



CRETE VALLEY Digital Twin, data-driven services & apps (second wave)/ D4.2

WP 4, T4.1-T4.5

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Abbreviations list

ADMM	Alternating Direction Method of Multipliers
AI	Artificial Intelligence
API	Application Programming Interface
CEL	Community Energy Lab
CIM	Common Information Model
CNN	Convolutional Neural Network
CPU	Central Processing Unit
DAM	Day-Ahead Market
DL	Deep Learning
DP	Dynamic Phasor
DR	Demand Response
DSO	Distribution System Operator
DT	Digital Twin
EnC	Energy Community
EV	Electric Vehicle
G2V	Grid to Vehicle
GRN	Gated Residual Network
HTTP	HyperText Transfer Protocol
IEC	International Electrotechnical Commission
IQR	Interquartile Range
ISD	Initial Supply Demand
LEED	Leadership in Energy and Environmental Design
LSTM	Long Short-Term Memory
MAE	Mean Absolute Error
ML	Machine Learning
MNA	Modified Nodal Analysis
MAPE	Mean Absolute Percentage Error
NRP	Newton-Raphson Polar
OCPP	Open Charge Point Protocol
OPF	Optimal Power Flow
P2P	Peer-to-Peer
PI	Physics-Informed
PQ	Power Quality
PV	Photovoltaic
RES	Renewable Energy Sources
REV	Renewable Energy Valley
RMSE	Root Mean Square Error
RNN	Recurrent Neural Network
RDF	Resource Description Framework
SFA	Shifted Frequency Analysis
SCADA	Supervisory Control and Data Acquisition
SQL	Structured Query Language
SOC	State of Charge

SSH	Steady State Hypothesis
SSL	Secure Sockets Layer
TFT	Temporal Fusion Transformer
TSO	Transmission System Operator
V2G	Vehicle to Grid
V2X	Vehicle to Everything
VD	Voltage Deviation
VPP	Virtual Power Plant
VSN	Variable Selection Networks

Executive Summary

This document presents the second wave of data-driven applications and services aimed at supporting the System-of-systems Digital Twin (DT) as a digital representative of CRETE VALLEY's assets, primarily focused on the island of Crete, Greece. The integrated solution unites multiple advanced modules and tools into a cohesive architecture that supports grid operators, energy suppliers, and consumers in optimizing energy flow, improving operational efficiency, and promoting energy autonomy.

Crucially, this deliverable showcases the successful integration of all developed components into a production-ready, Kubernetes-based cluster environment, establishing a robust and unified architectural platform that acts as the digital backbone for the system-of-systems Digital Twin. A central feature of this integrated ecosystem is the deployment of a fully operational Energy Forecasting Service, which transitions from standalone models to leveraging advanced time-series foundation models for highly accurate, zero-shot predictions of energy generation and consumption. Working in parallel with this forecasting capability are optimized scheduling systems for flexible assets—including renewable energy sources, controllable loads and Electric Vehicles (EVs). Another critical element is the integration of the Dynamic Phasors Simulation Engine (DPSim), which enables real-time simulation and analysis of power network parameters, primarily addressing the needs of TSOs and DSOs. Furthermore, network optimisation through the involvement of the flexibility analysis and modelling showcases an active collaboration between services, to empower grid operators combined efforts and shared initiatives. Notably the main stakeholders of this platform include the Distribution System Operators (DSOs), Transmission System Operators (TSOs), Energy Community Managers and Renewable Energy Sources (RES) operators, or in CRETE VALLEY's context, Renewable Energy Valley (REV) managers.

WP4 aims to develop a robust DT capable of supporting diverse stakeholders in the efficient coordination, management, and operation of the Community Energy Labs' (CEL's) local energy grids across CRETE VALLEY. In parallel, it will provide data-driven services that empower individual consumers to enhance energy efficiency and optimize load management.



1. Introduction

The CRETE VALLEY project, co-funded by the European Union’s Horizon Europe programme, aims to establish a Renewable Energy Valley ‘Living Lab’ (REV Lab) on the island of Crete—a decentralised renewable energy system designed to meet local energy needs through the integration of advanced technologies, social innovation, and novel business models. Within this multi-layered framework, Work Package 4 (WP4) focuses on the development of a robust Digital Twin and its respective data-driven services and applications, that serves as the digital counterpart of the physical energy ecosystem. Building on business and technological insights and methodologies from WP2 and WP3, WP4 will deliver an integrated suite of tools, services, and simulation engines that support the monitoring, forecasting, and optimisation of local energy flows. These tools will facilitate engagement across various stakeholders, including grid operators, energy community and renewable energy managers, and consumers, enabling efficient coordination and management of Crete’s local energy systems. The current Deliverable is the second version of the services and the Digital Twin itself, following “D4.1 – CRETE VALLEY Digital Twin, data-driven services & apps (first wave)”, submitted on M17.

Motivation and objectives

The rapid shift toward decentralized, data-heavy, and renewable-dependent energy grids has created a pressing demand for comprehensive digital platforms capable of modelling, analysing, and optimizing these intricate networks. Cloud computing architectures offer a robust approach to augmenting the flexibility and efficiency of power system management. Moreover, the integration of Artificial Intelligence (AI) and Machine Learning (ML) has revolutionized the energy industry by drastically improving system security, intelligence, and operational efficiency. By leveraging AI for tasks such as energy conservation and the precise forecasting of both demand and generation, the sector has increasingly embraced DT technology to fulfil these operational and maintenance enhancement goals (Antonesi, 2025).

The motivation behind WP4 stems by the escalating necessity of DTs in facilitating intelligent energy management—acting as a nexus where simulation, forecasting, and the coordination of flexible assets unite to empower data-driven decisions across user, grid, and system levels. Delivering the second wave of services for this initiative, the CRETE VALLEY REV Lab offers an unparalleled real-world testbed to showcase the profound impact of this integrated platform. Consequently, this second wave of development targets the following primary objectives (which can also be seen in [TwinREV](#)):

- Enhance situational awareness for grid operators through system monitoring, simulation, optimisation and visualization of local energy flows and network conditions.
- Support data-driven decision-making for energy community managers by providing accurate energy forecasting (using Foundation Models) and optimized scheduling of flexible assets, including battery systems, EVs, and controllable loads.
- Facilitate stakeholder coordination by enabling seamless integration and collaboration across different actors—such as DSOs, TSOs, energy community managers, and RES operators—within a unified digital environment.



- Empower local energy consumers through user-facing applications that offer insights into personal energy behaviour, promote sustainable choices, and encourage active participation in local energy communities.

Relation to other activities of the project

As part of the multi-layered strategy of the CRETE VALLEY project, the activities undertaken within the scope of WP4 are not only interdependent but also closely aligned with the tasks and progress of other work packages. WP4 plays a central role developing the digital representative of CRETE VALLEY, TwinREV. Several important linkages and points of collaboration have already been identified, highlighting the nature of the work. Given the inherently interconnected themes addressed throughout the various WPs, it is anticipated that further synergies and collaborative pathways will continue to unfold as the project evolves.

- Previous collaboration with Task 2.1 (WP2) to identify the business requirements and functional specifications of the technological enablers, and more specifically the DT, and alignment with Task 3.1 (WP3) to streamline DTs' technical specifications, standardisation and forming the reference architecture of the project.
- T5.5 (WP5) is responsible of deploying the Digital Twin developed in our WP in the Crete REV-Lab & CELs, as well as integrating it with energy infrastructure and systems.
- The Digital Twin will be assessed in Task 6.1 (WP6), based on the effectiveness and usability used to simulate different operational scenarios for the local energy system.
- The engagement of the energy citizens on the usage of data-driven services and apps will be evaluated through Task 6.2 (WP6).
- The day-ahead market simulator (Task 7.3 in WP7) for the island will also be incorporated into the Digital Twin, with indicative results showcased in this document.

Structure of the document

This report is structured into five main sections, each corresponding to a key task (T4.1–T4.5) in the second wave of services for the development of the DT for multi-carrier grid management, from M17 to M32. These sections outline the methodologies, tools, and expected outcomes of each task, highlighting their role in achieving an efficient, scalable, and autonomous energy management system.

The first section (T4.1) focuses on optimizing local energy grid performance by integrating transmission (IPTO) and distribution (HEDNO) network models into the DPsim simulation framework. It details how time-series operational data is used to automate power flow studies and assess network performance indicators, such as bus voltages and branch loadings, under various projected scenarios.

Following this, in the second section (T4.2) the document explores the architectural shift toward a unified, production-ready Energy Forecasting Service. It details the application of large-scale, pre-trained time-series foundation models (specifically the Chronos family) to provide zero-shot



forecasting capabilities for renewable energy production and consumption, significantly reducing the need for localized retraining.

Next, in the third section (T4.3) the focus shifts to a multi-energy optimization tool designed to ensure the cost-effectiveness and technical feasibility of energy set-points for grid operators. It covers the integration of an Optimal Power Flow (OPF) framework and a dedicated EV flexibility module (datafev_flex) to compute day-ahead energy schedules, reserve capabilities, and smart-charging baselines.

The document continues with the fourth section (T4.4), which details the maturation of the DT (TwinREV) into an integrated interaction layer deployed on a Kubernetes cluster. It outlines dedicated functionalities tailored to specific stakeholders, including 3D asset visualizations and maintenance scheduling for CEL Managers, and time-series power flow visualizations for the TSO.

Finally, the fifth chapter (T4.5) of the document covers the consumer-facing digital activation components, specifically the SSH-based closed-loop ‘nudging’ service. It details the hardware and software architecture of the EUNICE App, which leverages smart meters (ESM105 and ESM304) and a cloud-based rules engine to provide users with near real-time consumption feedback, alerts, and recommendations to optimize behavioural patterns.

2. Data-driven operational analysis for optimising local energy grid performance through power flow simulations

Overview

During the reporting period, the activities focused on preparing and validating the simulation environment required for the operational analysis of the Crete energy system. Network models representing both the transmission and distribution electrical grids were integrated into the DPsim framework and connected to time-series operational data provided by the project partners. This included the processing of transmission system measurements from IPTO and distribution system profiles from HEDNO to create realistic simulation scenarios.

A data exchange interface was further developed to enable communication between the DT platform and the DPsim simulation environment. This allows the automated execution of power flow studies based on external inputs and facilitates the evaluation of grid conditions under varying operational scenarios.

The implemented workflow supports the assessment of key network performance indicators, including bus voltages, line loadings, transformer utilisation, and power exchanges between network areas. By combining detailed grid models with realistic operational data, the developed framework provides the basis for analysing the impact of load and generation patterns variations, as well as the integration of future flexibility services, on the secure and efficient operation of the local energy system.

Initial Status

The functionality of DPsim and the power flow problem formulation is described in the last deliverable for the reporting period M1 to M15. The initial status description will be split up between the IPTO case (TSO grid) and the HEDNO case (DSO grid) because of the different topologies.

Transmission Power System (TSO)

The initial status at the start of the current reporting period (M15) consisted of a reduced CIM-based loading example of the IPTO (TSO) system according to CGMES 2.4.15 standards. The model was functional for static simulation studies and provided the foundation for further extensions and validation work carried out during the reporting period.

The primary modelling data for the transmission system has been initially provided via PSS/E (PTI, 2013) operational files and converted into a DigSILENT PowerFactory (DIgSILENT GmbH, 2021) format. These files captured the high-voltage transmission grid topology of Crete along with its interconnections with the mainland power system. The simulation model has been accompanied by



a comprehensive spreadsheet metadata index detailing the network configuration parameters. Topology validation was supported by two distinct single-line diagrams, i) one exported directly from the PSS/E environment and ii) another operational architecture acquired from the relevant GIS IPTO API reflecting real-time topology baselines. The provided topology involved the two interconnections i) a HVAC linking Chania to the Peloponnese and ii) a HVDC that connects Damasta to Attiki. The electrical characteristics, inductive/capacitive impedances, and thermal limits of all cables and overhead lines are fully modelled within the PSS/E environment.

To analyse grid behaviour and conduct power flow simulations in the transmission grid of Crete island, historical datasets have been collected and provided, including short-term 1-minute resolution profiles. Active and reactive power time-series at a 1-minute resolution are provided for two representative operational extremes; i.e. a typical winter day (January 10, 2024) and a typical summer day (June 10, 2024). These profiles were provided per substation and involve load, RES and conventional thermal generation units, and shunt compensation status. In addition, the generation dispatch schedules for the conventional thermal power plants are provided for the selected days to serve as baseline unit commitment targets.

In this initial setup, loads and static generators like solar and wind were represented as aggregated single objects, providing a simplified baseline model for subsequent development and refinement activities. In addition, an initial foundation for time-series power flow simulations using DPsim had already been established within Jupyter notebooks. The results of the power flow simulations were compared to those of DigSILENT PowerFactory and showed similar results, like described in the last deliverable of the first reporting period M1-M15.

Distribution network (DSO)

At the beginning of the reporting period (M15), no CIM representation of the DSO grid was available. Consequently, the initial activities focused on establishing the required data basis and preparing the network model for subsequent integration and simulation workflows. The developed CIM should be in CGMES 2.4.15 standard and usable with the same workflow as the network topology from IPTO.

The developed 20 kV medium-voltage (MV) network model covers the CEL 3 distribution network, extending from the HV/MV substation point down to the radial distribution load and PV buses, providing the basis for the visualization of the distribution network and its integration into the DT platform. The network model was extracted from the organization's archive and verified, using a comprehensive dataset of historical SCADA and telemetry measurements, specifically active power, voltage magnitudes, current, and power factor, to establish a baseline. The network topology was reconstructed from single-line diagrams and GIS data to accurately represent the network baseline topology, omitting geodata and other identifiers. The model underwent a preprocessing step to remove outliers and incomplete records before being converted into standard CIM XML files, ensuring it could be successfully compiled and executed within the DPsim power flow simulation environment.

At present, the availability of direct measurements across individual local nodes remains limited, meaning the complete load profile of the network is not directly accessible, which consequently reduces overall network observability. To address this limitation, telemetry data was utilized to



estimate downstream power flow. The methodology employs a lightweight, modular framework designed specifically for low-observability networks that rely primarily on feeder-level SCADA measurements. It implements two distinct estimation strategies depending on data availability: a baseline estimator that assumes uniform loading, and a profile-based estimator that leverages temporal variations extracted from available smart meters. This approach allows for accurate nodal load and voltage estimation even under severe observability constraints, as validated on a real medium-voltage feeder. The methodology is described in a project publication presented in conference (<https://zenodo.org/records/18981463>).

Current Status

During the reporting period M15–M30, significant progress was achieved in the development of the data-driven power flow simulation framework based on DPsim. The work focused on extending the simulation capabilities for both the TSO (IPTO) and DSO (HEDNO) use cases. This included the integration of updated grid models, the processing of operational profile data, and the implementation of a complete time-series simulation workflow capable of evaluating network behaviour under varying load and generation conditions.

General development

During the reporting period, the core simulation framework based on DPsim was further extended and integrated into the overall Crete Valley DT architecture. The work focused on establishing a common infrastructure that supports both transmission and distribution system use cases while enabling automated execution of power flow simulations and efficient data exchange between project components.

Development of DPsim server and API for the Digital Twin

A major development was the implementation of a dedicated DPsim server and application programming interface (API). The API provides a standardized communication layer between the DT platform and the simulation environment, allowing simulation scenarios to be configured, executed, and monitored remotely from the DT. Through this interface, network models, simulation parameters, and operational profile data can be transferred to the simulation backend, while simulation results are automatically returned to the DT for further processing and visualization. A visualization of the workflow between the DT and the DPsim environment is illustrated in Figure 1.

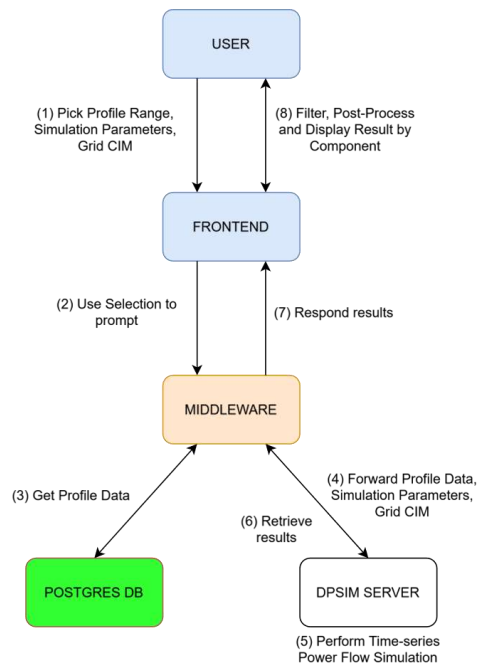


Figure 1: Communication architecture and data flow between the Digital Twin platform, middleware services, DPsim simulation backend, and PostgreSQL database

Figure 1 illustrates the communication architecture developed for integrating DPsim into the Crete Valley DT environment. The workflow follows a layered approach consisting of a user interface, frontend services, middleware components, the DPsim simulation backend, and a PostgreSQL database for data storage.

The process starts with the user interacting with the DT through the frontend application. Simulation requests, including network models, operational profiles, and scenario parameters, are submitted via the frontend and forwarded to the middleware layer. The middleware acts as the central coordination component, handling communication between the DT services and the simulation backend.

Through a dedicated API, the middleware triggers DPsim simulations and transfers the required input parameters. DPsim performs the requested power flow calculations and returns the resulting network states, including bus voltages, branch loadings, and power injections. Afterwards, the simulation results are filtered, post-processed and visually displayed on the DT platform.

Development and Enhancement of the Newton-Raphson (NRP) Solver of DPsim

During the reporting period, the DPsim power flow solver underwent significant improvements to support the requirements of large-scale operational and time-series grid studies. While DPsim was originally developed primarily for electromagnetic transient and dynamic phasor simulations, the increasing focus on long-term operational analysis within Crete Valley required further enhancements of its steady-state power flow capabilities.

Emphasis was placed on improving the initialization and convergence behaviour of consecutive power flow calculations. A warm-start mechanism was implemented that allows previously converged solutions to be used as initial guess for consecutive timesteps. This significantly reduces

the number of solver iterations required for time-series simulations and improves computational efficiency when analysing extended periods of operation. Also, the ratio of converged to not converged timesteps was increased by this feature, so that reasonable results could be obtained for most of the profile timesteps.

Another improvement which was achieved is the improved update mechanism of the Newton-Raphson (NRP) solver demonstrated in Figure 3.

```
void PFSolverPowerPolar::updateSolution() {
    UInt npqpv = mNumPQBuses + mNumPVBuses;
    UInt k;

    for (UInt a = 0; a < npqpv; ++a) {
        k = mPQPVBusesIndices[a];
        sol_D(k) += mX.coeff(a);

        if (a < mNumPQBuses)
            sol_V(k) = sol_V.coeff(k) * (1.0 + mX.coeff(a + npqpv));
    }

    //Correction for PV buses
    for (UInt i = mNumPQBuses; i < npqpv; ++i) {
        k = mPQPVBusesIndices[i];
        Complex v = sol_Vcx(k);
        // v *= Model.buses[k].v_set_point / abs(v);
        sol_V(k) = abs(v);
        sol_D(k) = arg(v);
    }
}
```

Figure 2: Old NRP solver update function

```
void PFSolverPowerPolar::updateSolution() {
    UInt npqpv = mNumPQBuses + mNumPVBuses;

    const double alphaD = 0.6;
    const double alphaV = 0.6;

    for (UInt a = 0; a < npqpv; ++a) {
        UInt k = mPQPVBusesIndices[a];

        double dD = alphaD * mX.coeff(a);
        dD = std::clamp(dD, -0.15, 0.15);
        sol_D(k) += dD;

        if (a < mNumPQBuses) {
            double dVrel = alphaV * mX.coeff(a + npqpv);
            dVrel = std::clamp(dVrel, -0.25, 0.25);

            sol_V(k) *= std::exp(dVrel);
            sol_V(k) = std::clamp(sol_V(k), 0.7, 1.3);
        }
    }

    for (auto node : mSystem.mNodes) {
        UInt idx = node->matrixNodeIndex();
        sol_V_complex(idx) = Math::polar(sol_V(idx), sol_D(idx));
    }
}
```

Figure 3: Improved update function

During the reporting period the NRP solver was extended with damping and step-size control strategies that limit excessive corrections which led to non-convergence before.

The update routine of the DPsim polar power flow solver was revised to improve numerical robustness during NRP solver iterations. In the previous implementation, Figure 2, the full correction vector was applied directly to the voltage angles and magnitudes. The voltage angle was updated by adding the full correction term, while the voltage magnitude at PQ buses was updated using a linear relative correction:

$$\delta_k^{new} = \delta_k + \Delta\delta_k$$

$$V_k^{new} = V_k \cdot (1 + \Delta V_k)$$

This approach led to large voltage or angle changes when the Newton correction became too large, especially for stressed operating points or poor initial guesses; in cases large grids some guesses might become unreasonable.

In the updated implementation, Figure 3, damping factors are applied to both voltage angle and voltage magnitude corrections. The corrected update terms are limited to predefined maximum step sizes before being applied:

$$\begin{aligned}\Delta\delta_k^{lim} &= \text{clip}(\alpha_\delta\Delta\delta_k, -0.15, 0.15) \\ \Delta V_k^{lim} &= \text{clip}(\alpha_V\Delta V_k, -0.25, 0.25)\end{aligned}$$

$$\alpha_\delta = 0.6, \quad \alpha_V = 0.6$$

The voltage angle is then updated as

$$\delta_k^{new} = \delta_k + \Delta\delta_k^{lim}$$

while the voltage magnitude is updated using an exponential formulation:

$$V_k^{new} = V_k \cdot e^{\Delta V_k^{lim}}$$

Finally, the voltage magnitude is constrained to a physically meaningful range:

$$0.7 \leq V_k^{new} \leq 1.3$$

This prevents unrealistic intermediate voltage states during the iterative solution process. After the real-valued voltage magnitude and angle have been updated, the complex voltage representation is recalculated for all nodes:

$$\underline{V}_k = V_k e^{j\delta_k}$$

Overall, the updated routine improved the convergence behaviour of the power flow solver by avoiding excessive Newton steps, limiting non-physical voltage values, and ensuring that the complex voltage vector remained consistent with the polar state variables after each iteration. These improvements are particularly relevant for time-series simulations, where the solver is executed repeatedly for many consecutive operating points.

Collection of historical electrical measurements and construction of power profiles by IPTO

For the power flow simulations of the transmission grid the generation profiles of all renewable assets and demand profiles of all substations in Crete are essential. However, all the renewable assets and loads are connected to the distribution grid. For this reason, in this reporting period, IPTO collected and provided real historical measurements that had available for the generation of wind parks, spanning a time range of a complete year. The wind production is provided per substation and has been calculated by the summation of all wind parks output fetched by the IPTO SCADA system. As shown in Figure 4, the measurement instrument placed at point A was used to calculate the generation of the wind park connected at the substation. For the PV parks of the island, IPTO does not have direct telemetry or historical profile access. To that end, IPTO provided the installed capacities of all PV parks per substation which was used to calculate their generation based on a typical PV profile for the island. The demand profiles for each substation in Crete have been derived by considering topological parameters from the single-line diagrams, alongside historical telemetry extracted from each substation. The load of each substation was calculated as the net-consumption of the substation plus the electrical power produced by local solar parks. In detail, if measurements from points A and B as shown in Figure 4 are denoted as P_A and P_B , respectively, and solar generated power as P_{pv} , then demand power, P_L , is calculated as:

$$P_L = P_A - P_B - P_{pv}$$

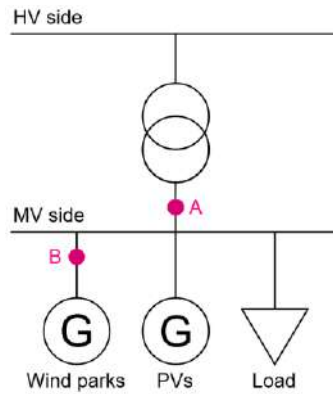


Figure 4: Simple diagram of a substation, denoting the points where the measurement sensors are connected

To ensure the integrity of the data before feeding it into the power flow simulations, an advanced data-cleaning pipeline was deployed to eliminate telemetry corruption. This processing framework targeted i) outliers: erroneous spikes and measurement noise caused by sensor communication drops were filtered using statistical smoothing approaches, ii) constant data values resulting from frozen telemetry units were identified and repaired, and iii) faulty measurements: missing or erroneous data blocks were reconstructed using interpolation techniques.

In this reporting period, long-term data are provided to evaluate seasonal variations from September 1, 2024, to January 31, 2026. This dataset includes active power, load and RES and conventional units generation per substation at a 1-hour resolution.

Development of profile-based time-series power flow simulations in DPsim

During the reporting period, a general functional time-series power flow simulation workflow was successfully developed. Figure 5 illustrates the workflow of the developed time-series power flow simulation framework. The process starts with the user providing the required simulation inputs, including the CIM network model, time-series power profiles, and optional scenario-specific scaling factors. The CIM model is imported into DPsim with its CIMReader class, which maps the components of the CIM in CGMES 2.4.15 standard to simulation objects inside the DPsim environment. The network topology and corresponding simulation objects are automatically generated through this CIMReader.

Subsequently, the power profile data is loaded and mapped to the respective network components. After the initialization of the power flow solver, the simulation enters an iterative time-series loop. For each timestep, the corresponding profile values are assigned to the associated CIM components, such as loads and generation units without reimporting the CIM in each timestep. User-defined weighting factors can then be applied to modify the active and reactive power values to analyse alternative operating conditions and future planning scenarios. Based on the updated component setpoints, a power flow calculation is executed for the current timestep. One simulation timestep of the NRP solver corresponds to one row of the given power flow profile. In the later described use-cases one power flow time step corresponds to one hourly setpoint change.

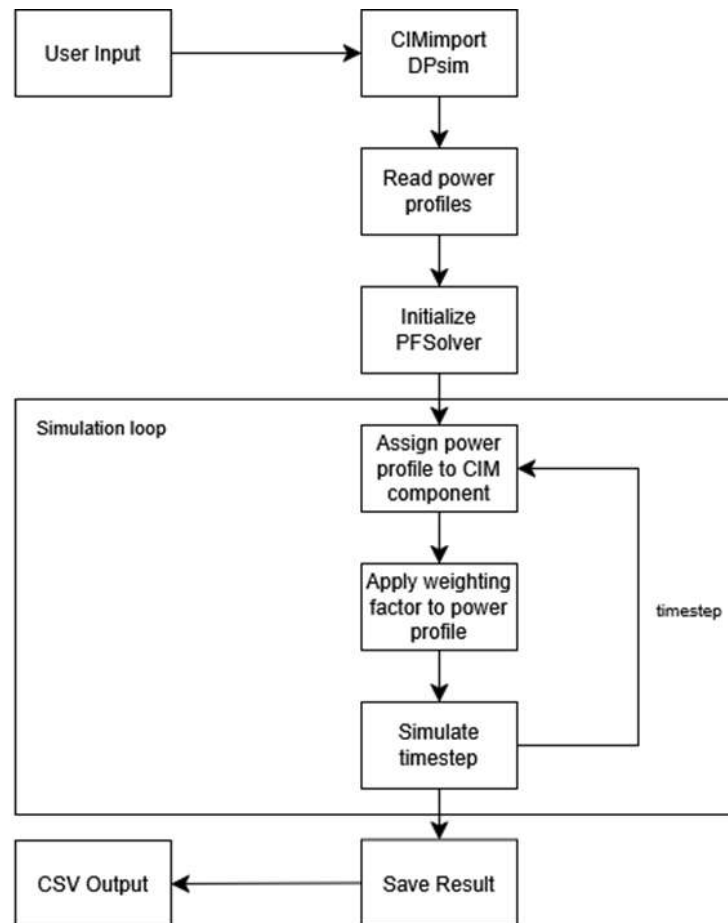


Figure 5: Workflow of power flow simulation with power profiles for IPTO case

The resulting network state, including bus voltages, branch currents, and power injections, are stored inside the result CSV before the simulation advances to the next timestep. This procedure is repeated until all profile entries have been processed. Finally, the simulation results are exported in CSV format, enabling further post-processing, visualization, and integration into the Crete Valley DT platform. The simulation expects certain data inputs from the user:

Table 1: Data inputs for timeseries power flow simulations

Description	Data type	Default value
CIM	Zipped XML files	-
Timeseries power profile	XLSX	-
load_factor	Float	1.0
gen_factor	Float	1.0
pv_factor	Float	1.0
wind_factor	Float	1.0

For a successful network import, the Equipment (EQ) and Topology (TP) profiles are required. The EQ profile contains the electrical equipment data, including lines, transformers, loads, generators, shunt elements, and external network injections, while the TP profile provides the topological connectivity between these elements through terminals and topological nodes.

In addition, the SSH profile is used to initialize the operational state of the network. The SSH profile provides operating point information such as active and reactive power injections, generator dispatch values, and transformer tap positions. This information is required to establish a realistic network state prior to the execution of power flow simulations.

Optionally, State Variable (SV) profiles can be imported to provide voltage magnitudes, voltage angles, and power flow values from an existing network state. When available, these values can be used to improve the initialization of the power flow calculation. However, the import and simulation workflow remains functional without SV data, as the power flow solver can determine the network state from the imported network model and steady-state operating conditions.

In addition to the CIM network model, the time-series power profiles must follow a predefined XLSX structure. The profile file contains one sheet for active power setpoints and one sheet for reactive power setpoints. In both sheets, the first column contains the timestamp information, while the remaining columns contain the time-dependent setpoints for the corresponding network components. The column names of the power profile file must match the component names defined in the CIM model. This enables a direct mapping between the imported profile data and the DPsim simulation objects. Compared to the previous implementation, where a replacement map was required to translate profile names to CIM component names, the updated workflow no longer requires this additional mapping step. This simplifies the preprocessing process, reduces the risk of assignment errors, and improves the transparency of the simulation input data.

During each simulation timestep, the active and reactive power values are imported from the respective sheets and assigned to the matching components in the DPsim model. The timestamp column defines the chronological order of the simulation and allows the results to be stored with the corresponding date and time information.

The resulting workflow is largely independent of the underlying network model and profile dataset, making it suitable for the integration of additional grid use cases and future extensions with only minor configuration changes.

IPTO case (TSO)

During the reporting period, as previously mentioned, IPTO updated operational profile data, providing hourly active and reactive power measurements for a complete year of operation. These measurements form the basis for realistic time-series simulations and enable the evaluation of network behaviour under varying operating conditions throughout the year.

In parallel, the existing CIM network model of the transmission system was further refined and extended. The original model contained several aggregated representations of generation and load assets, which limited the level of detail available for scenario analysis. To improve modeling accuracy, these aggregated elements were separated into individual network components. Static generation units and their associated loads are now represented as distinct objects, allowing generation and demand to vary independently during simulation studies.

Following this distinction, a flexible scaling mechanism was implemented for all major load and generation categories. Individual weighting factors can now be applied to conventional generation, photovoltaic generation, wind generation, and electrical loads. This enables the systematic investigation of alternative operating scenarios, such as increased renewable penetration, future demand growth, or changes in the generation mix, without requiring modifications to the underlying network model or profile dataset.

At the end of the reporting period, the complete IPTO simulation workflow was successfully deployed within the Crete Valley DT, enabling automated execution of time-series simulations together with result management and visualization capabilities.

HEDNO case (DSO)

During the reporting period, a fully functional CIM network model for the HEDNO distribution grid was obtained and successfully integrated into the DPsim simulation workflow. The model was provided in CGMES format and could be imported using the developed CIM-based interface, allowing the automatic generation of the corresponding DPsim network representation.

In addition to the network model, estimated load and generation profiles were provided for the DSO use case. While measured operational data is not yet available, the estimated profiles provide a basis for initial simulation studies and enable the development and validation of the time-series simulation workflow for the distribution grid. The profile structure follows the same generic format as used for the TSO use case, ensuring compatibility with the common simulation framework and facilitating future integration of measured data.

The successful import and simulation of the DSO network represent an important milestone towards the integration of the distribution grid into the Crete Valley Digital Twin. The use of a common CIM-based modeling and simulation approach for both transmission and distribution systems establishes a consistent foundation for future studies involving coordinated TSO–DSO operation and flexibility assessments.

Case study

The case studies presented in this section are based on the Crete island electrical transmission network model provided by IPTO. The model represents a projected future configuration of the Cretan power transmission system and serves as the reference network for all subsequent power flow analyses and scenario evaluations.

The electrical power system of Crete island consists of a 150 kV high voltage transmission network, three thermal power plants based on conventional fuels allocated at the two ends and the center of the island, dispersed RES generation units connected to the medium voltage network and electrical load. The initial design of the system and the power stations aimed at the islanded operation of the electrical system. However, on December 2020 the Crete power system was interconnected to the Hellenic mainland system through an AC submarine link of a 200 MVA capacity. Except for the AC link, an HVDC link has been constructed connecting Crete with Attica, Greece, and became fully operational within 2025, offering a transferring capacity of 1000 MW



(Karystianos, et al., 2021). The interconnections of Crete with the mainland provide stability to the island power system, increase the hosting capability for RES units, and finally enables the decommissioning of conventional power plants and the transition to a sustainable power system based on RES, enabling the creation of a REVs.

The expected system topology is provided in the single line diagram, Figure 6, that depicts the HV/MV substations of the system and the transmission lines connecting them. Most of the substations are designed to supply the electricity demand and receive the production from dispersed RES stations connected at the MV network, whereas some of them have been built to host RES stations in rural areas. The HVAC link connects Chania GIS station in Crete with Sklavouna station in Peloponnese, and through another overhead line to the mainland power system, which is defined as the slack bus for the power flow simulations. The HVDC link is simulated as a synchronous generator providing/absorbing active power and maintaining the voltage at its nominal value by its Q-V control, connected at Damasta substation in Crete. The main operating conditions projected for the Cretan power system in 2030 are summarized below:

- Load: 9.4% increase in energy demand by 2030 in relation to 2025, with an annual demand of 3110 GWh (Independent Power Transmission Operator, 2025).
- RES: Installed capacity of 624 MW (normal penetration) and 1300 MW (extreme penetration) by 2030 (Independent Power Transmission Operator, 2025)
- Conventional: Gradually closed until the complete disconnection in 2030.

The power system is expected to have the specified topology of Figure 6 in 2030 (Independent Power Transmission Operator, 2024), provided that the transmission grid reinforcement projects are completed on schedule. (Independent Power Transmission Operator, 2024)

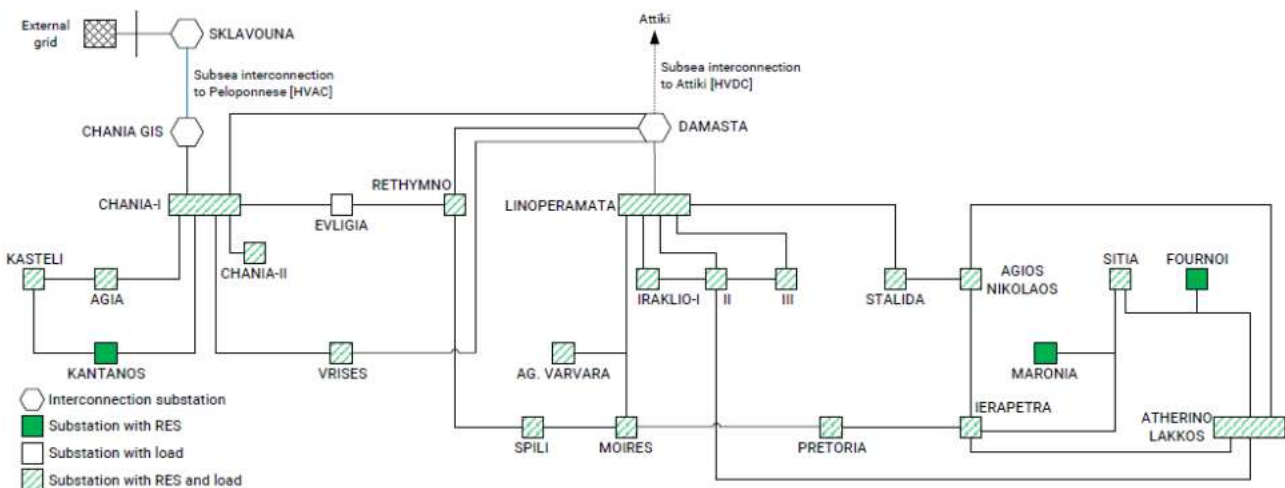


Figure 6: Single line diagram of HV grid of Crete, as planned for 2030 (Independent Power Transmission Operator, 2024)

The diversity of generation assets allows the investigation of different operational conditions, including variations in renewable generation and electricity demand. Additionally, the generation unit “Damasta” mimics the power cable between Athens and Crete. The power setpoint of “Damasta” is calculated from the power difference of total load and total generation of the system so that there is an equilibrium of power.

The Crete 2030 model was imported into the DT environment using the CIM-based workflow developed during this reporting period, as described earlier. Time-series power flow simulations were subsequently performed using DPsim, enabling the assessment of network behaviour under different operating scenarios. The baseline scenario represents the expected operating conditions derived from the available power profiles and serves as the reference case against which all modified scenarios are compared.

TSO case – baseline scenario

For the baseline scenario, the simulation results are evaluated using three main groups of quantities. First, the voltage magnitudes of all buses are analysed over the selected simulation period to assess the overall voltage profile of the network and identify possible voltage deviations at different voltage levels. Second, the current magnitudes of all branches are plotted to evaluate the loading of lines and transformers and to identify the most heavily loaded network elements. Third, the active power balance of the system is investigated by comparing the total load, local generation, and the active power exchanged with the external grid connection. This provides an overview of how the internal generation, and the external grid contribution supply the demand of the Crete 2030 system during the baseline operating condition. All simulation plots are selected to show the results of the power profiles measured from 01 January to 08 January (1 week) for reader's convenience.

