



From conceptual use cases to real demonstration - DT for forecasting and optimal grid and market actions

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Document Authors		
Nikolaos Koltsaklis (UPRC)	Vladan Ristic (SCBG)	Aikaterini Forouli (HENEX)
Evgenia Tsiotsia (UPRC)	Nikolay Palov (SCBG)	Dimitra Makrygiorgou (IPTO)
Spyridon Roukanas (UPRC)	Pencho Zlatev (SETECHCO)	Angelos Nousdilis (IPTO)
Athanasios Dagoumas (UPRC)	Angel Markov (SETECHCO)	Panagiota Kyrimlidou (IPTO)
Yasen Todorov (EDG West)	Eleni Tekki (UCY)	Apostolos Gizas (RAAEY)
Milena Kovacheva (EDG West)	Lenos Hadjidemetriou (UCY)	Bálint Hartmann (F4STER)
Efstratia Sarafoglou (HEDNO)	Markos Asprou (UCY)	Gellért Tóth-Kovács (MAVIR)
Ralitsa Rumenova (Entra Energy)	Verzhinia Ivanova (Entra Energy)	Bence Brúnó Bereczki (BME)
Nikolay Chavdarov (ESO EAD)	Vanessa Markaki (HENEX)	Péter Márk Sörös (BME)
Andrey Andreev (ESO EAD)	Emmanouil Bakirtzis (HENEX)	

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Responsible Partner	UPRC
Checked by WP leader	Nikolaos Koltsaklis (UPRC), 09/10/2026
Verified by the appointed Reviewers	Janja Dolenc (EG), 07/10/2026
Approved by Project Coordinator	Padraic McKeever (Fraunhofer), 09/10/2026

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List of Abbreviations and Acronyms

Acronym	Meaning
AC	Alternating current
aFRR	Automatic frequency restoration reserve
AGC	Automatic generation control
AI	Artificial intelligence
AMPL	A Mathematical Programming Language
ANN	Artificial neural network
API	Application programming interface
ATC	Available transfer capacity
BE	Balancing energy
BESS	Battery energy storage system
BM	Balancing market
BME	Budapest University of Technology and Economics
BUC	Business use case
CCT	Critical clearing time
CGMES	Common Grid Model Exchange Standard
CHP	Combined heat and power
CIM	Common Information Model
CM	Congestion management
CNEC	Critical network element with contingency
CPLEX	IBM ILOG CPLEX Optimizer
CSV	Comma-separated values
DACC	Day-ahead capacity calculation
DAM	Day-ahead market
DER	Distributed energy resource
DLR	Dynamic line rating
DR	Demand response
DSA	Dynamic security assessment
DSO	Distribution system operator
DT	Digital twin
EHV	Extra-high voltage
EMS	Energy management system
EMT	Electromagnetic transient

ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	Frequency containment reserve
FFR	Fast frequency response
FSM	Frequency Sensitive Mode
FSP	Flexibility service provider
GA	Genetic algorithm
GAMS	General Algebraic Modeling System
HEDNO	Hellenic Electricity Distribution Network Operator
HENEX	Hellenic Energy Exchange
HUPX	Hungarian Power Exchange
HV	High voltage
HVDC	High-voltage direct current
IDA	Intraday auction
IDCC	Intraday capacity calculation
IPTO	Independent Power Transmission Operator
JAO	Joint Allocation Office
JSON	JavaScript Object Notation
KPI	Key performance indicator
LSTM	Long short-term memory
LTS	Local Trading System
MAE	Mean absolute error
MAPE	Mean absolute percentage error
mFRR	Manual frequency restoration reserve
MILP	Mixed-integer linear programming
MTU	Market time unit
MV	Medium voltage
NECP	National Energy and Climate Plan
NG	Natural gas
NTC	Net transfer capacity
OHL	Overhead line
OLTC	On-load tap changer
PMU	Phasor measurement unit
PTDF	Power transfer distribution factor
PV	Photovoltaic

RAM	Remaining Available Margin
RES	Renewable energy sources
RMS	Root mean square
RMSE	Root mean square error
RoCoF	Rate of change of frequency
RR	Replacement reserve
SCADA	Supervisory control and data acquisition
SLR	Static line rating
SoC	State of charge
SPP	Solar power plant
SQL	Structured Query Language
SUC	System use case
TSO	Transmission system operator
TSOC	Transmission System Operator – Cyprus
TYNDP	Ten-Year Network Development Plan
UCY	University of Cyprus
UPRC	University of Piraeus Research Center
WAC	Wide Area Controller
WP	Work package
WPP	Wind power plant
XML	Extensible Markup Language

Executive Summary

Deliverable D7.1 consolidates the TwinEU demonstrations of forecasting, optimisation and decision support for electricity grids and markets. It explains how conceptual use cases are translated into working digital-twin applications, bringing together the models, data flows, analytical functions and validation methods developed across Greece, Hungary, Bulgaria, Cyprus and Slovenia. Its contribution is a common methodological framework that connects predictive information with technically meaningful decisions while preserving the purpose and implementation context of each demonstration.

The framework is modular. Forecasting, scenario preparation, mathematical optimisation, control and security assessment perform complementary roles, and each application combines the functions appropriate to its needs. Historical records, operational measurements and scenario assumptions establish the study conditions. Analytical tools then produce forecasts, schedules, candidate actions or stability assessments, which are evaluated against the relevant resource, network and market constraints.

The demonstrations address complementary aspects of system coordination. Greece connects day-ahead and balancing-market simulations with reserve allocation and transmission- and distribution-grid validation, examining how flexibility can be scheduled and its local deliverability assessed. Hungary investigates joint energy and balancing-capacity clearing, dynamic network ratings and coordination between successive auctions. Bulgaria combines renewable-production and line-ampacity forecasts with network-security studies, flexibility assessment and connection-point optimisation. Cyprus uses real-time simulation to investigate coordinated frequency support through an HVDC interconnection, including the effects on both disturbed and supporting systems. Slovenia integrates operational snapshots and dynamic network models into a security-assessment environment that provides a technical foundation for further frequency-service development.

The demonstrations link operating conditions, available flexibility, scheduling decisions and physical constraints. The deliverable describes how analytical tools exchange data and models, how their results are checked and how operators use those results. Consistent asset identifiers, compatible time bases, appropriate model detail and clear responsibilities support coordination across market scheduling, network planning and dynamic assessment.

Performance assessment covers model accuracy, technical and economic outcomes, computational performance, interoperability and usability. Each indicator is presented with its reference conditions, calculation basis and study scope. The results cover market and network simulations, real-time controller experiments and operational-data-based security assessment.

D7.1 provides a methodological basis for developing and evaluating digital-twin services for grid and market management. The demonstrations combine predictive information, constrained decision-making and physical assessment, contributing to TwinEU's objective of interoperable digital twins for secure, efficient and coordinated electricity systems.

1 Introduction

Task 7.1 provides the conceptual and methodological framework for embedding forecasting and optimisation within digital-twin environments for electricity systems. It connects predictive information with grid and market decisions, while allowing the national demonstrations to use models, tools and execution arrangements suited to their applications.

A digital representation of a network becomes useful for decision support when its operating state, inputs and outputs are consistent with the question being studied. Market clearing requires coherent orders, resource capabilities and network restrictions. Connection planning requires a defined set of candidate assets, a network state and an explicit selection criterion. Frequency-support studies require dynamic models, controller settings and disturbances. Dynamic security assessment requires a correctly initialised operating point before any stability indicator can be interpreted. The demonstrations bring these requirements into working simulation and assessment environments.

The report distinguishes five analytical functions. Forecasting estimates future quantities such as renewable production or line ampacity. Scenario preparation defines possible operating configurations. Optimisation selects decisions according to an objective and constraints. Control responds to measurements according to a control law. Network and stability assessment evaluates the consequences of a specified state or action.

The transition from conceptual use case to demonstration is described through the implemented functions and interfaces. The technical and economic results are associated with the relevant simulation, data-exchange or operational-assessment workflow.

1.1 Task 7.1

Task 7.1 connects the conceptual work on use cases in WP2, the architectural work in WP3, the WP7 demonstration tasks and subsequent evaluation and replication activities in WP9. It establishes a common way to describe predictive and decision-support functions without requiring identical software, network detail, forecast horizons or optimisation objectives. The shared questions concern the physical or market system represented, the data used to initialise it, the computation performed, the information exchanged and the evidence supporting the result.

Within WP7, the Greek work under Task 7.2 concerns the balancing market context and TSO–DSO coordination. The Hungarian work under Task 7.3 addresses energy and balancing-capacity co-optimisation and dynamic network capacity [1]. The Bulgarian activities under Tasks 7.4 and 7.5 combine forecasting-enabled network assessment with resource connection-point optimisation [2]. Task 7.6 develops the Cypriot HVDC investigation environment [3]. Task 7.7 concerns development of a new Slovenian FFR service and uses the network and simulation environment developed in the Slovenian demonstration.

The Slovenian network-operation and DSA results [4] provide the technical foundation for frequency-stability studies and support the development of the Task 7.7 FFR service.

At the methodological level, Task 7.1 supports a modular description of inputs, analytical services, decision outputs and validation. The same structure can accommodate a deterministic market study, a weather-dependent network-rating calculation, an evolutionary placement search and a real-time controller experiment. Cross-pilot synthesis then identifies which implementation patterns are reusable and which depend on local data, assumptions or operator practices.

Figure 1 summarises the task interfaces with conceptual design, architecture, demonstration and validation activities.

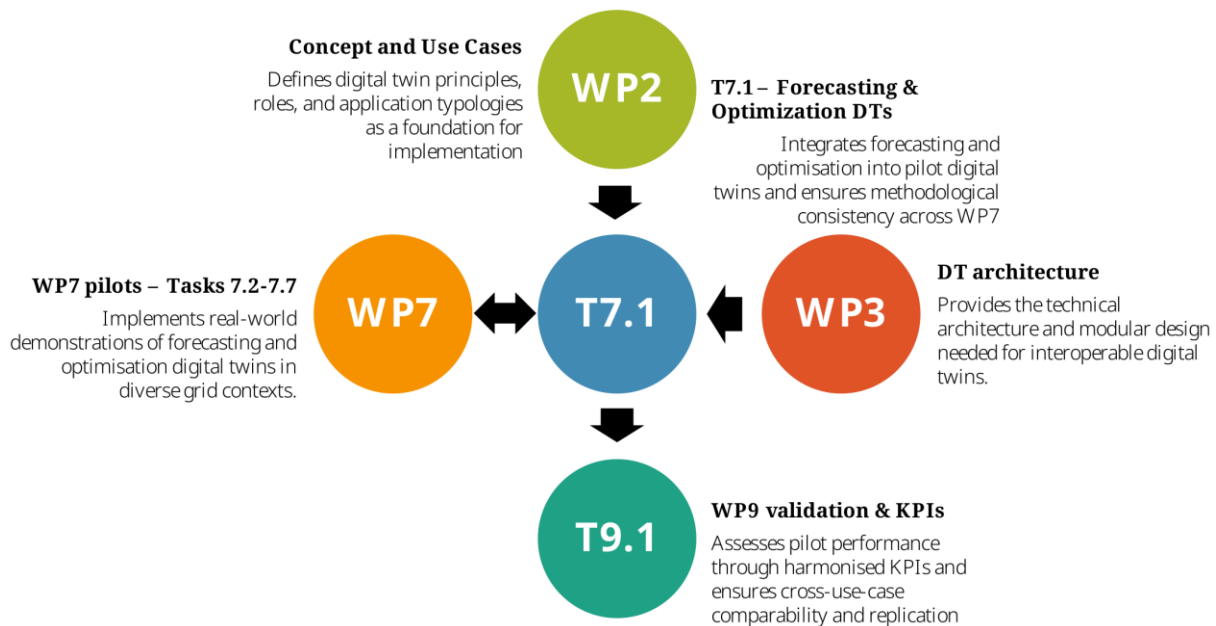


Figure 1. Task 7.1 interfaces with conceptual design, architecture, demonstration and validation activities.

