] EUniversal deliverable D2.2, "Business Use Cases to unlock flexibility service provision", April 2021.
[3] EUniversal deliverable D4.3, "Self-healing and dynamic islanding schemes for resilient
[4] distribution networks – Specification and acceptance testing", March 2023.
[5] EUniversal deliverable D7.2: "Specifications of test scenarios within the Portuguese Demonstrator", July 2023.
[6] EUniversal deliverable D6.2: "Definition KPI for DEMOs", July 2021.
[7] EUniversal deliverable 11.4: "Coordination with BRIDGE EU-funded projects, Participatory Processes and training", November 2023.