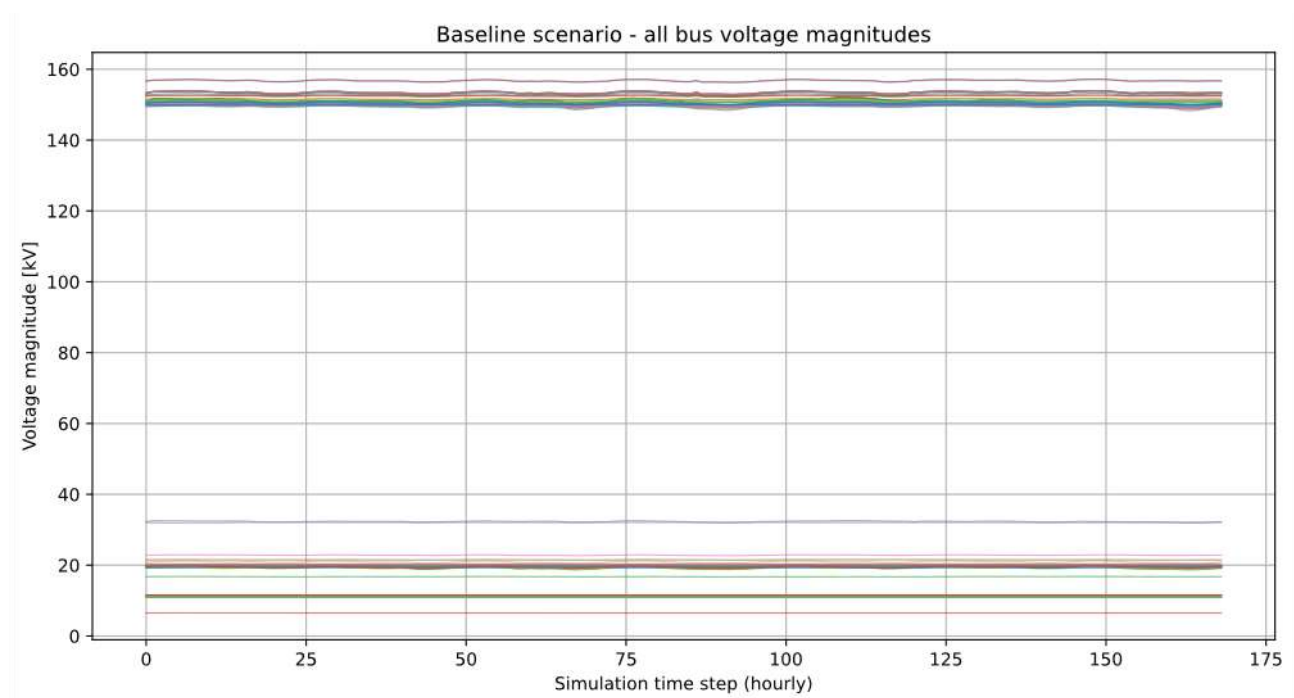


Figure 7: Bus voltage magnitudes of baseline scenario

The baseline simulation indicates a stable operating condition of the Crete network throughout the analysed period. The voltage magnitude results show a clear separation between the different voltage levels present in the system. The high-voltage buses operate close to their nominal voltage level of approximately 150 kV, while the medium-voltage buses remain clustered around their respective nominal voltages (20KV), Figure 7. Only small voltage variations can be observed over

time, indicating that the network is able to accommodate the changing load and generation profiles without significant voltage deviations. No voltage instability or critical voltage drops are visible in the simulated period.

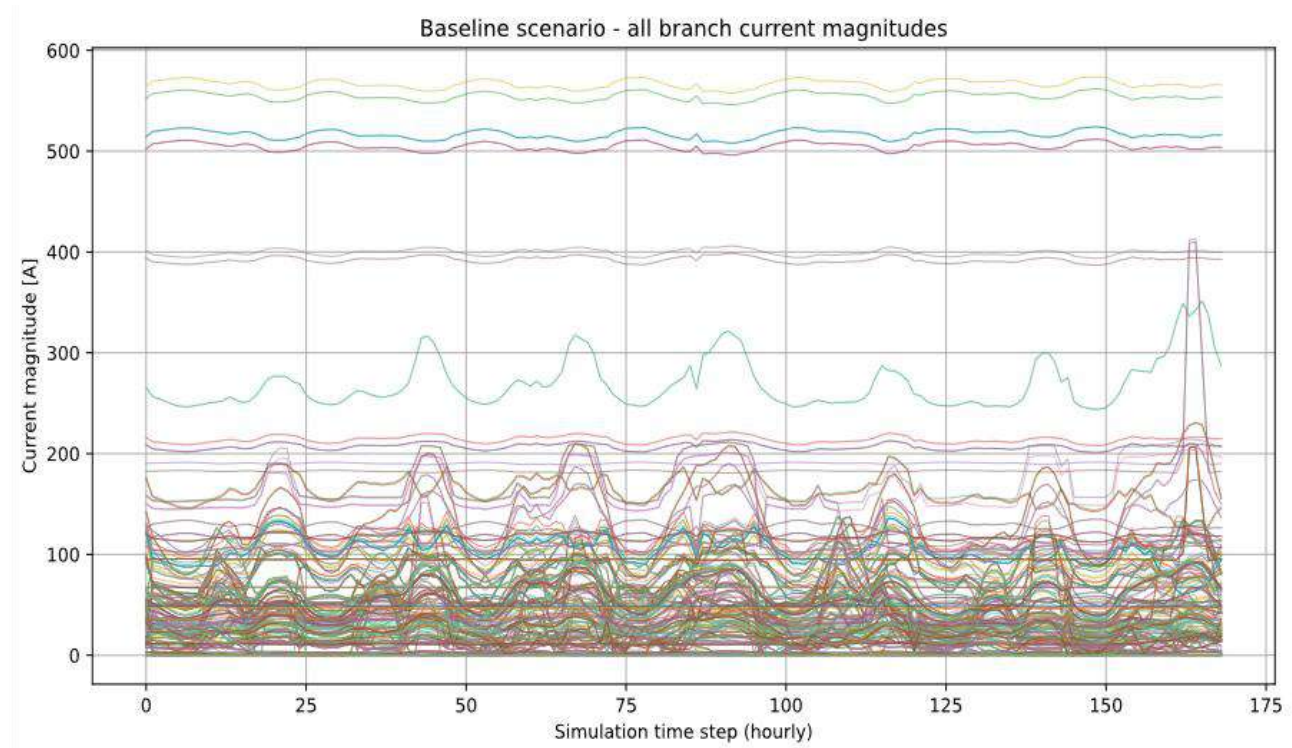


Figure 8: Branch current magnitudes of baseline scenario

The branch current magnitudes exhibit a larger temporal variation than the bus voltages, reflecting the changing power flows caused by varying demand and generation, Figure 8. Several transmission corridors carry substantially higher currents than the rest of the network, with peak values approaching 550–570 A, while most branches operate well below 200 A. The periodic variations visible in many branch currents correspond to the daily fluctuations of load and renewable generation. Despite these variations, all branch currents remain bounded, and no signs of congestion or abnormal operating conditions are observed in the baseline scenario.

Overall, the baseline scenario demonstrates a well-behaved operating point of the Crete network. Voltage levels remain within acceptable ranges, branch loadings are moderate, and the local generation portfolio can supply most of the system demand during the considered time-period. These results provide the reference operating condition against which the subsequent sensitivity scenarios can be evaluated.

TSO case – projected increased load scenario for 2030

To investigate a future operating condition with increased dependency on RES, a projected load scenario was simulated in which the system load was increased by 9.4% compared to the baseline, while all conventional generation units were assumed to be unavailable. Renewable generation profiles for photovoltaic and wind power remained unchanged. Consequently, the additional

demand must be supplied by the available renewable generation and increased power imports from the Greek mainland. This scenario represents a possible future operating condition with higher electricity demand and reduced dispatchable generation capacity.

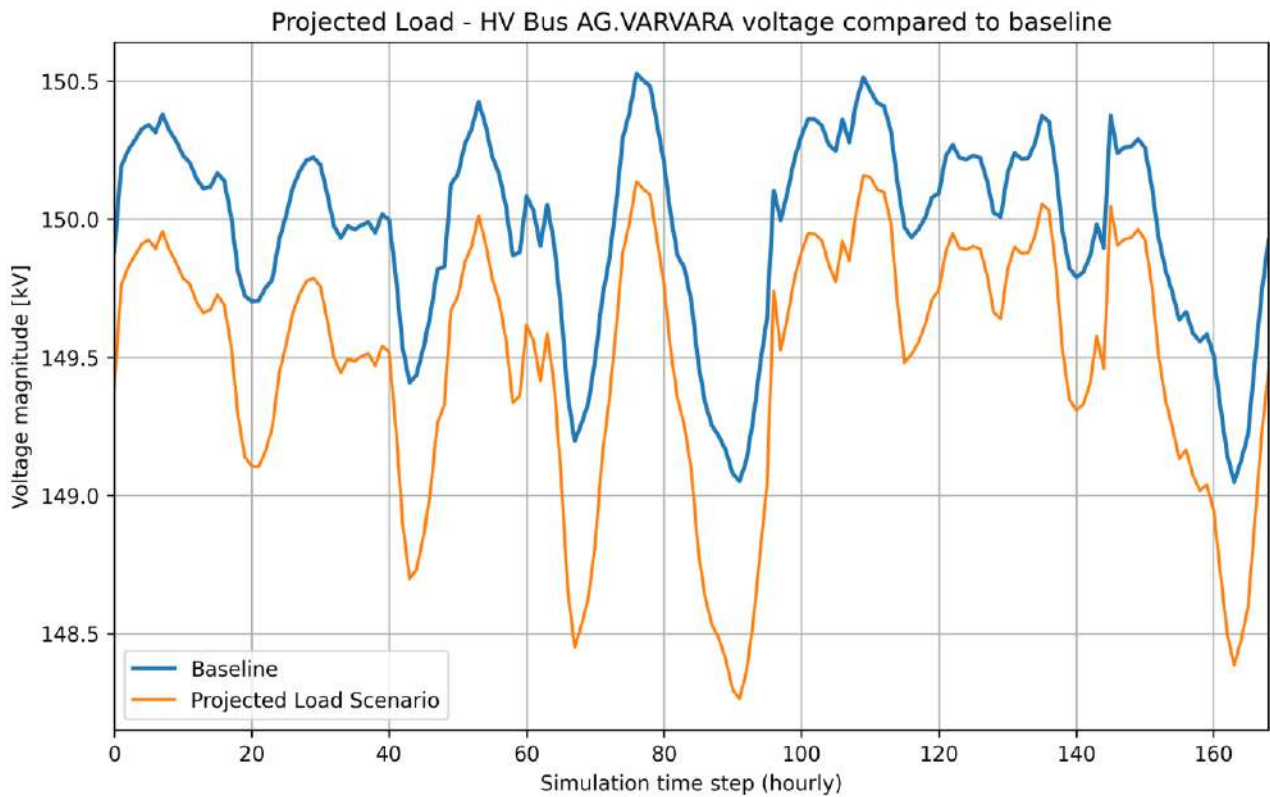


Figure 9: Comparison of the HV bus voltage magnitude at AGIA VARVARA for the baseline case and the projected load scenario

Figure 9 compares the voltage magnitude at the HV bus AGIA VARVARA for the baseline case and the projected load scenario. Despite the increased electricity demand and the absence of conventional generation, the voltage profile remains stable throughout the simulation period and follows the same daily and seasonal trends as the baseline. A slight reduction in voltage magnitude can be observed over most of the simulation period, which is expected due to the increased loading of the transmission network and the higher dependence on imported power. No voltage stability issues or convergence problems were observed during the time-series simulation, demonstrating the robustness of the implemented power flow calculation under the investigated operating conditions.

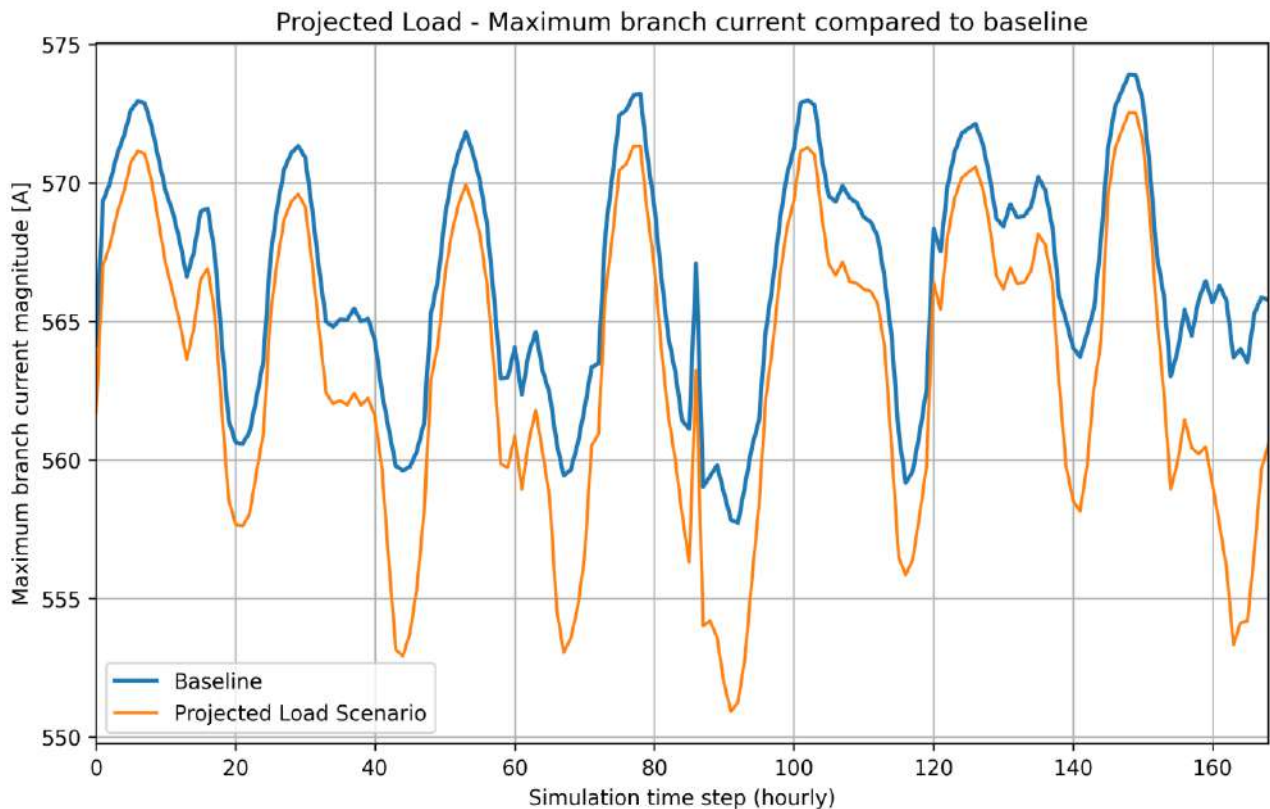


Figure 10: Maximum branch currents comparison for baseline case and projected load scenario

Figure 10 shows the maximum branch current in the transmission network for both scenarios. The cable carrying the maximum current is the HVAC connection to the mainland which connects the nodes MOLAOI T1 and MOLAOI SC1. The HVAC connection is the carrier of the maximum current for every other scenario as well. The overall temporal behaviour closely follows that of the baseline, indicating that the general loading pattern of the network remains unchanged. Although the projected load scenario exhibits slightly lower maximum branch currents during most of the simulation period, this behaviour indicates that the removal of conventional generation alters the distribution of power flows within the network. Rather than uniformly increasing the loading of the most heavily loaded branch, the changed generation pattern redistributes the power transfers across the transmission system, resulting in only minor differences in the observed maximum branch current.

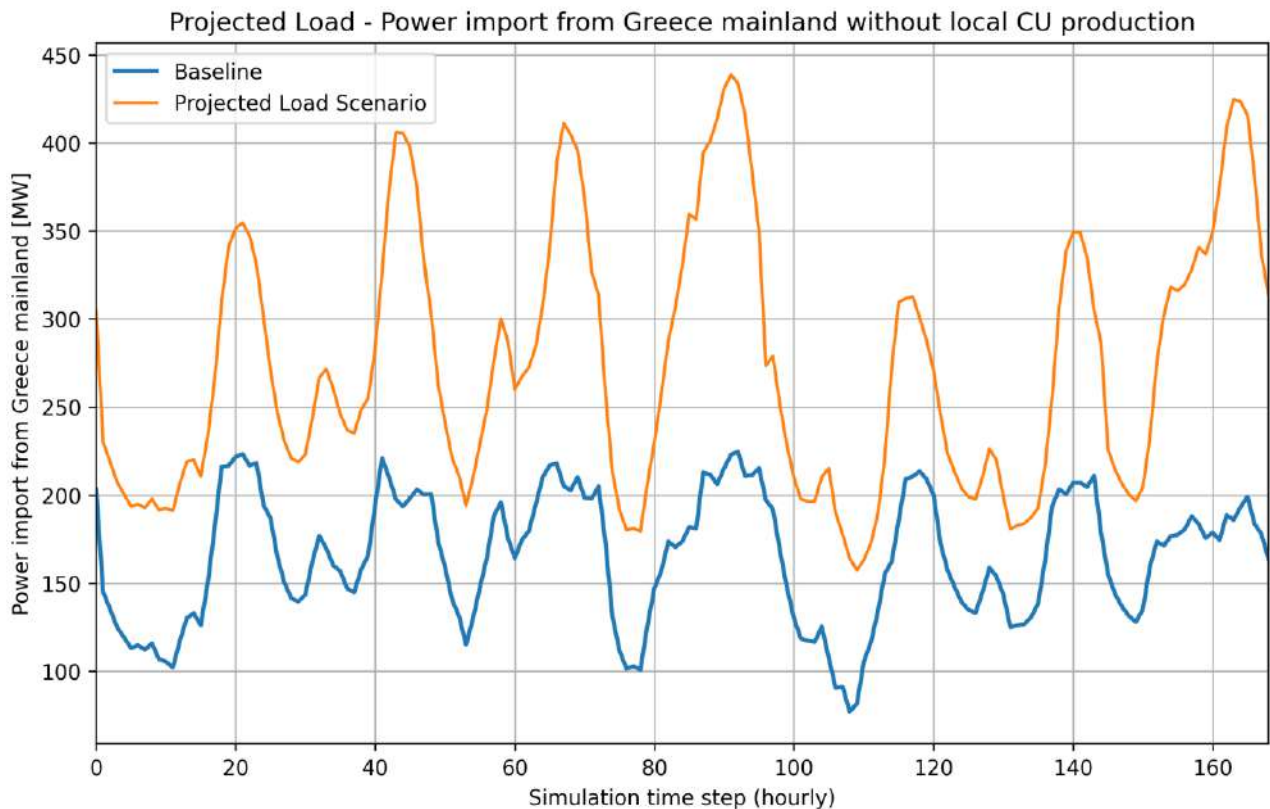


Figure 11: Comparison of the imported power from the Greek mainland for the baseline case and the projected load scenario

The most significant impact of the projected load scenario can be observed in the imported power from the Greek mainland, as shown in Figure 11. The shown total imported power is the summation of the imported power of both interconnections from the mainland. Compared to the baseline, imported power increases substantially throughout the entire simulation period. This behaviour results from the combination of higher electricity demand and the complete absence of local conventional generation, leaving renewable generation and the mainland interconnection as the primary sources for meeting the system load.

During periods of low renewable generation, the imported power reaches considerably higher peak values than in the baseline case, illustrating the increased reliance on the interconnection to maintain the generation-demand balance. These results highlight the important role of dispatchable conventional generation in reducing external energy dependency and demonstrate how its removal significantly increases the required import capacity under higher demand conditions.

TSO case – projected RES increase for 2030

To evaluate the impact of increased renewable energy integration, a projected RES scenario was simulated. In this scenario, photovoltaic generation was increased by a factor of 2.5 and wind generation by a factor of 1.6 compared to the baseline, representing the normal RES penetration scenario, while all conventional generation units were assumed to be unavailable. The system load remained unchanged. As a result, the local electricity demand is supplied primarily by renewable generation, with the mainland interconnection balancing any remaining power deficit or surplus.

This scenario represents a possible future operating condition with significantly higher renewable penetration and a complete phase-out of conventional generation.

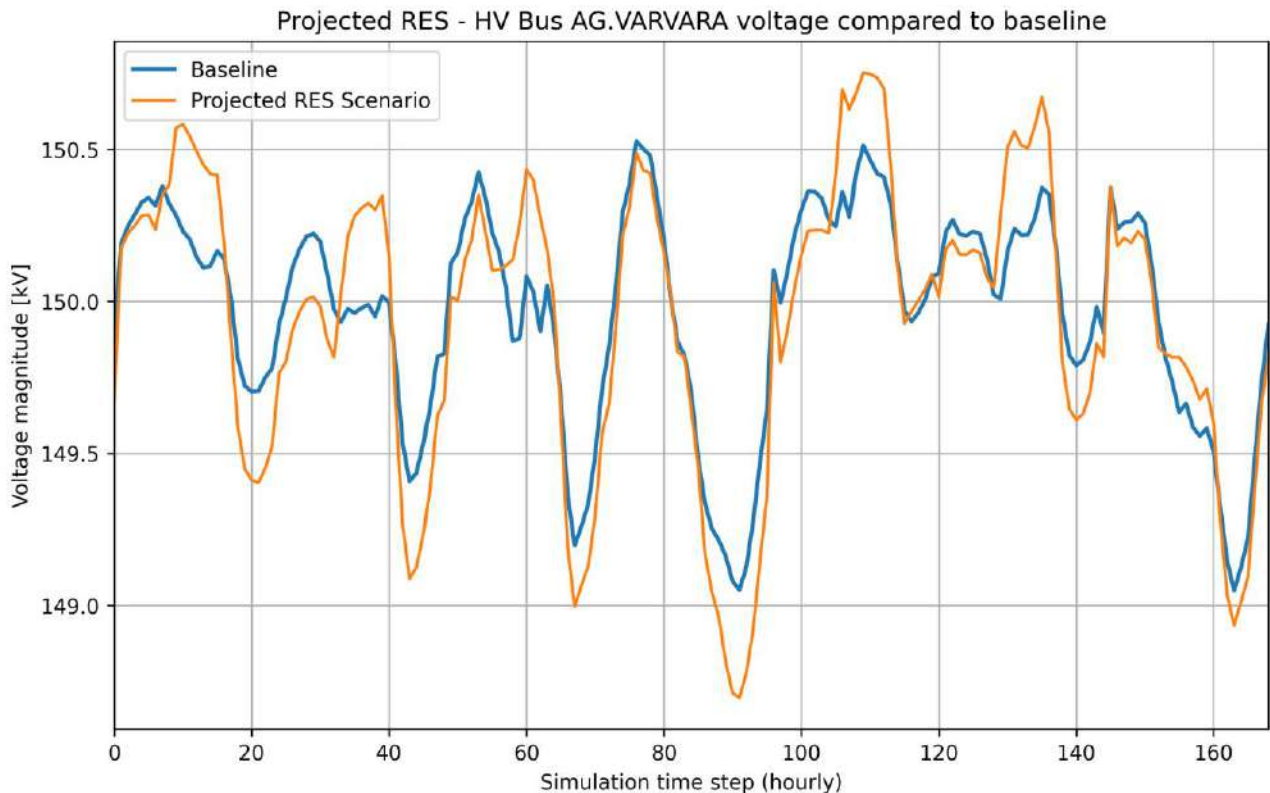


Figure 12: Comparison of the HV bus voltage magnitude at AGIA VARVARA for the baseline case and the projected RES scenario

Figure 12 compares the voltage magnitude at the HV bus AGIA VARVARA for the baseline case and the projected RES scenario. In this analysis, the RES units are modelled as fixed active- and reactive-power injections and do not provide automatic voltage regulation. Furthermore, the transformer tap positions remain fixed throughout the simulation, as no on-load tap-changer control is applied. The observed voltage variations therefore result directly from the modified power injections and resulting network power flows. Despite the considerable increase in renewable generation and the absence of conventional generation, the voltage profile remains stable throughout the simulation period. Compared to the baseline, slightly higher voltage magnitudes can be observed during periods of high renewable generation, while lower voltages occur during periods of reduced renewable output. Consequently, the voltage profile exhibits larger temporal variations, reflecting the increased dependence of the network operating point on the availability of renewable resources. Nevertheless, all observed voltage variations remain within a stable operating range during the entire simulation period.

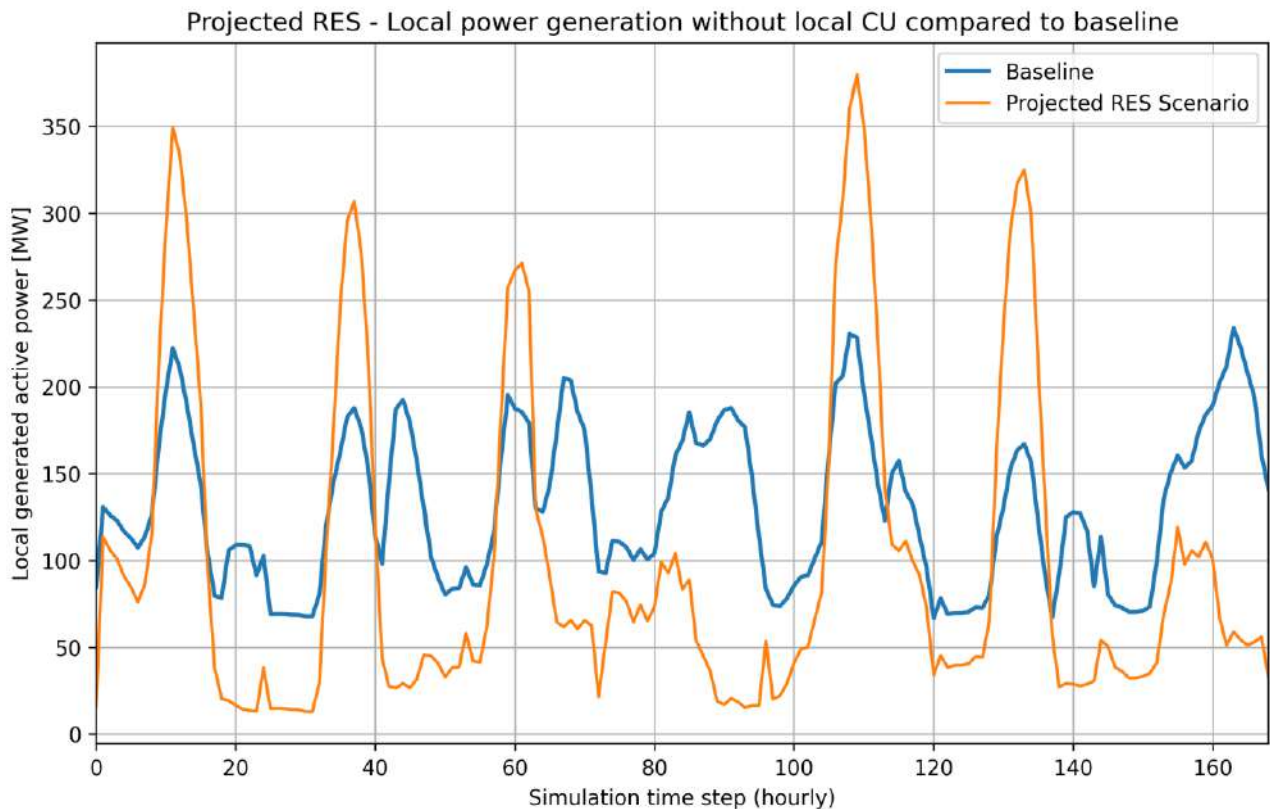


Figure 13: Comparison of locally generated active power for the baseline case and the projected RES scenario

Figure 13 compares the locally generated active power for the baseline case and the projected RES scenario. Since all conventional generation units are assumed to be unavailable, local power production is entirely determined by photovoltaic and wind generation. As a result, the generated power exhibits significantly greater temporal variability than in the baseline case, closely following the availability of renewable energy resources.

During periods of high renewable production, the projected RES scenario achieves substantially higher local generation than the baseline, with peak values exceeding 350 MW. Conversely, periods of low renewable availability result in considerably lower local generation, as no dispatchable conventional units are available to compensate for the reduced renewable output. This increased variability directly influences the amount of power exchanged with the Greek mainland, requiring higher imports during renewable deficits and enabling exports when renewable generation exceeds the local demand.

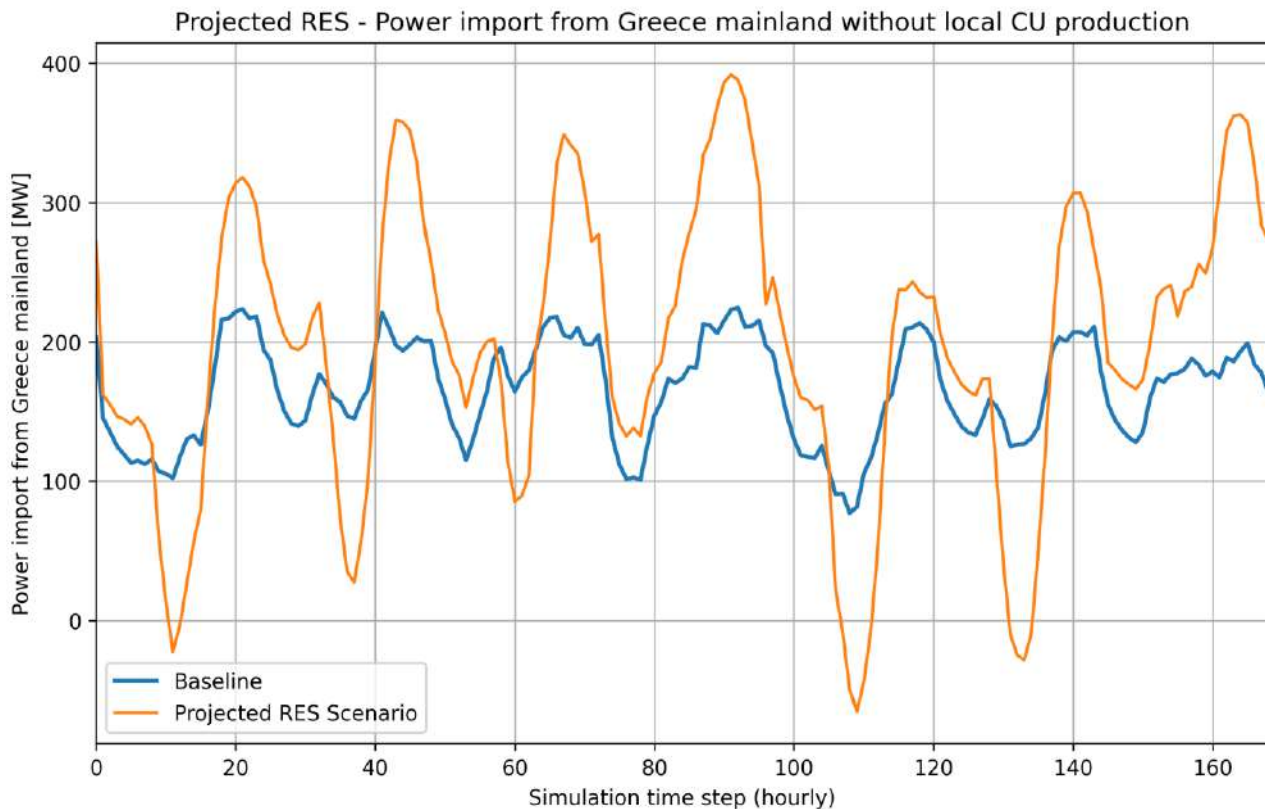


Figure 14: Comparison of the imported power from the Greek mainland for the baseline case and the projected RES scenario

The influence of the increased renewable generation is most clearly visible in the imported power from the Greek mainland, shown in Figure 14. Compared to the baseline, the imported power is substantially reduced during periods of high renewable generation and, in several time intervals, becomes negative. Negative values indicate that renewable production exceeds the local electricity demand, resulting in power export from Crete to the Greek mainland through the interconnection.

Conversely, during periods of low renewable production, imports from the mainland remain necessary to satisfy the local demand because no conventional generation is available within the island. The imported power therefore exhibits significantly larger variations than in the baseline case, illustrating the increased dependence of the transmission system on the variability of renewable energy sources. These results demonstrate that high renewable penetration can considerably reduce the reliance on imported electricity and may even enable temporary power exports under favourable generation conditions.

Overall, the results demonstrate that increasing renewable generation significantly raises the potential for local electricity production while simultaneously increasing its dependence on weather conditions. Consequently, the transmission system experiences larger fluctuations in local generation, highlighting the importance of the mainland interconnection for balancing supply and demand in a highly renewable energy system.

TSO case – projected RES and load combined scenario

The third scenario combines the assumptions of the projected load and projected RES scenarios to evaluate a future operating condition with both increased electricity demand and a significantly

higher share of renewable generation. The system load was increased by 9.4% compared to the baseline, photovoltaic generation was scaled by a factor of 2.5, and wind generation by a factor of 1.6. At the same time, all conventional generation units were assumed to be unavailable. Consequently, the local electricity demand is supplied exclusively by renewable generation and power exchanged through the interconnection with the Greek mainland. This scenario represents a possible long-term operating condition with increased electrification, high renewable penetration, and a complete phase-out of local conventional generation.

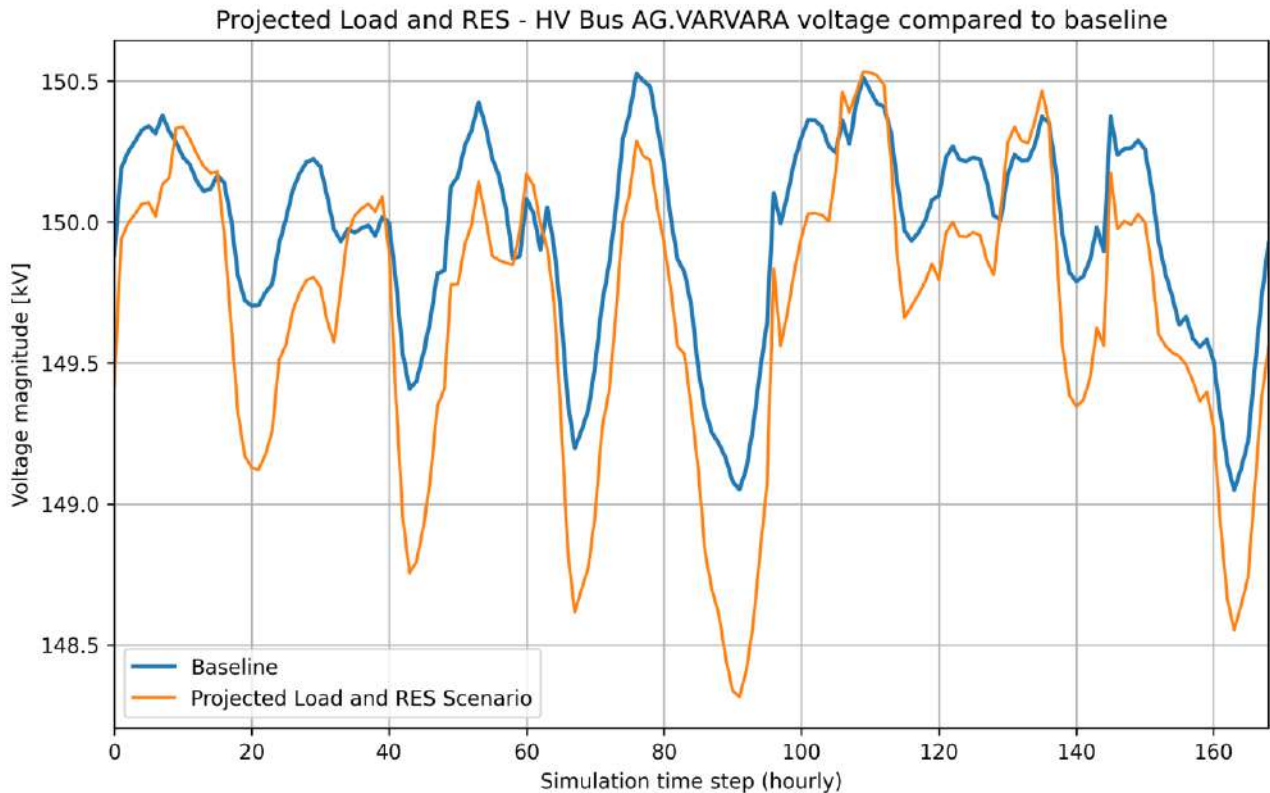


Figure 15: Comparison of the HV bus voltage magnitude at AGIA VARVARA for the baseline case and the combined projected load and RES scenario with increased electricity demand, increased renewable generation, and no local conventional generation

Figure 15 compares the voltage magnitude at the HV bus AGIA VARVARA for the baseline case and the combined projected load and RES scenario. The overall voltage profile remains stable throughout the simulation period and continues to follow the same temporal behaviour as the baseline. Compared to the baseline, slightly lower voltage magnitudes are observed during periods of low renewable generation, when increased electricity demand must be supplied primarily through imports from the Greek mainland. Conversely, periods of high renewable production result in voltage levels comparable to or slightly above the baseline. These variations reflect the combined influence of increased loading and highly variable renewable generation on the network operating point. Despite these changes, no voltage stability or convergence issues were observed during the simulation.