1.2 Objectives of the Work Reported in this Deliverable

The first objective is to explain how forecasting and optimisation are positioned within each demonstration. This includes the forecasted quantities, the source and temporal structure of the inputs, the mathematical or control logic applied and the decisions supported. Where a pilot uses prescribed scenarios or state-dependent stability estimates instead of conventional forecasts, that role is identified directly.

The second objective is to describe the integration of these functions with the digital twin. Market schedules, network representations, forecasts, equipment limits, control parameters and operating snapshots have different meanings and update requirements. Their movement between tools must preserve those meanings. The report therefore examines the actual exchange mechanisms, model formats, synchronisation arrangements and points of human intervention.

The third objective is to present the results in a consistent evaluation framework. Forecast errors, welfare changes, reserve-capacity volumes, line loadings, frequency indicators and calculation times are assessed against defined references, with explicit units and baselines.

The fourth objective is to identify practical lessons for deployment and replication. These concern the separation of scheduling from network validation, the use of shared flexibility capability, weather-dependent ratings, neighbouring-system security and dynamic-model initialisation.

1.3 Implementation Context and Challenges

The demonstrations use different modeling arrangements. Greece combines asset-based market simulation with aggregate balancing resources and detailed grid tools. Hungary connects market orders with a flow-based capacity domain and alternative auction sequences. Bulgaria combines operator network models, statistical forecasts and scripted studies. Cyprus integrates real-time

simulation, external data services and controller interaction. Slovenia combines operational snapshots with dynamic models and automated security assessment.

Data availability shapes the modeling approach. Greek network constraints are assessed via dedicated grid tools. Hungarian forecast DLR uses the available 24-hour weather horizon. Bulgarian ampacity-training targets are calculated from thermal models. Slovenian stability assessment uses a detailed national model and an external observability area with the available dynamic data.

Temporal alignment is equally important. The workflows combine 15-minute energy schedules, hourly planning models, 24-hour forecasts, microsecond-scale EMT integration and 15-minute SCADA/EMS snapshots. Each receiving tool uses the time basis appropriate to the input: period average, limit, state, forecast or instantaneous measurement.

The Greek market–grid chain uses manual and semi-automated file transfers. Hungary implements selected standalone and sequential auction configurations. Bulgaria combines scripted internal tool exchange with a separate Connector demonstration. Cyprus integrates real-time simulation and communication for testing. Slovenia automates routine preparation and assessment, with expert supervision for validation against PMU recordings.

The evaluation covers four future-system days in Greece, available valid observations from the 2024 simulation campaign in Hungary, selected Bulgarian network cases, eleven Cypriot disturbance scenarios and Slovenian operational snapshots. Cross-pilot comparison focuses on the implemented functions, validation methods and study conditions.

1.4 Outline of the Deliverable

Chapter 2 presents the common demonstration framework, including the completed pilot profiles for functional scope, forecasting and optimisation roles, and integration levels. Chapter 3 describes the five national demonstrations through their existing pilot-specific sections: overview, use-case logic, predictive or control functionality, optimisation, architecture and implementation status. Chapter 4 consolidates the functional architecture, data flows, synchronisation and operator interfaces. Chapter 5 maps the use cases to the KPI framework and presents the numerical results and implementation lessons. Chapter 6 draws the overall conclusions. The References section identifies the supporting technical deliverables and the national energy-planning document cited in this report.

2 Digital Twin Demonstration Framework for Forecasting and Optimisation

The common framework links a represented system state to an analytical output and its validation. Historical or operational data provide the starting point. Forecasts or scenario assumptions describe relevant variations. An optimiser, controller or assessment tool evaluates the resulting state or selects an action. The output is then checked at the market, resource, network or dynamic-system level appropriate to the application.

The framework separates data preparation, predictive inputs, decision logic, physical evaluation and user interaction. This functional structure supports comparison of market–grid simulation, real-time controller testing and operational security assessment.

The pilot-identification profiles in Tables 1–5 summarise the organisations, system boundaries and principal functions before the more detailed descriptions in Chapter 3.

Table 1. Overview of pilot identification and functional scope – Greece

Field	Pilot description
Country / pilot	Greece; scenario-based market and network assessment for projected 2030 conditions.
Organisations	UPRC, IPTO, HEDNO and HENEX, covering balancing optimisation, transmission-system assessment, distribution-system assessment and day-ahead market simulation.
DT scope	Sequential DAM and BM simulation with separate transmission and distribution validation.
Main forecasting focus	Demand and renewable-generation forecasts; distribution-level load and PV profiles; historical-data-based scenario alteration and reserve requirements/expected imbalance inputs.
Main optimisation focus	Day-ahead welfare maximisation and balancing energy/reserve co-optimisation under resource constraints and aggregate congestion-management requirements.

Table 2. Overview of pilot identification and functional scope – Hungary

Field	Pilot description
Country / pilot	Hungary; non-binding cross-zonal market and network-capacity demonstration.
Organisations	BME, MAVIR, HUPX, Artelys and F4STER contribute coordination, market data, capacity inputs, optimisation and DLR-related work.
DT scope	Co-optimised energy and balancing-capacity auctions under flow-based constraints, including retrospective DLR adjustments and sequential market variants.
Main forecasting focus	Deterministic weather-based thermal-rating forecasts; measurement-supported ANN conductor-temperature estimation; historical DLR market sensitivities.
Main optimisation focus	Joint energy and balancing-capacity clearing; evaluation of cross-zonal capacity use, bid forwarding and residual-capacity cascading.

Table 3. Overview of pilot identification and functional scope – Bulgaria

Field	Pilot description
Country / pilot	Bulgaria; forecasting, network assessment and connection-point planning for RES and storage systems.
Organisations	SCBG, SETECHCO, ESO EAD, EDG West and Entra Energy.
DT scope	EHV/HV and selected MV network twins in PSS/E; cross-border energy-exchange twin in ANTARES; a reduced high-level twin and auxiliary neural models.
Main forecasting focus	Wind and solar production, overhead-line ampacity and, in an additional application, next-hour demand at two distribution substations.
Main optimisation focus	Selection of connection points for virtual wind plants and battery storage using a genetic algorithm and an average percentage line-loading objective.

Table 4. Overview of pilot identification and functional scope – Cyprus

Field	Pilot description
Country / pilot	Cyprus, with Crete and mainland Greece represented in the HVDC-interconnection study.
Lead organisation	University of Cyprus (UCY). TSO, market-operator, regional-coordination, HVDC-operator and FSP roles are represented in the demonstration.
DT scope	Aggregate power-system and HVDC models executed in real time on OPAL-RT, with communication services and operator interfaces for pre-deployment investigation.
Predictive / scenario inputs	Historical or real-time operating data and prescribed disturbances for initialisation of the simulated systems.
Control and coordination focus	Market-allocated FCR, additional inertia-adaptive FSM support and WAC-mediated cross-border support subject to transfer limits.

Table 5. Overview of pilot identification and functional scope – Slovenia

Field	Pilot description
Country / pilot	Slovenia; dynamic-security assessment and its relevance to frequency-service development.
Organisations	ELES, University of Ljubljana and EIMV contribute to the network and DSA framework. Dynamic generator and controller data are exchanged with MAVIR.
DT scope	National transmission dynamics, the external observability area, distribution equivalents and periodically updated SCADA/EMS operating states in PowerFactory.
Predictive-assessment focus	State-dependent estimates of stability margins, followed by the verification or assessment method applicable to each stability category.
Decision-support and FFR scope	Stability assessment and evaluation of remedial options supporting prospective FFR service development.

2.1 Core Functional Roles: Forecasting and Optimization in DTs

Forecasting provides a time-dependent description of quantities that will affect subsequent operation. In the Greek workflow, forecast and scenario profiles support market inputs and reserve calculations. In Hungary, meteorological forecasts support deterministic line-rating calculations. In Bulgaria, neural models estimate renewable production and conductor ampacity for subsequent network studies. The Cypriot experiments instead prescribe operating conditions and disturbances, while the Slovenian AI component estimates stability indices for an identified operating state.

Optimisation selects among admissible decisions. The Greek DAM allocates energy to maximize social welfare, while the subsequent BM co-optimizes the residual energy and reserve quantities according to system cost-minimization principles. The Hungarian engine co-clears energy and balancing-capacity bids under cross-zonal constraints. The Bulgarian genetic algorithm searches a finite set of connection configurations. Cyprus applies FCR/FSM coordination, while Slovenia provides dynamic-security assessment.

The coupling between functions depends on the use case. Forecasts update model inputs, network feedback supports schedule revision, and stability estimates guide further simulation. Table 6 –Table 10 summarise these roles for each pilot.

Table 6. Forecasting and optimisation roles – Greek pilot

Question	Pilot response
What forecasting functions are included?	IPTO demand and RES forecasting; HEDNO MV-load and distributed-PV forecasting; historical-data-based future market scenario construction.
How are the inputs used?	They establish market and grid operating conditions and support calculation of reserve requirements and projected imbalances. The reported BM runs use deterministic profiles.
What decisions are optimised?	DAM order acceptance and exchanges; BM commitment, balancing energy and eligible reserve, congestion-management and FFR allocations.
Is there a coupled loop?	Balancing Market schedules are linked to separate grid checks and corrective feedback through manual or semi-automated file exchange.
What remains simulated?	Market outcomes, flexibility schedules and grid impacts under the examined configurations.

Table 7. Forecasting and optimisation roles – Hungarian pilot

Question	Pilot response
What predictive functions are included?	Measurement-supported ANN estimation of conductor temperature and deterministic weather-based DLR forecasting. Historical DLR information is used in the evaluated market sensitivities.
How are the inputs used?	Line ratings inform RAM adjustments on relevant CNECs. The resulting constraints enter the market-clearing model.
What decisions are optimised?	Energy and balancing-capacity order acceptance, market prices and cross-zonal allocations within each evaluated auction stage.
Is there a coupled loop?	Capacity calculation supplies market constraints; sequential auctions transfer residual orders and/or capacity.
What remains simulated?	Non-binding market clearing, bid acceptance and network-capacity effects.