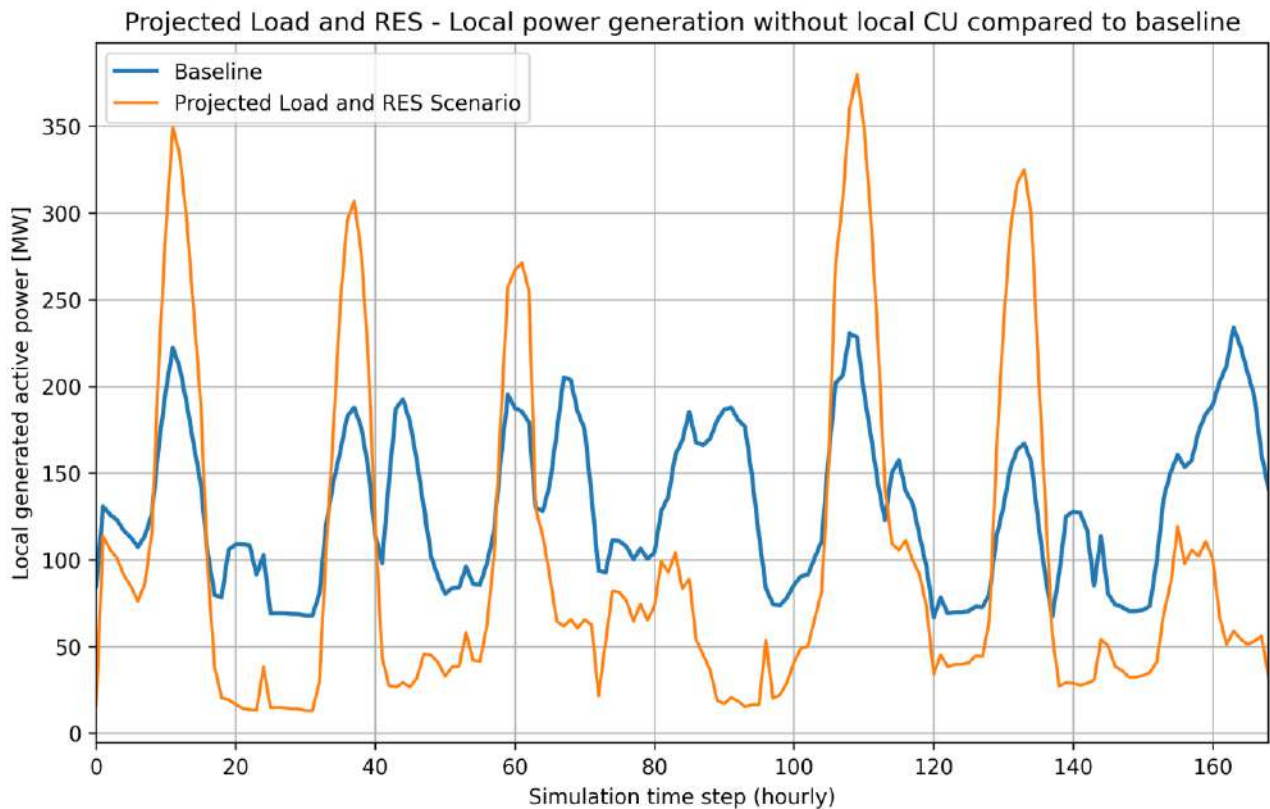


Figure 16: Comparison of locally generated active power for the baseline case and the combined projected load and RES scenario

Figure 16 compares the locally generated active power for the baseline case and the combined projected load and RES scenario. Since conventional generation is unavailable, local generation is entirely supplied by photovoltaic and wind resources. As in the projected RES scenario, the renewable generation exhibits considerably greater temporal variability than the baseline, with periods of very high production alternating with intervals of low renewable availability.

Peak local generation substantially exceeds the baseline during favourable renewable conditions, while production drops significantly during periods of limited solar and wind resources. Although the electricity demand is higher in this scenario, the local renewable generation profile remains primarily determined by weather conditions rather than the system load. Consequently, periods of renewable surplus and deficit become more pronounced, increasing the importance of the mainland interconnection for balancing the system.

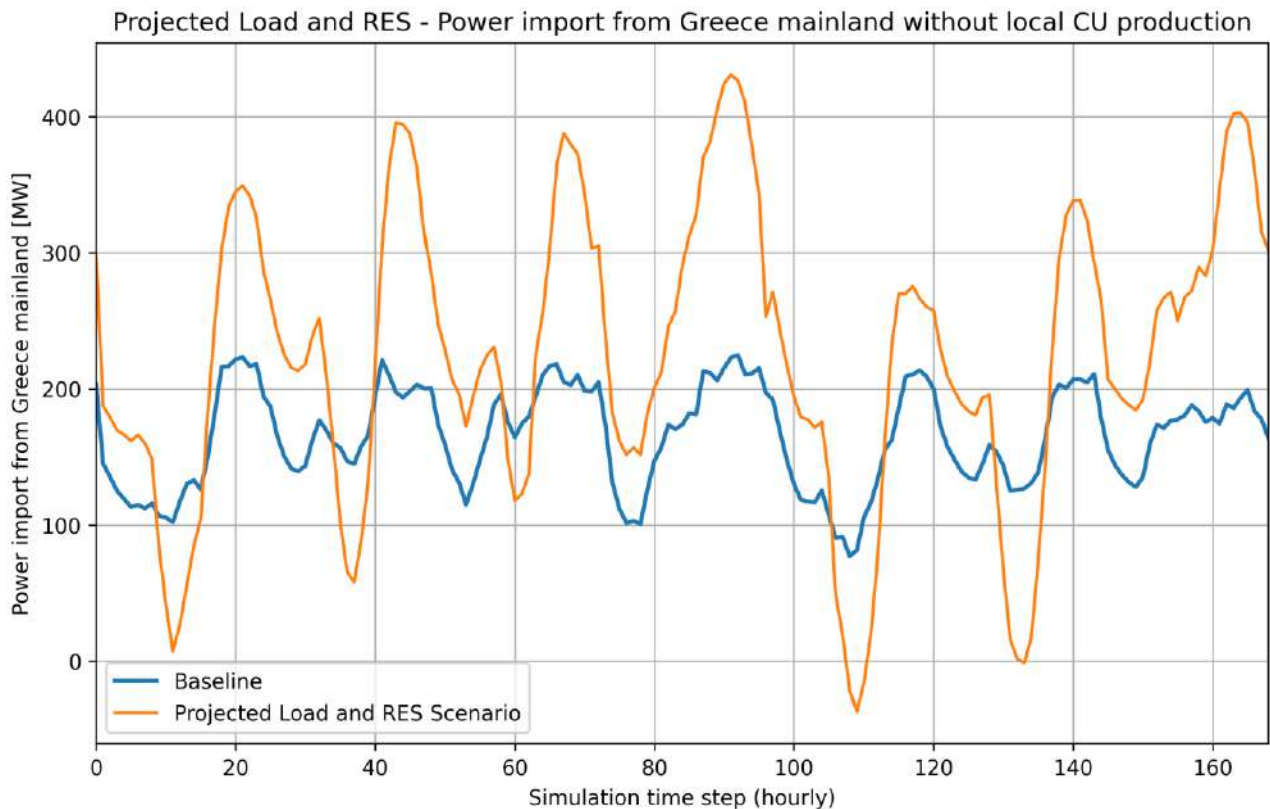


Figure 17: Comparison of the imported power from the Greek mainland for the baseline case and the combined projected load and RES scenario

Figure 17 illustrates the imported power from the Greek mainland for the baseline case and the combined projected load and RES scenario. Again, the plotted imported power is the summation of power import of both interconnections to the mainland. The interaction between increased electricity demand and highly variable renewable generation leads to considerably larger fluctuations in imported power than in the previous scenarios. During periods of low renewable production, imports increase substantially above the baseline to compensate for both the higher demand and the absence of conventional generation. In contrast, periods of high renewable generation significantly reduce the required imports and even result in temporary power exports to the mainland when local renewable production exceeds the system demand.

Compared to the previous scenarios, the combined scenario exhibits the widest range of power exchange across the interconnection. This demonstrates that while increased renewable penetration can substantially reduce dependence on imported electricity, the simultaneous increase in electricity demand offsets part of this benefit during periods of low renewable availability. The results highlight the increasingly important role of the mainland interconnection in maintaining the balance between generation and demand under future operating conditions with high renewable penetration and no dispatchable conventional generation.

TSO case – Extreme RES scenario

The extreme RES scenario represents a future operating condition with a very high penetration of renewable energy sources. Compared to the baseline, the system load was increased by 9.4%, photovoltaic generation was scaled by a factor of 4.3, and wind generation by a factor of 3.9. In

addition, all conventional generation units were assumed to be unavailable. Under these conditions, the electricity demand is supplied almost entirely by renewable generation, while the interconnection with the Greek mainland is used to compensate for renewable deficits and export surplus renewable energy. This scenario investigates the impact of very high renewable penetration on the operation of the Crete transmission network.

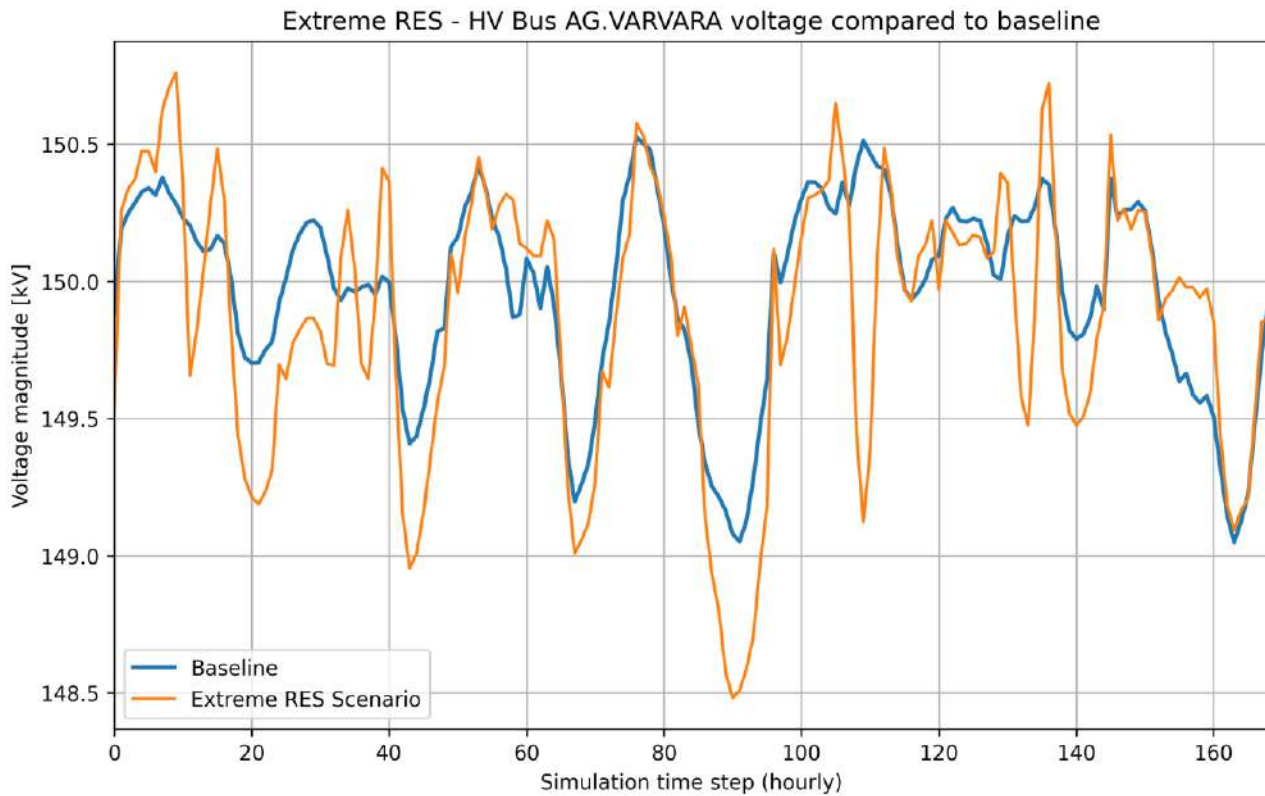


Figure 18: Comparison of the HV bus voltage magnitude at AGIA VARVARA for the baseline case and the extreme RES scenario with significantly increased photovoltaic and wind generation, increased load, and no local conventional generation

Figure 18 compares the voltage magnitude at the HV bus AGIA VARVARA for the baseline case and the extreme RES scenario. Compared with the previous scenarios, the extreme RES case produces larger voltage deviations due to the substantially modified active- and reactive-power flows. Periods of high renewable generation generally result in higher local voltage magnitudes, whereas lower renewable availability and increased imported power lead to lower voltage levels. In these simulations, the RES units are represented by prescribed active- and reactive-power injections and do not provide automatic voltage regulation. In addition, the transformer on-load tap changers are not activated, and their tap positions remain fixed throughout the simulation. Consequently, the observed voltage variations result directly from the changed power injections and network loading rather than from corrective voltage-control actions. Nevertheless, the calculated voltages remain within the considered operating range and the power-flow simulation converges for all analysed time steps.

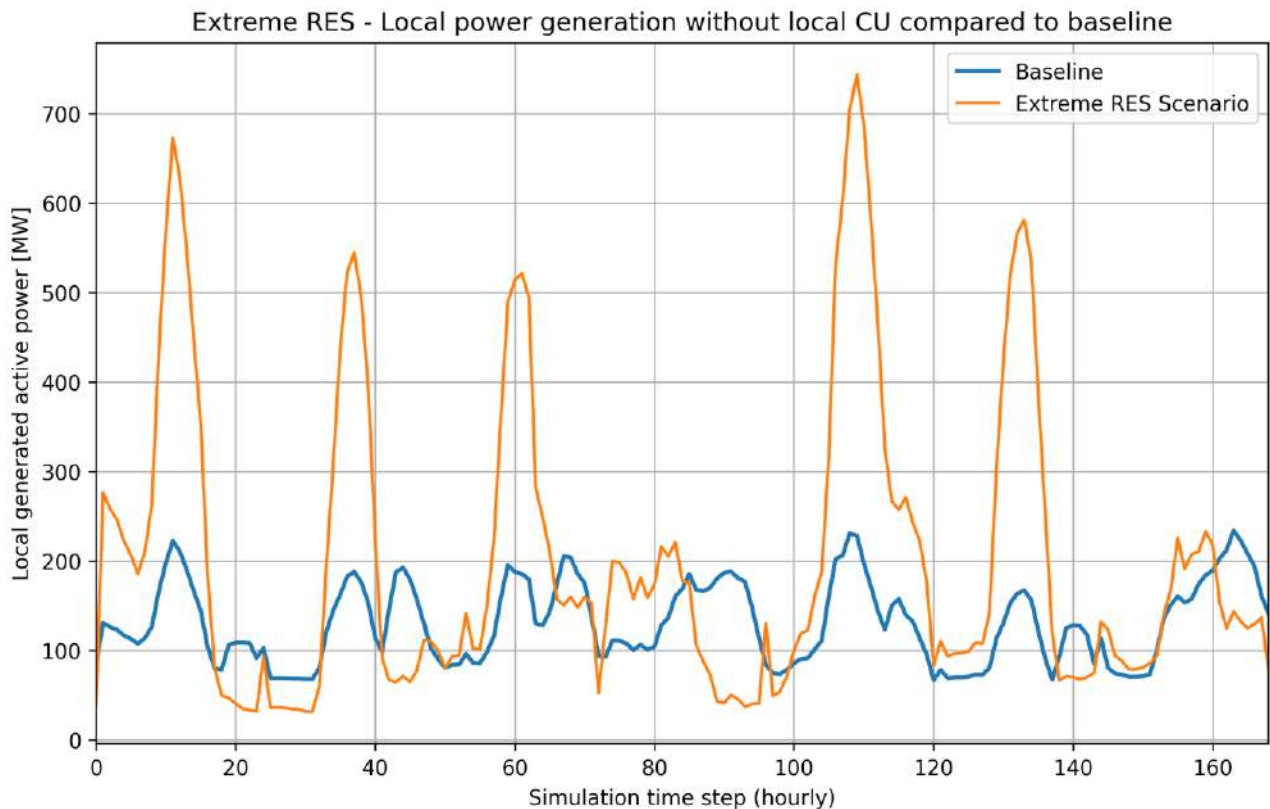


Figure 19: Comparison of locally generated active power for the baseline case and the extreme RES scenario

Figure 19 compares the locally generated active power for the baseline case and the extreme RES scenario. The considerably increased photovoltaic and wind capacities lead to a substantial increase in local renewable generation, with peak values exceeding 700 MW. These peaks are significantly higher than those observed in both the baseline and the previous projected RES scenarios.

At the same time, local generation remains highly dependent on weather conditions. Periods of low renewable availability still result in comparatively low generation levels because no conventional generation is available to provide dispatchable power. Consequently, the local generation profile exhibits pronounced fluctuations throughout the simulation period, alternating between periods of renewable surplus and renewable deficits. These results illustrate the challenges associated with operating a power system dominated by variable renewable energy sources.

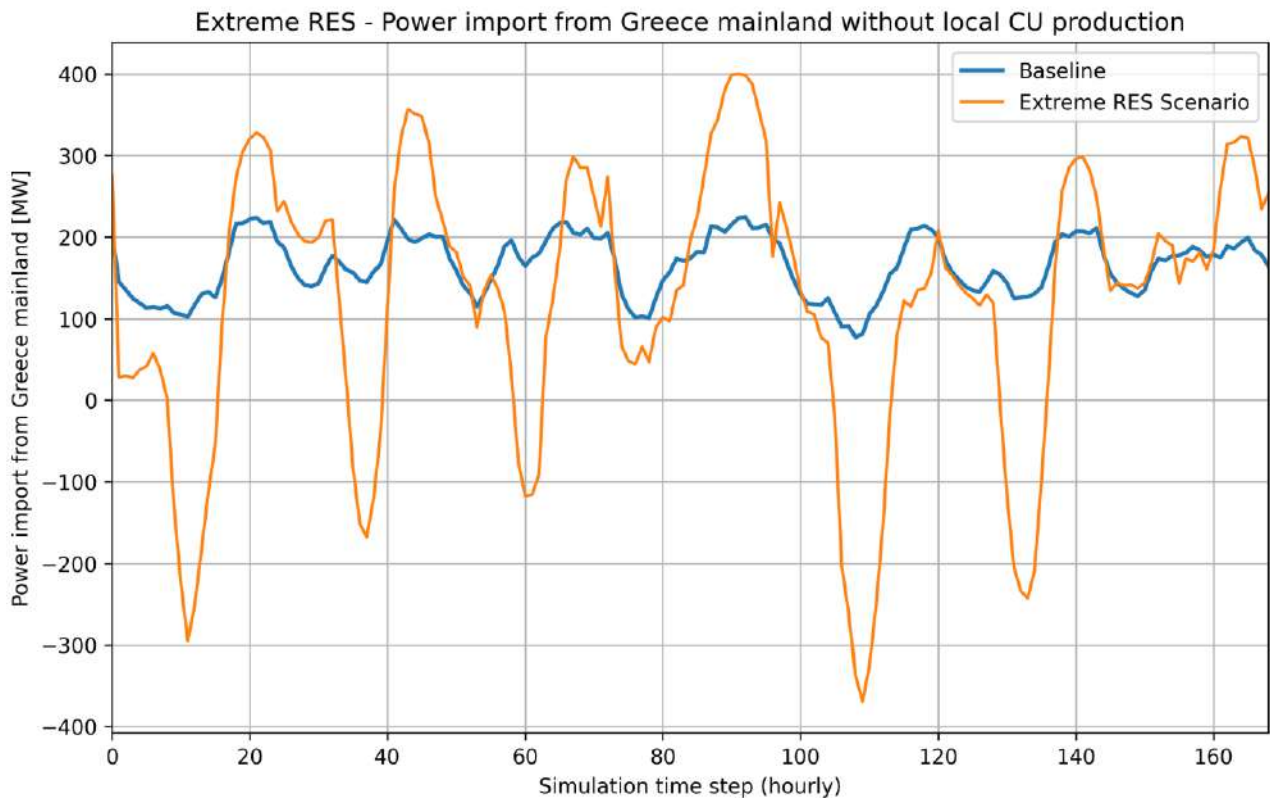


Figure 20: Comparison of the imported power from the Greek mainland for the baseline case and the extreme RES scenario. The high renewable penetration results in large bidirectional power exchanges, with substantial imports during renewable deficits

The effect of the extreme RES scenario is most evident in the imported power from the Greek mainland, shown in Figure 20. Again, the plotted imported power is the summation of power import of both interconnections to the mainland. Compared to all previous scenarios, the power exchange through the interconnection exhibits the largest variations. During periods of high renewable generation, the imported power becomes strongly negative, indicating substantial exports from Crete to the mainland as local renewable production exceeds the island's electricity demand. Conversely, periods of low renewable availability still require significant imports because no conventional generation is available to supply the remaining demand.

The alternating import and export behaviour demonstrates that the interconnection changes from primarily supplying electricity to also serving as an important export path for excess renewable energy. The magnitude of these power exchanges is considerably larger than in the baseline case, highlighting the increasing importance of interconnection capacity and system flexibility under very high renewable penetration.

TSO case – Low-RES scenario

The low-RES scenario investigates a future operating condition with limited renewable generation availability. Compared to the baseline, the system load was increased by 9.4%, photovoltaic generation was reduced to 20% of the baseline capacity, and wind generation was assumed to be unavailable. In addition, all conventional generation units were removed from the system. As a result, only a small amount of local renewable generation remains available, and most of the electricity demand must be supplied through imports from the Greek mainland. This scenario

represents an unfavourable operating condition with low renewable production and high dependence on external power supply.

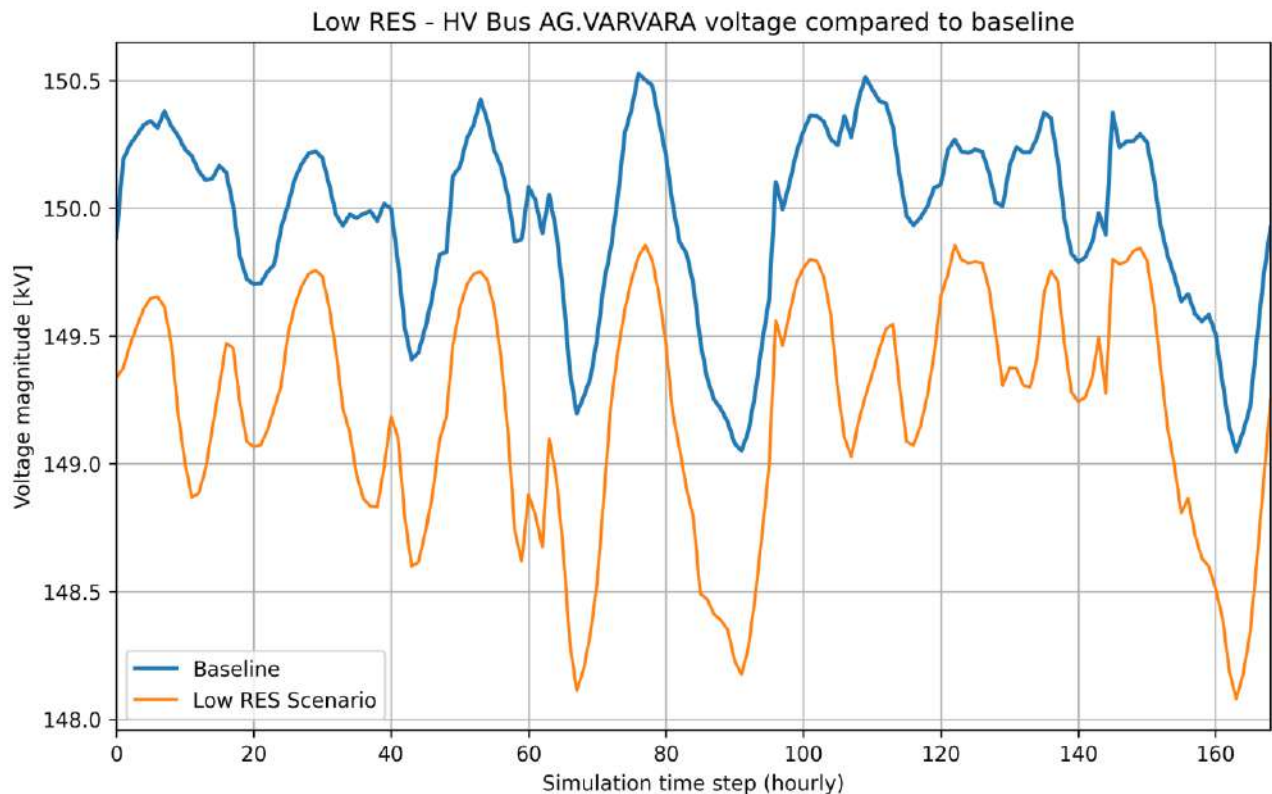


Figure 21: Comparison of the HV bus voltage magnitude at AGIA VARVARA for the baseline case and the low-RES scenario with reduced renewable generation, increased load, and no local conventional generation

Figure 21 compares the voltage magnitude at the HV bus AGIA VARVARA for the baseline case and the low-RES scenario. Compared to the baseline, noticeably lower voltage magnitudes are observed throughout almost the entire simulation period. The reduction is caused by the combination of increased electricity demand, the absence of conventional generation, and the significantly reduced local renewable generation, resulting in higher power transfers from the mainland interconnection. Although the voltage profile continues to follow the same temporal pattern as the baseline, the larger dependence on imported power leads to a nearly uniform reduction in voltage magnitude. Despite these lower voltage levels, the system remains numerically stable throughout the complete time-series simulation.

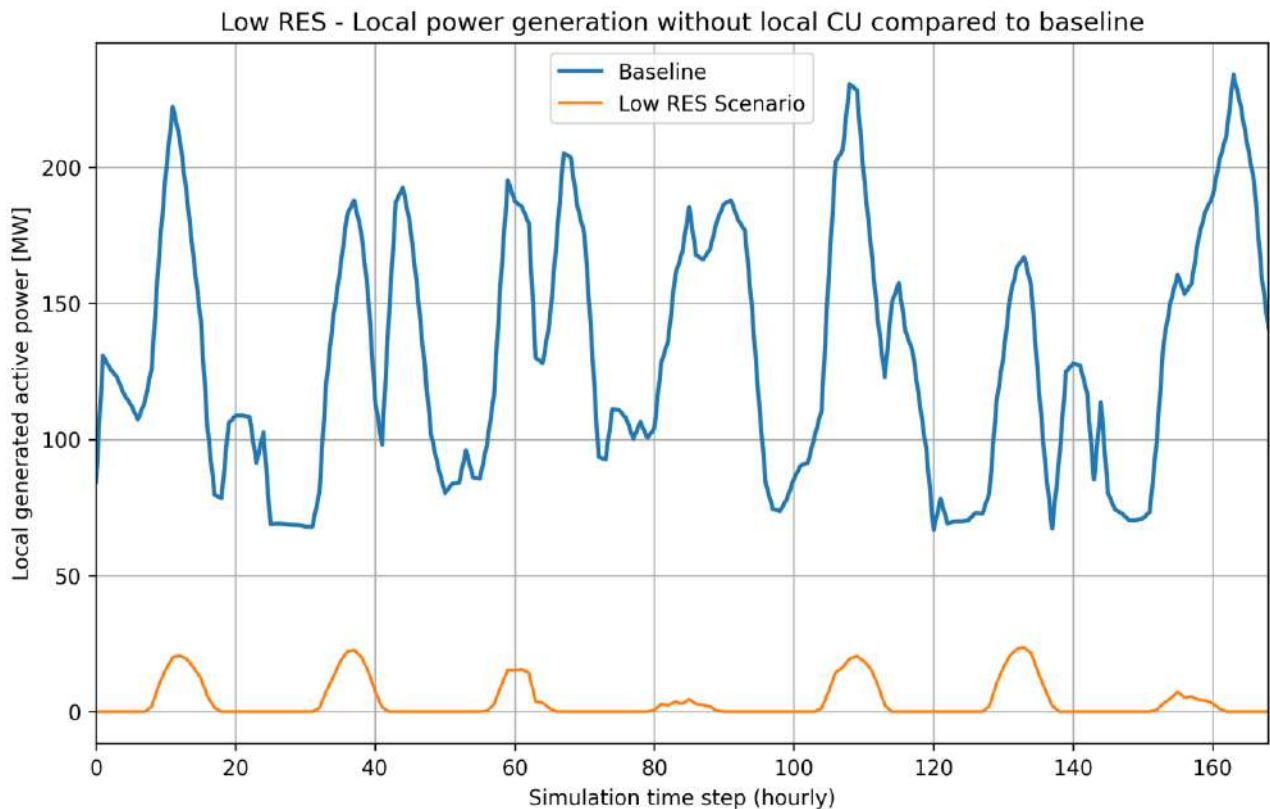


Figure 22: Comparison of locally generated active power for the baseline case and the low-RES scenario. The absence of conventional generation together with very limited renewable generation results in only minimal local electricity production throughout the simulation

Figure 22 compares the locally generated active power for the baseline case and the low-RES scenario. Due to the absence of conventional generation, local production consists exclusively of photovoltaic generation operating at only 20% of the baseline level, while wind generation is completely unavailable. Consequently, local electricity production is drastically reduced throughout the entire simulation period.

Only small peaks of photovoltaic generation are visible during periods of favourable solar conditions, while local generation remains close to zero for most of the simulation. Compared to all previous scenarios, this represents the lowest level of local electricity production and illustrates the strong dependence of the system on renewable resource availability when no dispatchable generation is present.

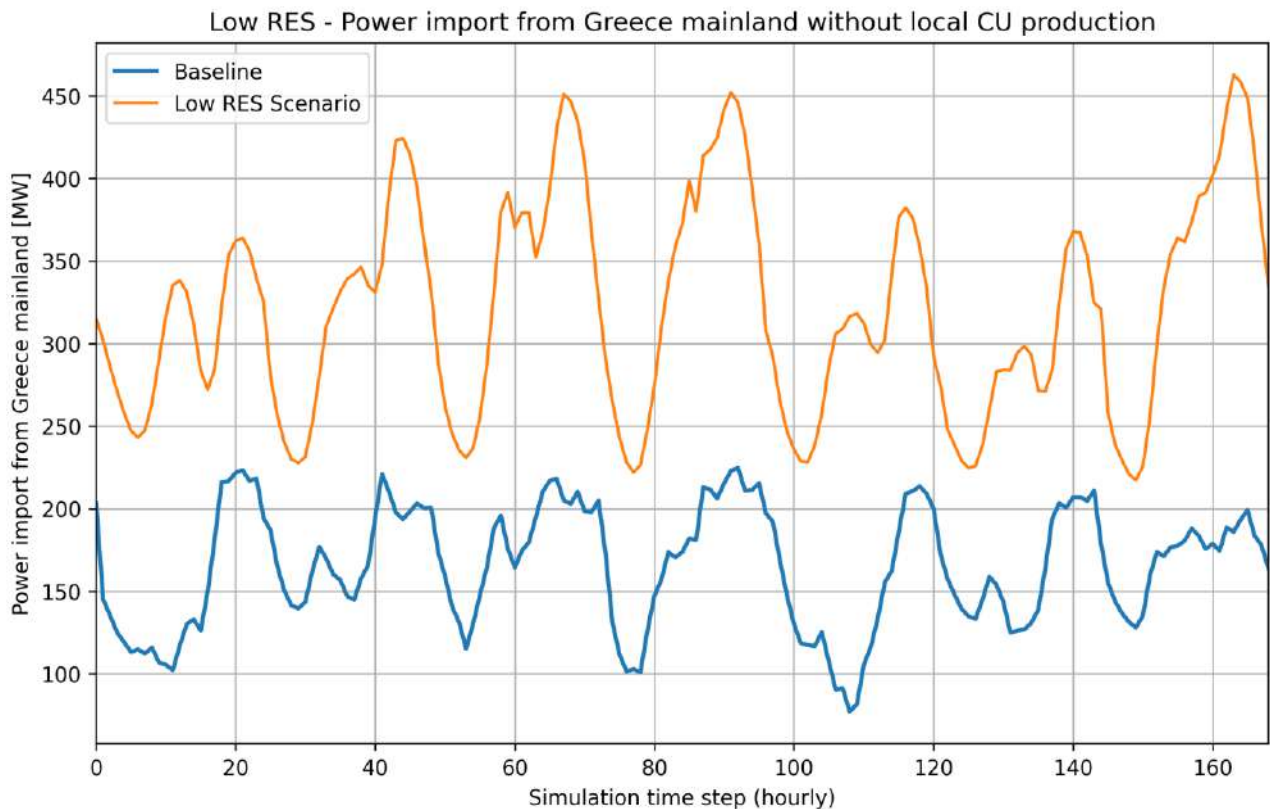


Figure 23: Comparison of the imported power from the Greek mainland for the baseline case and the low-RES scenario

Figure 23 shows the imported power from the Greek mainland for the baseline case and the low-RES scenario. Again, the plotted imported power is the summation of power import of both interconnections to the mainland. As expected, the imported power increases substantially throughout the entire simulation period and remains significantly above the baseline. Since only a small amount of local photovoltaic generation is available and wind generation is absent, the mainland interconnection supplies most of the island's electricity demand.

Although short reductions in imported power occur during periods of photovoltaic production, these have only a minor influence on the overall import requirement. Unlike the projected and extreme RES scenarios, no periods of power export are observed. Instead, the interconnection operates almost continuously as the primary source of electricity supply. This scenario demonstrates the critical importance of the mainland connection for maintaining secure system operation under conditions of low renewable availability and no local dispatchable generation.

DSO case – baseline scenario (estimated profile)

In addition to the transmission network analysis, a baseline power flow simulation was performed for the HEDNO distribution network model. Unlike the transmission system, the DSO case currently relies on estimated load and generation profiles, as measured operational data are not yet available. To address this limited observability, the framework employs two lightweight load estimation strategies that rely solely on feeder-level SCADA data. The first is a baseline null-hypothesis

estimator that assumes a uniform load distribution across the network. The second is a profile-based estimator that utilizes typical consumer smart meter profiles to capture realistic daily power usage patterns. By calibrating these estimated load shapes to match the actual power measurements recorded at the SCADA reference point, the framework successfully reconstructs demand across unmonitored nodes. The objective of this analysis is therefore to validate the simulation workflow and to obtain an initial assessment of the network behaviour under representative operating conditions.

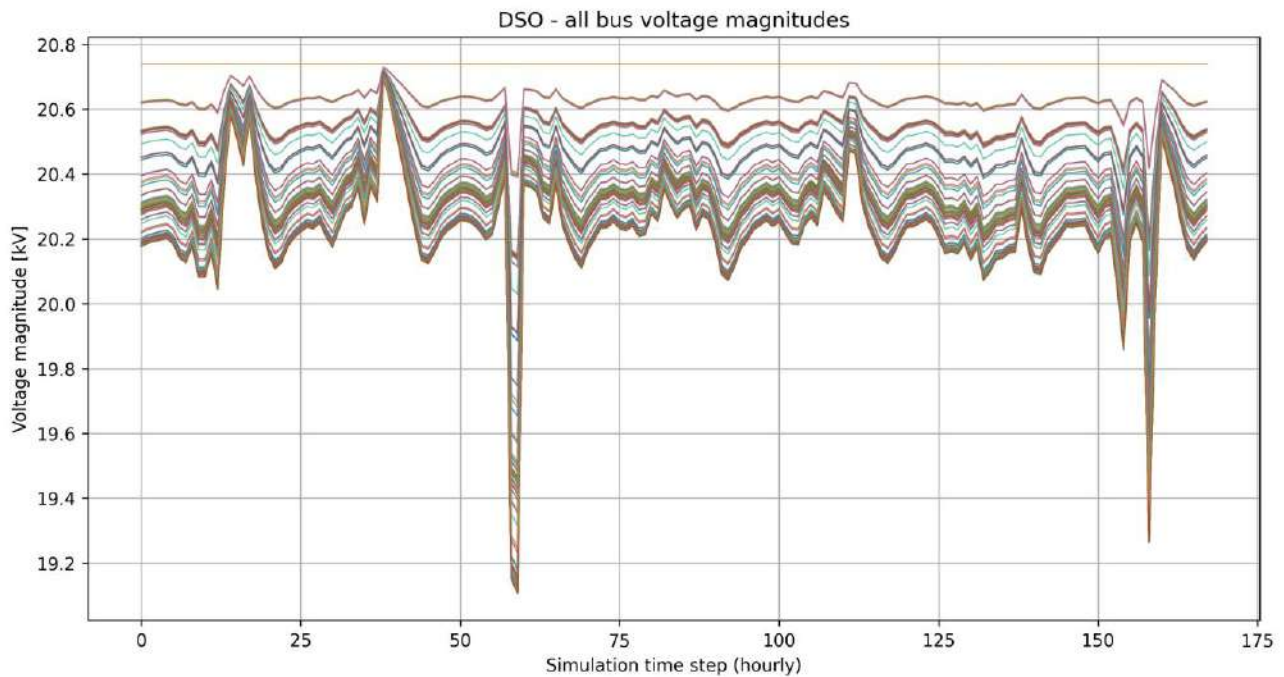


Figure 24: Bus voltage magnitudes for estimated DSO power profiles

Figure 24 shows the voltage magnitudes at all buses of the HEDNO distribution network over the simulated week. During most of the simulation period, the voltages remain within a relatively narrow range around the nominal operating level and follow a similar temporal pattern. This indicates that the estimated changes in load and generation affect the entire distribution network in a consistent manner. Several short-duration voltage reductions can be observed, particularly around simulation hours 58 and 157, where the minimum voltage decreases to approximately 19.1 to 19.3 kV. These deviations are temporary, and the voltage levels recover immediately after the corresponding profile changes. No continuously decreasing voltage trend or persistent low-voltage condition is observed.

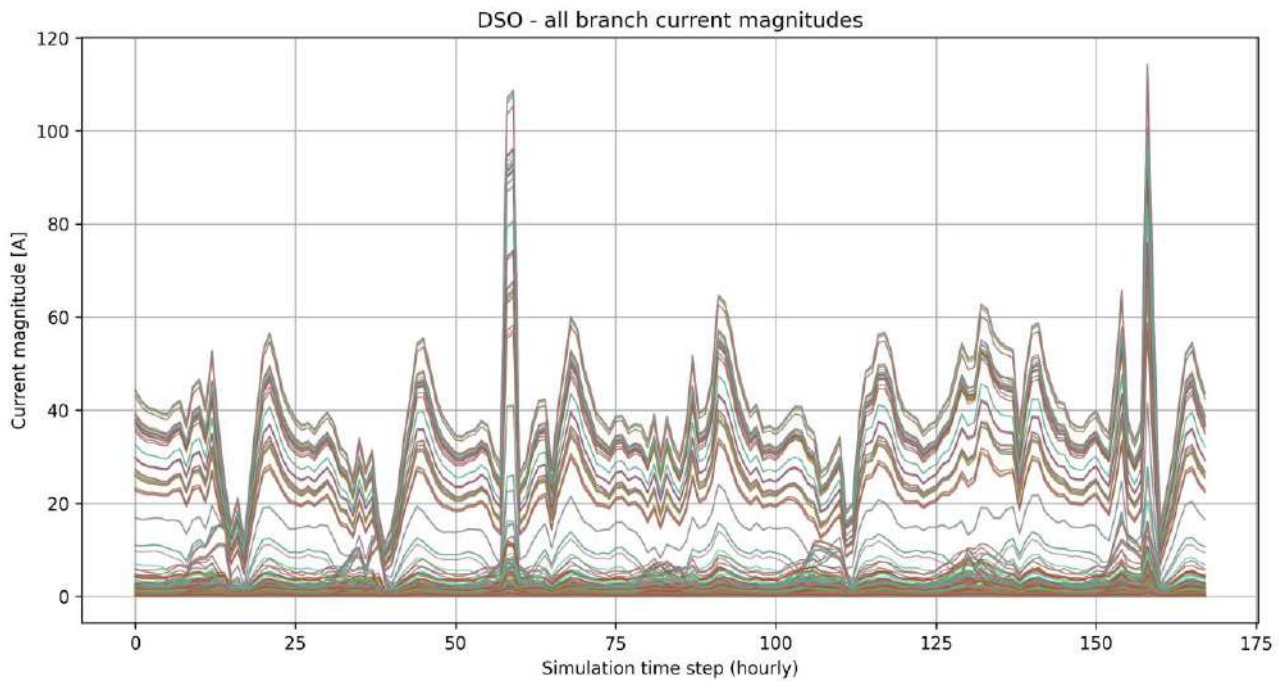


Figure 25: All branch current magnitudes for estimated DSO power profiles

The branch current magnitudes presented in

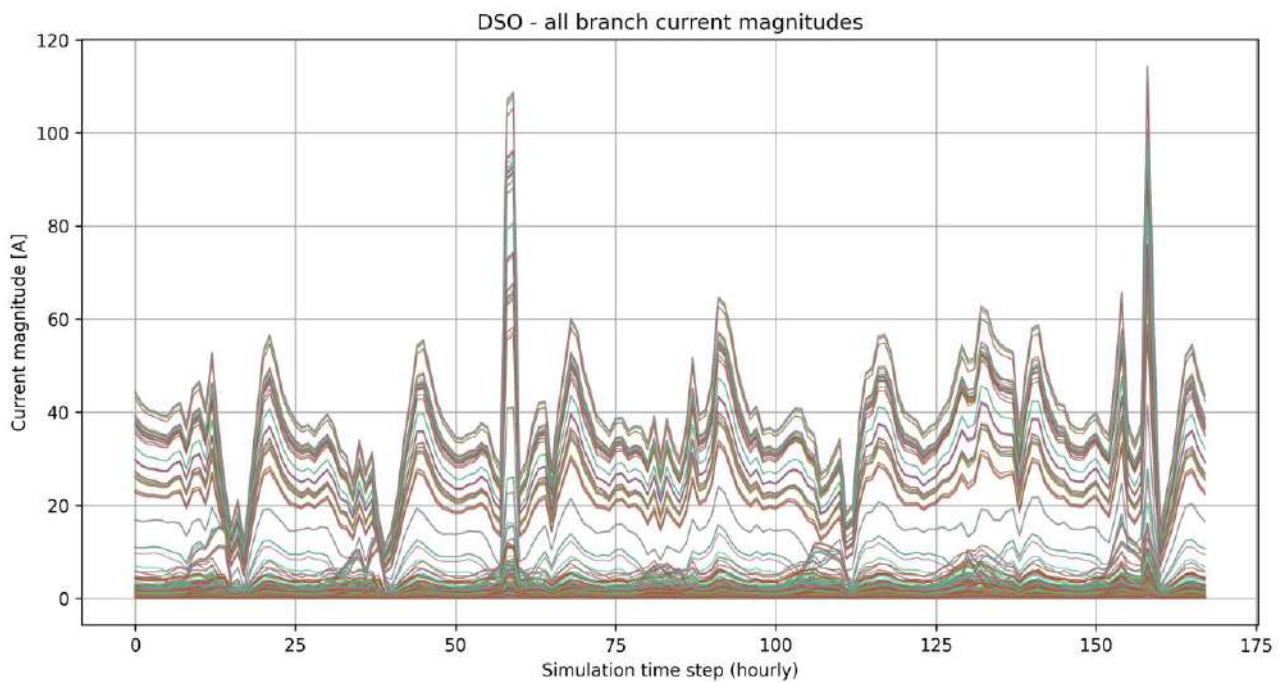


Figure 25 show a stronger variation over the simulation period. Most branches operate at comparatively low or moderate current levels, while a smaller number of branches carry significantly higher currents. The most pronounced current peaks occur around the same simulation hours as the largest voltage reductions, reaching approximately 110 A. This simultaneous occurrence indicates that the voltage deviations are associated with periods of increased network loading and concentrated power flows in individual feeders. The current peaks are limited to short time intervals and do not represent a continuous increase in network utilisation.

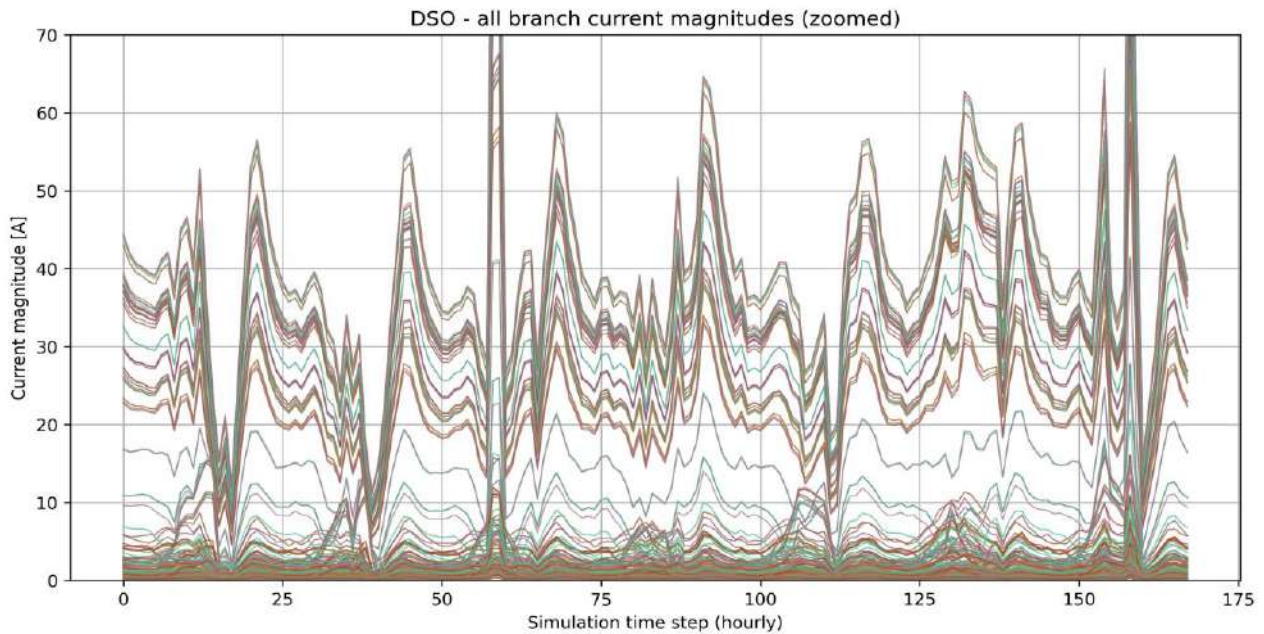


Figure 26: All branch current magnitudes for estimated DSO power profiles (zoomed)

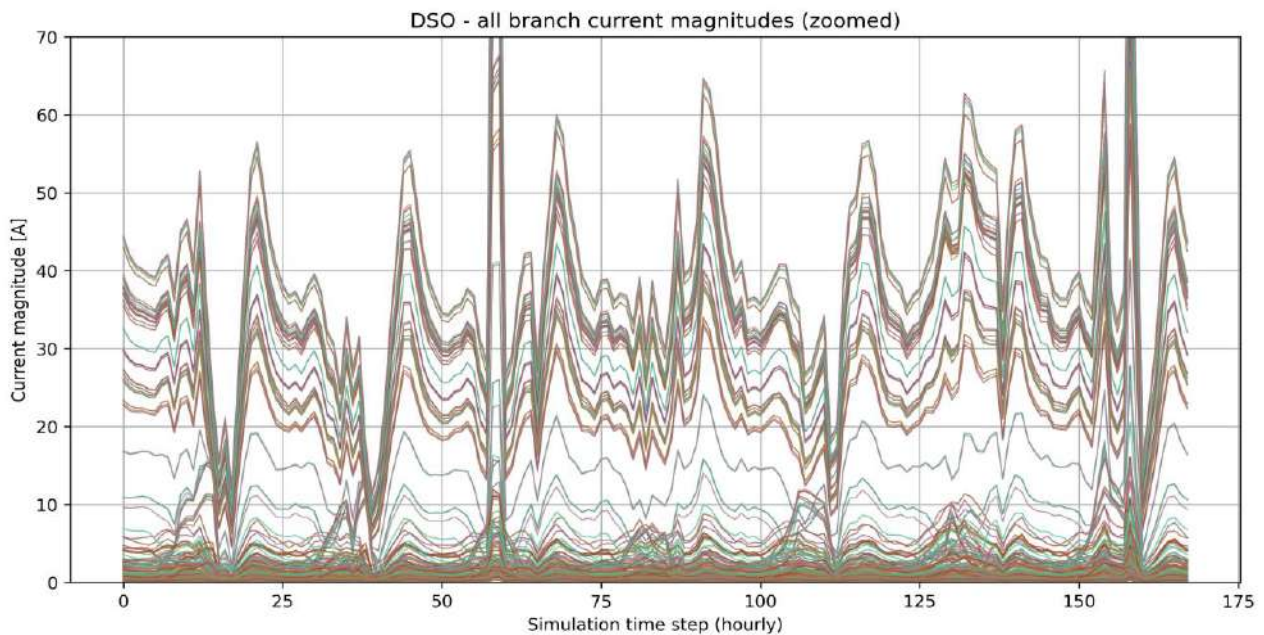


Figure 26 provides a zoomed representation of the branch currents and therefore gives a clearer overview of the behaviour of most network elements. Most branch currents remain below approximately 40 A, although several recurring peaks between 40 A and 70 A can be identified. These variations reflect the hourly changes in the estimated demand and generation profiles. The different current levels also illustrate the unequal loading of the distribution feeders, with some branches supplying larger downstream demand areas than others.

Overall, Figures 24–26 show a clear relationship between increased branch loading and temporary voltage reductions. The results indicate that the time-series power-flow workflow consistently reproduces the expected electrical response of the network to variations in the estimated profiles. However, because the profiles are currently based on estimated rather than measured operational data, the identified peaks should be interpreted primarily as representative operating conditions

and as a validation of the simulation framework. Future analyses using measured DSO data will allow these loading events and voltage deviations to be assessed more accurately.

Conclusion and future developments

During the current reporting period, significant progress was achieved in the development of the Digital Twin simulation framework for the Crete Valley use cases. The primary focus was placed on establishing a complete workflow for CIM-based network import, profile integration, and time-series power flow simulation using DPsim as the simulation engine. As a result, both the IPTO transmission network and the HEDNO distribution network were successfully integrated into the Digital Twin environment and can now be simulated using time-varying operational profiles.

For the transmission network use case, the available network model and operational profiles were refined and extended, enabling detailed time-series simulations under different operating conditions. Additional functionality was implemented to support scenario-based analyses through configurable scaling factors for loads, photovoltaic generation, wind generation, and conventional generation. The performed baseline and sensitivity studies demonstrate that the developed framework can analyse the impact of changing operating conditions on network voltages, branch loadings, and power exchange with the external grid. Furthermore, the integration of DPsim into the Digital Twin was completed through the development of a dedicated communication interface, allowing simulation results to be exchanged with the Digital Twin platform.

For the distribution network use case, a functional simulation workflow was established based on the available HEDNO network model and estimated operational profiles. While the current results are primarily intended as a proof of concept and validation of the workflow, they demonstrate that the developed methodology can be applied consistently across both transmission and distribution level networks.

The next reporting period will focus on extending the capabilities that have been established during the current phase. A key objective will be the incorporation of measured operational data for the HEDNO use case, enabling a more realistic representation of distribution network operation. In parallel, the optimization functionality currently under development will be further integrated with the existing power flow framework. This includes the extension towards Optimal Power Flow (OPF) analyses and the incorporation of flexibility resources and optimization services developed in other project tasks. Additional efforts will also focus on improving the interaction between the Digital Twin platform and the simulation backend, enabling more advanced operational analyses and decision-support functionalities.

Overall, the current reporting period established the technical foundation required for data-driven operational studies within the Crete Valley Digital Twin. The next phase will build upon this foundation by increasing the realism of the input data, expanding the optimization capabilities, and further integrating the different tools and services developed throughout the project.



3. AI-based models for accurate renewable energy & demand forecasting

Overview

The primary objective of this task within the CRETE VALLEY initiative is to design, implement, and validate high-efficiency AI-based forecasting models for renewable energy production and consumption across various CELs. This capability is a critical cornerstone of the project's DT infrastructure. The DT relies heavily on short-term forecasts to simulate localized energy dynamics, optimize grid management, maximize community autonomy, and provide real-time operational insights for operators, energy managers, and REV stakeholders.

Historically, time-series forecasting in the energy domain has relied on localized, specialized models. Each distinct renewable energy asset (such as wind, solar, biomass, biogas, geothermal, and hydrogen) and individual building load required its own standalone methodology, architecture and dedicated training dataset. While functional, this traditional approach introduces significant operational friction, requiring continuous retraining pipelines, extensive hyperparameter tuning for each isolated deployment and massive susceptibility to data noise or localized sparsity.

To overcome these scalability and maintenance bottlenecks, this task introduces an architectural paradigm shift. The development has evolved from isolated, single-task ML models toward a unified, foundation-model-centric approach powered by a production-ready forecasting service. By leveraging large-scale, pre-trained time-series foundation models (such as the Chronos family), the system introduces zero-shot capabilities to the DT. This means the service can ingest historical context from entirely different energy sources or physical locations and immediately output highly accurate forecasts without needing specialized architectural redesigns or standalone localized training loops for every new asset. This transition significantly lowers computational overhead, streamlines integration within the WP4 system-of-systems framework, and simplifies the workflow from raw data ingestion to DT orchestration.

Architecture

The new architecture moves away from maintaining independent infrastructure for separate models and instead unifies all forecasting processes into a single, modular, containerized application environment. As shown in the task's structural schema, the system functions as an inference-focused, high-performance ecosystem optimized for energy dynamics. Our service is split into two main services: the backend (fastAPI) and the frontend (streamlit).

Previous developments

At the project's inception, the forecasting models were strictly in the conceptual and architectural design phases, building upon legacy ML methodologies applied in previous European initiatives such as MATRYCS, BD4NRG, and I-ENERGY.

The previous developmental framework mandated standalone methodologies for each task:

- **Consumption Forecasting:** Relying on deep learning architectures (LSTMs, CNNs, and standard Transformers) trained explicitly on historical consumption profiles gathered across specific residential structures within isolated CELs enhanced with Transfer Learning techniques achieving promising results.
- **Production Forecasting:** Segmented into two distinct asset portfolios, Wind and Solar. One promising element was the introduction of Physics-informed inputs into wind and solar power forecasting whilst using Temporal Fusion Transformers as the deep learning architecture of choice.

These classical approaches (e.g., Temporal Fusion Transformers) suffered from rigid data requirements, typically demanding a strict minimum context of 168 to 170 continuous rows of historical records to formulate basic lag features and context steps before any inference could occur.

Current Status

This task has successfully transitioned from standalone, experimental training scripts into a fully operational, production-ready Energy Forecasting Service. The system natively handles classical models while placing primary emphasis on serving advanced time-series foundation models.

The current implementation provides instant deployment access to three major foundation model families via HuggingFace and specialized MLflow URIs:

- **Chronos-Bolt (amazon/chronos-bolt-small):** Optimized for low-latency operational environments, executing up to 250× faster than legacy T5 architectures with superior accuracy.
- **Chronos-2 (amazon/chronos-2):** Representing state-of-the-art forecasting precision, featuring native support for multidimensional exogenous covariates.
- **Chronos T5 (amazon/chronos-t5-large):** The original baseline high-capacity foundation model.

All legacy pipelines have been standardized. While individual deep learning and gradient-boosting models can still be trained via containerized offline scripts, they are now compiled directly into the uniform MLflow Model Registry schema (ForecastingService.{model_type}.{model_id}), allowing them to be served alongside foundation models under a unified API payload format.

Input data description

Data format structures have been fully consolidated across the service. The API ingests uniform JSON payloads, removing the necessity for custom input parsers between different renewable assets or consumption loads.



- **timestamps:** An ordered array of ISO 8601 formatted datetime strings representing the historical observation window.
- **values:** A corresponding array of floating-point historical measurements representing load demand (MW) or generation output.
- **exogenous (Optional):** A key-value dictionary containing matching arrays of external driver variables (e.g., temperature, is_holiday) used specifically by advanced models like Chronos-2 to capture environmental impacts on solar, wind, or consumption patterns.

Table 2: Structural Data Specification

Model Architecture	Recommended Minimum Context Length	Primary Ingestion Target
LightGBM	≥ 170 rows	Localized historical asset files
LSTM / CNN / Transformer	Exactly 168 rows (Default sequence)	Siloed building or asset histories
Chronos Foundation Models	As few as 10 rows (Zero-shot)	Generalized across any CEL load or generation stream

Output data description

The forecasting service standardizes outputs into a unified JSON schema, allowing the DT interface to read predictions from any underlying model through an identical parsing structure.

The standard output response contains:

- **forecast:** An array of calculated numeric predictions extending cleanly across the user-configured short-term horizon (supporting arbitrary lengths from 1 up to 720 steps).
- **confidence_intervals:** Probabilistic uncertainty bounds returned automatically by foundation models. By default, the Chronos family outputs explicit 80% confidence intervals, providing upper and lower margins.

In the Streamlit interface, these arrays are flattened automatically into downloadable CSV structures, transforming confidence intervals into dedicated spreadsheet columns for immediate operational planning.

Illustrative Example

To demonstrate the operational capabilities of the Energy Forecasting Service within the CRETE VALLEY ecosystem, this section provides an end-to-end walkthrough of the unified forecasting pipelines across both machine-to-machine (backend-API) and human-interactive (frontend-GUI) interfaces.

Backend API

For core Digital Twin integration, automated scripts communicate directly with the high-performance REST API. As illustrated in Figure 27, the service exposes a completely self-documented OpenAPI interface via Swagger UI, ensuring seamless service-layer orchestration without manual backend configuration. All endpoints are protected via secure API Keys and Secure Sockets Layer (SSL) configuration.

The endpoints are categorized into clear functional blocks:

- **System Liveness (/health):** Provides a public endpoint for the service's continuous health monitoring and uptime checks.
- **Model Lifecycle Management (/models/):** Exposes programmatic paths to list, load, unload, and inspect cached pre-trained models. It features explicit tools like `/models/mlflow/registered` to dynamically fetch active registry versions, alongside utility endpoints such as `/models/{model_name}/window` to look up optimal input historical context dimensions prior to making queries.
- **Single-Model Inference (/forecast/):** Handles immediate, dedicated short-term predictions for standalone targets.
- **Comparative Batch Inference (/forecast/batch):** Allows the system to ingest a single dataset and dispatch it across multiple underlying models simultaneously within a single HTTP request, facilitating instant side-by-side performance assessments.

Energy Forecasting Service 1.0.0 OAS 3.1

/openapi.json

Multi-model time series forecasting API

health			^
GET	/health	Health Check	▼
models			^
GET	/models/	List Models	▼
DELETE	/models/	Clear Cache	▼
POST	/models/{model_name}/load	Load Model	▼
DELETE	/models/{model_name}	Unload Model	▼
GET	/models/{model_name}	Get Model Info	▼
GET	/models/mlflow/registered	List Mlflow Models	▼
GET	/models/{model_name}/window	Get Model Window	▼
forecasting			^
POST	/forecast/	Create Forecast	▼
POST	/forecast/batch	Create Batch Forecast	▼

Figure 27: FastAPI backend side of the Forecasting Service

Frontend-GUI

To empower grid operators, asset manager stakeholders, and community representatives who require analytical capabilities without writing software code, the service deploys a parallel Streamlit GUI. As captured in Figure 28, the dashboard abstracts complex ML and foundation model paradigms into a seamless, interactive workflow:

- **Data Ingestion Hub:** Users can drag-and-drop any standard time series CSV file up to 200MB. The system provides downloadable ready-to-use sample templates, including basic target configurations and advanced datasets enriched with weather covariates.
- **HuggingFace / Chronos Panel:** Provides instant, out-of-the-box access to zero-shot foundation models (such as the Chronos-Bolt, Chronos-T5, and Chronos-2 families) requiring absolutely zero specialized training datasets.
- **MLflow Registered Panel:** Displays dynamically pulled, custom fine-tuned models matching unique CEL profiles, explicitly detailing their lifecycle version numbers and targeted window size metadata.



- **Ensembling and Multi-Model Selection:** Operators can pick individual models or select multiple variations at once to perform automated multi-model comparisons or formulate combined ensemble projections.

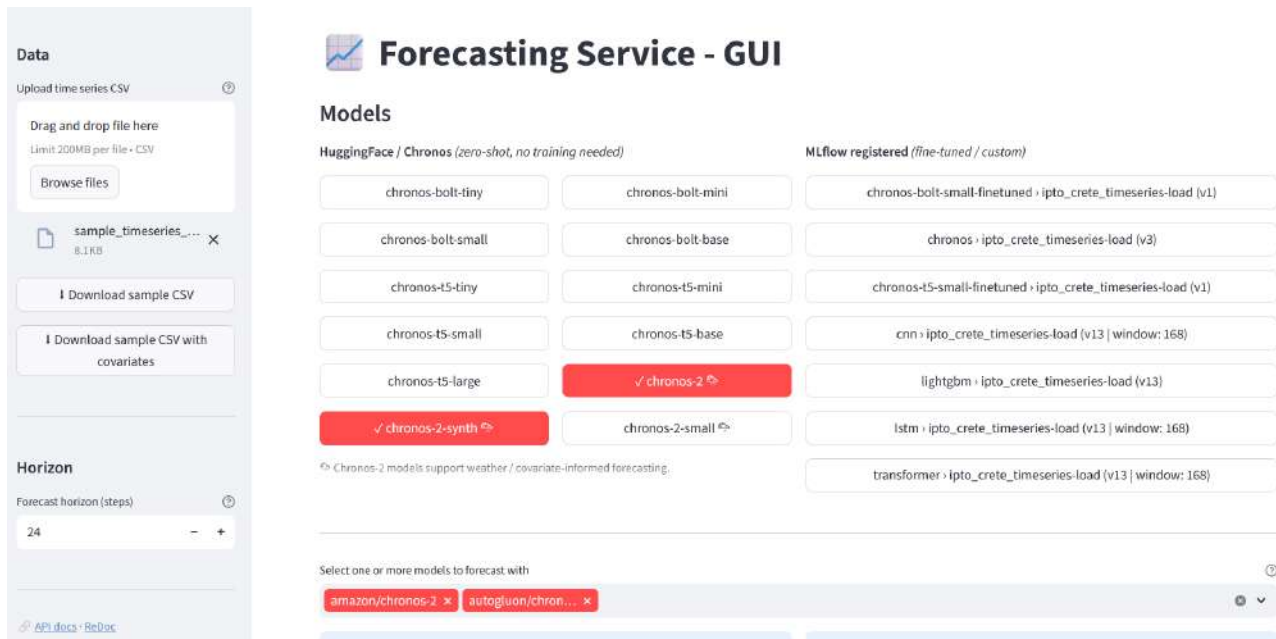


Figure 28: Frontend-GUI of the Forecasting Service

When a covariate-enriched dataset is uploaded into the interactive platform, the processing engine automatically upgrades its baseline workflow into an advanced, context-informed pipeline. Figure 29 displays the real-time operational dashboard visualizing an end-to-end forecast execution conditioned on external driver dynamics. About input data:

- The graphical engine initially renders a highly scannable dual-axis visualization.
- The primary vertical axis (left) tracks historical consumption/production loads over a targeted timeline window (e.g., a 168-hour continuous sequence).
- The secondary vertical axis (right) maps past and future weather indicators, such as temperature variations (temperature_c) and localized wind speeds (wind_speed_ms).
- A vertical red dashed line clearly delineates the exact historical boundary from the future forecasting horizon.

Then the advanced zero-shot generation:

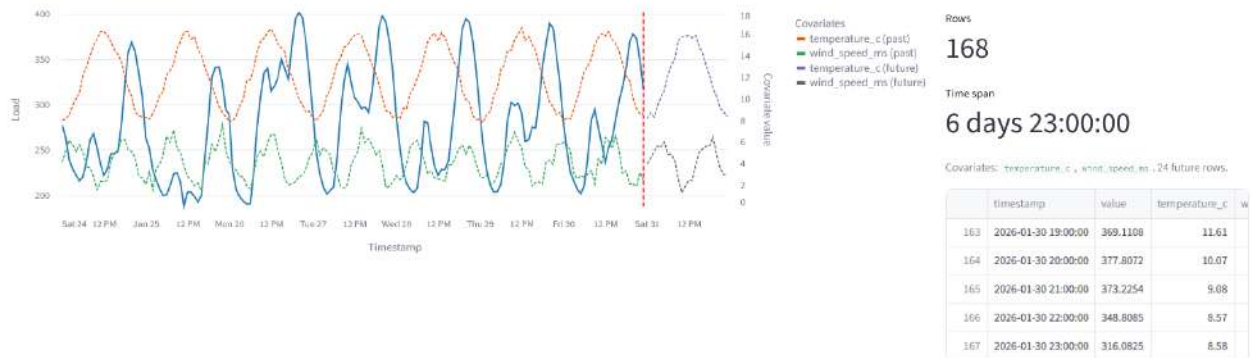
- Two separate high-capacity models—amazon/chronos-2 and autogluon/chronos-2-synth—are executed simultaneously in zero-shot mode.
- Both foundation algorithms ingest the exact same temperature and wind speed future covariate forecasts to accurately anticipate weather-driven energy swings.

And finally, the forecast comparison generation capability:

- The final output aggregates the raw historical timeline and projects individual color-coded model prediction vectors across the future horizon.
- The UI overlays explicit probabilistic uncertainty bands around the forecast lines.

- Operators can visually contrast how structural nuances within the two distinct foundation architectures generate slightly separate yet highly aligned confidence margins.
- This provides grid operations with explicit safety boundaries during volatile climatic transitions.

Input data preview



Forecast complete - 2 / 2 models succeeded.

Forecast comparison



Figure 29: Forecasting example using Chronos

Future developments

Moving forward, Task 4.2 will continuously strengthen its integration within the broader WP4 ecosystem, ensuring that its standardized forecasting outputs feed directly into operational analytics, flexibility forecasting, and user-centric applications across connected tasks (T4.1, T4.3, T4.4, and T4.5). Also, while the Chronos-2 foundation models currently support the ingestion of multidimensional exogenous variables (such as temperature and holiday indicators) to refine accuracy, future iterations will explore injecting a wider array of real-time environmental and grid-state covariates across all applicable architectures

4. Empowering local grid management through advanced flexibility modelling and DR services

Overview

Architecture

The flexibility modelling tool is designed to optimize energy set-points and flexibility services, ensuring their cost-effectiveness and technical feasibility for TSOs and DSOs.

At the input level, the tool is connected to the project database, which serves as the main data hub of the system. This database provides all the inputs required for the optimization process, including resource and building parameters, load and generation forecasts, electricity price forecasts, and electrical network parameters for both transmission and distribution grids. In addition to these standard inputs, the system also incorporates outputs from the external EV flexibility tool.

The EV flexibility tool operates as a dedicated external module responsible for estimating the power and reserve provision capabilities of EV clusters. These results are written into the project database in the form of EV setpoints. The flexibility optimization tool retrieves this information and integrates it into the overall optimization problem, ensuring that electric vehicle energy consumption and flexibility is properly represented and constrained within the system operation.

Once all inputs are collected, the flexibility tool performs a multi-energy optimization process that determines optimal energy schedules and flexibility provision setpoints. This process explicitly accounts for technical and operational constraints of the resources as well as the constraints of the electricity network.

At the output level, the tool generates the optimized energy setpoints for electricity and gas, as well as aggregated flexibility setpoints for each resource.

Figure 30 presents a graphical representation of the tool architecture and its interaction with the surrounding system components, as described in the text above.

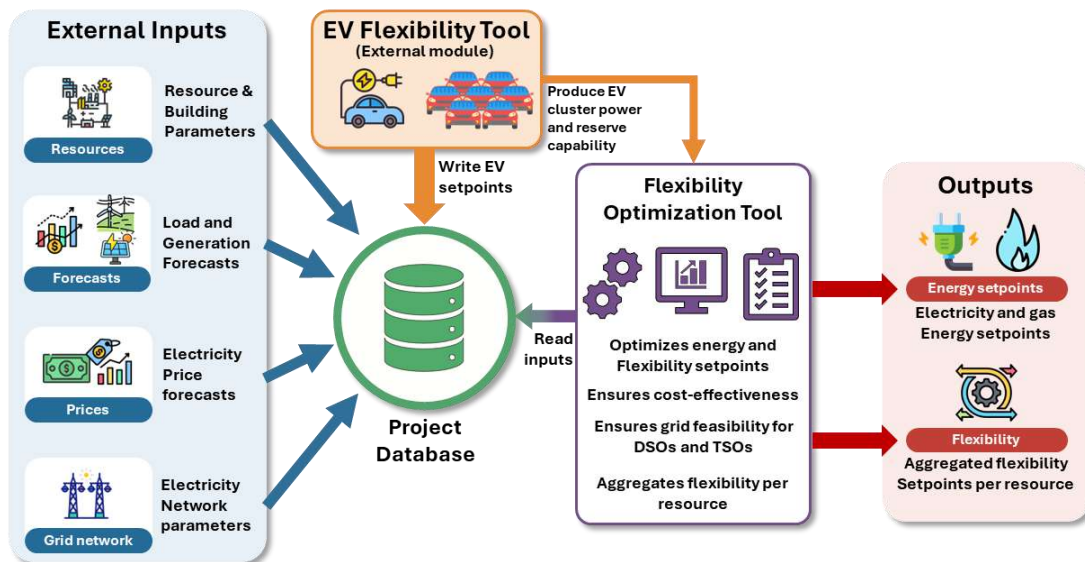


Figure 30: Flexibility tool architecture

Previous developments

During the previous reporting period, the flexibility tool architecture and the main resource models were developed to support three use cases: flexibility provision to DSOs, flexibility provision to TSOs, and reserve provision through the aggregation of distributed energy resources.

The use case for DSO flexibility provision was defined together with the required inputs, including distribution network topology, load and renewable generation forecasts, network state information and power flow data. To support this use case, the overall flexibility procurement and activation framework was established, defining the interaction between the optimization, communication and data management modules. In addition, mathematical models of the distributed energy resources were developed, including photovoltaic systems, energy storage systems, heat pumps, combined heat and power units, and hydrogen systems. These models were integrated into the optimization framework and were undergoing validation through simulations under different operating conditions.

The TSO use case was defined by identifying the required transmission network data and flexibility services to be supported. The flexibility tool architecture was designed to allow the coordination of distributed flexibility resources while considering transmission network requirements. The developed multi-energy resource models provide the basis for the future incorporation of transmission network constraints within the optimization framework.

The reserve provision use case focused on the aggregation of flexibility available at the meter level. The resource models developed during this period enabled the calculation of power and reserve capabilities from distributed energy resources. Furthermore, the integration of the V2X tool developed by RWTH was initiated to incorporate the reserve capabilities of electric vehicle clusters. The initial integration architecture and data exchange mechanisms between the V2X tool and the flexibility platform were also defined.

Current Status

During the current reporting period, work has focused on extending the functionality of the flexibility tool through the integration of the V2X tool, the development of OPF formulations, and the deployment of the optimization framework within the project's digital twin environment.

Significant progress has been achieved in the implementation of the OPF framework for distribution networks. A LinDistFlow-based formulation was developed for radial distribution systems and implemented using the open-source HiGHS solver. This formulation was integrated with the multi-energy resource models, allowing flexibility activation while respecting distribution network constraints. Furthermore, the optimization framework was integrated into the project's digital twin, with the input/output interfaces adapted to the project database and deployed through a Docker environment.

Development of the transmission network OPF progressed during this reporting period. Several formulations from the literature were evaluated, although their initial performance was not satisfactory. A revised transmission OPF formulation was subsequently implemented and integrated with the resource models. The implementation is currently undergoing final validation, with preliminary results demonstrating satisfactory performance for the considered test cases.

The integration of the RWTH V2X tool has reached an advanced implementation stage. The V2X tool provides the available power and reserve capability of electric vehicle clusters, which is written to the project database and subsequently used by the flexibility tool. The flexibility optimization then computes updated power and reserve capabilities while considering the network constraints represented by the OPF formulations.

Input data description

The input data for the flexibility tool can be divided into three main categories: energy resource modelling inputs, energy market inputs, and electricity network inputs.

The energy resource inputs define the parameters used to represent the operation of the energy resources through mathematical constraints (Table 3). These inputs provide information on the technical characteristics of each resource, including maximum power limits, efficiency parameters, and energy storage capacity. In addition, they specify whether each resource is eligible to participate in reserve provision services. The dataset also includes forecasts of energy consumption and generation, as well as information regarding the connection of each resource to the electricity network.

It should be noted that the parameters listed in the table below are defined for the full set of resources considered in the model. As a result, certain resources may not include all parameters presented, depending on their specific technical characteristics and operational capabilities.

Table 3: Resources parameters

	Parameter	Unit
Resources	Resource number	-
	Reserves participation	-
	Maximum capacity	kWh
	Minimum capacity	kWh

	Maximum Power	kW
	Maximum charging power	kW
	Maximum discharging power	kW
	COP	-
	Efficiency (heat, electricity, charging)	%
	Flexibility range	%
	Wind speed (begin, max and wind shutdown)	m/s
Network	Electrical bus connection	-
Energy consumption forecasts	Electricity consumption	kWh
	Gas consumption	kWh
	Heat consumption	kWh
Generation forecasts	PV generation	kWh
	Wind generation	kWh

The market input data for the flexibility tool include electricity and gas day-ahead market prices, as well as electricity flexibility market prices (Table 4).

Table 4: Day-ahead market prices parameters

	Parameter	Unit
Electricity	Day-ahead energy prices	€/MWh
	Upward and downward flexibility prices	€/MW
	Band sold activation ratios	-
Gas	Day-ahead energy prices	€/MWh

The network input data consist of grid, branch, bus, and transformer parameters, Table 5. In addition, penalties for voltage and current deviations are considered. These penalties ensure that the power flow solution remains feasible, while discouraging violations of the defined operational limits for voltage and current levels.

Table 5: Electrical network parameters

	Parameter	Unit
Grid	System base	MVA
	Voltage, current penalty	-
Bus	Id	-
	Type	-
	Base voltage	kV
	Maximum voltage	p.u.
	Minimum voltage	p.u.
	Shunt conductance	MW
	Shunt susceptance	MVAr
Branch	Id	-
	From bus	-
	To bus	-
	Resistance	p.u.
	Reactance	p.u.
	Total charging susceptance	p.u.
	Rating	MVA
Transformer	Id	-
	From bus	-
	To bus	-
	Resistance	p.u.
	Reactance	p.u.
	Total charging susceptance	p.u.
	Line rating	MVA
	Transformation ratio	-
	Minimum transformation ratio	-
	Maximum transformation ratio	-
	Number of tap positions	-

Output data description

The output of the flexibility tool consists of the day-ahead electricity, gas, and flexibility setpoints, Table 6. Currently, the setpoints are aggregated at the resource level. However, the developed framework also supports the aggregation of results at the bus level or at the distribution network level, depending on the intended operational analysis and application scenario.

Table 6: Day-ahead tool outputs

	Parameter	Unit
Electricity	Energy setpoint (per hour, per resource)	MWh
	Upward flexibility setpoint (per hour, per resource)	MW
	Downward flexibility setpoint (per hour, per resource)	MW

Gas

Energy bid

MWh

Case study

Characterization

The case study used to test the developed flexibility tool presented in the previous section focused on the use of tool to control the bidding strategy of the CEL 3 PV resource integrated into the island's distribution grid. The bidding strategy was evaluated under two different scenarios. In the first scenario, the photovoltaic system only participates in the day-ahead spot market, meaning that it exclusively sells the energy produced. In the second scenario, the photovoltaic system participates not only in the day-ahead spot market but also in reserve provision services.