Table 8. Forecasting and optimisation roles – Bulgarian pilot

Question	Pilot response
What forecasting functions are included?	ANN-based WPP and SPP production and OHL ampacity forecasts, plus a complementary next-hour LSTM substation-demand application.
How are the inputs used?	They update hourly network states and cross-border energy-exchange studies and support congestion and security assessment.
What decisions are optimised?	Connection points for the defined virtual wind plants and battery, according to the selected line-loading criterion.
Is there a coupled loop?	Forecast outputs are transferred into network-study models used for security assessment and connection-point selection.
What remains simulated?	New connections, outages, maintenance states and FSP operating changes. The separate Connector exercise exchanges files between represented roles.

Table 9. Predictive inputs and coordination roles – Cypriot pilot

Question	Pilot response
What predictive inputs are used?	Operating data and prescribed scenarios initialise the equivalent systems.
How are the inputs used?	They define system strength, load, generation, scheduled HVDC transfer and disturbances against which controller responses are tested.
What decisions are supported?	FCR/FSM gain configuration, HVDC transfer constraints and coordination of local and cross-border frequency support.
What feedback loop is implemented?	Measurement-based controller response and regional coordination within the real-time simulation.
What remains simulated?	The future interconnected system, its disturbances and coordinated frequency-support response.

Table 10. Predictive assessment and decision-support roles – Slovenian pilot

Question	Pilot response
What predictive functions are included?	AI estimates of stability indices conditional on the current operating state, combined with dynamic and small-signal analyses.
How are the inputs used?	Operational snapshots initialise the twin; estimates support screening and reduce the search effort for stability margins.
What decisions are supported?	Identification of critical contingencies, poorly damped modes and possible remedial adjustments; selection and interpretation of further studies.
What recurring workflow is used?	Snapshot acquisition, model preparation, validation, stability assessment and visualisation.
How does the work support FFR?	The assessment infrastructure supports frequency-stability studies and prospective FFR service development.

2.2 System Integration Levels and Use Case Typologies

Integration level is described through execution mode, time horizon, represented system and update mechanism. The classification covers offline studies, real-time simulation and periodically updated operational assessment.

Greece and Hungary use non-binding market simulations, with external grid validation in the Greek workflow. Bulgaria performs network and connection-planning studies. Cyprus runs dynamic models and controllers in real time. Slovenia periodically reconstructs operational states and assesses dynamic security. Each workflow follows its own temporal requirements.

The use-case typology covers market scheduling, capacity assessment, network-security studies, resource placement, regional frequency support and dynamic-security monitoring. The integration profiles identify the principal application, forecast horizon, model time step and execution interval.

Table 11. DT integration level and use-case typology – Greece

Dimension	Pilot response
Integration level	Offline, scenario-based market simulation with separate network validation.
Primary use cases	Future DAM/BM operation, multi-service flexibility allocation and TSO–DSO coordination.
Horizon and resolution	Projected 2030 scenarios; 96 quarter-hourly BM intervals per day. IPTO supplies intraday, day-ahead and longer-horizon forecast products.
System layers	Wholesale and balancing markets, transmission network and selected distribution networks.
Execution frequency	Scenario-driven execution with exchanged forecasting, market and network datasets.

Table 12. DT integration level and use-case typology – Hungary

Dimension	Pilot response
Integration level	Scenario-based market and capacity-calculation environment.
Primary use cases	DLR-informed flow-based capacity and energy/balancing-capacity co-optimisation.
Horizon and resolution	Forecast DLR is limited to 24 hours from issue time. The evaluated numerical market cases use 24 MTUs for one delivery day after temporal harmonisation.
System layers	Market, balancing-capacity and cross-zonal network-constraint layers.
Execution frequency	The design covers DAM and three IDAs; the evaluated batch comprises selected standalone and sequential stages.

Table 13. DT integration level and use-case typology – Bulgaria

Dimension	Pilot response
Integration level	Planning and scenario-based assessment in a simulation environment.
Primary use cases	Forecast-informed security checks, flexibility exchange and connection-point selection.
Horizon and resolution	A 72-hour sequence of hourly network states; additional LSTM models forecast the next hour from historical look-back windows.
System layers	Transmission, selected MV distribution areas and cross-border energy exchange.
Execution frequency	Study-based execution with scripted data transfer and calculations.

Table 14. DT integration level and use-case typology – Cyprus

Dimension	Pilot response
Integration level	Real-time execution of a non-intrusive pre-deployment simulation.
Primary use cases	Regional frequency support through a simulated HVDC interconnection.
Horizon and resolution	Microsecond-scale fixed-step EMT execution and short disturbance experiments. Market coordination and field-data reporting have separate time bases.
System layers	Country-level equivalents, HVDC terminals, local FSPs and represented regional actors.
Execution frequency	Continuous simulated controller response within an experiment; scenario inputs and gains are configurable.

Table 15. DT integration level and use-case typology – Slovenia

Dimension	Pilot response
Integration level	Operational-data-driven DSA with retrospective and near-real-time assessment capability.
Primary use cases	Dynamic RMS studies, extended network modelling and SCADA/EMS integration.
Horizon and resolution	A new operational snapshot every 15 minutes; simulation time step and calculation runtime are separate from snapshot cadence.
System layers	National transmission system, observability area and distribution equivalents.
Execution frequency	Automated snapshot preparation and assessment, with manual study execution also supported.

3 Pilot Demonstrations Overview

The five pilot descriptions explain the implementation from the use-case perspective. Each description identifies the represented system, the predictive or scenario inputs, the decision logic, the architecture and the demonstrated state of development. The purpose is to make the technical chain understandable before the numerical comparison in Chapter 5.

The pilots also illustrate different meanings of validation. Greek balancing market schedules are validated through transmission and distribution power-flow models. Hungarian comparisons test market mechanisms under controlled input changes and examine consistency between standalone and sequential stages. Bulgarian forecasts are combined with network studies, and the placement result is checked against a finite exhaustive search. Cypriot controls are exercised under prescribed dynamic disturbances. Slovenian snapshots pass model-initialisation checks before stability assessment. These validation activities are complementary and are described at the level actually implemented.

3.1 Greece – Forecast-Integrated Reserve Market Co-Optimisation

3.1.1 Pilot Overview

The Greek pilot develops a scenario-based digital twin for the interconnected electricity system and its day-ahead and balancing-market processes. UPRC, IPTO, HEDNO and HENEX contribute the balancing optimisation, transmission assessment, distribution assessment and day-ahead market functions. The demonstration uses historical market and operational information together with projected 2030 asset and system configurations. A common scenario reflecting the anticipated evolution of the Greek electricity system towards 2030 is investigated, providing the basis for all use cases. It is designed to examine future coordination arrangements without affecting live market clearing or physical dispatch [1].

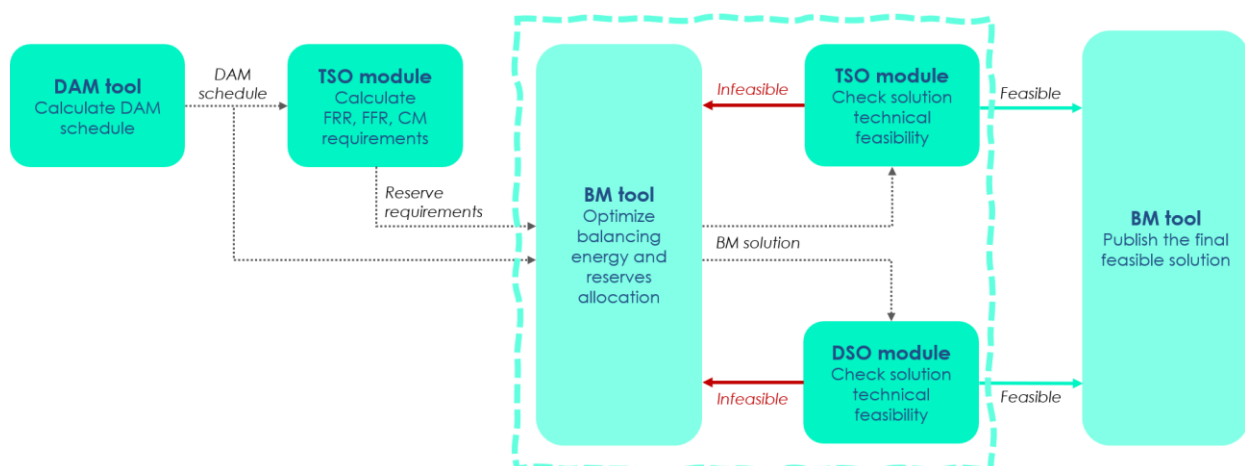


Figure 2. Market, reserve-requirement and network components of the Greek digital-twin workflow.

The core implementation comprises the HENEX DAM Simulator, the Balancing Market Digital Twin, the IPTO transmission-grid tool and the HEDNO distribution-grid tool. IPTO also provides the reserve-requirement and projected-imbalance calculations. These components share schedules and scenario information but retain separate purposes. The DAM model establishes market positions; the BM

model adjusts those positions and allocates service capacity; the grid tools assess their physical consequences.

The balancing formulation enforces resource constraints and TSO- and DSO-level service requirements. Dedicated transmission and distribution tools assess network physics. Together, these components form a coordinated market–grid modeling chain.

Figure 2 shows the market, reserve-requirement and network components of this workflow.

3.1.2 Pilot Scope and Use Case Logic

The pilot examines how distributed and conventional flexibility can support balancing, reserve procurement and congestion management in a renewable-rich system. The workflow links asset-level day-ahead schedules to a technically assessed operating configuration, accounting for resource capability and network conditions.

The day-ahead and balancing stages run sequentially. The DAM Simulator maximises welfare and produces the reference schedule. The BM formulation then minimises balancing-system cost while remaining linked to that schedule. It jointly considers upward and downward balancing energy, FCR, aFRR, mFRR and the additional TSO-CM, DSO-CM and prospective FFR requirements enabled in each scenario.

The operating conditions span four combinations of demand and renewable availability. Historical observations provide seasonal profiles, while the projected asset mix, market topology and system assumptions define the 2030 configuration. The selected days represent contrasting operating regimes.

Table 16. Representative Greek operating conditions and projected study dates

Operating condition	Historical reference	Projected date	Study emphasis
Low RES / low load	1 November 2025	1 November 2030	Autumn operating regime and flexibility allocation.
Low RES / high load	21 January 2026	21 January 2030	Winter demand, conventional commitment and reserve requirements.
High RES / low load	17 May 2026	17 May 2030	Renewable surplus and high relative flexibility stress.
High RES / high load	6 July 2026	6 July 2030	Summer demand, congestion and multi-service capability.

The historical reference identifies the input day; the projected date identifies the future-system scenario. Comparisons of historical and 2030 DAM configurations differ from reduced-service versus full-flexibility BM comparisons.

The market-transformation comparison contrasts the historical DAM configuration with the complete 2030 configuration. The latter changes demand, renewable availability, conventional capacity, storage, demand response and interconnection representation. The associated welfare and price changes describe this combined transformation.

The balancing comparison contrasts reduced-service and full-flexibility configurations. The full configuration activates congestion-management and FFR requirements and uses eligible battery and

demand-response capability. The 17 May pair holds common BE, FCR, aFRR and mFRR requirements fixed and removes BESS/DR provision of those products from the reduced case. On the other three days, common-product requirements or resource participation also change. This distinction identifies which comparisons hold the common-product requirements constant, so that changes in balancing needs are not conflated with changes in service allocation. The additional CM and FFR requirements remain part of the full configuration.