The PV installation has an installed capacity of 1 MW and is connected at bus_24b16k2. The flexibility tool was executed for a one-day operation horizon considering a temporal resolution of 15 minutes.

The distribution network considered in the case study has a radial topology composed of 425 nodes. The network also includes transformers connecting the medium-voltage level (20 kV) to low-voltage buses (0.4 kV). Figure 31 presents the configuration of the distribution grid considered in the simulations.

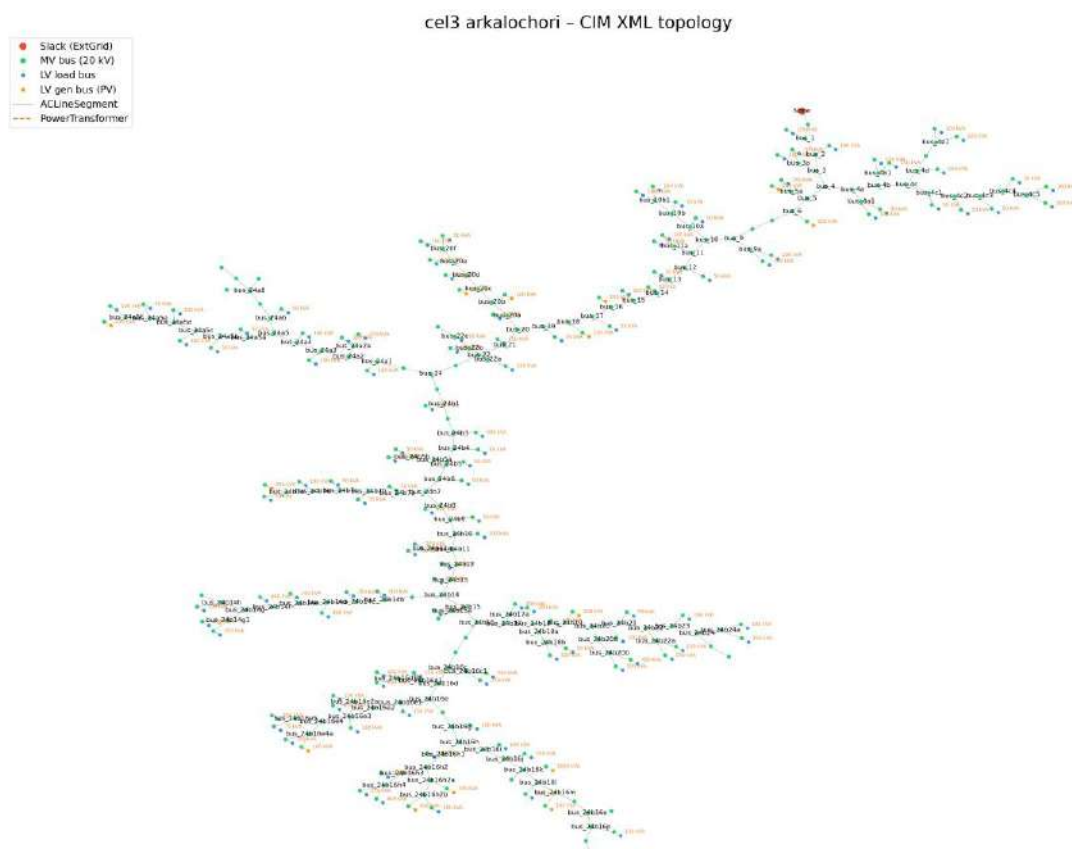


Figure 31: Distribution network

As it was not possible to obtain real consumption and generation data for each node of the distribution network, as well as real PV generation values, synthetic load and generation profiles



were considered for the simulations. Load profiles were assigned to the nodes identified as consumption nodes, while PV generation profiles were assigned to the nodes identified as PV generation nodes.

Figure 32 presents the representative electrical load and photovoltaic generation profiles considered in the simulations and validation studies. The profiles shown in figure are represented in per-unit (p.u.) values. For the simulations, the active power associated with each node was considered to be equal to 70% of the corresponding node nominal power.

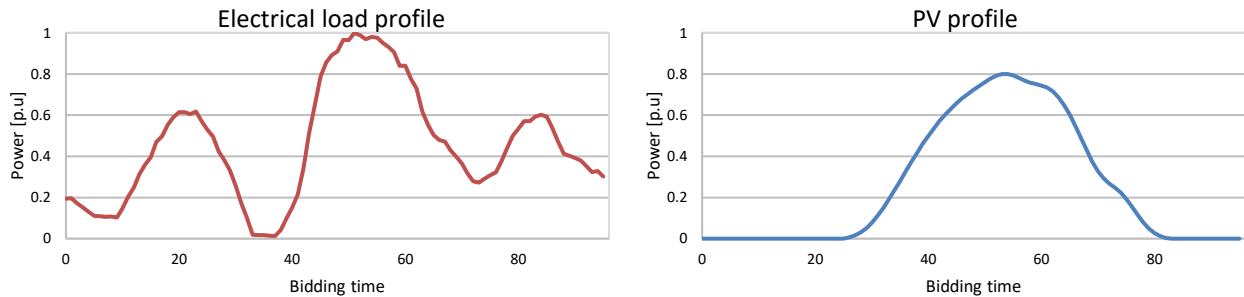


Figure 32: Electrical load and PV profiles

The market data used, as presented in Figure 33, corresponds to a randomly selected day and includes electricity spot prices as well as secondary reserve band prices.

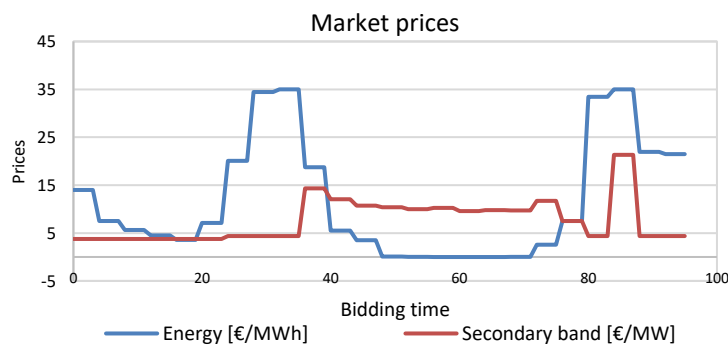


Figure 33: Market prices

Results

In this section, the results of the performed simulation studies are presented. The objective of the case study was to validate the resource optimization formulation, while considering the operational constraints of the networks in which the resources are integrated. Therefore, the results presented focus on these two main aspects.

First, the results of the day-ahead energy set-points obtained from the optimization process are presented. Subsequently, the power flow results calculated by the optimization framework are compared with the power flow results obtained using Pandapower to verify the correct implementation and operation of the developed methodology.

As explained in the case study section, the PV day-ahead energy setpoints were computed for two different scenarios: participation only in the day-ahead spot market (W/O R), and simultaneous participation in both the spot and reserve markets (W/R).

In the first scenario, the PV system only participates in the day-ahead spot market (W/O R), the bidding strategy follows the expected PV generation profile throughout the day whenever electricity market prices are positive, i.e., when energy production is economically viable. Figure 34 presents the comparison between the PV market bidding and the corresponding generation profile. As can be observed, the submitted bids follow the PV generation profile during the periods with positive market prices.

During periods in which the electricity market prices are zero or negative, the PV system does not inject power into the grid, since energy production under these market conditions would not be economically beneficial.

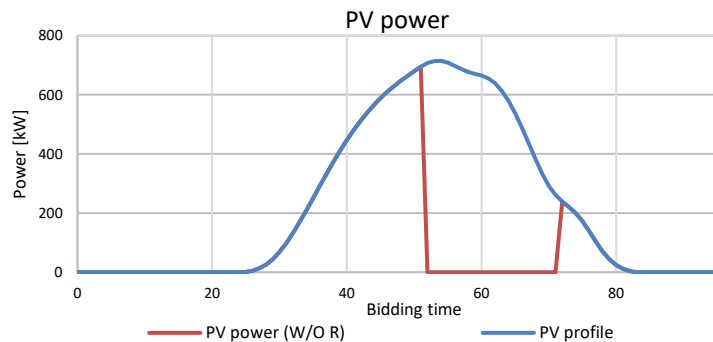


Figure 34: PV energy bids and forecasted power profile (W/O R)

In the second scenario, the participation of the PV unit in the secondary reserve market is considered (W/R). The PV production profile follows a similar pattern to the one presented previously, as illustrated in Figure 35. However, in this case, the PV unit simultaneously participates in the provision of upward and downward reserve capacity.

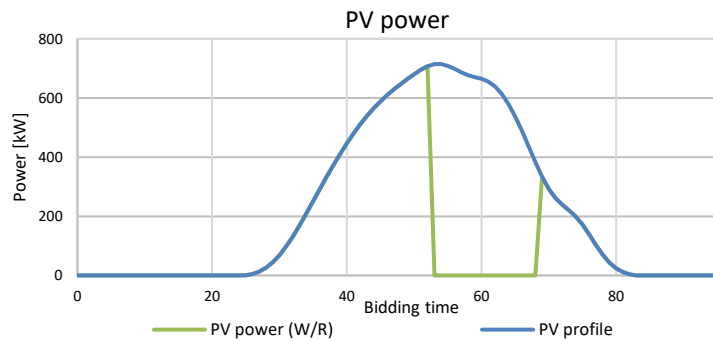


Figure 35: PV energy bids and forecasted power profile (W/R)

Figure 36 presents the resulting upward and downward reserve bands offered by the PV unit in the market. The upward reserve band is defined as the difference between the forecasted PV production profile and the actual PV power output at each time step. The downward reserve band is defined as the available PV generation at each time step, corresponding to the actual PV power output.

As can be attested by Figure 36, the selection between providing upward or downward reserve capacity is directly driven by the associated economic revenue. At each time step, the PV unit evaluates the expected revenue from energy sales combined with reserve provision and selects the most profitable option. For example, from time step 0 to 52 and from time step 69 to 82, the PV

unit sells downward reserve capacity, as the combined revenue from electricity and downward reserve sales is higher than the alternative scenario of reducing generation and selling upward reserve capacity. On the other hand, between timesteps 53 and 68, when the electricity spot market prices are negative, the economic revenue obtained from curtailing PV generation and selling upward reserve capacity is higher than the revenue associated with generating electricity and providing downward reserve capacity. Consequently, the PV unit prioritizes the provision of upward reserve capacity for these time steps.

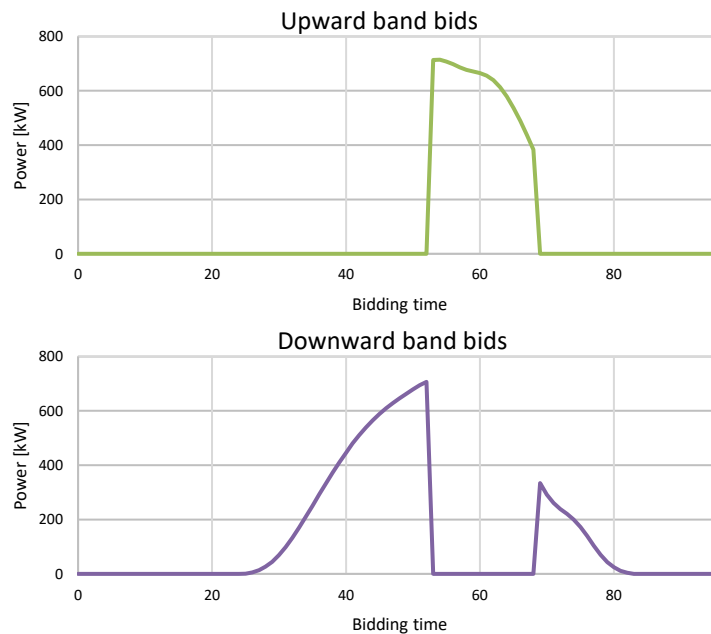
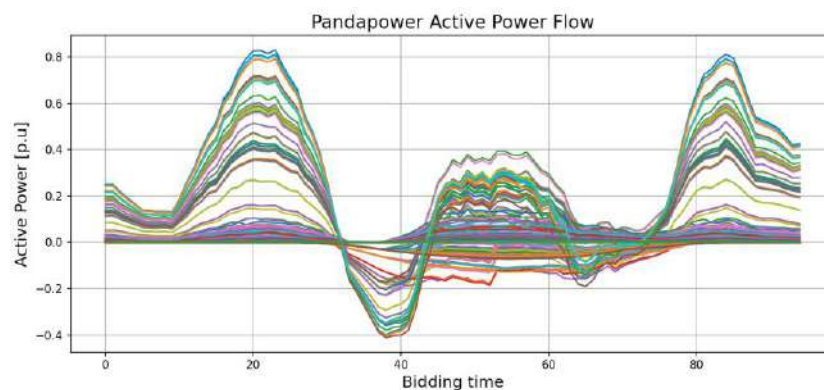


Figure 36: PV upward and downward band bidding

Focusing on the power flow validation results, the outputs provided by the flexibility tool, based on the LinDistFlow formulation, were validated through a comparison with power flow simulations performed in Pandapower using the same energy setpoints. This validation process aimed to assess the accuracy and consistency of the linearized power flow approach when compared with a detailed power flow simulation framework.

As can be observed in Figure 37 and Figure 38, the results obtained for the active power flows and bus voltages from both approaches are highly similar, demonstrating the correct operation and accuracy of the developed power flow implementation within the flexibility tool framework.



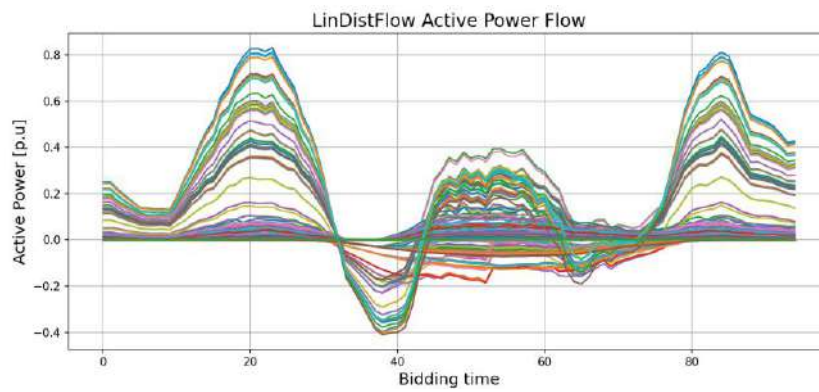


Figure 37: Active powerflow results (PandaPower vs LinDistFlow)

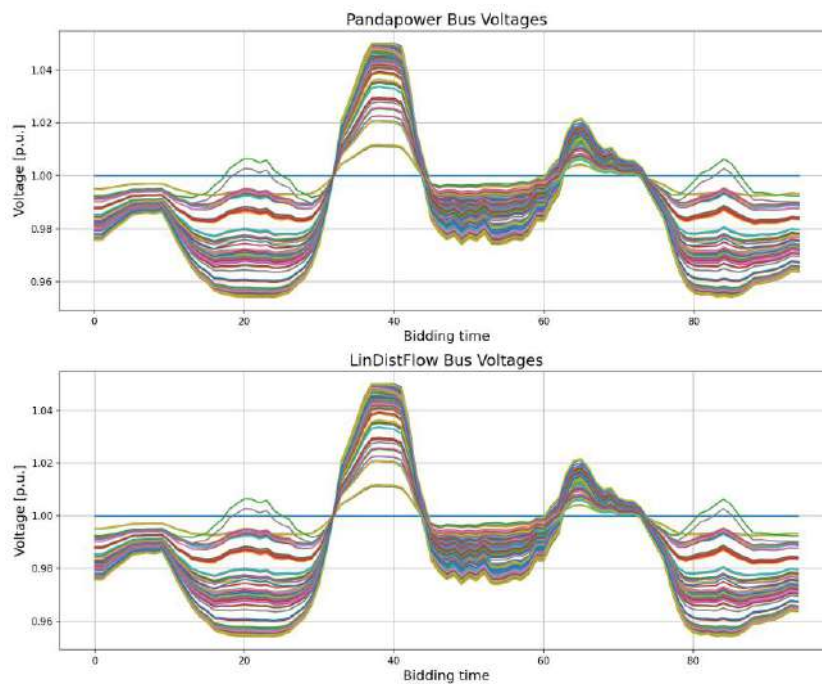


Figure 38: Bus voltages (Pandapower vs LinDistFlow)

EV flexibility tool

Architecture

datafev_flex is a Python-based optimization service for assessing and scheduling EV flexibility at charging-cluster level. The service follows a two-stage workflow. In Stage-1, it estimates the flexibility potential of each charging cluster over a defined planning horizon by computing downward and upward capability envelopes. In this context, downward flexibility refers to additional charging demand (G2V / grid consumption), while upward flexibility refers to reduced charging demand or V2G export. Stage-1 also computes a day-ahead smart-charging baseline using market-price information. This baseline is intentionally charge-only and represents the planned charging operation of the EV fleet under price-aware conditions.

In Stage-2, the service evaluates whether clusters can track requested flexibility commands while respecting EV availability, state-of-charge (SOC) requirements, charger power limits, and cluster-level capability bounds. Commands can be provided as absolute setpoints or flex bands. In local or service-based execution, these commands may come from external inputs or from built-in fallback generation. In strict mode, invalid or infeasible commands are rejected. In best_effort mode, the optimization minimizes tracking deviation or band violation when exact compliance is not feasible.

Within the current project scope, Stage-1 is the primary operational mode. It is used to estimate available upward and downward flexibility and to derive a day-ahead smart-charging baseline. Stage-2 has already been implemented, but it is currently not part of the active project scope. It has been developed to support future use cases involving flexibility requests, aggregate power setpoints, or flexibility bands.

The service can be executed either through a local workflow runner or through a FastAPI-based HTTP interface. In both modes, the core orchestration logic is shared. A structured Excel workbook is used to define the planning horizon, EV fleet, charging infrastructure, and day-ahead market prices. These inputs are parsed into internal EV fleet, charger-cluster, and multi-cluster system objects adapted from *datafev*. For Stage-2, commands can additionally be supplied through a separate Excel file or via API payloads, depending on the execution mode. The optimization routines are formulated in Pyomo and orchestrated through a central workflow layer.

Figure 39 illustrates the high-level architecture of the service. It summarizes the main flow from input data to service execution and output generation, without going into detailed data-field definitions. A more detailed description of the input data and output data is provided in the following sections.

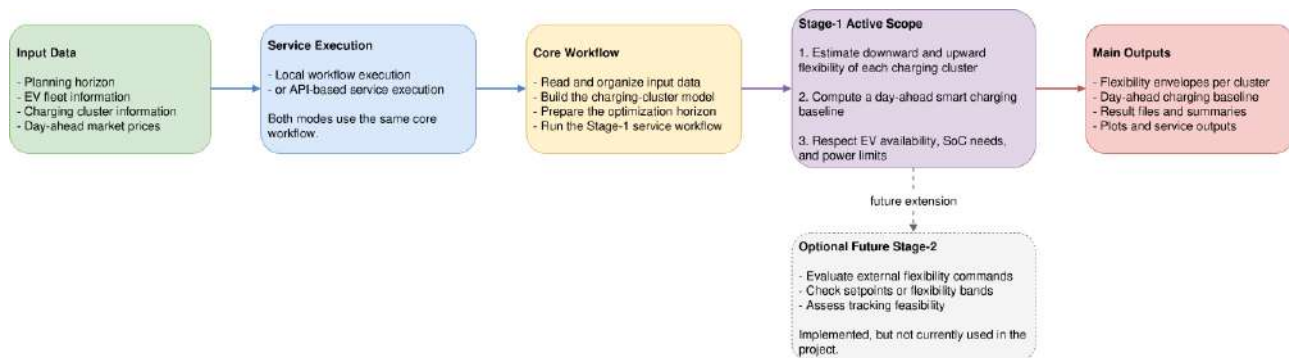


Figure 39: *datafev_flex* architecture

Previous developments

The current EV tool builds on earlier developments from the *datafev*, which is a Python framework for the development, testing, and assessment of management algorithms for EV charging scenarios. In particular, the internal representations of EV fleets, EVs, charging units, charger clusters, and multi-cluster systems are reused or adapted from previous *datafev* components. These legacy data models provide the basis for representing the e-mobility system and for connecting the newer flexibility optimization workflows to established EV charging simulation structures.

Current status

Within the scope of this project, these existing components were further developed into a dedicated service tool, referred to as *datafev_flex*. The project work therefore focused not only on reusing the existing EV and charging infrastructure models, but also on embedding them into a service-oriented flexibility workflow. This includes dedicated modules for input parsing, optimization workflow orchestration, flexibility envelope calculation, day-ahead smart charging, result export, and API-based execution.

Through this development, *datafev_flex* extends the original simulation-oriented capabilities of *datafev* toward EV flexibility assessment at charging-cluster level. The tool is currently used for Stage-1 flexibility potential estimation within the project, while the Stage-2 scheduling functionality has already been implemented to enable future applications involving flexibility command tracking, absolute setpoints, or flexibility bands.

Input data description

The input data for the EV flexibility tool, *datafev_flex*, can be divided into three main categories: planning-horizon inputs, EV and charging-cluster modelling inputs, and electricity market inputs. Together, these inputs define the optimization horizon, the technical and operational characteristics of the EV charging system, and the economic signals used to compute the day-ahead smart-charging baseline.

The planning-horizon inputs specify the temporal scope of the optimization. These parameters define the start and end of the planning period as well as the timestep resolution used throughout the workflow. They therefore determine the discrete time structure on which both the flexibility estimation and the day-ahead charging optimization are based.

The EV and charging-cluster modelling inputs define the physical and operational constraints of the system. On the charging-infrastructure side, they include charger identifiers, maximum charging and discharging power, and efficiency values. On the vehicle side, they include battery capacity, arrival and departure times, initial and target state of charge, minimum and maximum allowed state of charge, cluster assignment, and vehicle-specific charging and discharging power limits. In addition, control flags specify whether a target state of charge must be enforced and whether this target must be satisfied exactly at departure.

The electricity market inputs provide the day-ahead electricity prices used in the smart-charging optimization. In the current project scope, these prices are used to derive a charge-only day-ahead baseline for the EV fleet, which complements the flexibility envelope estimation carried out in Stage-1.

Since only Stage-1 is used operationally in the current project, no additional command input is required in normal operation. Nevertheless, the tool already supports optional Stage-2 command inputs for future applications. In that case, cluster-level absolute setpoints or flex bands can be provided separately as timestamped command data.

Table 7: Planning-horizon input parameters

Parameter	Unit	Description
planning_start	datetime	Start timestamp of the optimization horizon

planning_end	datetime	End timestamp of the optimization horizon
time_step_minutes	datetime	Temporal resolution of the optimization

Table 8: EV and charging-cluster modelling input parameters

Parameter	Unit	Description
cluster_id	-	Cluster identifier
cu_id	-	Charging unit identifier
p_max_ch_kW	kW	Maximum charging power of the charging unit
p_max_ds_kW	kW	Maximum discharging power of the charging unit
efficiency	p.u.	Charging/discharging efficiency factor of the charging unit
vehicle_id	-	Electric vehicle identifier
battery_capacity_kWh	kWh	Usable battery capacity of the EV
arrival_time	datetime	EV arrival time within the planning horizon
departure_time	datetime	EV departure time within the planning horizon
initial_soc	p.u.	Initial SOC at arrival
target_soc	p.u.	Desired SOC at departure
use_target_soc	0/1	Flag indicating whether the target SOC must be enforced
exact_target_soc	0/1	Optional flag indicating whether the target SOC must be met exactly
min_allowed_soc	p.u.	Minimum allowable SOC
max_allowed_soc	p.u.	Maximum allowable SOC
target_cluster	-	Cluster to which the EV is assigned
p_max_charge_kW	kW	Maximum EV charging power
p_max_discharge_kW	kW	Maximum EV discharging power

Table 9: Electricity market input parameters

Parameter	Unit	Description
timestamp	datetime	Timestamp of the market-price observation
price_eur_per_kwh	EUR/kWh	Day-ahead electricity price used for smart charging

Table 10: Optional future Stage-2 command input parameters

Parameter	Unit	Description
cluster_id	-	Cluster receiving the command
timestamp	datetime	Command timestamp
p_set_kw	kW	Absolute cluster power setpoint
p_min_kw	kW	Lower bound of the requested flex band
p_max_kw	kW	Upper bound of the requested flex band

Output data description

The output data of *datafev_flex* can be divided into three main categories: flexibility capability outputs, day-ahead baseline scheduling outputs, and reporting and visualization outputs. In the current project scope, the operational outputs are those produced by Stage-1.

The flexibility capability outputs describe the downward and upward flexibility potential of each charging cluster over the planning horizon. Here, downward flexibility represents additional charging demand from the grid, whereas upward flexibility represents reduced charging demand and, where technically feasible, V2G export potential. These outputs are provided as time series per cluster and are also summarized over the full horizon.

The day-ahead baseline scheduling outputs describe the price-driven charging plan computed for the EV fleet. These results include the day-ahead market price trajectory, cluster-level aggregate charging power, EV-level charging power schedules, EV SOC trajectories, and a charging-cost summary. Since the Stage-1 smart-charging model is charge-only, this baseline does not include V2G dispatch.

The reporting and visualization outputs support result interpretation and communication. They include per-cluster capability plots, an aggregate capability plot across all clusters, and optional key performance indicator (KPI) post-processing files. When the tool is executed through the API, the service also returns metadata such as the generated stage1_id, the number of processed clusters, and the output directory in which the artifacts are stored.

Although Stage-2 outputs are already implemented, they are currently outside the active project scope. If Stage-2 is used in future applications, the tool can additionally export command-status information, tracking reports, and cluster- and EV-level scheduling results for requested setpoints or flex-band commands.

Table 11: Main output data products

Output product	Format	Main contents
cluster_capability_timeseries	XLSX / CSV / Parquet	Per-cluster time series of downward_capability_kW, upward_capability_kW, optional connected_evs, and Stage-1 cluster_power_kW

day_ahead_smart_charging_schedule	XLSX / CSV	Market prices, cluster aggregate charging power, EV charging power trajectories, EV SOC trajectories, and charging-cost summary
cluster_<id>_capability	PNG	Per-cluster flexibility capability plot
aggregate_capability	PNG	Aggregate flexibility capability plot across all clusters
kpi_summary	CSV	Optional KPI summary generated during post-processing
aggregate_timeseries	CSV	Optional aggregate time-series results for KPI analysis
API response metadata	JSON	stage1_id, cluster_count, output_dir, job_output_root
Future Stage-2 scheduling results	XLSX / CSV / PNG	Command status, command bands or setpoints, cluster power, EV power, EV SOC, and tracking reports

Case Study

To illustrate the Stage-1 workflow of *datafev_flex*, a small single-cluster example with two EVs was evaluated. The study considers one charging cluster with two 11 kW charging units and two EVs connected over a six-hour planning horizon with a 15-minute resolution. The objective of this example is to demonstrate, in a compact and transparent setting, how the tool estimates the flexibility potential of the cluster and derives a day-ahead smart charging baseline.

Figure 40 introduces the setup of the case study. It summarizes the EV connection windows, the initial and target SOC levels, and the day-ahead electricity price profile used in the optimization. The example is intentionally simple and therefore well suited for illustrating the operational logic of the current Stage-1 workflow.

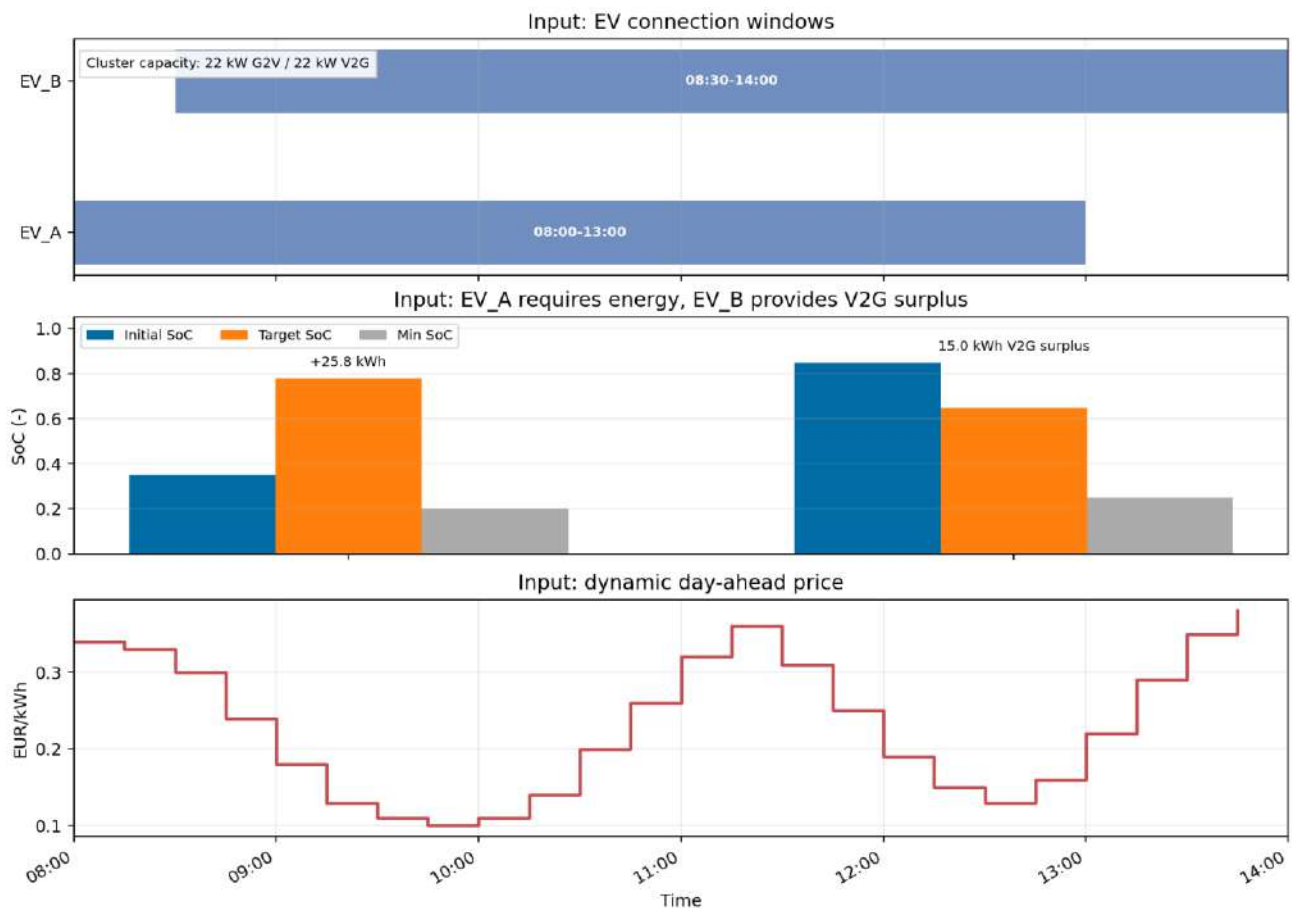


Figure 40: Input overview of the single-cluster two-EV Stage-1 case study.

In this scenario, EV_A arrives with an initial state of charge of 35% and requires charging up to a target SOC of 78% before departure. EV_B arrives with an initial state of charge of 85%, which is already above its target SOC of 65%, and therefore does not require additional charging in the day-ahead baseline. This setup creates a simple but illustrative case in which the Stage-1 workflow can show both charging flexibility and limited discharge potential.

The resulting flexibility estimation is illustrated in Figure 41. The figure shows the Stage-1 capability band of the charging cluster over the planning horizon and highlights when downward flexibility, i.e. additional charging demand, and upward flexibility, i.e. reduced charging or limited V2G support, are available. The results show that the cluster provides a total downward flexibility potential of 52.59 kWh and an upward flexibility potential of 8.59 kWh over the planning horizon. The maximum downward flexibility reaches 22.0 kW, while the maximum upward flexibility reaches 11.0 kW.

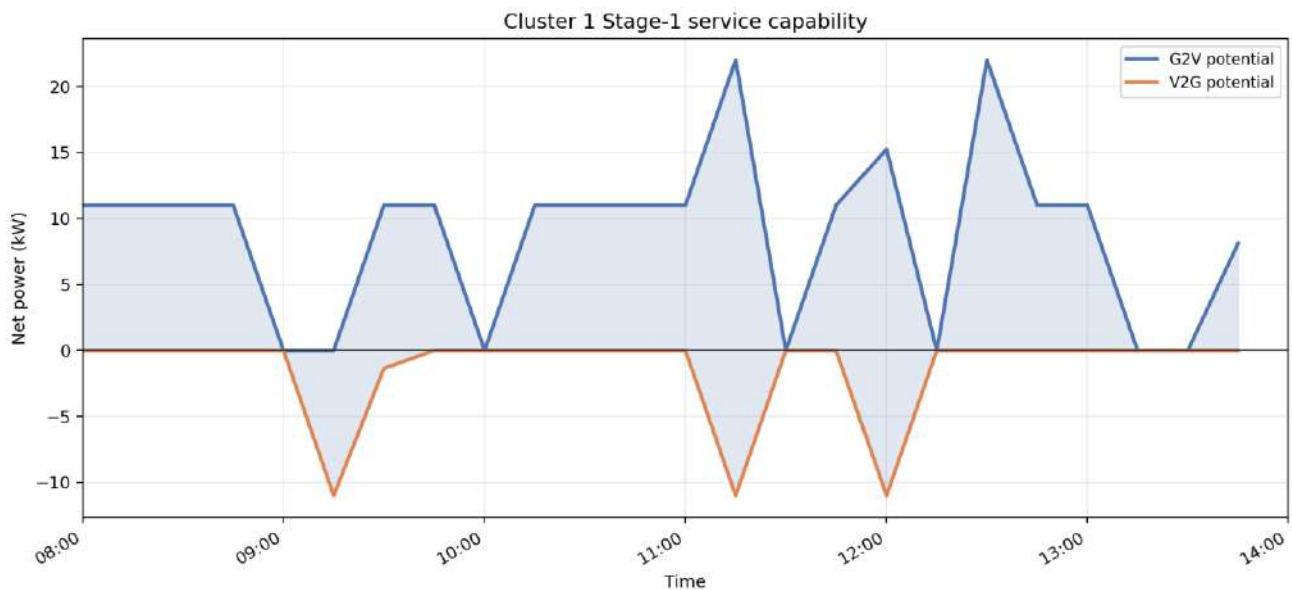


Figure 41: Stage-1 flexibility capability band for the example charging cluster.

The price-driven day-ahead baseline is then presented in Figure 42. This figure shows how the charging schedule is aligned with the electricity price signal and how charging is shifted toward lower price timesteps while EVs availability, SOC, and charger power constraints remain satisfied. In total, the day-ahead baseline schedules 27.16 kWh of charging energy at a total charging cost of 3.785 EUR.

If an EV-level view is included, Figure 43 can further be used to show how the baseline charging energy is distributed across the connected vehicles. In this case, the figure confirms that EV_A is the only vehicle that requires active charging, while EV_B remains above its target SOC throughout the horizon and therefore is not scheduled for additional charging.

Taken together, the mini case study provides an intuitive and compact example of how datafev_flex transforms structured input data into operational Stage-1 flexibility results. It therefore serves as a useful demonstration of both main Stage-1 outputs: the flexibility capability envelopes and the day-ahead smart charging baseline.

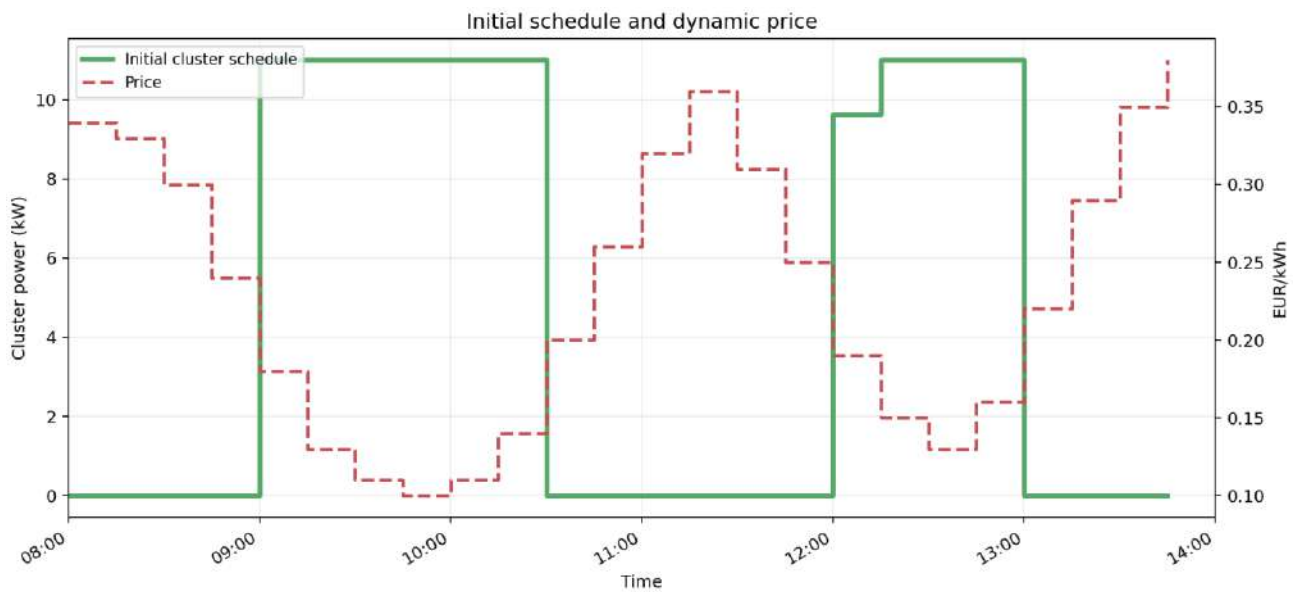


Figure 42: Day-ahead smart charging baseline and electricity price profile for the case study.

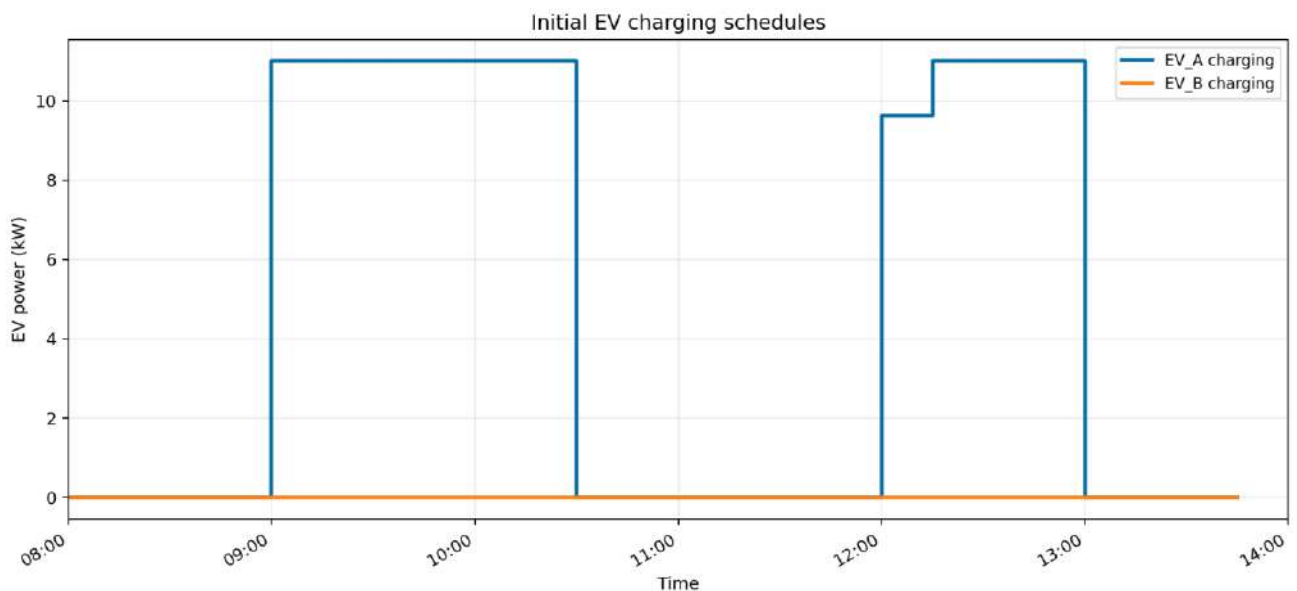


Figure 43: EV-level day-ahead smart charging schedule for the Stage-1 mini case study.

Future developments

Future developments include the finalization and integration of the transmission network OPF tool with the existing distribution network OPF and the overall flexibility optimization framework. The integration of both OPF formulations will enable the validation of the centralized OPF approach within the full system architecture.

Following the validation of the centralized framework, work will proceed with the development of the decentralized power flow approach, based on distributed optimization using the Alternating Direction Method of Multipliers .

Also, simulation studies will be conducted to assess and validate the accuracy, robustness, and effectiveness of the proposed methodologies under different grid operation scenarios.

Finally, the EV flexibility tool will be integrated into the project's DT, enabling users to test and evaluate the service within the digital twin environment.



5. System-of-system Digital Twin for multiple carrier grid management & operation

Overview

Task T4.4 concerns the development of the CRETE VALLEY System-of-Systems DT (TwinREV) for the management and operation of multiple energy carriers at the REV, CELs and transmission/distribution grid levels. The DT constitutes the interaction layer where data, analytical services and functionalities developed across the different tasks of WP4 are brought together, forming the digital backbone of the REV concept. Its purpose is to support monitoring, simulation, forecasting and optimization of energy flows by enabling the relevant stakeholders to interact with functionalities aligned with their operational responsibilities in a common environment. The DT is fully operational and can be accessed (with the appropriate role-based authentication) in the following url: <https://digital-twin.crete-valley1.epu.ntua.gr/>. Furthermore, the project has been uploaded to GitHub, with a detailed guide on how to replicate it, here: <https://github.com/Crete-Valley/TwinRev>.

During the second wave of developments, the DT progressed from the initial demonstrator reported in D4.1 to a more mature and integrated platform. The main progress concerns the deployment and integration of forecasting and flexibility provision services developed in T4.2 and T4.3, respectively, as well as the implementation of an initial end-to-end operational pipeline for the TSO-oriented case, with the integration of T4.1 functionalities and power systems simulation engine DPsim. Further enhancements regarding each stakeholder-specific interface were also developed which are presented in detail in the following subsections.

Previous developments

The first wave of developments, documented in D4.1, defined the conceptual, architectural and technical foundations of the DT platform. Based on the reference architecture, Figure 44, and requirements developed in WP2 and WP3, the initial implementation established the DT as a multi-layer solution connecting physical assets and data sources with data interoperability mechanisms and digital services. At this stage, the principal roles interacting with the platform were identified as CEL/REV managers, TSOs/DSOs, market actors and RES operators, Figure 45. The specified workflow was defined as consumption, production and weather data feeding into forecasting and optimisation services which support CEL/REV managers' operational decisions and market participation, while enabling grid operators to assess the technical feasibility of these decisions and utilizing them to support efficient network operation.

The first version of the platform also established the initial environment required for the DT operation. A front-end demonstrator including the homepage, sign-in interface, CEL maps and analytics pages for load and production monitoring was implemented, providing the first illustration of how CEL data are accessed and visualised. In detail, the load analytics pages were designed to enable the visualisation of energy consumption and cost-related information of the CEL members, and the Production analytics page enabled the visualisation of production data of the CELs' energy



assets, as well as weather information. In addition, the platform was structured so that authenticated users can access only the platform components aligned with their respective roles and responsibilities, with identification and access managed through Keycloak. This role-based architecture of the DT provided the foundation for seamless integration of subsequent platform extensions which require distinct access rights.

Furthermore, the first-wave established the underlying technical environment required for the deployment and operation of the DT services. This environment was based on a Kubernetes cluster supporting the deployment and orchestration of platform components and analytical services. Monitoring capabilities were implemented through Prometheus and Grafana, enabling the observation of server and pod-level operation. In addition, a PostgreSQL-based database environment, supported through PgAdmin for database administration and the Zalando PostgreSQL Operator for database management and backup-related operations, was established to support the storage and management of platform data. The aforementioned have also been described in detail in D4.1.

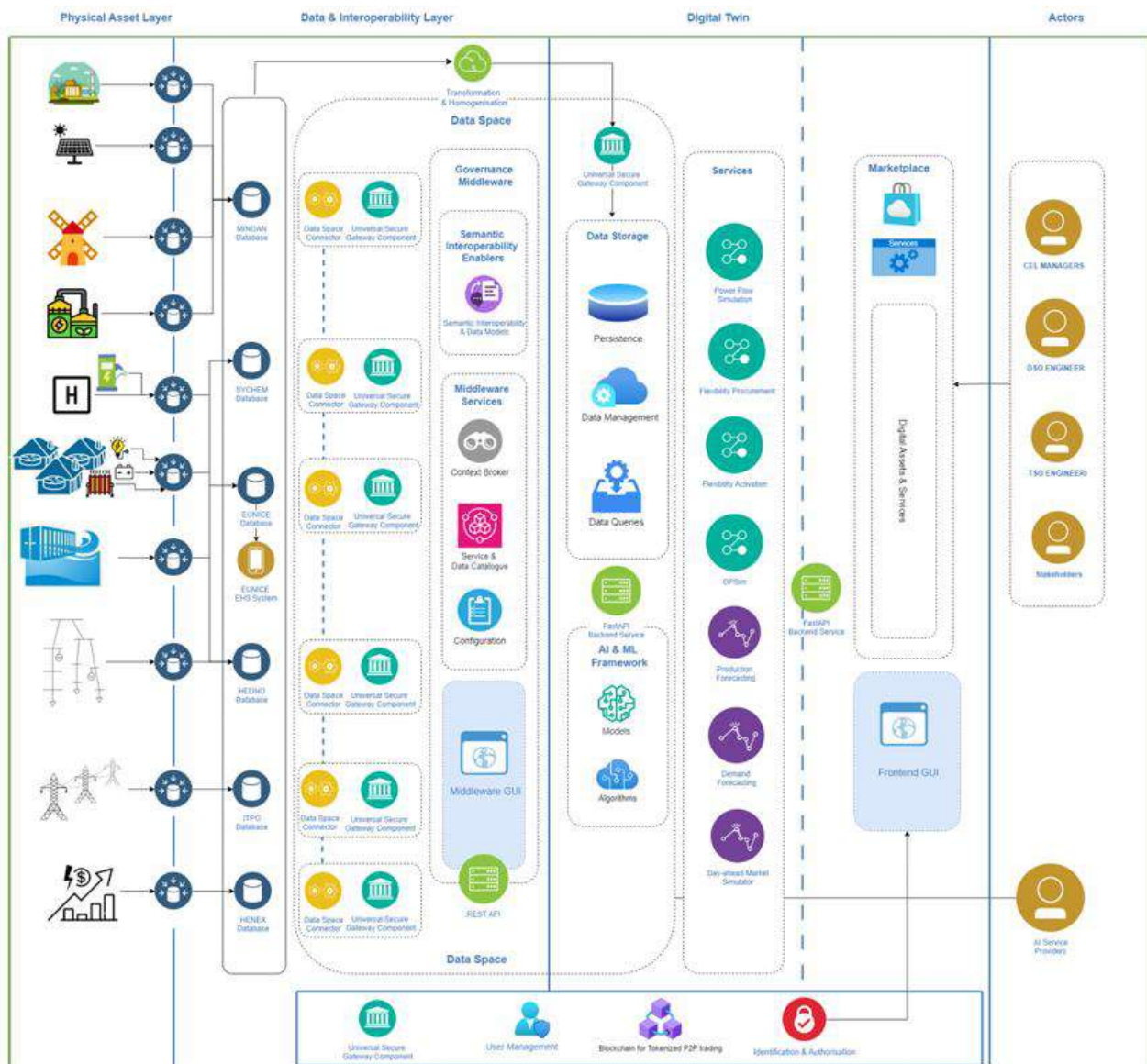


Figure 44: Crete Valley Reference Architecture v.1.0

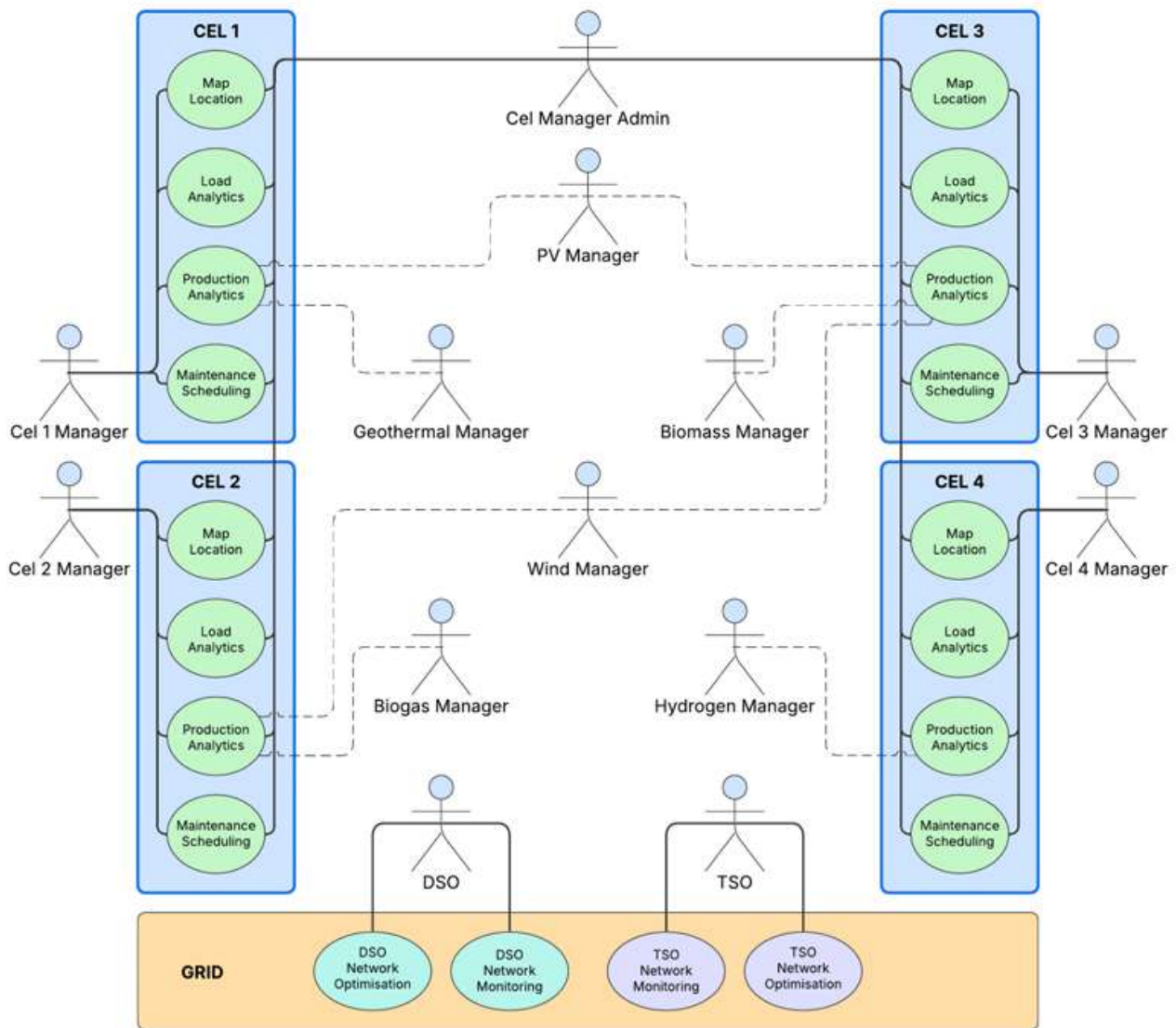


Figure 45: Digital Twin User Roles and relation with the CELs

Current Status per Stakeholder

As mentioned, during the second wave of developments, the DT progressed from the initial demonstrator to an integrated platform. The technical infrastructure, including the Kubernetes-based deployment environment, monitoring components, database services and role-based access management mechanism, was maintained and used to support the deployment and operation of the newly integrated services. The main progress during this period concerns the deployment and integration of forecasting and flexibility provision services developed in T4.2 and T4.3, as well as the implementation of an initial end-to-end operational pipeline for the TSO-oriented case, integrating the services developed under T4.1 and implemented through the DPsim engine. At front-end level, the DT platform was extended through the development of stakeholder-oriented pages, including the completed first version of the TSO page, an initial draft version of the DSO page and the further development of CEL, REV overview and homepage interfaces.

CEL Manager status

The DT components dedicated to CEL Managers have been designed to provide the required information regarding energy production and consumption, to enable the maintenance of RES infrastructure, to support operational and market-oriented decisions through forecasting and flexibility provision services and finally to connect analytics with recognizable physical infrastructure through 3D visualisations of energy assets and CEL maps. To support these functions, the CEL Manager interface is organised around a dedicated page for each CEL, divided into the following subpages:

- CEL map
- Load Analytics
- Production analytics (with a dedicated page for each energy asset)
- Maintenance scheduling

Since the first wave, the major advancements concern mainly the Production Analytics page functionalities. First, Unity-based 3D visualisations for every asset, provided by ONE TEAM, have been integrated, allowing the CEL manager to associate analytical information with a recognisable digital representation of the corresponding physical infrastructure, Figure 46. Second, the forecasting service developed in T4.2 and the flexibility provision service developed in T4.3 have been integrated into the Production Analytics environment, enabling the user to access asset-level production information together with forecasted behaviour and available flexibility-related outputs through the same interface. For CEL 3, the Production Analytics page functionalities are fully operational for a 1 MW photovoltaic plant owned by MINOAN. For the remaining energy assets to be installed, the database has been populated with synthetic production data in order to test the integrated services and validate the functionality of the corresponding pages before the availability of field data. These synthetic datasets have been generated in a manner consistent with the operational characteristics and technical constraints of the represented assets. Figure 47 presents a screenshot of the production analytics page for the windmill in CEL 3.

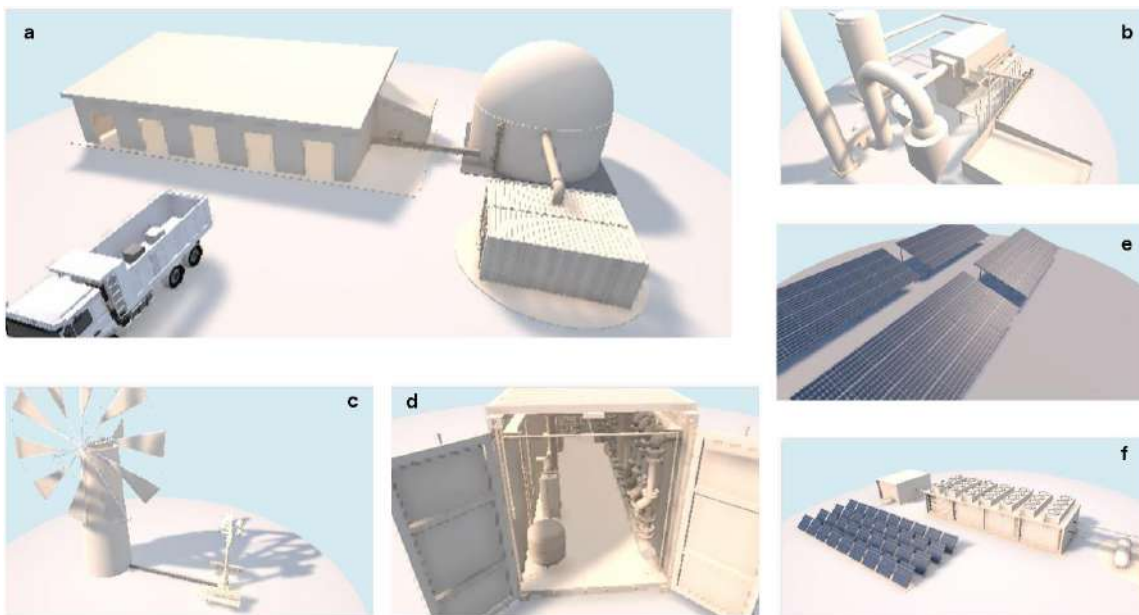


Figure 46: Overview of all 3D asset visualizations: a) Biogas, b) Biomass, c) Windmill, d) Geothermal, e) Photovoltaics, f) Hydrogen

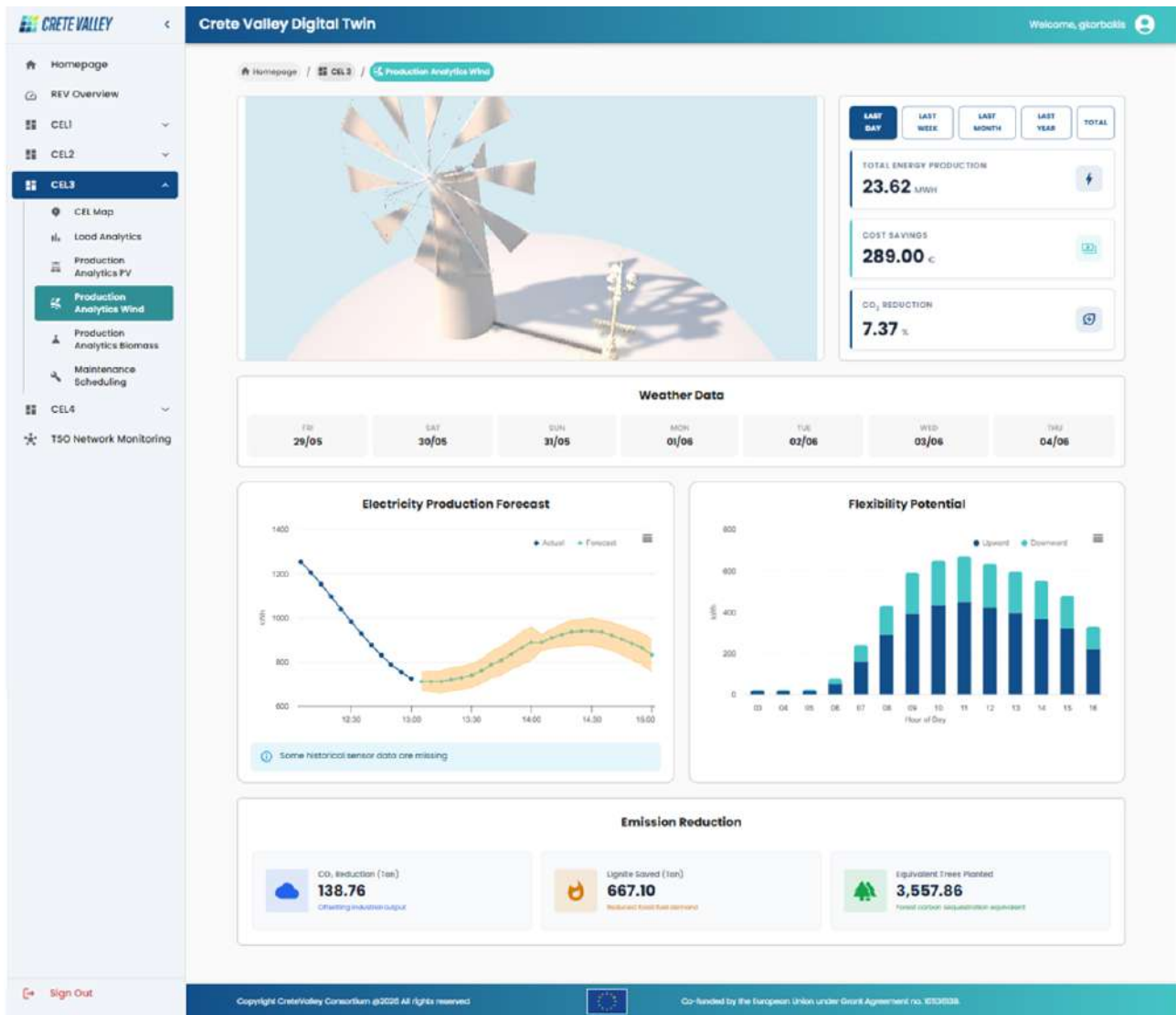


Figure 47: Production analytics page for the windmill of CEL3

In addition, a new Maintenance Scheduling page was developed during the second wave, Figure 48. This page enables CEL managers to schedule maintenance events for the energy assets associated with their CEL and to monitor asset condition through maintenance-relevant indicators. The page also supports the generation of fault warnings when abnormal values of selected KPIs are detected in the available measurements or calculated through the implemented monitoring logic. The implemented monitoring logic allows the DT to identify deviations from expected operation and to communicate potential fault or maintenance-relevant conditions to the user through the CEL Manager interface.

In more detail, the page is structured to provide both an overview of existing maintenance activities and an interface for scheduling new ones. At the top of the page, the user can view maintenance events that have already taken place, as well as maintenance events that are scheduled to occur in the future. This allows the user to quickly review the maintenance history and upcoming planned actions for the selected assets.

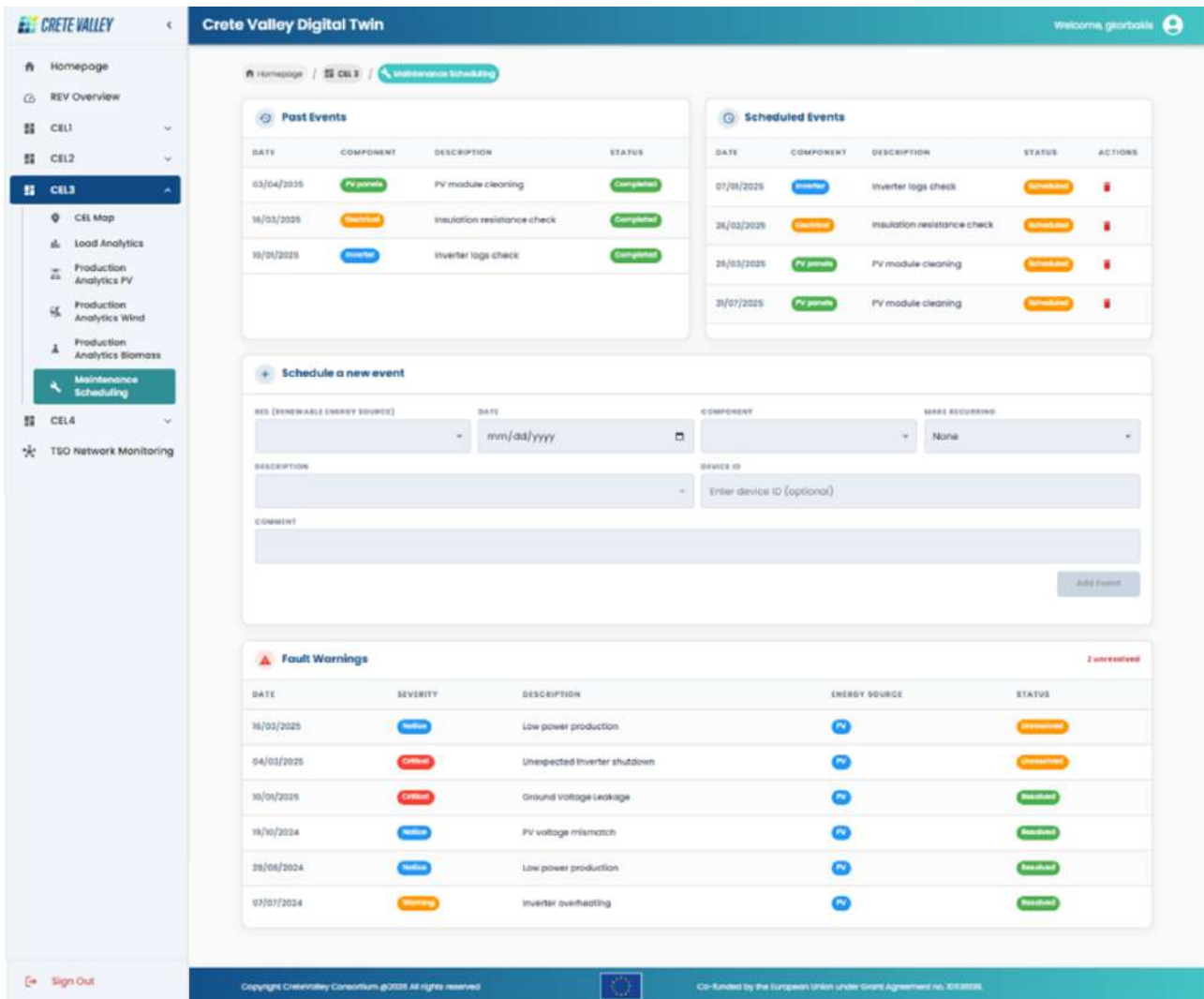


Figure 48: Maintenance scheduling page

The middle section of the page contains the interface for scheduling a new maintenance event. For the time being, the module includes predefined maintenance options for PV plants. The available options are organized based on the selected CEL. Depending on the CEL, the field “RES (RENEWABLE ENERGY SOURCE)” displays the RES assets that belong to that CEL. After selecting the relevant RES asset, the user can choose a corresponding component of that asset.

The predefined maintenance options for PV plants, already included in the DT, are divided into the following component categories (field “COMPONENT”) and events (field “DESCRIPTION”):

- **Inverter:** firmware updates, electrical connections check, fans and filters cleaning, other.
- **Electrical:** insulation resistance check, grounding system check, water ingress check, other.
- **PV panels:** PV panel cleaning, visual inspection, IR thermography check, IV curve tracing, other.
- **Mounting system:** corrosion check, structure alignment check, bolts torque check, other.
- **Environment:** vegetation cleaning, pest control, other.

An optional Device ID field is also provided. This is useful in cases where the RES asset contains multiple devices of the same type, for example multiple inverters for the PV plants. By entering the Device ID, the user can specify exactly which device the maintenance event refers to. The module also includes a Description field, where the user can add comments or additional information about the maintenance event. This field helps the user record useful details for future reference. Since the option “Other” is available under each component category, the user can also schedule a custom maintenance event that is not included in the predefined lists.

At the bottom of the page, the Fault Warnings section provides an overview of automatically detected operational issues affecting the monitored RES assets. At present, the DT communicates with a 1 MW PV plant owned by Minoan, located in CEL3. Operational measurements from the plant are collected and analysed by the backend to identify abnormal inverter behaviour and potential performance issues.

Five scheduled backend jobs have been implemented. Four analyse inverter and plant measurements from the previous 24 hours against predefined rules, while the fifth manages the lifecycle of scheduled maintenance events. When an abnormal condition is newly detected, a corresponding fault warning is created. When a previously detected condition is no longer present, the associated entry is automatically marked as resolved. The implemented checks are described below:

- **Inverter overheating**

The check is executed every hour, at 35 minutes past the hour. It identifies inverters whose internal temperature exceeds 55°C while they are operating in the “Grid Connected” state. The applied detection rule is: **temperature > 55°C and inverter state = “Grid Connected”**. Each measurement satisfying these conditions is recorded separately, together with the corresponding Device ID and timestamp. The detected event is registered as an inverter-level **Warning**. Devices for which no overheating measurements are detected during the examined period are considered to be operating at a normal temperature.

- **Inverter leakage and unexpected shutdown**

The check is executed every hour, at 45 minutes past the hour. It considers only measurements for which irradiance exceeds 50 W/m², because these operating conditions are meaningful primarily during daylight hours. The inverter state “OFF: unexpected shutdown” is interpreted as an unexpected inverter shutdown and is registered as a Critical inverter fault. The state “Standby: insulation resistance detection” is interpreted as a possible insulation problem or ground-leakage condition and is registered separately as a Critical electrical fault. The two fault categories are managed independently, and the backend reports the number of newly created and automatically resolved entries for each category.

- **Inverter efficiency**

The check is executed once per day, at 01:35 UTC. For each inverter, the backend calculates the average reported efficiency over the previous 24 hours, considering only measurements for which the inverter was grid-connected and actively producing power. An average efficiency above 95% is classified as **Good**, while an average efficiency equal to or below 95% is classified as **Bad**. An inverter classified as “Bad” is assigned an inverter-level **Warning**. The check is applied separately to each inverter, allowing the specific underperforming device to be identified.

- **PV plant underperformance**

The check is executed once per day, at 01:45 UTC. It compares the plant's actual daily production with the production theoretically expected under the measured irradiance and temperature conditions. The expected production is calculated using a simplified PV performance model that accounts for solar irradiance and the reduction in PV output caused by elevated module temperatures. The model uses a temperature coefficient of approximately -0.5% per degree Celsius relative to the standard test temperature of 25°C . The expected power is calculated as $P_{\text{expected}} = Y \times (G / G_{\text{STC}}) \times [1 + \alpha \times (T - T_{\text{STC}})] \times \text{cutoff percentage}$. The default cutoff percentage is 80%, meaning that the plant is expected to produce at least 80% of its estimated theoretical output. The expected and actual production values are accumulated over the entire day. When actual production falls below the acceptable expected value, a plant-level **Notice** is created under the electrical fault category. This event refers to the complete PV plant rather than to an individual inverter. When no measurable production is available during the examined period, the check is skipped because a meaningful comparison cannot be performed.

- **Maintenance lifecycle management**

The maintenance-lifecycle job is executed once per day, at 00:15 EET/EEST, and applies to all plants included in the Digital Twin. Maintenance events whose scheduled dates have passed are automatically transferred from the scheduled-events list to the maintenance-history section. For recurring events, the next occurrence is generated automatically. Supported recurrence intervals include monthly, quarterly, semi-annual and annual maintenance. If several recurring occurrences have been missed, the job generates the necessary subsequent occurrences until the schedule is brought up to date. The job reports the number of events transferred to the past-events list and the number of new recurring events created. It can also be executed in dry-run mode, in which the expected updates are reported without modifying the stored maintenance data.

TSO status

During the second wave, significant progress was achieved with a dedicated TSO page created and an initial end-to-end pipeline completed. The TSO functionality is technically supported through the successful integration of power systems simulator DPsim. This integration enables the DT to communicate with the power flow simulation service and constitutes the basis for executing operational analyses through the platform. The TSO-oriented use case addresses the transmission-level network analysis under different demand and RES generation scenarios.

The workflow supports time-series power flow simulations combined with configurable scenarios of projected load growth and increased RES penetration. The CIM topology includes future structural developments such as the retirement of thermal units and the full interconnection of the island of Crete with the Greek mainland through the HVDC Attica-Damasta interconnection. Demand and generation power profiles, for the whole complete year of 2025, based on available measurement data for Crete's HV network were obtained and integrated together with a validated CIM-based topology. The available power profiles distinguish between loads, conventional generators and renewable generation sources, enabling the evaluation of network security in the examined scenarios.

The TSO page is divided into two main modules. In the first page, data analytics are presented to the user, displaying the power profiles for every substation of the network, based on the selected day of the year, Figure 49. In addition, days of special interest (peak/minimum load/generation) have been highlighted as they represent the network's most stressing conditions. Data of RES (PV and wind park) and conventional production, load and reactive power compensators are presented in hourly resolution to the user based on the selected scenario. The defined scenarios include the following current or future status of the Crete power system, based on scaling coefficients calculated as described below:

- Scenario 1: Current status (As-is)
- Scenario 2: Projected Load growth scenario (Loads x1.094)
- Scenario 3: Projected RES growth scenario (PVs x2.5, WPs x1.6)
- Scenario 4: Projected Load + RES growth scenario (Loads x1.094, PVs x2.5, WPs x1.6)
- Scenario 5: Extreme RES growth scenario (Loads x1.094, PVs x4.3, WPs x3.9)
- Scenario 6: Low RES production scenario (Loads x1.094, PVs x0.2, WPs x0)

while the user is also provided with the option to create a custom scenario by manually scaling loads, PV and wind production profiles. Future RES generation has been calculated based on real measurements for the year 2025 and the ratio of the currently installed capacities to the projected capacities in the future scenarios. In a similar manner, future system load has been calculated based on the 2025 annual baseline and a growth rate projected for 2030. Table 12 presents the baseline (2025) and projected (2030) installed capacities of PVs and wind parks of all substations in Crete among two different RES penetration scenarios: future normal penetration and future extreme penetration, as provided in [6].

In particular, for normal level penetration, PVs installed capacity will be increased by $\frac{301.9}{116.3} \cong 2.5$, while for extreme level penetration the increase coefficient is calculated as $\frac{500}{116.3} \cong 4.3$. In a similar manner, the wind parks normal penetration ratio is provided as $\frac{322.1}{202.7} \cong 1.6$, while for extreme wind park penetration the ratio is derived as $\frac{800}{202.7} \cong 3.9$. To account for the future load growth, a scaling factor of 1.094 was applied, representing a 9.4% net increase in active power demand by 2030 (Independent Power Transmission Operator, 2024). The reactive power demand was derived by assuming a constant power factor $\cos\phi = 0.95$.

Table 12: Baseline and future installed capacities of PVs and wind parks in Crete

Substation	Wind parks (MW)			Photovoltaic parks (MW)		
	Baseline 2025	Future Penetration	Future Extreme Penetration	Baseline 2025	Future Penetration	Future Extreme Penetration
AG. NIKOLAOS	11.9	18.9	47.0	5.0	12.8	21.5
AG. VARVARA	14.5	23.0	57.0	1.0	2.7	4.3
AGIA	10.8	17.2	42.6	2.9	7.4	12.5
ATHERINOLAKKOS	0.0	0.0	0.0	0.5	1.3	2.1
CHANIA I	0.0	0.0	0.0	12.8	33.2	55.0
CHANIA II	0.0	0.0	0.0	0.0	0.0	0.0
EYLIGIA	0.0	0.0	75.0	0.0	0.0	0.0
IERAPETRA	3.0	4.8	11.8	5.0	12.8	21.5
IRAKLEIO I	0.0	0.0	0.0	1.6	4.2	6.9
IRAKLEIO II	0.0	0.0	0.0	9.6	25.1	41.2
IRAKLEIO III	6.0	9.5	23.5	5.1	13.3	21.9
KANTANOS	0.0	0.0	50.0	0.0	0.0	0.0
KASTELI	18.2	28.9	71.8	6.0	15.7	25.8
LINOPERAMATA	3.6	5.7	14.2	1.1	3.0	4.7
MARONIA	34.1	54.2	134.6	0.0	0.0	0.0
MIRES	17.4	27.6	68.7	16.3	42.5	70.4
PRETORIA	6.0	9.5	23.5	21.0	53.9	89.3
RETHIMNO	4.8	7.6	18.9	6.9	17.9	29.6
SITIA	55.7	88.5	94.9	6.1	15.9	26.2
SPHLI	16.8	26.7	66.3	10.0	25.9	43.0
STALIDA	0.0	0.0	0.0	3.2	8.3	14.2
VRYSESSES	0.0	0.0	0.0	2.2	6.0	9.9
TOTAL	202.7	322.1	800.0	116.3	301.9	500.0



Figure 49: TSO data analytics interface for scenario-based visualization of hourly substation load and generation profiles

The second part of the page includes the visualization of the time-series power flow simulation results, Figure 50 -Figure 52. At the top of the page, an SVG representation of the network topology at the 150 kV voltage level has been created, where results of the simulation such as bus voltages and line loadings are dynamically visualized. Colour coding has been applied for better representation of operationally safe or unsafe conditions. More specifically, when bus voltages are outside the operational limits of 0.95-1.05 p.u. or line loadings exceed 100%, the result boxes become red, else they remain green. A time slider at the bottom of the SVG allows the user to inspect the results for different hours of the day. At the bottom of the page plots presenting:

- Voltage magnitudes in kV and p.u.
- Voltage angles in degrees (°)
- Active and reactive power flows on transmission lines (MW/Mvar)
- Current passing through the transmission lines (kA)
- Loading of the lines (%)

for every bus and line are available. In addition, the user is able to download the full json produced after the simulation is run.