TSO–DSO coordination uses connection-aware requirements and eligibility rules. The separated congestion-management benchmark adds TSO and DSO needs. The coordinated configuration consolidates their simultaneous, directionally compatible overlap. The combined requirement lies between the larger individual need and the sum of both needs, preserving local DSO constraints.

3.1.3 Forecasting Functionality

Transmission-level demand and renewable forecasts

IPTO's Department of System Operation and Control provides demand and renewable-generation forecasts for mainland Greece and Crete. The products cover intraday, day-ahead and longer horizons, with hourly, 30-minute or 15-minute profiles according to the consuming process. The renewable forecast covers the aggregate output of wind, utility-scale and building-integrated PV, biomass, CHP and small hydro. Two contracted providers supply renewable forecasts, which are assessed alongside an internal prediction before a consolidated profile is communicated.

Renewable-forecast inputs include the plant registry, geographical location, installed power and technology, historical production, historical forecasts and regional meteorological information. Weather variables include temperature, wind speed and direction, and solar radiation. IPTO's internal tool uses regression and machine-learning methods.

Demand forecasting covers the electrical load served by the transmission system and distribution grid. It combines an externally supplied forecast with an internal regression- and neural-network-based assessment. Historical SCADA demand, forecast information and meteorological conditions support scheduling-input preparation.

Distribution-level forecasts and operating profiles

HEDNO's contribution concerns the local conditions under which proposed DER schedules can be accommodated. Short-term load forecasts at MV substations and feeders use historical consumption patterns, temperature relationships and time-of-day or day-of-week profiles. Distributed-PV forecasts use irradiance, temperature, panel characteristics and historical production. These inputs support both normal operating representations and future or stressed network conditions.

The distribution assessment applies load and DER profiles to a detailed MV network representation. It examines thermal loading, voltages and local export or import limits under selected seasonal, simultaneous-activation and reverse-flow conditions.

Scenario generation and requirement preparation

Scenario generation is initiated by HENEX's Day-Ahead Market (DAM) Simulator through its dedicated Scenario Alteration Suite, which constructs the corresponding 2030 Greek day-ahead market configuration. Starting from historical market data, namely market participants' orders and network topology data, the module modifies order quantities, order types, asset attributes, topology or cross-border capacity for a selected future configuration. These alterations are implemented as

dedicated functions that are dynamically applied to the historical input datasets. Each simulation cycle is configured through user-defined parameters, including the delivery day, scenario ID and selected alteration functions that define the simulation scenario. The resulting scenario-adjusted inputs are used to construct the market instance passed to the Market Solver.

The 2030 market scenario combines changes driven by future system operational requirements and market-specific modelling assumptions with projections and targets derived from national energy and network planning documentation [5]. Accordingly, the 2030 market configuration includes scaled demand and renewable output, removal of lignite generation, additional natural-gas and hydro/pumped-storage assets, synthetic storage and demand-response orders, Cretan renewable assets and updated interconnection assumptions. These modifications use the shared asset registry so that new resources can be represented consistently across modules. Market inputs from other bidding zones are included where suitable orderbook information is publicly available.

IPTO's requirement module converts the selected system conditions into the quantities needed by the balancing model. FCR uses a system-share methodology with a uniform annual value across the examined intervals. Upward aFRR combines the relevant minimum requirement, generation-loss, cross-border schedule and rapid-consumption components through RMS aggregation; downward aFRR uses the corresponding maximum-based treatment. mFRR also incorporates the aFRR requirement, renewable and load variations and schedule deviations. The extreme-conditions term is not activated in the representative-day cases.

Projected system imbalances are calculated from the difference between day-ahead schedules and updated demand and renewable conditions. The demonstration calculation covers these demand- and renewable-related deviations.

The BM experiments use deterministic profiles. Weather effects, forecast information, reserve requirements and aggregate flexibility availability are supplied as fixed scenario inputs for each run.

Table 17. Predictive and scenario inputs in the Greek workflow

Input / function	Content	Use in the workflow
IPTO RES forecast	Plant characteristics, production history, forecast history and regional weather.	Defines aggregate renewable conditions; supports scheduling and requirement preparation.
IPTO demand forecast	SCADA demand, forecast history and weather-dependent demand patterns.	Defines transmission-system and total-load conditions.
HEDNO local profiles	MV feeder/substation demand and distributed-PV forecasts or selected stress profiles.	Initialises distribution studies and evaluates local DER deliverability.
DAM scenario alteration	Historical orderbook and network data modified by the selected 2030 asset and market assumptions.	Constructs the market instance for the selected future scenario.
Reserve / imbalance inputs	FCR, aFRR, mFRR and projected BE requirements per direction and interval (expected imbalances).	Exogenous requirements for the 96-period balancing optimisation.
CM / FFR requirements	Aggregate congestion and high-renewable stress indicators.	Prospective CM and FFR planning requirements for the scheduling model.

3.1.4 Optimisation Capabilities

Day-ahead market clearing

The DAM clearing model is a mixed-integer linear programming (MILP) welfare-maximisation problem based on EUPHEMIA principles [6] and adapted for simulation purposes. It explicitly represents stepwise curve orders and simple, linked, circular storage, and exclusive block orders. Cross-zonal exchanges are constrained by available-transfer-capacity limits. The simulation formulation permits Paradoxically Accepted Blocks.

The welfare objective determines accepted orders and exchanges for the simulated market instance. After clearing, accepted curve quantities are disaggregated to assets and accepted block volumes are mapped to the relevant intervals. The resulting market clearing prices, asset-level schedules and import/export flows form the input position for the balancing stage. The quality of the historical market-price reconstruction is evaluated separately from the projected future-market outcomes.

Balancing energy and multi-service scheduling

The balancing formulation covers one day in 96 consecutive 15-minute Market Time Units. Binary variables describe commitment, start-up, shutdown and operating modes. Continuous variables describe final power schedules, balancing adjustments and service allocations. The final schedule is explicitly linked to the DAM position.

Thermal and hydro resources are subject to technical output bounds, initial conditions, ramping restrictions, minimum up/down times and service-specific capabilities. Upward reserve uses headroom above the final generation point, while downward reserve uses the available margin above technical minimum. aFRR provision is restricted to eligible AGC operating ranges. Spinning and non-spinning mFRR capabilities are distinguished where applicable. mFRR and TSO congestion management share the relevant tertiary capability, preventing the same physical response from being allocated in full to both products.

The objective includes balancing-energy and reserve offers, congestion-management and FFR offers, start-up and shutdown costs, and flexible-resource costs. In strict runs, unmet-requirement variables are fixed to zero and accepted contributions are checked against each energy and service balance. Provider-count and concentration conditions are configurable scenario safeguards.

TSO–DSO coordination is implemented as a single-level, constraint-based co-optimisation. Connection-level service assignments and local requirements enter the same scheduling problem. External network assessment supplies limits and corrective feedback.

Storage, demand response and product eligibility

Storage is represented by separate transmission- and distribution-connected aggregates. The BM power envelope is 1,730 MW: 1,211 MW at TSO level and 519 MW at DSO level, following a 70%/30% split. The 2030 DAM scenario represents 4,325 MW of installed storage and 10,996 MWh of energy capacity.

Charging and discharging are mutually exclusive for each battery aggregate. The operating point and eligible services share the connection-level power envelope. Balancing energy is incorporated in the final charge/discharge position. The two aggregates can follow different schedules and directions.

Each battery aggregate satisfies a daily energy balance in which discharged energy equals 84% of charged energy. Storage energy feasibility in the BM is represented at daily aggregate level. Device-level state-of-charge trajectories are assessed in the separate distribution validation study.

Demand response uses exogenous, directional, time-dependent availability and mutually exclusive reduction/increase modes. The calibrated portfolio provides mFRR and TSO congestion management. The downward channel represents increased consumption or rebound within the prescribed availability profile.

Table 18. Service eligibility of the Greek flexible-resource aggregates in the calibrated BM configuration

Resource	BE	FCR / aFRR	mFRR	TSO-CM	DSO-CM	FFR
TSO BESS	Yes	Disabled	Yes	Yes	No	TSO level
DSO BESS	Yes	Disabled	No	No	Yes	DSO level
Demand response	Disabled	Disabled	Yes	Yes	No	Not assigned

Non-dispatchable wind and PV enter system conditions and requirement preparation. Pumping resources are represented separately. A fixed pumping-unit mFRR-down contribution is credited before optimisation of the residual requirement; any excess over the original requirement is recorded as fixed overcoverage.

The optimisation produces schedules and capacity allocations. Prospective FFR is represented by a planning requirement derived from high-renewable stress indicators. External network tools assess the physical feasibility of the resulting schedules.

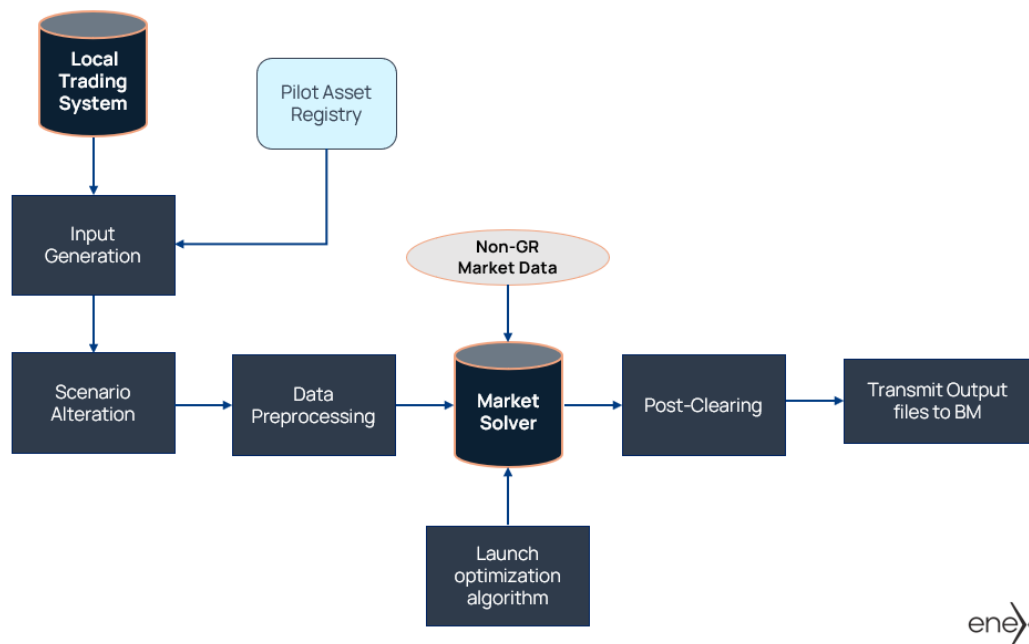
3.1.5 DT Architecture and Integration Flow

The DAM Simulator constitutes the starting point of the market simulation chain, with the resulting Greek day-ahead schedules subsequently serving as inputs to downstream components. The Simulator is deployed within the HENEX environment and features a modular architecture, as illustrated in Figure 3. It interfaces with two main backend systems. Historical market data are retrieved from HENEX's Local Trading System (LTS), while the Market Solver database serves as the data interface between the Python-based simulation workflow and the market-clearing model. The market-clearing process reads the input data from the Market Solver database and, upon execution, stores the resulting outputs back in the same database. These outputs are subsequently retrieved by the post-clearing module for further processing and generation of asset-level market schedules, which are exported in standardised CSV format.