Figure 50: TSO results visualization page - Time-series power-flow simulation results in the interactive SVG representation

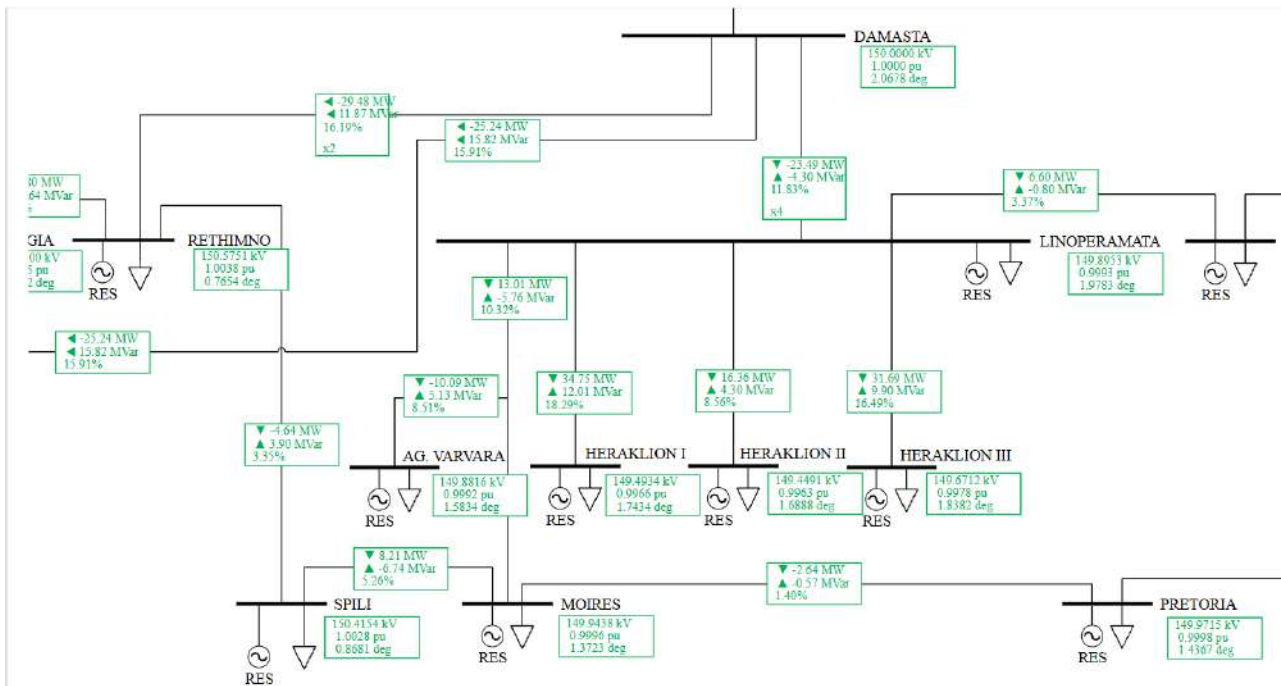


Figure 51: TSO results visualization page - Time-series power-flow simulation results in the interactive SVG representation (close-up)

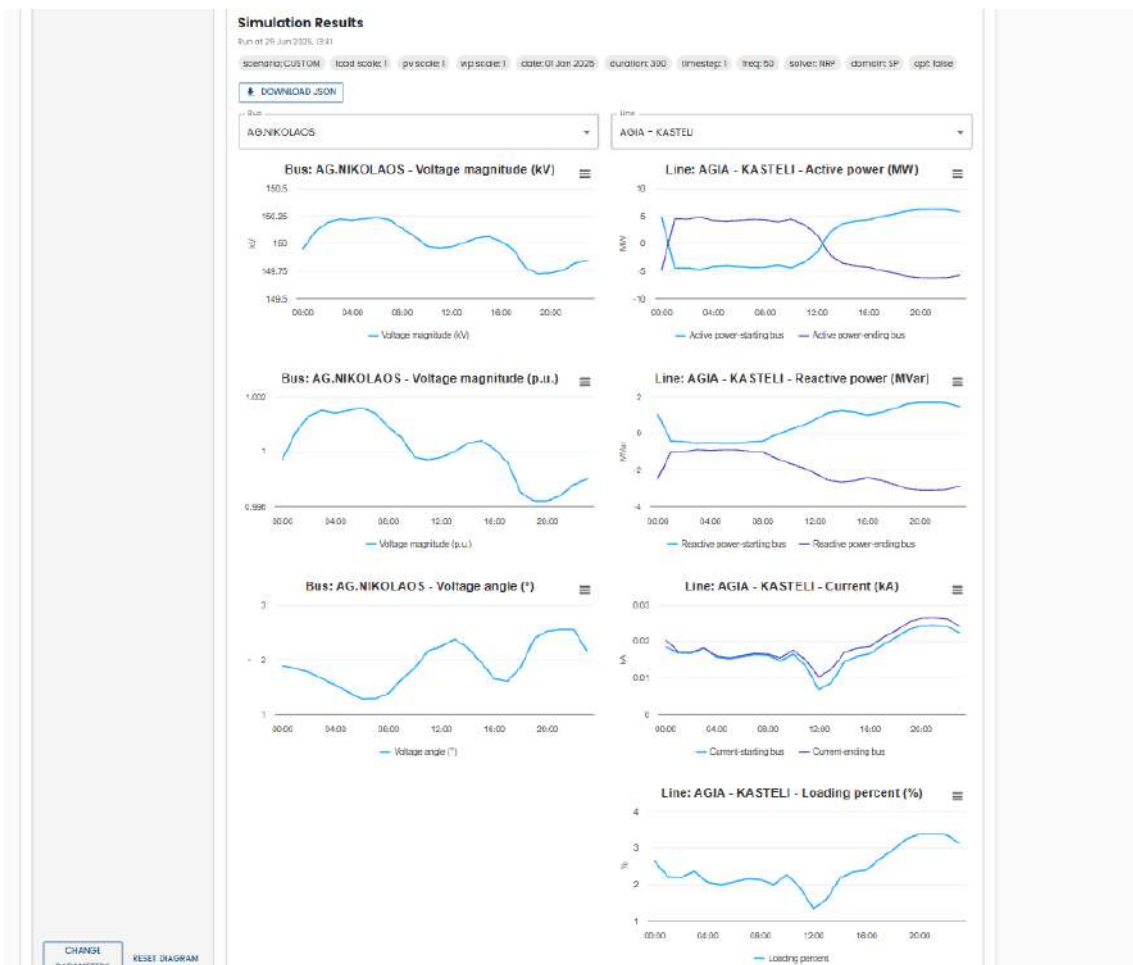


Figure 52: TSO results visualization page - Time-series plots of bus-voltage and transmission-line simulation results

DSO status

During the second reporting period, progress relevant to the DSO use case was achieved through the acquisition and integration of the data required for distribution-level simulations. In particular, power-profile datasets for the HEDNO distribution network in CEL3 were incorporated into the simulation workflow. At the present stage, these profiles rely on model-based estimations, in contrast to the measurement-based profiles available for the transmission network. Working CIM topologies for the distribution network in CEL3 were also acquired, validated and integrated into the DT framework.

In addition to these integration activities, the work carried out during this period also led to a scientific publication in the 26th International Conference on Environment and Electrical Engineering (EEEIC), to be included in the next Deliverable. This publication demonstrates how distributed flexibility sources, in particular rooftop PV systems and battery energy storage systems, can be used to address distribution-network operational issues, such as line and transformer loading constraints, as well as bus-voltage regulation. Therefore, although the full DSO-oriented pipeline has not yet been completed within the DT platform, an underlying methodology for using distributed flexibility to support secure distribution-network operation has already been developed.

The deployment of DPsim as an integrated DT backend service is also directly relevant to the DSO use case, since it provides the technical basis for distribution-level simulation studies of operating scenarios involving local loads, renewable production and flexibility resources. Moreover, the integration of the energy flexibility service establishes a pathway towards evaluating how distributed flexibility can contribute to local grid operation and constraint management.

Whilst visualisation and simulation components have progressed, the available reporting evidence at this stage demonstrates a simplistic operational pipeline. Thus, the present development status should be considered an integration stage in which the distribution network models, estimated profiles, backend simulation services and prospective flexibility interactions are being consolidated for future stakeholder-oriented deployment and validation. At the present time, the data analytics page for the DSO use case has also been developed for CEL 3, as illustrated in Figure 53. Following an approach similar to that adopted for the TSO use case, this page presents the load profiles associated with the individual buses of the distribution network, together with the available SCADA measurements recorded at the network head. These SCADA data constitute the reference basis used to derive and calibrate the estimated load profiles assigned across the distribution system. Regarding the overall organisation of the DSO interface, the platform has been structured so that each CEL-specific page includes a dedicated tab for the corresponding DSO use case.

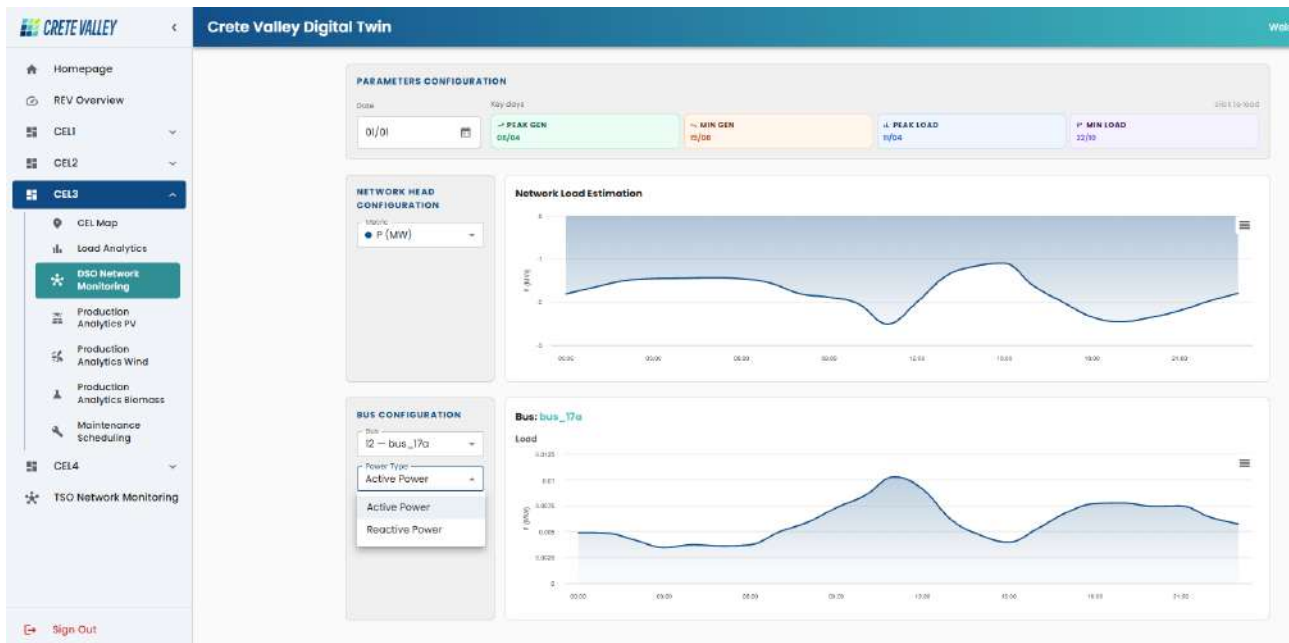


Figure 53: DSO data analytics interface for visualization of hourly bus load and generation profiles

Similarly to the TSO case, the user can select the relevant load and generation profiles by choosing a specific day of the year and then run power flow simulations for the selected operating conditions. The simulation results are visualised dynamically through an integrated SVG representation of the Arkalochori's region electrical network. As the selected profiles or simulation conditions change, the network visualisation is updated accordingly. The user can also examine the same result charts provided in the TSO case, enabling the detailed assessment of bus voltages, line loadings, power flows and other relevant network quantities.

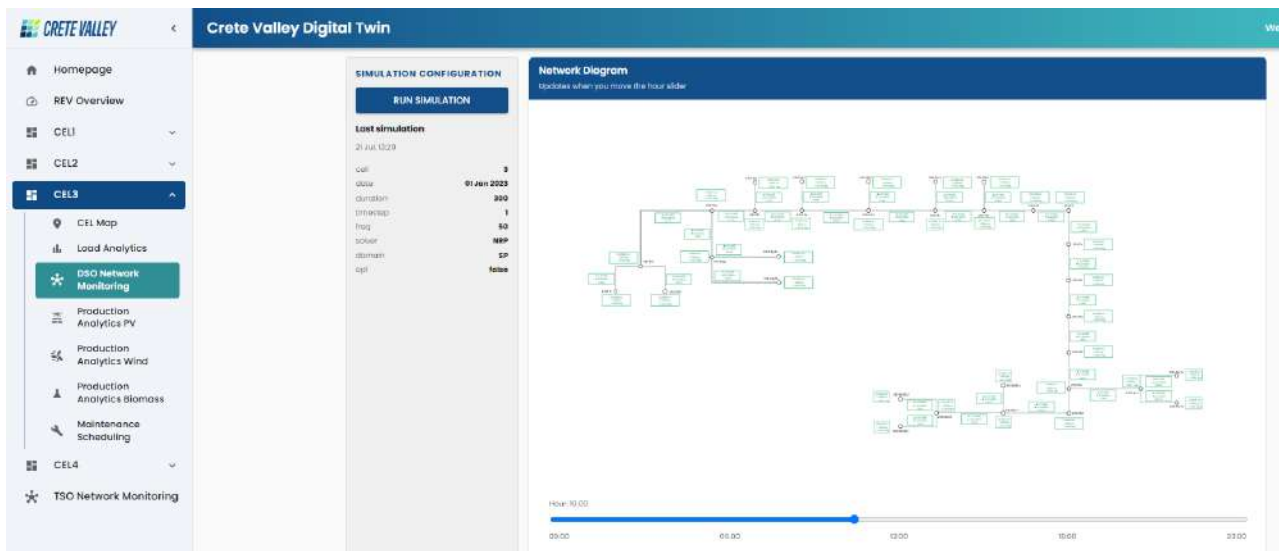


Figure 54: DSO results visualization page - Time-series power-flow simulation results in the interactive SVG representation

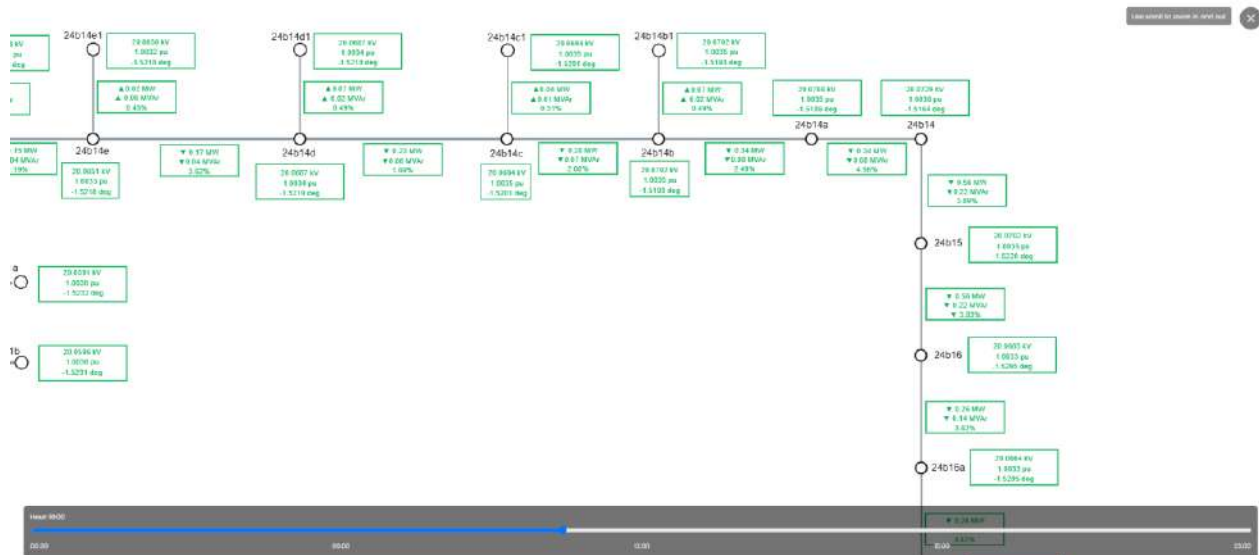


Figure 55: DSO results visualization page - Time-series power-flow simulation results in the interactive SVG representation (close-up)

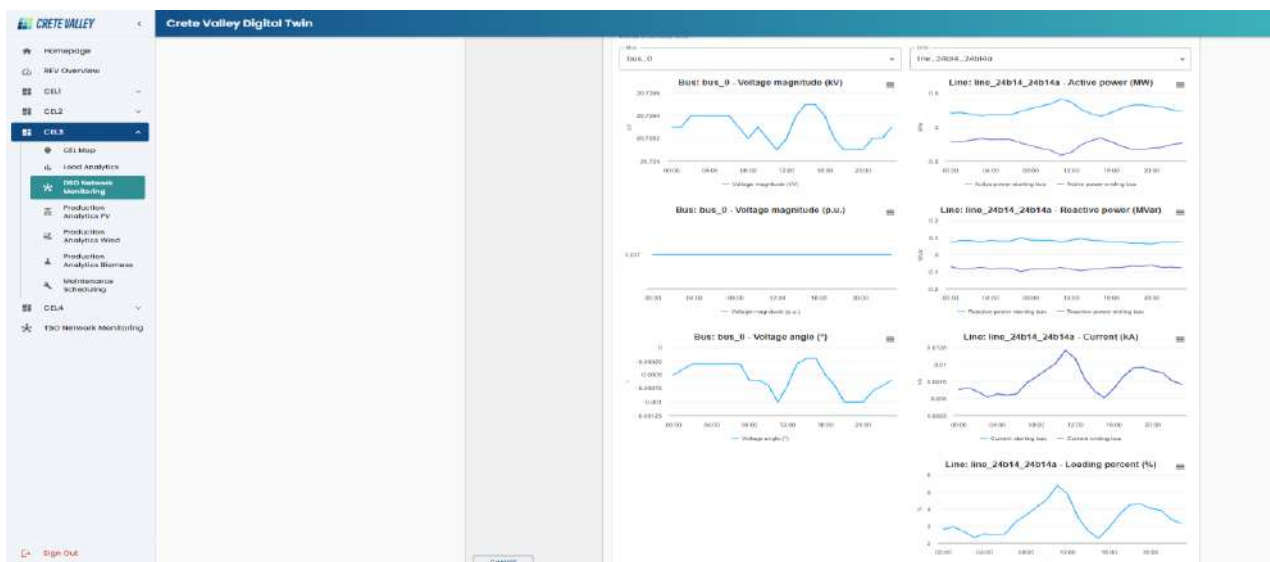


Figure 56: DSO results visualization page - Time-series plots of bus-voltage and distribution-line simulation results

Energy Markets

In D4.1, the market-oriented workflow of the DT was defined as a future functionality, through which CEL-level production, consumption and flexibility information could support the participation of CELs in the energy market. In this context, each CEL is represented as an energy community able to make market-oriented decisions based on the operation of its assets.

During the second wave, no energy market functionality was directly integrated into the DT platform. Instead, the work focused on preparing and assessing the approach to be implemented in the next development stage. More specifically, a scientific paper was accepted in the 8th International Conference on Smart Energy Systems and Technologies, investigating the participation

of an Energy Community (EnC), representing a CEL, in the Greek Day-Ahead (DA) market, in line with the developments in T7.3. The paper will be published soon, and it will be included in the next Deliverable. In this context, the EnC submits optimal bidding curves, and its participation is evaluated based on the resulting market outcomes under both current and future system conditions. The DA market simulator developed in T7.3 performs the complete market workflow, from the integration of EnC optimal bids to market clearing and the generation of market results.

Methodology

The proposed approach considers two Greek DA market configurations for assessing the participation of the EnC: the historical 2025 configuration and a projected 2030 configuration. Both market configurations are built on historical Greek market data and incorporate all order types available in the Greek DA market, namely curve and block orders. Curve orders consist of price–quantity pairs forming stepwise and/or linearly interpolated segments, submitted separately for each market time unit (MTU) of the delivery day, and are ultimately aggregated into a price–quantity curve per MTU. Block orders are defined by a fixed price limit, a minimum acceptance ratio and a variable quantity profile that can span multiple consecutive MTUs of the delivery day.

The Greek DA market follows an asset-based representation model that enables the development of alternative market configurations through technology-specific processing of market orders. A 2030 market scenario is constructed by extending the historical 2025 market framework to reflect the expected evolution of the Greek electricity system. System-level objectives are derived from national energy planning sources, namely the Greek National Energy and Climate Plan (NECP) (Ministry of Environment and Energy, 2024) and the Ten-Year Network Development Plan (TYNDP) of IPTO (Independent Power Transmission Operator, 2024), entailing changes in the generation mix driven by higher penetration of renewable and distributed energy sources, market participation levels, market topology, such as the commercial operation of the Attica-Crete HVDC interconnection, and transmission network capacity. These developments are implemented through targeted modifications to the historical orderbook and network topology data. Technologies already represented in the historical market configuration are modeled by scaling order quantities (MW) using technology-specific factors calculated as the ratio between the 2030 targets and the corresponding 2025 baselines. Synthetic orders are generated for new participating technologies (storage and demand response) based on technology-specific modelling assumptions. Bid quantities are defined as shares of the projected capacities, while bid prices are positioned competitively around the prices of gas-fired units in the merit order of the actual Greek DA market. For newly introduced assets of existing technologies (natural gas, hydro and pumped storage), synthetic orders are generated by replicating the bidding behaviour of the corresponding technology. Table 13 summarizes the underlying modifications forming the projected 2030 market configuration.

Table 13: Summary of the 2030 market scenario modifications

Component	2025	2030	Implementation
Demand (incl. Crete Load)	55.8 TWh	61.3 TWh	Scaling of historical orders
RES (incl. Crete RES)	15.6 GW	24.4 GW	Scaling of historical orders



Lignite	Historical fleet	0	Removal of historical orders
Hydroelectric	Existing fleet	+0.92 GW	Synthetic orders for additional assets
Pumped storage	Existing fleet	+0.78 GW	Synthetic orders for additional assets
Natural gas	Existing fleet	+3.0 GW	Synthetic orders for additional assets
Storage	-	4.3 GW	Synthetic block orders
Demand Response	-	3.1 GW	Synthetic curve orders
Attica–Crete HVDC	Not commercially integrated	Commercial operation	Phase-out of Crete conventional diesel units
Cross border capacities (ATC)	Historical values	Projected values	Network constraints update

First, the Greek DA market is simulated under both market configurations (2025 and 2030) to produce the corresponding baseline market outcomes. The resulting market clearing prices subsequently serve as inputs to a stochastic optimization methodology, which determines the optimal sell and buy stepwise curve orders of the EnC. These orders are then integrated into both market configurations, producing the corresponding EnC participation scenarios.

Case Study

The Greek DA market was first simulated without EnC participation under the historical 2025 and projected 2030 market configurations over the two-month period of November–December 2025. For each delivery day of the examined period, the market clearing prices (MCPs) were obtained and used as inputs to the EnC optimal bidding methodology. Table 14 summarizes the MCP key characteristics over the two-month period under the 2025 and 2030 market configurations.

Table 14: MCP key characteristics (€/MWh) for the historical 2025 and projected 2030 market configurations over the November–December

	Min	Max	Mean	Std	CV (%)
2025	-4.50	347.85	108.27	43.01	39.73
2030	-11.35	328.14	80.95	48.50	59.91

The projected 2030 market configuration results in lower average MCPs, mainly driven by the increased RES penetration. At the same time, price variability increases compared to the historical 2025 market configuration.

A representative week (15–21 December 2025) within the examined period was then selected to assess the EnC participation. Optimal EnC buy and sell bidding curves were generated for both the 2025 and 2030 market configurations and subsequently introduced into the market simulator, producing the 2025+EnC and 2030+EnC scenarios. In these scenarios, the EnC demand is assumed to represent already installed loads in Crete, while the EnC renewable generation is assumed to consist of 30% existing and 70% planned or future capacity. Therefore, the historical Crete load

quantities are reduced by the total quantity of the EnC buy orders, whereas the historical Crete RES quantities are reduced by 30% of the corresponding EnC sell orders.

Given that the examined EnC represents a relatively small share of the total bid volume submitted in the Greek DA market, an additional scaled participation case (x50) was considered to investigate the impact of larger EnC participation on market outcomes. The 2025 and 2030 market configurations were re-simulated with scaled EnC participation (2025+EnCx50 and 2030+EnCx50) for the week 15-21/12/2025. Figure 57 and Figure 58 illustrate the total weekly cleared sell-side and buy-side quantities under the baseline (2025 and 2030) and the corresponding scaled EnC participation scenarios. Table 15 presents the daily mean MCP differences between the scaled EnC participation scenarios and the corresponding baseline market configurations.

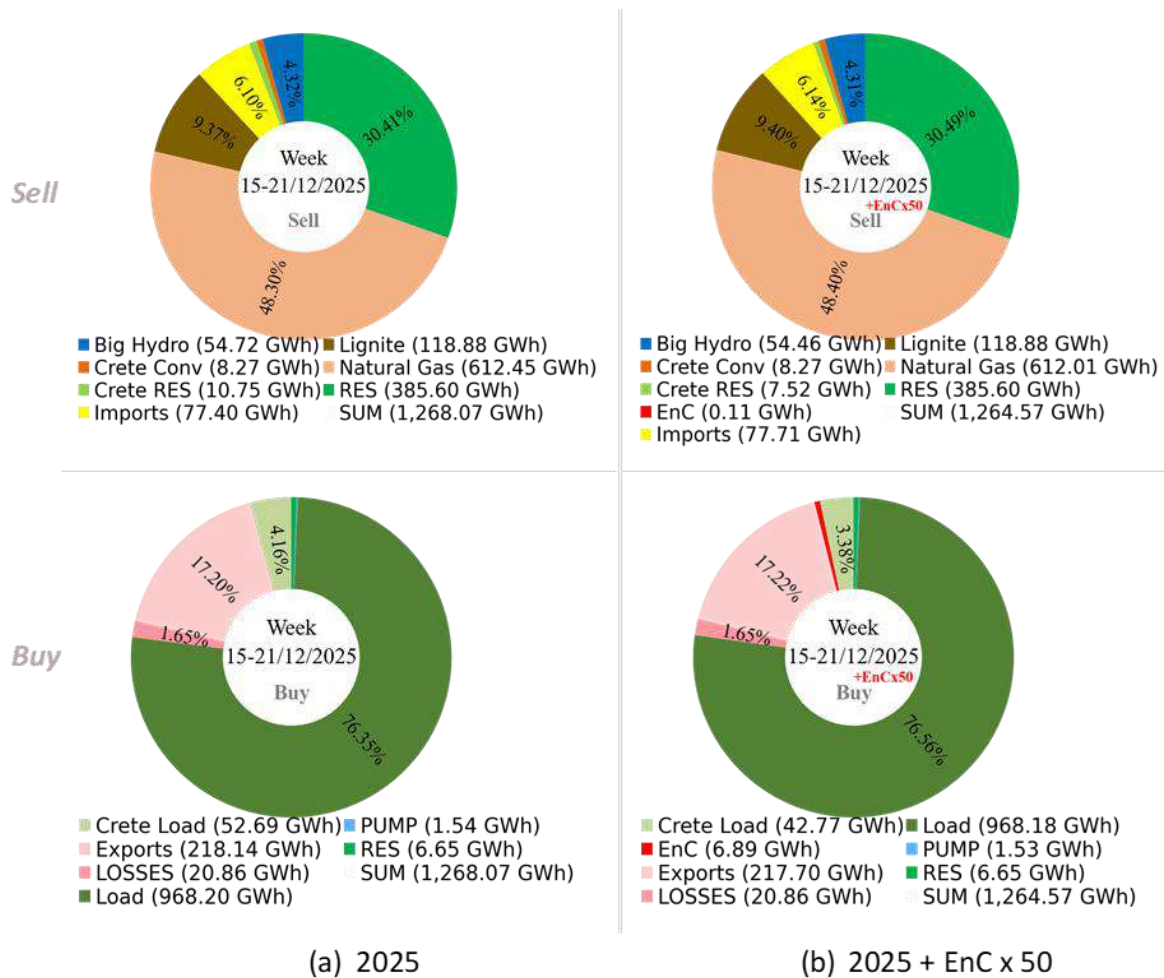
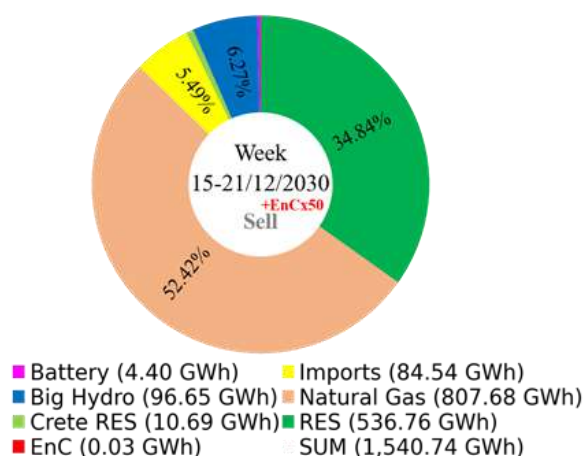
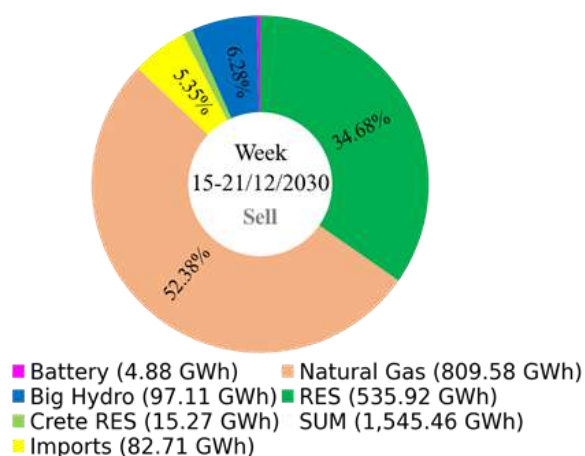
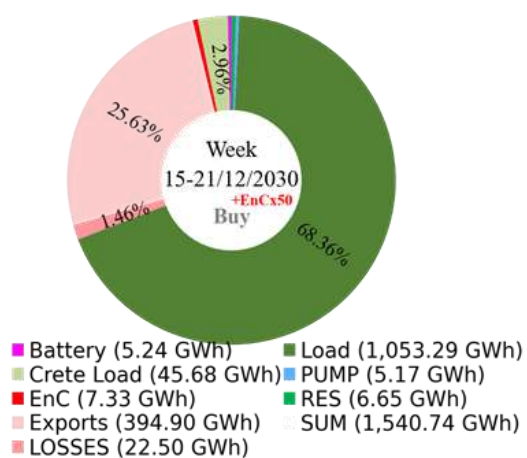
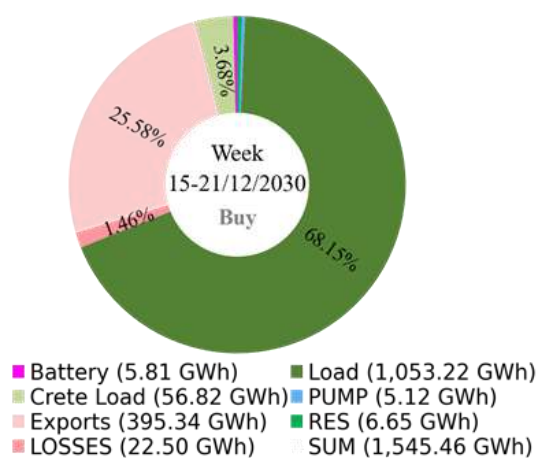


Figure 57: Total weekly cleared supply-side and demand-side volumes by technology for the week 15-21/12/2025: (a) without and (b) with scaled EnC participation

Sell



Buy



(a) 2030

(b) 2030 + EnC x 50

Figure 58: Total weekly cleared supply-side and demand-side volumes by technology for the week 15-21/12/2030: (a) without and (b) with scaled EnC participation

Table 15: Daily mean MCP differences (€/MWh) between scenarios with and without scaled EnC participation under the 2025 and 2030 market configurations

Delivery Day	2025+EnC×50 – 2025 ΔMean MCP (€/MWh)	2030+EnC×50 – 2030 ΔMean MCP (€/MWh)
15/12	+0.40	+0.03
16/12	+0.38	+1.97
17/12	+0.24	+1.23
18/12	-1.50	-2.28
19/12	-0.13	+1.20
20/12	+0.10	+2.33
21/12	+0.01	-3.34

The impact of the scaled EnC participation is more pronounced under the projected 2030 market configuration, where daily mean MCP variations range from -3.34 €/MWh to $+2.33$ €/MWh. Overall, the observed price changes depend on the underlying system conditions and the adopted EnC bidding strategy.

This work provided an assessment of how future power-system developments may affect the economic performance of a CEL/REV actively participating in the DA market. In particular, the analysis made it possible to examine the impact of expected structural changes in the Greek power system, including the retirement of lignite units, load growth, RES expansion, the retirement of diesel units in Crete, increased natural gas capacity, hydroelectric and pumped-storage additions, energy storage deployment, demand response integration, and adjusted cross-border capacities. By comparing current and future system conditions, the study highlighted how these developments can influence market prices, bidding decisions, and ultimately the economic results achieved by the community.

This is an initial basis for integrating market-oriented functionalities into the DT. As a first step, the outputs from T4.3 can be incorporated, as they provide profit-maximizing strategies based on DA market participation and flexibility remuneration. At a later stage, this functionality could be extended with a bidding-curve model based on forecasted CEL production and consumption. Such an extension would require an appropriate market-clearing representation and further assessment of the regulatory framework for CEL participation in electricity markets.

Conclusions and Future developments

During the second wave, the DT evolved from the initial demonstrator of D4.1 into a more integrated platform. The CEL Manager functionalities were extended through the integration of forecasting and flexibility provision services, Unity-based 3D visualisations of energy assets and a new Maintenance Scheduling page. In parallel, an initial end-to-end operational pipeline was implemented for the TSO-oriented case, while preparatory work was performed for the future integration of market-oriented and DSO functionalities.

Further work will also include the completion of the DSO operational pipeline and its subsequent extension with capabilities for assessing CEL operation against distribution network security constraints, including optimal power flow analyses. Through this extension, the DT will move towards a fully connected workflow, where forecasts of CEL-level production and consumption will feed directly into distribution-network analyses. These analyses will support the assessment of optimal asset operation, network constraints, and potential TSO-DSO coordination requirements, ensuring that CEL operation is evaluated not only from the perspective of local energy management but also in relation to wider grid security and operational feasibility.

Finally, the market-oriented components will be integrated by combining CEL-level forecasts, flexibility information, and relevant market signals to support optimal market participation strategies. The exact implementation approach remains to be finalized with the objective being to provide users with actionable information on optimal asset operation and market participation based on expected economic outcomes driven by DA market prices. The resulting outputs will allow



CEL managers to understand how different operational strategies affect market revenues, costs, and overall economic performance, with the corresponding outcomes presented through the DT.



6. Data-driven services and apps for consumers individual & REV-level activation towards energy autonomy

General Characterization

Task 4.5 delves on the development of data-driven services and applications that support consumer activation, self-consumption optimization and REV-level energy autonomy within the CRETE VALLEY ecosystem. Led by EUNICE, T4.5 combines individual smart energy management with collective flexibility services, through two complementary service streams: the Social-Science Humanities (SSH)-based closed-loop nudging service on household-level end-user application and the collective smart EV charging service for EV-users. The first service, thus, addresses consumer awareness, behavioural activation and household-level monitoring through the EUNICE App platform and smart metering infrastructure, while the second service focuses on smart EV charging and V2X flexibility, developed in cooperation with PARITY, aiming to support renewable energy utilization, peak management and future bidirectional charging scenarios. During the second wave, the task progressed from service concept definition towards concrete pilot planning, monitoring platform and smart-meter rollout development and coordination, EV charger specification, data-flow definition and simulation-based validation pathways. Therefore, the two services together create the digital basis for activating consumers and flexible assets as part of a more autonomous, responsive and renewable-based local energy ecosystem.

SSH-based closed-loop ‘nudging’ service

Overview

The SSH-based closed-loop nudging service forms the consumer-facing digital activation component of T4.5. Its objective is to support individual and community-level energy autonomy by translating household-level energy data into understandable feedback, recommendations and where technically feasible, control actions. The service is implemented through the EUNICE App environment, which combines smart-metering devices, cloud-based data collection, backend services, analytics, mobile and web application interfaces and interoperability mechanisms with the wider CRETE VALLEY digital ecosystem.

The service is designed to move beyond passive monitoring. By providing near real-time visibility of consumption patterns, historical comparisons, alerts and user-oriented recommendations, it creates the basis for a closed-loop interaction between the consumer and the energy system. In this loop, the platform collects metering data, processes and analyses it, identifies potential opportunities for energy saving or load shifting, communicates a nudge to the user and subsequently, evaluates whether the user response has affected the energy profile. In this way, the service supports behavioural activation, self-consumption optimization and future benefit-sharing mechanisms at household and REV level.



Within CRETE VALLEY, the service is mainly linked to the smart-metering deployment in selected members of the MINOAN Energy Community and to the preparation of the EUNICE App as the digital monitoring and user engagement layer. It also provides a relevant foundation for future interaction with the DT, the Energy Data Space and community-level energy attribution models, especially in relation to the wider CRETE VALLEY objective of activating citizens as participants in the local energy transition.

Architecture

The architecture of the SSH-based closed-loop nudging service follows a modular data collection, processing, analysis and user-interaction workflow. At field level, EUNICE smart meters are installed in selected household or small commercial buildings' electrical panels. Depending on the technical characteristics of each supply point, the deployment foresees the use of either the ESM105 smart meter for single-phase installation or the ESM304 smart meter for three-phase installations (Figure 59, Figure 60) The meters collect high-resolution electrical measurements through current-transformer-based measurements and communicate with the EUNICE cloud platform through the household or building's internet connection.



Figure 59: EUNICE ESM105 smart meter for single-phase installations



Figure 60: EUNICE ESM304 smart meter for three-phase installations

Table 16: Indicative technical specifications of EUNICE smart meters for T4.5 monitoring

Device/Characteristic	ESM105 – Single-phase Meter	ESM304 – Three-phase Meter
Application	Residential and small commercial installations	Residential, commercial and community/building installations
Installation	Electrical panel, DIN rail, CT-based measurement	Electrical panel, DIN rail, CT-based measurement
Measured Parameters	Voltage, current, active/reactive power, active/reactive energy, frequency	Voltage, current, active/reactive power, active/reactive energy, frequency
Connectivity	Wi-Fi 2.4 GHz, EUNICE cloud communication	Wi-Fi 2.4 GHz, EUNICE cloud communication
Accuracy	±1%, Class 1	±1%, Class 1
Power Consumption	≤2 W	≤2 W
Protection/Robustness	IP51, operation from –20°C to +60°C	IP51, operation from –20°C to +60°C
Certifications	CE, FCC, RCM, RoHS	CE, FCC, RCM, RoHS

The data transmission layer connects the smart meters to the cloud ingestion environment through the local router and secure communication channels. Incoming measurements are received by cloud endpoint, where the data is buffered and prepared for further processing. The processing layer then performs validation, cleaning and enrichment, ensuring that incomplete, inconsistent or anomalous readings are identified before the data is stored.

The storage layer is based on time-series data management, enabling the platform to retain and analyse consumption measurements across different time resolutions. These range from minute-level or hourly values to daily, weekly, monthly and yearly views, depending on the use case and the required aggregation level.

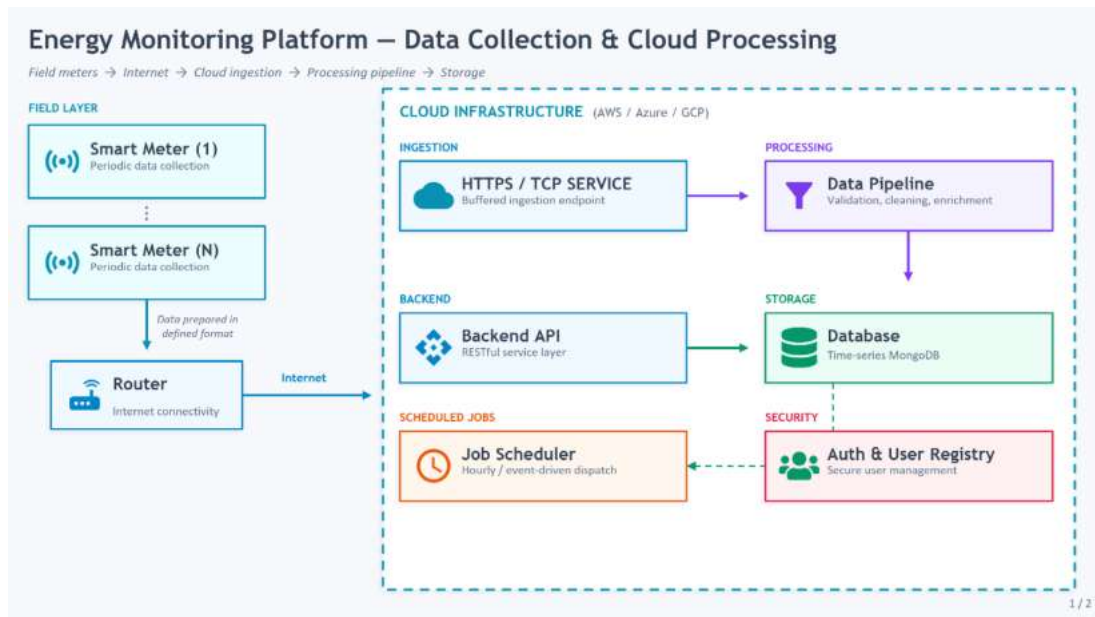


Figure 61: EUNICE App - Energy Monitoring Platform Architecture (smart-meter data collection, cloud processing and secure storage)

The backend API acts as the service layer between the database, the EUNICE App frontend and other authorized systems. It provides structured access to meter readings, user-related data, processed indicators and analytics outputs. Authenticated users can access the data through the mobile or web application, while Project Partners and authorized systems may access structured data through appropriate API or data exchange mechanisms.

The analytics and nudging layer evaluates consumption patterns, baseline profiles, possible deviations and where available, generation or storage-related data. Based on these inputs, the rules and recommendation engine can generate alerts, energy-saving suggestions, load-shifting prompts or other user-oriented notifications to optimize behavioural consumption patterns. In future iterations, this layer may also incorporate additional contextual information, such as RES availability, DT outputs or community-level energy indicators, in order to generate more targeted recommendations.

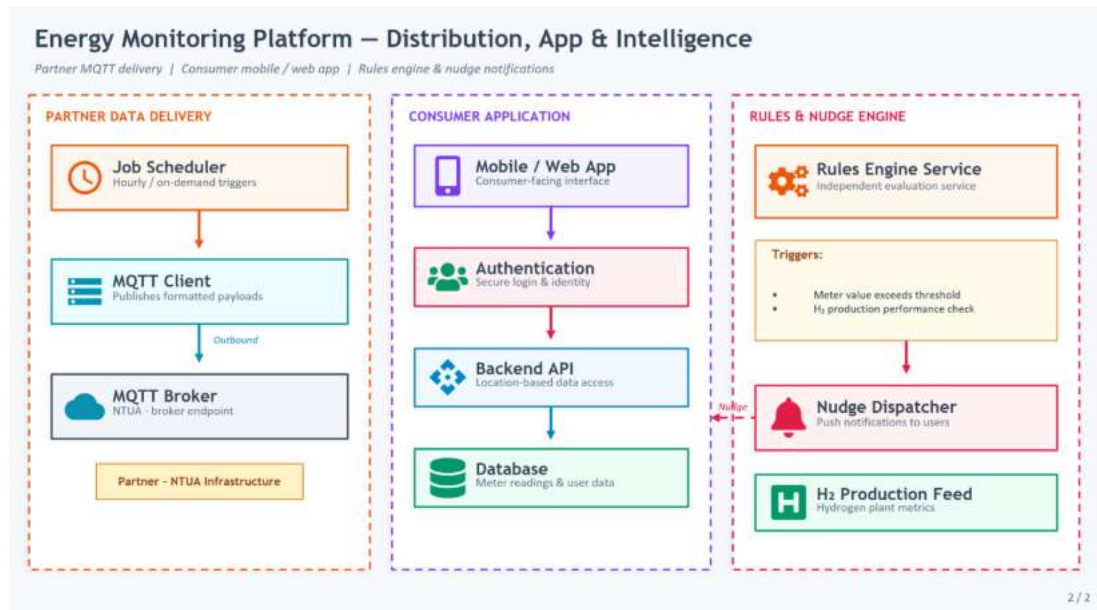


Figure 62: EUNICE App - Energy Monitoring Platform App Intelligence (app access, MQTT data delivery and rules-based nudge notifications)

Finally, the interoperability layer enables interaction with the broader CRETE VALLEY digital ecosystem. This includes potential data dispatch to NTUA's DT or other Project infrastructure through API or MQTT-based mechanisms, where relevant for DT analysis, data-driven services or Energy Data Space workflows.

Previous developments

In the first wave of the service, as described in D4.1, focus was placed on defining and demonstrating the core monitoring and data exchange capabilities required for the SSH-based nudging service. D4.1 documented the first version of the monitoring and analytical functionalities, including building-level monitoring, community-level aggregation, per-phase measurements, calculated indicators, baseline estimation and forecasting. The standardised API output structure was also described for hourly metering data and forecasted consumption values.

The second wave builds on these first developments by moving from platform-level capability definition towards the preparation of real pilot deployment in selected energy community members. The focus of D4.2 is therefore not only on the existence of the monitoring platform, but also on the operational pathway for installing smart meters, validating household-level data flows, preparing the nudge logic and connecting the service with the wider CRETE VALLEY use cases and digital infrastructure.

Current Status

During this reporting period, the EUNICE App environment was further developed and prepared as the digital monitoring layer for the Energy Communities use case. The platform now provides the main functionalities required for real-time and historical energy monitoring, including consumption visualization, historical analysis, alerts, recommendations and where technically available, device scheduling and control.



Figure 63: EUNICE App Mobile and Web application User Interface and Environment

A significant step towards field deployment was achieved through the consolidation of the list of selected supply points for the smart-meter rollout. With the support of MINOAN, EUNICE collected a list of 30 household or Community-member supply points where the EUNICE smart meters are planned to be installed. These include members of the MINOAN Energy Community, either already participating in energy offsetting schemes or newly registered in connection with the CRETE VALLEY activities.

On this basis, EUNICE has already begun the process of coordination and planning for the installation of the smart meters, including direct communication with selected members and relevant partners in Crete. Before the installation works, preliminary site inspections will be carried out where required, to assess the suitability of each location, the condition of the electrical panel, the type of metering device required and any possible practical installation constraints.

The smart-meter deployment will provide the first CRETE VALLEY household-level data foundation for the EUNICE App use case. It will enable real-time monitoring, historical analysis, baseline development, future recommendation logic and at a later stage, the evaluation of behavioural responses to energy-saving or load-shifting nudges.

In parallel, interoperability and data-continuity aspects have been considered. The monitored data generated through the EUNICE App and the smart-metering infrastructure is expected to support future interaction with the CRETE VALLEY Digital Twin and data-sharing workflows and tools within WP3's Energy Data Space. This is particularly important for linking individual consumption behaviour with aggregated community-level analysis, as well as for supporting future benefit-sharing models.

Input data description

The input data required for the SSH-based closed-loop nudging service consists of smart-meter measurements, technical metadata, optional contextual data and user-interaction data. The core dataset is generated by the EUNICE smart meters installed as selected household or community-member buildings. Additional data streams, such as local RES or hydrogen production and storage status, smart device measurements, environmental data and aggregated CEL-level indicators, may be also integrated and displayed via the EUNICE App, where technically available.

Table 17: Input data description

Data asset/Input Category	Description	Unit/Form at	Data format	Indicative volume	Velocity/Granularity
Smart Meter ID	Unique Meter ID, Building/Supply-point ID	String/Serial Number	.csv export .json through API also available	<1 MB per supply point per year	Static data, updated when installation or user details change
Household/Community Member electricity consumption	Active electricity consumption measured by the smart meter	Wh, kWh	.csv export .json through API also available	20-40MB per household per year	Per minute, with hourly/daily/monthly/yearly aggregation
Per-phase electrical measurements	Voltage, Current and Frequency per phase, where applicable for L1, L2, L3	V, A, Hz	.csv export .json through API also available	30-80 MB per household per year for three-phase measurements	Per minute, with hourly aggregation available
Local RES and hydrogen generation data (where available)	Local generation from rooftop PV, Community solar assets or other RES or Hydrogen connected to the monitored user (virtually also) or node	W, kW, Wh, kWh	.csv export .json through API also available .sql possible where data originate from local SCADA/inverter databases	50MB per asset per year for household-level data; higher for SCADA-based assets	Per minute, per 10-15 minutes or per hour, depending on sourcer system
Storage data (where available)	Battery SoC, charging/discharging power and storage energy flows	%, W, kW, Wh, kWh	.csv export .json through API also available	10-30 MB per storage asset per year	Per minute or per event, with aggregated views available
Smart load/Device control data (where available)	Status and measurable energy data from smart plugs, smart relays or controllable loads, where technically available	On/Off status, W, kWh, control event	.csv export .json through API also available	5-10 MB per household per year, depending on number of devices	Per action/event or per minute where measurement is enabled
Environmental data (where available)	Temperature, humidity, air quality, to support interpretation of consumption patterns and recommendations	°C, %, weather variables	.csv export .json through API also available	15-20 MB per household per year	Per hour; higher frequency possible where local sensors are installed

Historical consumption profiles	Aggregated historical data used for baseline calculation	kWh, average demand, profile indicators	.csv export .json through API also available	1-5 MB per household per year for aggregated profiles; derived from raw metering data	Hourly, daily, weekly, monthly and yearly aggregation
Forecasting inputs and baseline indicators	Forecasted consumption, expected baseline demand, deviation indicators and possible flexibility windows	kWh, kW, forecast value, deviation index	.csv export .json through API also available	1-5 MB per household per year	Hourly or day-ahead forecast; may be updated periodically
User interaction / Nudging feedback data	User notifications, recommendations sent, user acknowledgment, response or behavioural feedback	Event ID, timestamp, message type, status	.csv export .json through API also available	<5 MB per user per year	Per event, per nudge, per user action

Further on, all readings are timestamped and associated with the corresponding smart meter and supply point, while where three-phase meters are installed, data is collected per phase, enabling more detailed analysis of household energy behaviour and potential power quality issues.

Before being used by the analytics or nudging layer, incoming measurements are validated and processed to ensure consistency. This includes checks for missing values, abnormal values, communication gaps and possible meter-related errors. Validated data is then stored in the platform database and made available for visualization, analysis and authorized exchange.

Output data description

The output data of the SSH-based closed-loop nudging service is structured around four main categories: monitoring outputs, analytics outputs, recommendation outputs and interoperability outputs.

The monitoring outputs are delivered through the EUNICE App web and mobile interfaces. They allow users and authorized Project Partners to view real-time and historical electricity consumption at different time resolutions. These outputs support comparison of consumption patterns across time and provide the user with a clearer understanding of household energy behaviour.

The analytics outputs include calculated indicators such as average consumption, baseline consumption profiles, forecasted consumption values and possible deviations from typical behaviour. These outputs are used internally by the platform and may also be made available to authorized external services through APIs.

The recommendation outputs represent the actual nudging component of the service. These may include notifications such as energy-saving advice, prompts to shift selected loads to more favourable periods, alerts on unusual consumption, or future suggestions linked to higher renewable availability or community-level optimization needs. The exact content of each nudge will depend on the available data, user profile, technical controllability of loads and project-related requirements.

An indicative nudge output can be structured as follows:

```
{
  "userId": "<user_id>",
  "buildingId": "<building_id>",
  "timestamp": "<datetime>",
  "recommendationType": "load_shift",
  "priority": "medium",
  "message": "Consider shifting flexible consumption to a later time window with higher renewable availability.",
  "validFrom": "<datetime>",
  "validTo": "<datetime>",
  "expectedImpact": {
    "energySaving_kWh": null,
    "costSaving_EUR": null,
    "co2Reduction_kg": null
  },
  "status": "sent"
}
```

The interoperability outputs include formatted measurement payloads that can be exchanged with authorized CRETE VALLEY systems and tools. These outputs may follow the hourly structure already described, where each hourly object contains minute-level measurements for voltage, current, frequency and consumption. This enables external systems, such as DT components or project-level analytics, to retrieve standardized data for simulation, validation or aggregated energy analysis.

Case study

For D4.2, the case study of the SSH-based closed-loop nudging service should be presented as a planned and partially prepared field deployment case, rather than as a completed operational validation. The case study concerns the deployment of the EUNICE smart meters in 30 selected household or community-member supply points linked to the MINOAN Energy Community. The selected users are located in areas participating in CRETE VALLEY activities and demonstrations, and more specifically in CEL1 (Arvi) and CEL2 (Arkalochori). Through this pilot, the EUNICE App energy monitoring platform and accompanying infrastructure will be used to collect real household-level energy data, visualize consumption patterns and prepare the basis for future user nudging and behavioural activation.

The case study will follow a phased methodology. First, selected supply points will be contacted and technically assessed. Second, the appropriate smart-meter model will be installed according to the



type of supply point (single-phase or three-phase). Third, the data flow from the meters to the EUNICE platform will be validated. Fourth, baseline consumption profiles will be developed using the collected measurements. Fifth, once sufficient data is available, the service will be able to generate recommendations and evaluate whether users respond to the nudges.

The main objective of the case study is to validate the complete data chain from physical metering to user-facing insight generation. It will also provide the foundations for evaluating how household-level information can support individual energy awareness, self-consumption optimization and future benefit-sharing mechanisms on a community level.

Characterization

Table 18: Characterization of the planned SSH-based closed-loop nudging service deployment

Characteristic	Description
Service Type	Consumer-facing digital energy monitoring and nudging service
Main users	Households, Energy Community members, Project Partners and authorized technical users
Activation level	Individual household level, with future aggregation at community/REV level
Main assets involved	Smart meters, household loads, possible local RES or storage assets, EUNICE App
Data granularity	Minute-level or high-resolution metering data, aggregated to hourly/daily/monthly/yearly views
Control logic	Primarily behavioural nudging; direct device scheduling/control only where technically available
Main outputs	Monitoring dashboards, alerts, recommendations, baseline profiles, forecast values, structured API data
Integrational potential	Digital Twin, WP3 – Energy Data Space tools, benefit-sharing logic, End users' training
Current maturity	Platform and deployment preparation advanced; field validation pendins full smart-meter

Results

At the current stage, the main results are preparatory and implementation-oriented. The EUNICE App platform has been prepared as the digital environment for household energy monitoring and future nudging. The smart-metering approach has been specified, including the use of suitable single-phase and three-phase EUNICE smart meters. Finally, the set of 30 selected supply points has been consolidated with the support of MINOAN, creating thus the basis for the first household-level monitoring deployment under T4.5.

The data architecture has also been clarified, covering data collection, cloud ingestion, validation, storage, backend API access, application-level visualization and future data dispatch to project-level systems. This provides the technical basis for the closed-loop service.

Quantitative results on energy savings, behavioural response, load shifting or self-consumption improvement are not yet available, as the full installation and operational data collection phase has not been completed. These results will be generated in the next stages of the task, once smart-meter data is collected over a sufficient period and the nudging logic can be tested with real users.

Future developments

The next development steps will focus on the completion of the smart-meter rollout, the validation of end-to-end data flows and the activation of the nudging functionality under real pilot conditions. EUNICE will proceed with the coordination of site inspections, smart-meter installation, user onboarding and initial technical validation.

Once sufficient data has been collected, the platform will be used to develop household baseline profiles, identify flexible consumption patterns and define suitable nudging rules. Future work will also include the refinement of user-facing messages, the preparation of end-user guidance material and the alignment of the EUNICE App interface with training and demonstration activities.

Further development will address integration with the wider CRETE VALLEY digital ecosystem, including the DT, Energy Data Space and potential benefit-sharing workflows. This will allow the household monitoring layer to contribute not only to individual energy awareness, but also to REV-level analysis, flexibility assessment and community-level energy autonomy services.

Collective smart EV charging service

Overview

The collective smart EV charging service corresponds to the V2X-aware smart charging component of T4.5. Its objective is to support the flexible and renewable-driven operation of EV charging infrastructure by combining smart charging, V2X readiness, forecasting inputs, user guidance and future bidirectional charging capabilities.

The service is being developed in cooperation between EUNICE and PARITY, building on the EV Loader platform and the planned deployment of V2X-compatible charging infrastructure. It is aligned with the TE-17 objective of enabling valley filling, peak clipping, demand stimulation and future grid-support services. The service aims to influence charging behaviour and charging station operation based on renewable energy availability local or regional demand conditions and flexibility needs.

In the CRETE VALLEY context, the service is linked to both an early V2X-compatible charger installation and the later CEL4 deployment at the Mires hydrogen production and storage site. The phased implementation approach allows the Project to generate early integration experience

before the full CEL4 infrastructure is ready, while maintaining the broader Project concept of coupling EV charging, hydrogen fuel cells, storage and community-level energy management.

Due to current limitations of the Greek Regulatory framework regarding full V2X and V2G operation in public spaces and public charging infrastructure, the service will also include a V2X simulation scenario. This will allow the Project to test technical assumptions, control logic and business models using real operational data, while avoiding overstatement of physical V2G operation before the Regulatory framework becomes sufficiently mature.

Architecture

The architecture of the service consists of five main layers, namely the charging infrastructure, the communication and platform management, forecasting and optimization, user interaction and data exchange with Project-level systems.

- i) The charging infrastructure layer includes V2X-ready EV chargers, V2X-compatible EVs and, where applicable, a stationary battery acting as a buffer. The initial approach foresees an early V2X-compatible charger installation in a location selected by the consortium, followed by the installation of additional EV chargers at the CEL4 site in Mires, once the hydrogen production and storage infrastructure is commissioned. The battery-as-a-buffer concept in turn, is intended to provide additional flexibility for peak shaving, local balancing and the demonstration of EV batteries and stationary storage as complementary flexible assets.
- ii) The communication and platform management layer is based on the PARITY EV Loader platform and the direct integration of chargers through OCPP-based communication protocol. For the first V2X-compatible charger, the baseline technical direction concerns a V2G DC charger with minimum charging and discharging power of 7kW, OCPP 1.6J communication capability as a minimum requirement, ISO 15118-related V2X readiness, separate input and output cabling, direct OCPP communication without intermediary proprietary cloud layers, and the possibility for local configuration and control. Where supported by the selected equipment and pilot needs, OCPP 2.0.1 remains the preferred direction for advanced smart charging and V2X functions.
- iii) The forecasting and optimization layer receives data on renewable energy availability and total demand for each examined interval. Based on these inputs, the service calculates the expected renewable share and assigns an incentive index that can guide the activation of flexible charging loads. This index can be translated into charging recommendations, pricing signals or operational instructions.
- iv) The user interaction layer includes the Charging Station Manager Dashboard and the Driver's App. Through these interfaces, charging station owners and users can receive information on recommended charging periods, high renewable availability periods or periods where charging should be avoided if possible. In future V2X-compatible configurations, the same layer may also support guidance related to discharging or participation in flexibility services.
- v) The Project-level data exchange layer enables the transfer of charger and platform data to the DT and other authorized systems and tools developed in the CRETE VALLEY ecosystem,

for monitoring, analysis, evaluation and future flexibility assessment. The service is therefore designed not only as an EV charging management tool, but also as a data-driven flexibility component.

Previous developments

In D4.1, the collective smart EV charging service was presented as an evolution of the PARITY EV Loader platform. Before CRETE VALLEY, the EV Loader already supported core EV charging management functionalities, including charger monitoring, payments, user access and charging station management. However, the platform did not yet include the full set of advanced smart charging features required for the CRETE VALLEY use case, such as dynamic pricing linked to renewable availability, smart activation of charging sessions and V2G/V2X logic. During the project new functionality has been added to EV Loader platform that enables charging stations managers to trigger discharging for compatible vehicles and charging stations. The platform also handles financial settlement for discharging transactions, where the charging station owner transfers credits to drivers of vehicles that discharge energy in their stations, when such action is requested.

Two conceptual cases studies were also described in D4.1, one related to grid load shifting via public charging control and another related to renewable utilization in solar-enabled hotels. These scenarios provided the first functional framing of how EV charging could be aligned with grid stress, renewable generation and user incentives.

Current status

D4.2 builds on this first-wave work by updating the implementation pathway, clarifying the phased deployment strategy, defining the first V2X-compatible charger requirements and introducing the V2X scenario as a necessary and technically meaningful approach.

As the implementation approach has been structured in a phased approach, an early V2X-compatible DC EV charger, provided by EUNICE and currently under procurement, is foreseen to be installed within Q4 2026 at a location to be selected in CEL 4. This installation will be used to generate early implementation, integration and operational experience. The remaining EV chargers foreseen under the CEL4 development will be later installed at EUNICE's hydrogen production and storage site in Mires, once the site has been commissioned and is ready to host the relevant infrastructure.

This approach preserves the broader CEL4 concept, where V2X-ready charging infrastructure will be integrated with hydrogen production, fuel-cell electricity generation, storage and the community-energy environment. At the same time, it allows the Project to proceed with earlier technical validation before the full CEL4 site is operational.

EUNICE and PARITY have also aligned on the need to include a V2X simulation scenario, due to current regulatory limitations in Greece regarding bidirectional charging in public spaces and public charging infrastructure. The simulation will use real or realistic operational data from chargers, EVs and relevant energy assets to model bidirectional energy flows, valley filling, peak clipping and grid-support uses cases. This will allow the Project to test control logic and business assumptions even if full physical V2G operation cannot yet be implemented under the current regulatory conditions.



Input data description

The minimum input dataset for the smart EV charging service remains the renewable energy forecast and load forecast for each examined 30-minute interval. This dataset is used to determine when charging should be encouraged, discouraged or potentially combined with V2X actions.

Table 19: Input data of the Collective Smart Charging Service

Attribute	Description	Unit/Format
Date	Date of the examined day	Date
Time_interval_encounter	Integers from 1 to 48 indicating the 30 min interval starting from 00:00- 00:30 and ending at 23:30- 00:00	Integer
Re_kW	Renewable energy capacity available in kW during the specific 30 min interval	kW
De_kW	Total energy demand during the specific 30 min interval in kW	kW

For local building-node applications, Re_kW may represent available renewable energy from rooftop PV, or local solar generation, while De_kW may represent the baseline demand of the building or local node. This data may be collected through solar inverter SCADA systems, BMS systems or smart meters.

For broader regional scenarios, Re_kW and De_kW may be collected or estimated through integration with DSO-related data, regional forecasting tools or other project-level datasets.

For the second-wave implementation and the future V2X simulation, the input dataset is expected to be expanded with operational EV charging information, including:

Table 20: Indicative additional input data required for the second-wave implementation and future V2X simulation.

Indicative additional input	Description	Unit / Format
Charger ID	Unique identifier of the charging station	String
Connector ID	Identifier of the specific connector	String/Integer
EV session ID	Unique charging session identifier	String

Plug-in time	Time when the EV connects to the charger	Datetime
Expected departure time	User-declared or estimated departyre time	Datetime
Requested energy	Energy requested by the user for the charging session	kWh
Initial State of Charge (SoC)	EV battery state of charge at connection	%
Target State of Charge (SoC)	Desired EV battery state of charge at departure	%
Maximum charging power	Technical charging limit of the EV/Charger	kW
V2X capability flag	Indicates whether bidirectional operation is technically supported	Boolean
Battery buffer status	State of charge and available capacity of the stationary battery, where applicable	%, kWh
Tariff or incentive signal	Price or incentive category applied to the time interval	Index/€/kWh

Output data description

The main output of the service is the determination of the renewable share and the respective incentive index for each 30-minute interval. This output is used to guide the activation of flexible EV charging loads.

The incentive index can be interpreted as follows:

Table 21: RES-based incentive index for EV charging.

Incentive index	Interpretation	Indicative action
1	Very low RES share	Charging should be avoided where possible; flexible loads activated only on immediate need basis; V2X discharging may be examined in simulation
2	Low RES share	Charging may proceed only where needed; no strong incentive for flexible charging
3	High RES share	Charging can be encouraged and flexible loads can be activated

4	Very high RES share	Charging should be strongly incentivized to maximize renewable utilization
---	---------------------	--

An indicative output structure is presented below:

```
{
  "date": "YYYY-MM-DD",
  "timeInterval": 1,
  "resForecast_kW": 780,
  "loadForecast_kW": 5170,
  "resShare_percent": 15.1,
  "incentiveIndex": 1,
  "recommendation": "avoid_charging_if_possible"
}
```

For charging station owners, the outputs can be translated into operational guidance, such as time windows where charging should be promoted, limited or shifted. For drivers, the outputs can be translated into mobile app messages encouraging charging during high renewable availability periods or discouraging charging during low renewable share and high-demand periods.

For the future V2X simulation, additional outputs may include:

Table 22: Indicative outputs of the future V2X simulation

Output	Description
Charging power setpoint	Recommended or simulated charging power per interval
Discharging setpoint	Simulated V2X discharge power where technically available
Shifted energy	Amount of charging demand shifted from one time interval to another
Peak reduction	Estimated reduction of local or regional peak demand
RES utilization increase	Estimated increase in the use of renewable energy for charging
User cost impact	Estimated cost difference between baseline and optimized charging
Flexibility value	Estimated economic or technical value of the charging flexibility
CO ₂ impact	Indicative avoided emissions from shifting charging to higher-RES periods

Case study

This case study illustrates the application of the V2X flexibility service in a real hospitality setting on the southern coast of Crete. The hotel has installed a V2X-compatible EV charging station together



with a stationary battery energy storage system (BESS), complementing an existing rooftop PV installation. The three assets - PV generation, the stationary battery, and V2X-capable electric vehicles - are integrated behind the hotel's meter and jointly managed to maximise the local use of self-generated renewable energy.

The operational logic follows a layered dispatch priority. When solar production is available and exceeds the hotel's immediate demand, surplus PV energy is directed first to charging the EV and replenishing the stationary battery, reducing reliance on grid-supplied electricity. When solar generation is insufficient to meet demand, for example during periods of low irradiance, cloud cover, or night-time operation, the stationary battery discharges to cover the shortfall. If the battery's state of charge is also depleted and the connected EV has available battery capacity that is not required for the vehicle's near-term mobility needs, the vehicle can discharge to the stationary battery or directly to hotel loads (V2B/V2H), effectively acting as a secondary, mobile storage resource within the same local energy system.

All energy flows described above are confined to on-site consumption. Under the current Greek regulatory framework, stored energy, whether from the stationary battery or from vehicle batteries operating in V2X mode, cannot be exported or sold back to the public grid. Consequently, the control strategy is designed exclusively to optimise self-consumption and reduce grid import, rather than to generate revenue through energy injection or arbitrage. This constraint shapes both the sizing of the assets and the dispatch algorithm, which prioritises local balancing of generation, storage, and demand over any grid-facing flexibility service.

Characterization

Table 23: Characterization of the smart EV charging and V2X service

Characteristic	Description
Service type	Collective smart EV charging and V2X-ready flexibility management service
Main users	EV drivers, charging station owners, energy community actors, Project partners
Main assets	EV chargers, EVs, stationary battery buffer, PARITY EV Loader platform, EUNICE energy infrastructure
Activation level	Local charger level, site level and future REV/CEL level
Time resolution	3-minute intervals
Main input data	RES forecast, load forecast, charger data, EV session data, battery status, tariff/incentive signals
Main output data	Incentive index, charging recommendations, setpoints, simulated V2X actions, flexibility KPIs
Control approach	Smart charging and user nudging; V2X physical operation subject to regulatory feasibility

Main strategies	Valley filling, peak clipping, renewable utilization, demand stimulation, V2X simulation
Current maturity	Technical specification and phased deployment plan defined; procurement and operational validation ongoing

Results

During the second wave, EUNICE and PARITY clarified the technical requirements and phased deployment of the collective smart EV charging service, including the first V2X compatible charger installation and the later CEL4 deployment in Mires.

Moreover, the baseline charger specifications have been defined, covering charging/discharging capability, OCPP communication, ISO-15118-related readiness, direct communication and local configuration. The service will use 30-minute RES and load forecasts to calculate an incentive index, which in turn can support charging guidance, pricing signals or simulation setpoints.

Finally, due to current regulatory limitations in Greece, a V2X simulation scenario has been included as an interim validation step. Quantitative results will thus be reported after charger installation, data collection and pilot/simulation validation have been implemented.

Future developments

The next steps for this service include the finalization of the first V2X-compatible EV chargers' procurement, installation, integration with the PARITY EV Loader platform and validation of the OCPP-based data exchange. EUNICE and PARITY will also continue efforts to secure suitable V2X-capable vehicles through cooperation with relevant vehicle providers, such as dealerships, importers, as well as leasing or rental companies.

Following installation, the Project will be able to collect operational charger and EV session data to test the smart charger logic, evaluate data quality and prepare the bidirectional simulation scenarios. The simulation will be thus used to examine and validate smart charging, V2X optimization scenarios, as well as grid-support strategies.

At CEL4 also, future work will focus on preparing the Mires site for the deployment of additional EV charging infrastructure once the hydrogen production, storage and fuel-cell systems are sufficiently mature and ready for commissioning. This will enable the service to be demonstrated in the broader hydrogen valley and REV-level context.

The final development phase is expected to include the extraction of technical results, user and operator feedback, flexibility KPIs and recommendations for future V2X business models. These findings will feed into the next wave and support the wider CRETE VALLEY objectives related to energy autonomy, flexibility activation, digital services and replication.

Summary

During the second wave, T4.5 advanced both of its main service streams, strengthening the connection between household-level digital engagement and collective energy flexibility.

For the SSH-based closed-loop nudging service, EUNICE further worked on the development of the EUNICE App as the consumer-facing layer for monitoring, analytics, alerts and recommendations. The service progressed towards field deployment through the identification of 30 selected household/community-member supply points, in cooperation with MINOAN, where the EUNICE smart meters are planned to be installed. The data architecture was also clarified, covering data collection, cloud processing, validation, storage, API access, used validation and future interoperability with the CRETE VALLEY DT and data-sharing ecosystem.

In parallel, for the collective smart EV charging service, EUNICE and PARITY clarified the phased implementation approach, along with the definition of the baseline EV charger specifications and service data logic, utilizing RES and load forecasts to support incentive-based charging guidance and strategies. A V2X simulation scenario was also introduced as an interim validation pathway, due to current regulatory limitations in Greece.



7. Conclusions

WP4 of CRETE VALLEY constitutes a key pillar in advancing a digitally enabled, decentralized, and sustainable energy ecosystem for the island of Crete. The System-of-Systems DT is designed to transform the monitoring, forecasting, optimization, and coordination of local energy systems, thereby supporting the broader objectives of the project.

This deliverable presents the development and integration strategy for the second version of the System-of-Systems DT. It describes the methodologies, tools, and technical frameworks implemented across Tasks T4.1–T4.5, explaining how each component contributes to real-time energy monitoring, forecasting, and optimization. Furthermore, it demonstrates the interoperability of WP4 with the other work packages, ensuring that the business requirements and technical specifications identified throughout the project are consistently incorporated into the DT's design and implementation. One additional deliverable is planned to further advance WP4, presenting the third and final release of the System-of-Systems DT, together with the corresponding data-driven services and applications.

These efforts are considered essential groundwork, specifically for WP5 ‘Multiple renewable energy carriers in Crete REV-Lab (‘Install’)’: Task 5.5 which oversees the deployment of the DT within the REV Lab and CEL and WP6 ‘CRETE VALLEY real-life operation & impact assessment (‘Apply & Assess’)’: Task 6.1 that will conduct a thorough evaluation of the DT’s performance and usability by simulating various operational scenarios and Task 6.2 which will assess user engagement with the DT, focusing on how energy citizens interact with its data-driven applications and services.

Section Data-driven operational analysis for optimising local energy grid performance through power flow simulations **2 (T4.1)** details the advancement of a data-driven power flow simulation framework that integrates both transmission (IPTO) and distribution (HEDNO) network models into the DPsim environment. Significant improvements were made to the NRP solver to enhance numerical robustness during continuous time-series simulations. By applying historical and projected operational profiles for 2030, accounting for increased load and extreme renewable energy penetration, the framework successfully automated the evaluation of bus voltages, line loadings, and power exchanges, ultimately demonstrating the network's stability and the critical balancing role of Crete mainland interconnection.

Section 3 (T4.2) outlines a major architectural shift toward a unified, production-ready Energy Forecasting Service, moving away from localized, standalone ML models. The new containerized system leverages the Chronos family of pre-trained time-series foundation models to deliver zero-shot prediction capabilities for both renewable energy production and demand across various assets. Supported by a FastAPI backend and a Streamlit frontend GUI, this service streamlines data ingestion through standardized JSON payloads and seamlessly integrates highly accurate, multidimensional forecasting into the broader DT ecosystem.

Substantial progress has been achieved in **Section 4 (T4.3)**, which focuses on the development of a multi-energy flexibility modelling tool designed to optimize energy set-points and reserve capabilities for grid operators. The architecture integrates OPF formulations, such as LinDistFlow,



alongside an external EV flexibility module (datafev_flex) to estimate cluster-level charging baselines and capability envelopes. Through comprehensive case studies, the methodology was validated by demonstrating how assets like a 1 MW PV system can profitably participate in both day-ahead spot and secondary reserve markets while strictly adhering to the technical constraints of the distribution network.

Section 5 (T4.4) describes the maturation of the TwinREV System-of-Systems DT into a fully integrated, Kubernetes-hosted platform that centralizes the project's analytical services. The platform features tailored, role-based interfaces for CEL Managers, TSOs, and DSOs, enabling interactions such as Unity-based 3D asset visualizations, comprehensive maintenance scheduling, and real-time monitoring. Furthermore, it integrates dynamic power flow capabilities from DPsim and establishes the preparatory methodological groundwork for evaluating how Energy Communities can optimally participate in the Greek DA electricity market.

Finally, **Section 6 (T4.5)** details the deployment of consumer-facing digital services aimed at driving individual and collective energy autonomy within the REV. It highlights the SSH-based closed-loop nudging service, which utilizes EUNICE smart meters and a cloud-based application to provide real-time household monitoring, behavioural feedback, and energy-saving recommendations to community members. Concurrently, it outlines a collective smart EV charging service that defines specifications for V2X-compatible chargers and leverages simulated V2X scenarios to overcome current regulatory limitations, thereby validating future bidirectional grid-support strategies.

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