Inter-module communication is fully automated up to the optimisation stage, while post-clearing processing, including result extraction and the disaggregation of cleared quantities to the asset level, is semi-automated and requires user intervention. The Simulator operates in offline scenario mode, independently from real-time market processes.

The common Pilot Asset Registry serves as the common reference model, supporting consistent mapping between market data and the technical resources represented downstream. Delivery-day and scenario identifiers distinguish the original historical session from altered market instances, while asset identifiers are pseudonymised in the exported schedules. This enables scenario tracking and comparison across tools without exposing the original commercial identifiers.

Local DAM Simulator: High-level Workflow



enex

Figure 3. DAM Simulator Modular Workflow.

The BM model then reads the resulting schedules with technical data, service requirements, imbalance inputs and aggregate flexibility availability from structured input files. Its GAMS/CPLEX implementation produces final 15-minute schedules and product allocations, followed by post-solution balance checks.

IPTO uses PSS®E to apply the operating schedules to the transmission model. Demand and generation profiles, DAM/BM outputs and network topology define the power-flow operating point. Thermal-loading and voltage issues can be returned as corrective constraints. Figure 4 summarises this validation and feedback path.

HEDNO uses a detailed MV model in PowerFactory, including topology, loads, lines, transformers and DERs. In planning/simulation mode, the tool assesses activation schedules and returns accept, curtail or reject decisions together with the affected equipment and local thresholds.

Distribution feedback is exported in structured CSV files containing violation reports and per-asset decisions. The pilot uses manual and semi-automated transfers with common identifiers, timestamps, sign conventions and schema versions. Temporal preprocessing aligns quarter-hourly BM outputs with hourly or selected-snapshot network studies.

The workflow generates a schedule, evaluates it in a physical model and revises it where required. Each final schedule is linked to its scenario and network-validation case.

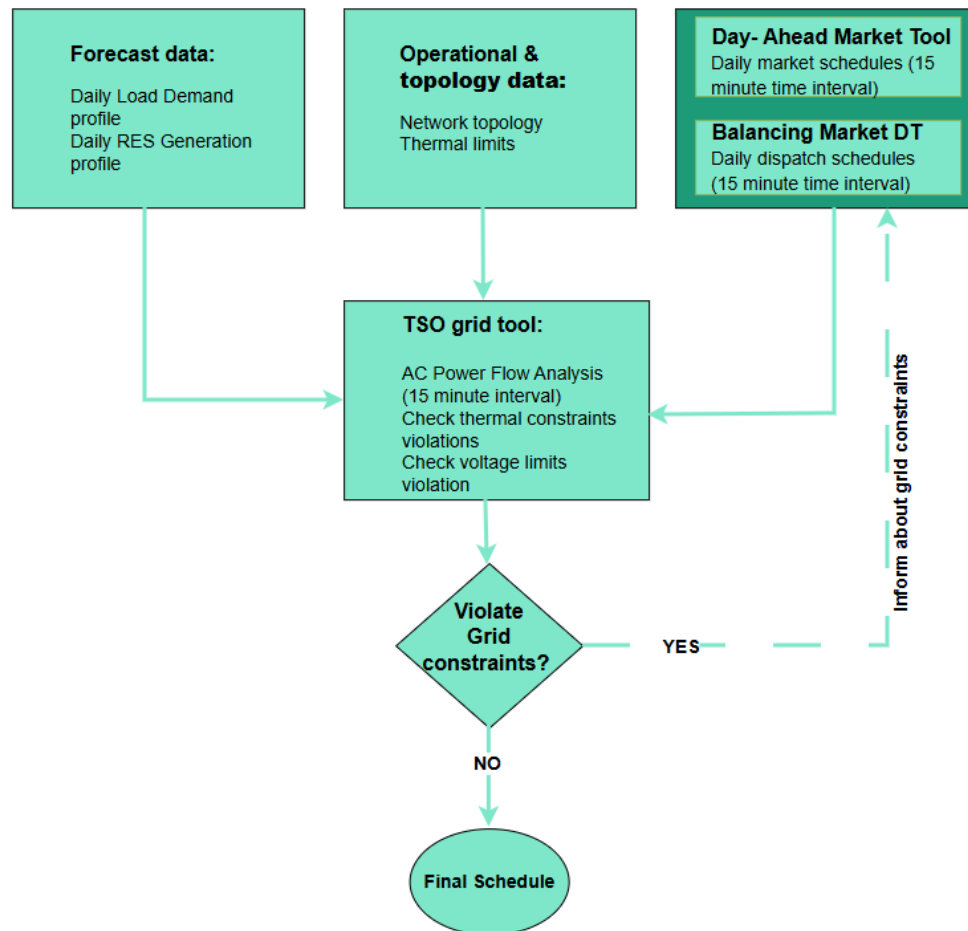


Figure 4. Transmission-grid validation and feedback to the Greek market simulation.

3.1.6 Current Status and Implementation Highlights

The implemented chain has produced historical DAM validation, projected 2030 market outcomes, eight balancing-result configurations across the four representative days and selected transmission/distribution feasibility results. The implementation status is established by the executed functions and their outputs.

The market simulator reproduces the selected historical Greek DAM price series and clears the market instances generated under the projected 2030 configuration. The deployment of an end-to-end DAM simulation tool capable of reproducing the procedures of the actual Greek market, from market input generation to market clearing and the generation of market schedules, represents a major achievement of the Greek pilot from a market perspective. In particular, its flexible, user-configurable scenario framework enables the systematic construction and assessment of alternative market configurations under historical and future system conditions aligned with Greece’s long-term energy planning.

The BM allocates multiple services under contrasting operating conditions, including energy-cycling-intensive and headroom-dominated battery schedules. Energy-cycling-intensive schedules involve substantial charging and discharging, whereas headroom-dominated schedules use the battery power envelope mainly for service capacity, with limited daily energy throughput (Section 5.3). The spring case reduces conventional reserve provision, natural-gas generation, average online gas units and gas-unit ramping.

In the selected summer case, batteries redistribute flows and remove congestion. On the representative MV feeder, assessed schedules remain within voltage and equipment limits, with device-level state-of-charge trajectories examined in the distribution model.

Section 5.3 presents the quantitative market, balancing and network results for the evaluated configurations.

The Greek KPI register covers line congestion, feeder transformer loading, four-day market averages and CM/FFR allocation. The FFR cashflow indicator measures the change in balancing-energy cashflow between paired FFR-ON/OFF simulations with integrated CM retained in both cases.

Building on the developed framework, the DAM Simulator architecture has more recently been upgraded to incorporate the Cypriot market within its workflow. The new architecture enables the generation and processing of market inputs for both Greece and Cyprus and their joint representation in the market-clearing process. This development is being applied within Pan-European Scenario #4 Flexibility Management and Frequency Support (WP4), carried out by HEnEx in collaboration with the Cypriot pilot, to simulate Cyprus participation in the Day-Ahead Market through market coupling with Greece (“Great Sea Interconnector” [7]).

Overall, a known limitation lies in defining realistic national energy scenarios for 2030. Long-term system and market configurations rely on assumptions regarding future generation capacity, demand, network infrastructure and market developments. Given the rapidly evolving energy landscape and frequent updates to policy and regulatory frameworks, these assumptions are inherently subject to uncertainty and may require revision over time.

From a market-simulation perspective, another limitation arises from the reliance on historical coupling data required for the market-clearing process. Day-ahead market simulations involving multiple bidding zones require consistent market datasets across all represented areas. While detailed historical market data are available for the Greek bidding zone, the representation of other bidding zones relies exclusively on publicly available market data.

3.2 Hungary – Dynamic Line Rating and Market Coupling via Forecast-Driven Optimisation

3.2.1 Pilot Overview

The Hungarian pilot investigates how weather-dependent network capability and joint energy/balancing-capacity clearing can be represented in a digital-twin environment. BME coordinates the task, with MAVIR providing system and balancing-capacity information, HUPX contributing market data and the HUPX Labs environment, Artelys developing the computational workflow and clearing implementation, and DLR-related work linked to the network-rating activities of the project [1].

The demonstration connects two analytical functions. HU02 concerns the use of Dynamic Line Rating in the represented transmission-capacity domain. HU03 concerns co-optimised clearing of energy and balancing capacity. The two functions can be evaluated separately or together, which makes it possible to distinguish a change in available network margin from a change in the economic allocation of that margin.

The environment is a non-binding market simulation that produces accepted quantities, clearing prices, net exchanges, reserve procurement and constraint values. The numerical evaluation covers standalone and sequential configurations from the 2024 campaign. Economic comparisons use valid observations common to the evaluated and reference configurations, with sample sizes reported separately for each indicator. The results are not extrapolated to missing campaign days.

3.2.2 Pilot Scope and Use Case Logic

The primary use case is the allocation of cross-zonal capability between energy and balancing-capacity products. When those decisions are considered separately, the capacity available to one market depends on decisions already made in another. The co-optimised formulation instead considers their interaction within each auction and evaluates the resulting welfare, price and accepted-volume outcomes under the same represented network constraints.

The network representation uses flow-based constraints for Critical Network Elements with Contingency. Power Transfer Distribution Factors relate zonal positions to monitored constraints, and Remaining Available Margin defines the available margin. DLR information updates the relevant ratings and RAM values used in market clearing.

The designed workflow spans day-ahead and intraday stages. Sequential variants transfer unused bid information, remaining network capacity, or both to later auctions. Each auction is cleared separately.

Table 19. Executed Hungarian scenario families and their roles

Identifier	Configuration	Interpretation
A0; B0	Standalone DAM and IDA2 separated-market references, respectively.	Reference energy and balancing-capacity clearing under SLR-based constraints.
C0a; D0a	Standalone co-optimised DAM and IDA2.	Baseline for the co-optimisation and DLR comparisons.
C0b; D0b	Alternative balancing-capacity bid-source variants.	Sensitivity to the source and construction of balancing-capacity bids.
C2a; D2a	DLR-enhanced co-optimised DAM and IDA2.	Historical DLR-based adjustment relative to C0a and D0a.
G0a	Sequential RAM cascading.	Residual-capacity sequence; its initial DAM stage fails the expected consistency check against C0a.
H0c	Sequential bid forwarding.	Transfer of residual order information between auction stages.
I0c	Combined bid-forwarding and RAM-cascading sequence.	Examines both mechanisms and their incremental contributions.
I2c	Combined sequence with DLR	Uses the same sequential mechanisms as I0c with DLR-adjusted network capacity.

The numerical character 0 denotes the SLR reference and 2 the DLR-enhanced variant. Stage-specific results identify the auction, for example H0c/IDA2.

Controlled pairwise comparisons are used to examine the main mechanisms. Co-optimisation is compared with separated energy and balancing-capacity clearing; DLR-adjusted capacity is compared with the corresponding static-rating configuration; and alternative balancing-capacity bid inputs are compared with a common market formulation. Sequential studies add further requirements: the initial stage must remain consistent with its standalone reference before a downstream difference can be attributed to forwarding or cascading.

3.2.3 Forecasting Functionality

Measurement-supported temperature estimation and forecast DLR

In the measurement-supported workflow, an ANN estimates conductor temperature from high-resolution sensor, meteorological and loading data. A deterministic thermal calculation then uses the estimated temperature and conductor characteristics to determine admissible loading.

Forecast DLR uses deterministic CIGRE and IEEE thermal-rating models [8], [9] with meteorological forecasts over a 24-hour horizon.

The weather-forecast horizon extends 24 hours from issue time. Coverage of the delivery day therefore depends on the capacity-calculation time, as shown in Table 20.

Table 20. Designed capacity-calculation timing and 24-hour forecast coverage

Run	Specified calculation time	Weather-supported DLR extent	Delivery-day coverage
DACC	D-1, 09:45	Up to D, 09:45.	Early delivery-day intervals within the 24-hour forecast horizon.
IDCC1	D-1, 14:45	Up to D, 14:45.	Delivery-day intervals up to 14:45.
IDCC2	D-1, 21:45	Up to D, 21:45.	Delivery-day intervals up to 21:45.
IDCC3	D, 09:45	Covers the relevant D, 12:00–24:00 window.	The final run’s market window lies within the available forecast horizon.

Historical DLR information used in the evaluated market cases

The evaluated DLR scenarios use historical information from the Task 6.8 network-rating work. Rating-related RAM modifications are applied to the relevant critical elements in the historical flow-based dataset.

Static line information includes nominal voltage, number of circuits, seasonal ratings and substation limits. Dynamic records include timestamps, terminal voltages, power factor, SCADA loading and conductor or line DLR values. Each rating is mapped to the corresponding CNEC and time interval.

Dynamic ratings can exceed or fall below static ratings according to environmental and operating conditions. They define state-dependent thermal limits within a cross-zonal capacity domain that also includes the remaining network constraints.

The forecast module estimates future admissible loading within its weather horizon. Historical ratings support retrospective RAM sensitivities, and the co-optimised solver evaluates their market effects.

3.2.4 Optimisation Capabilities

The co-optimised clearing workflow is implemented in AMPL and solved using FICO Xpress. It builds on the earlier energy-and-reserve allocation developments used in the project's methodological background and adapts them to the Hungarian demonstration. Its objective is welfare maximisation under energy balances, bid-acceptance conditions and cross-zonal network constraints.

The represented products include energy and upward/downward balancing capacity, with aFRR, mFRR and RR distinguished in the results. Simple and block orders are represented together with exclusive-order relationships. Accepted energy and reserve quantities share the available resource and network capability.

HUPX and MAVIR provide domestic energy and balancing information. Inputs for neighbouring bidding zones include external market datasets and ENTSO-E-derived balancing information. Supply and demand curves constructed from accepted balancing bids are evaluated through alternative bid-source scenarios.

Input preparation harmonises source formats and time resolutions. Simple orders with a common period, zone and direction are aggregated in 10 EUR/MWh price intervals. Non-exclusive block orders below 1 MWh are removed, single-hour non-exclusive blocks are represented as simple orders, and compatible blocks may be aggregated. Quarter-hourly products are harmonised to the simulation time base.

Flow-based restrictions use the relevant CNEC, RAM and PTDF information. Selected sequential stages with NTC-based data are transformed into a compatible representation for the common workflow. The solver produces acceptance ratios, allocated quantities, bid surpluses, energy and balancing-capacity prices, net exports and cross-zonal reserve procurement. Network shadow prices and relevant worst-case loading outputs support interpretation of the limiting constraints.

Bid forwarding transfers residual orders between intraday auctions. RAM cascading carries forward capacity remaining after earlier allocations. The DAM stage provides the initial consistency reference. Results identify both the complete sequence and the relevant auction stage.

3.2.5 DT Architecture and Integration Flow

The demonstration uses HUPX's proprietary HUPX Labs platform for data exchange, result storage and visualisation. Project-specific integration links market-bid preparation, flow-based constraint construction and market clearing. Figure 5 shows the relationships between the data sources and the clearing process.

Historical JAO flow-based data provide the principal network constraints for the evaluated scenarios. A separate PowSyBI-based capacity-calculation module combines TYNDP zonal data with a static network model for medium-term study preparation.

The evaluated workflow covers orderbook preparation, matching and post-matching market and network outputs in a non-binding simulation environment.

Bid quantities, price units, product directions, delivery intervals and network constraints are harmonised to compatible periods. Data exchange also follows the confidentiality requirements of the originating organisations.

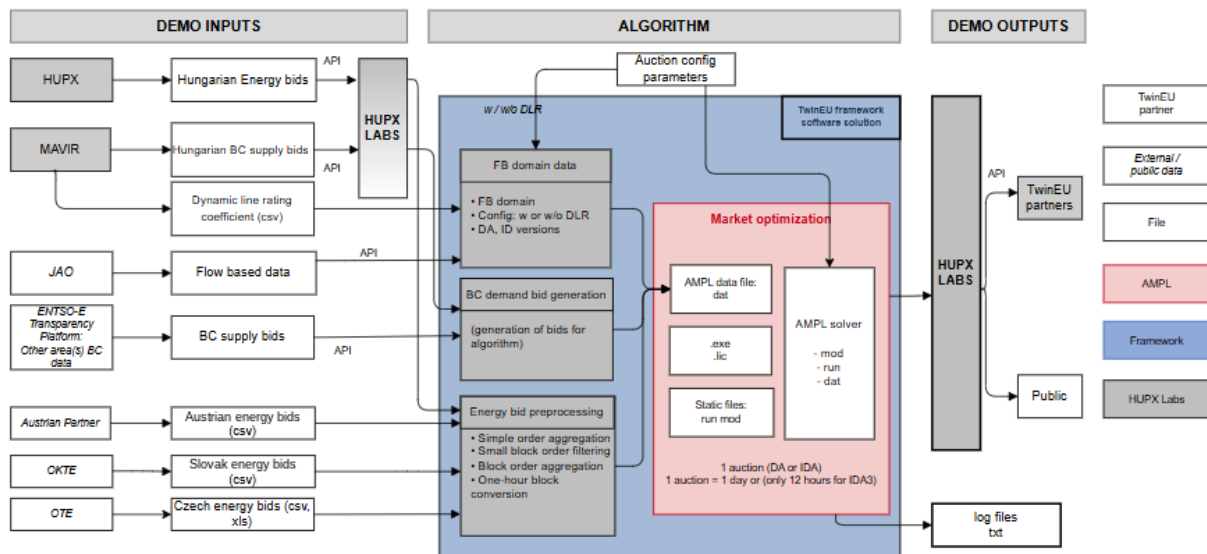


Figure 5. Hungarian data preparation, flow-based constraints and co-optimised market clearing.

3.2.6 Current Status and Implementation Highlights

The pilot has executed standalone and sequential configurations across the 2024 campaign and produced market, capacity and execution-performance indicators. Standalone co-optimisation increases aggregate welfare by EUR 63.77 million in DAM and EUR 2.89 million in IDA2, corresponding to 0.0217% and 0.0386% of baseline welfare on the respective paired samples. Balancing-capacity prices respond more strongly than energy prices in these standalone comparisons.

DLR increases mean RAM by 470.71 MW in standalone DAM, 468.20 MW in standalone IDA2 and 472.13 MW in the combined sequence. Its economic effect depends on whether additional capacity relaxes binding constraints. The direct I2c/I0c comparison yields an incremental IDA2 welfare gain of EUR 208.27 million, equivalent to 2.5837% of baseline welfare on the paired sample.

Configurations containing bid forwarding show the strongest IDA2 improvements against the separated-market reference. H0c, I0c and I2c increase aggregate welfare by 13.7594%, 11.3737% and 14.3413%, respectively, with higher welfare in more than 98% of comparable hourly observations. These comparisons describe complete configurations and do not isolate the contribution of each mechanism.

Repeated execution establishes the feasibility of the implemented workflow, while complete-day coverage remains more limited for the combined sequences. Section 5.3 summarises the results and their evaluation populations. Interpretation retains the distinction between individual-stage success and complete-sequence execution, and between scenario differences and effects attributable to individual mechanisms.

3.3 Bulgaria – Forecast-Based Grid Planning and Optimized RES Connection

3.3.1 Pilot Overview

The Bulgarian pilot links forecasting, network simulation and connection-point optimisation. ESO EAD provides the transmission-system perspective, EDG West the selected distribution-network model, and Enra Energy the flexibility and market-participant perspective. SCBG and SETECHCO support technical development. Connection-point optimisation uses a selected 110 kV transmission-network area [2].

Task 7.4 addresses the development and application of the twins, including renewable-production and overhead-line ampacity forecasts, network-security assessments and flexibility studies. Task 7.5 uses the network representation to optimise connection points for new renewable and storage resources. A common set of models supports both tasks, avoiding the need to create separate network representations for forecasting-informed studies and connection planning.

The principal enhancement relative to the underlying engineering models is the scripted preparation of forecast-informed operating states and the automated exchange of results between tools. The pilot develops EHV–HV and MV network twins in PSS/E, a cross-border energy-exchange twin in ANTARES, a reduced high-level twin and auxiliary neural-network models. Python and R scripts connect their inputs and outputs. The resulting environment supports repeatable studies without applying switching, dispatch or connection decisions to the physical grid.

3.3.2 Pilot Scope and Use Case Logic

The use cases are organised around a progression from reliable data exchange to prediction, network assessment and action evaluation. Forecasting of wind generation, solar generation and line ampacity first provides time-dependent inputs. These are incorporated into hourly network models, together with cross-border exchange results. The models are then used to examine contingencies, maintenance conditions, congestion and the effect of activating flexibility resources.

The connection-point study selects locations for a defined group of virtual wind and battery facilities under a network-loading objective. Virtual facilities preserve the confidentiality of connection-request information.

Table 21 summarises the model roles. The high-level twin supports simplified academic and system-overview applications, alongside the detailed transmission and distribution twins.

Ten Business Use Cases and four System Use Cases cover the implementation. BUC 01 establishes exchange between the twins. BUCs 02–05 address predictions of wind production, solar production, and internal-line and interconnector ampacities. BUC 06 performs connection-point optimisation. BUCs 07–10 cover N–1 assessment, maintenance-conditioned assessment, distribution congestion and inter-operator flexibility. The four SUCs support forecast integration, TSO–DSO exchange estimation, the network effect of forecast ampacity and selection of flexibility providers.

The MV model covers the distribution areas selected for the study. Ampacity calculations concern a selected internal line and the Bulgarian section of an interconnection. Cross-border assessment also depends on the neighbouring line section and other binding network elements.

Table 21. Model components and responsibilities in the Bulgarian pilot

Component	Implementation and inputs	Role in the demonstration
EHV–HV network twin	PSS/E network model supplied through the TSO; Python scripts incorporate forecasts and exchange results.	Transmission power flow, contingency and maintenance assessments; connection-point optimisation.
MV network twin	PSS/E representation of selected EDG West network areas, with scripted updates.	Distribution congestion studies and joint transmission–distribution flexibility assessment.
Cross-border energy-exchange twin	Operator-prepared ANTARES model and simulation; R scripts extract results and write them to an intermediate Excel file.	Generation and cross-zonal exchange results supplied to the network-study chain.
High-level twin	Reduced PSS/E representation incorporating simplified market-result information.	Simplified system-level estimates and academic studies.
Auxiliary prediction twins	Purpose-trained ANNs; additional LSTM models for two distribution substations.	Wind, solar and ampacity predictions, plus next-hour active-demand forecasts.

3.3.3 Forecasting Functionality

Renewable-production models

The wind and solar prediction models are trained using historical records covering 2018–2024, with more than 60,000 hourly observations available in the respective datasets. Meteorological features are combined with operational history so that the models can represent both the weather dependence of production and recurring temporal behaviour. The operational study sequence uses forecasts for a 72-hour period to prepare corresponding hourly network states.

For WPP Sveti Nikola, the selected ANN has two layers containing 64 and 32 neurons. Wind speed and direction are key inputs. Lagged production from the preceding hour and the same hour of the previous day improves the representation of temporal dependence. Different candidate structures were tested and refined during model selection.

For SPP Karadzholovo, the selected ANN has three layers containing 64, 32 and 24 neurons. Relevant inputs include solar radiation, temperature and wind speed, together with day/night information and lagged production. Representing the daily cycle is important when comparing simulated production with the measured series.

Reported wind and solar MAPE values are 5.09% and 3.08%, respectively. The use-case KPIs compare these errors with literature reference values [2]. The illustrative production plots include training-period comparisons. Section 5.3 presents the numerical results.

Overhead-line ampacity models

Ampacity-training targets are calculated from the thermal-balance relationships in IEEE 738-2023 [9] using conductor characteristics and meteorological inputs.

The thermal calculation balances Joule and solar heating against convective and radiative cooling. The internal-line study adopts a maximum conductor temperature of 80 °C. Wind speed, wind direction relative to the line, ambient temperature and solar radiation determine the admissible current.

The internal-line ANN represents the 220 kV Plovdiv–Aleko line with layers of 24, 12 and 24 neurons. The interconnector ANN represents the selected 400 kV Thessaloniki–Blagoevgrad line with layers of 32, 24, 16, 12 and 6 neurons. Their MAPE values measure agreement with the calculated thermal-rating references.

Forecast ampacity varies with weather conditions and can exceed or fall below the static rating. The interconnector study includes intervals with lower forecast ampacity and correspondingly more restrictive loading limits.

The ampacity forecasts enter network assessment together with internal-line and transformer limits and the neighbouring operator’s line-section assumptions.

Additional distribution-demand forecasting

An additional study forecasts next-hour active demand at the Alen Mak and Belene distribution substations using LSTM models and a six-year historical database. The output is active power at the substation inlet.

Meteorological inputs comprise solar irradiation, ambient temperature and wind speed, complemented by lagged demand and calendar variables. Alen Mak uses a 24-hour historical look-back window and Belene a 48-hour window. Both models predict the following hour.

Inputs are min–max normalised. The models use Adam with a maximum of 150 epochs, a mini-batch size of 64, an initial learning rate of 0.001 and a gradient threshold of 1. MAPE is 2.1437% for Alen Mak and 2.1126% for Belene.

3.3.4 Optimisation Capabilities

The implemented genetic algorithm selects connection points for three virtual wind power plants and one battery. WPP 1 and WPP 2 each have an installed capacity of 40 MW, WPP 3 has 50 MW, and the battery is represented at 30 MW in both charging and discharging modes. The five candidate nodes are 1025, 1026, 1027, 1028 and 1029 in the selected 110 kV network area. The numerical identifiers, taken from the created EHV-HV Digital Twin in PSS/E format, preserve the confidentiality of the network model.

Each candidate solution contains twenty binary positions: one group of five for each facility. Exactly one position in each group is active, thereby selecting one connection node per facility. Crossover and mutation are implemented so that new candidates preserve this condition. Multiple facilities may be assigned to the same candidate node.

The objective minimises the average percentage loading of eight monitored lines, evaluated with the battery charging and with it discharging. For each candidate, the network twin is updated with the proposed connections and both load-flow states are calculated. The new wind facilities operate at their installed capacities in these evaluations. The surrounding network state is taken from one selected hour of the 72-hour prepared sequence.

The search uses a population of 100, 100 generations, a crossover rate of 0.8 and a mutation rate of 0.1. Elitism retains the two best solutions between generations. Exhaustive evaluation of all 625 facility-to-node combinations confirms the selected solution, which is also reproduced by repeated genetic-algorithm runs.

The objective minimises the average percentage line loading. Section 5.3 presents the selected connections and loading values.

3.3.5 DT Architecture and Integration Flow

The internal calculation chain links renewable and ampacity forecasts, ANTARES exchange results and PSS/E network states. The operator updates the ANTARES time series and runs the simulation. The BUC 01 R script extracts the results into an intermediate Excel file. Python scripts read this file and the forecast file, update the base network model and save 72 hourly PSS/E study models for load-flow and security assessment.

Figure 6 shows the information relationships between the represented operator, forecasting and simulation functions.

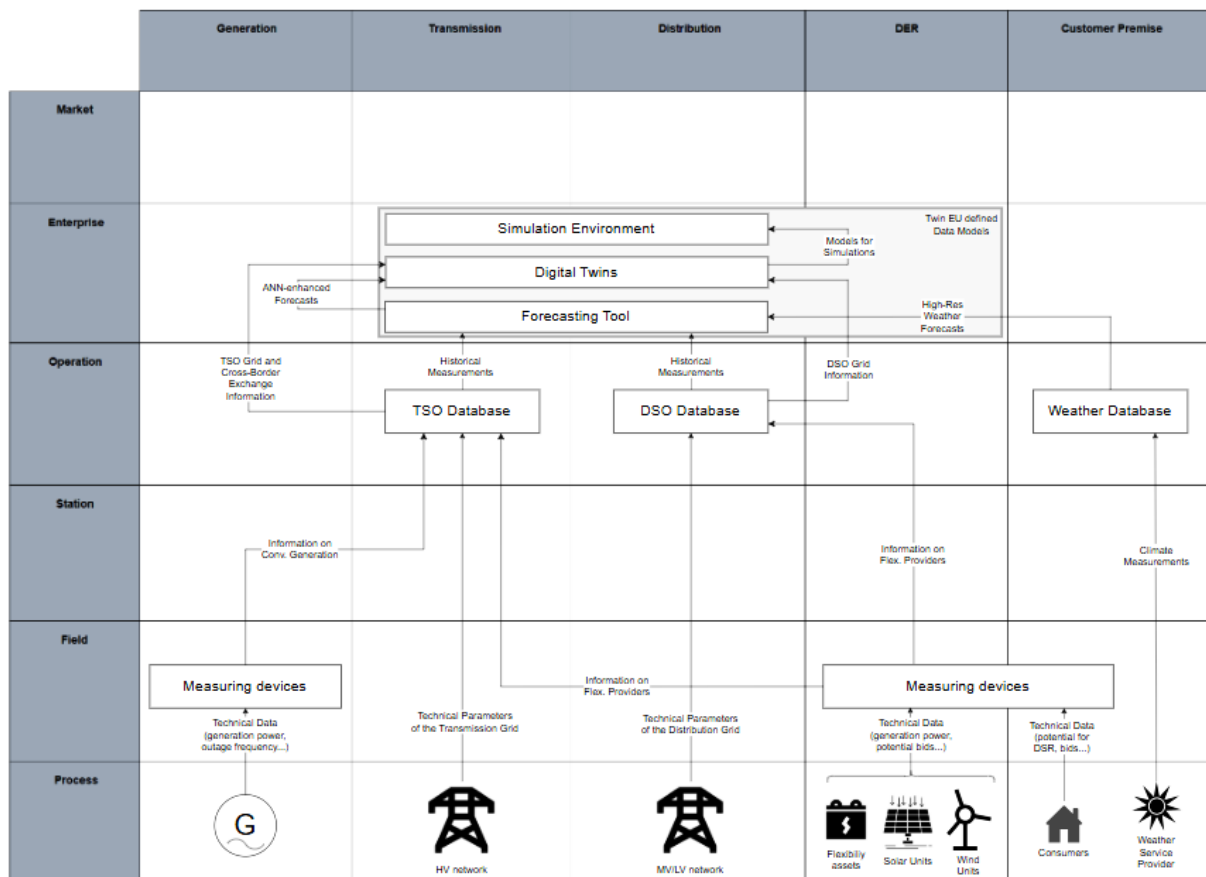


Figure 6. Information relationships between forecasting services, operator datasets and simulation functions in the Bulgarian pilot.

The workflow checks the transfer of forecast and exchange values into the network models. Forecast accuracy, power-flow feasibility and contingency performance are assessed through their respective calculations.

A separate demonstration uses the TwinEU data-space connector to exchange three CSV-based services: wind-production forecasts, solar-production forecasts and overhead-line ampacity forecasts. Two accounts represent the provider and the consuming TSO role. The provider creates the service offerings and uploads their payloads; the consumer requests subscriptions; and the provider approves access before the files can be consumed. The platform timelines record completion of these exchanges.

The Connector exercise verifies publication, access approval and consumption of forecast files between two represented pilot roles. It complements the scripted internal model coupling and provides additional evidence of the claim that the solution can be upscaled to cover more than one system.

3.3.6 Current Status and Implementation Highlights

The Bulgarian demonstration has completed the forecast, network-study and connection-optimisation applications described above. The hourly model-generation chain is available, the selected renewable and ampacity predictions have been evaluated, and the network twins have been used for the ten BUCs and four SUCs. The high-level twin and additional distribution-demand models extend the available analytical functions without replacing the detailed use-case models.

N–1 studies identify critical outages and test corrective switching measures. Maintenance-conditioned studies repeat the assessment for the modified topology and evaluate corrective actions against that operating state.

Distribution-congestion and inter-operator flexibility studies evaluate the network effects of FSP actions in the selected cases.

Exhaustive enumeration and repeated runs support the connection-point result. The Connector exercise demonstrates permissioned sharing of forecast outputs. These functions form part of the pilot's simulation and decision-support environment.

The KPI register contains 19 use-case measures and seven common validation measures. The selected N–1 study identifies three critical outages producing four overloads; the maintenance-conditioned study identifies four critical outages producing five overloads. Common indicators cover a forecasting-run duration below five seconds, a 72-hour forecasting horizon and usability feedback from two organisations.

3.4 Cyprus – HVDC Interconnection Simulation with Scenario Forecasting and Stability Analysis

3.4.1 Pilot Overview

The University of Cyprus develops a real-time simulation environment under Task 7.6 for the EM-CY-02 regional frequency-support use case. It represents a future HVDC interconnection between mainland Greece, Crete and Cyprus for pre-deployment investigation [3].

The model combines three equivalent AC systems with the HVDC converters, the DC links, local battery-based Flexibility Service Providers and their controllers. The investigated first-stage representation has a 1,000 MW HVDC transfer capacity and a ± 500 kV voltage level. The equivalent-

system approach preserves the principal frequency-response and controller interactions while keeping the simulation suitable for real-time execution.

Historical and real-time operating information defines representative system states. Prescribed power-imbalance events are introduced in the simulator to investigate the response under those conditions.

The platform is developed in MATLAB/Simulink and executed through RT-LAB on the OPAL-RT OP5707 simulator. It provides a controlled environment for pre-deployment testing of control logic, communication and operator interaction.

3.4.2 Pilot Scope and Use Case Logic

The use case connects two levels of decision-making. The regional coordination level establishes reserve allocations and the limits within which cross-border frequency support can be provided. The real-time simulation level applies the corresponding controller settings and evaluates the response to disturbances. The coordination framework represents TSOs, Market Operators, the Regional Security Coordinator, the HVDC Operator and FSPs.

Scheduled day-ahead HVDC exchanges define the reference transfer. Each represented TSO specifies FCR needs and operating constraints. The market-based coordination logic considers offers from the HVDC Operator and FSPs. The resulting allocations configure the controllers used in the frequency-support experiments.

The real-time control layer combines market-allocated FCR with Frequency Sensitive Mode support. FCR and FSM are distinct contributions: the first is linked to the allocated reserve capacity, whereas the second is an additional frequency-dependent controller response configured within the permitted operating range. Their combination must remain compatible with converter capability and interconnection constraints.

The country-level systems differ in their synchronous-generation commitment and corresponding inertia. Cyprus and Crete represent the weaker supporting systems, while the mainland-Greece equivalent represents the stronger system. This difference matters in both directions. A stronger system can support a disturbance in a weaker system with a relatively limited local frequency effect, but unrestricted support from weaker systems to the stronger system may cause substantial frequency deviations in the supporting areas.

The evaluation considers frequency performance in both the disturbed and supporting systems. Constrained and unconstrained HVDC support cases quantify the trade-off between local frequency improvement and disturbance propagation.

3.4.3 Control and Coordination Functionalities

Equivalent-system and converter representation

Each AC system contains an equivalent synchronous generator, inverter-based renewable generation, an inverter-based battery/FSP and aggregate load. The synchronous generator equivalent includes the main electromechanical, governor and excitation behaviour. The converter-based components retain the control functions required to examine their active-power response. A load-flow initialisation establishes the starting operating point before disturbances are applied.

The HVDC terminals in Cyprus and Crete operate in active- and reactive-power control mode, P–Q. Their active-power references can respond directly to local frequency conditions. The mainland-Greece terminal operates in DC-voltage and reactive-power control mode, V_{dc} –Q. It regulates the DC-link voltage, while the other terminals' power settings determine the corresponding active-power exchange. Figure 7 presents the model arrangement and its coordination interfaces.

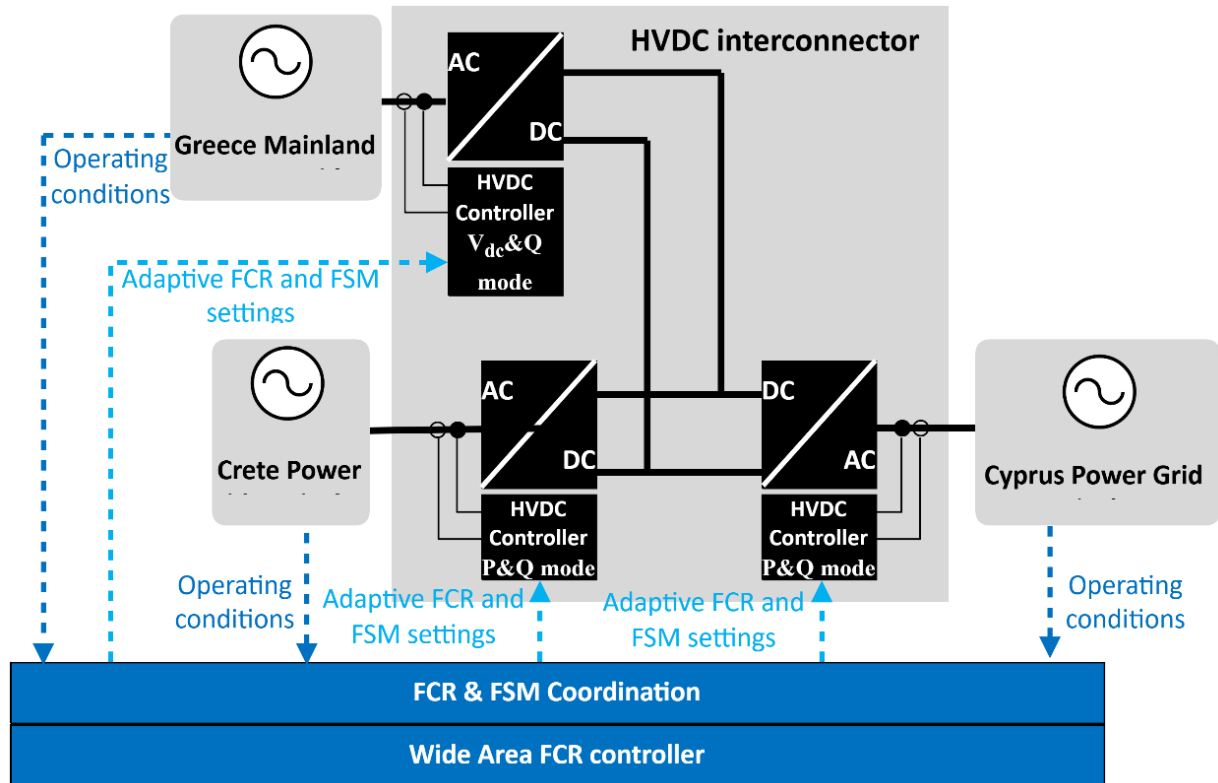


Figure 7. Three-system HVDC simulation model with complementary converter-control modes and regional coordination.

A disturbance on the mainland side therefore requires a coordinated change at the P–Q-controlled terminals. The local HVDC control calculates a support request, which is communicated through the Wide Area Controller. The WAC limits and distributes the request to the supporting terminals. In the investigated Greece cases, reducing imports by Cyprus and Crete reduces exports from the mainland and thereby supports the disturbed mainland system.

The FSP battery provides local support through its inverter. The renewable-generation inverter follows active- and reactive-power references derived from operational data, while coordinated FCR/FSM support is supplied by the battery and HVDC components.

FCR allocation and adaptive FSM response

The FCR gain is calculated from the allocated power and activation-frequency range. Delivered support increases with frequency deviation up to the assigned contribution, subject to the controller's operating conditions.

FSM support starts at a specified frequency threshold. The coordination unit adjusts its power–frequency gain using an inertia-related indicator based on synchronous-generation capacity and inertia characteristics. Lower inertia increases the support gain within the permitted range; higher inertia reduces it. The adaptive gain is interpolated between defined limiting operating points.

The control mechanism adjusts frequency-sensitive active-power support using an inertia-dependent gain. The response is governed by the FCR/FSM settings, converter limits and wide-area coordination.

The combined active-power reference is based on the pre-disturbance operating point and the applicable FCR and FSM additions. Physical converter ratings constrain the response. Cross-border limits introduce a further restriction on HVDC support, whereas a local FSP is not subject to that particular interconnection-transfer constraint. The local battery and the HVDC link can consequently supply different amounts even when their unconstrained support settings are similar.

Coordination and avoidance of counteracting actions

The WAC coordinates support according to disturbance location and supporting-system conditions. In the controlled mainland-Greece scenarios, each Cyprus and Crete HVDC terminal contributes up to 10% of the requested HVDC frequency-support power.

The interfaces allow local HVDC support functions to be disabled where they would counteract the intended cross-border transfer. Local FSP support and HVDC coordination are configured consistently for each scenario.

The simulation interface allows the operator to activate or deactivate FCR, FSM and overall coordination, select fixed or externally supplied gains, and initiate disturbances. These controls support repeatable baseline, fixed-support and adaptive-support experiments.

3.4.4 DT Architecture and Integration Flow

The digital-twin platform integrates the real-time model, data acquisition and middleware, a database, a monitoring/control interface and a web-based management interface. Figure 8 shows these components and the bidirectional paths for measurements, settings and simulation outputs.

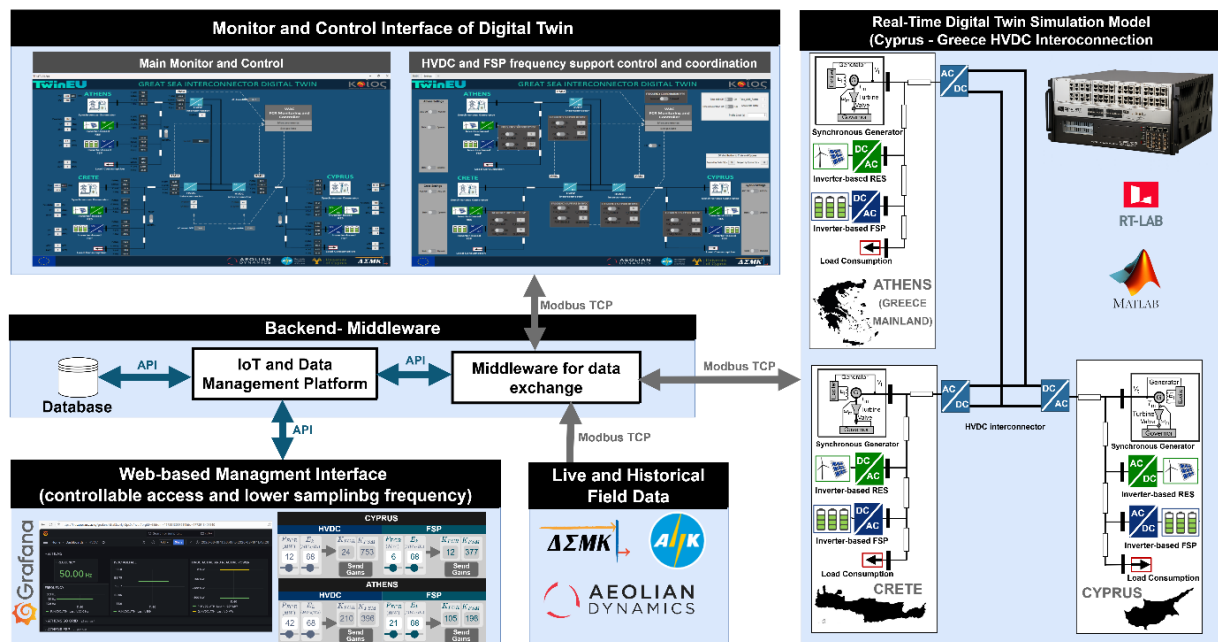


Figure 8. Integrated real-time model, middleware, data management and operator interfaces of the Cypriot platform.

The field-data layer provides wind and photovoltaic generation information from AEOLIAN Dynamics, grid operating information from TSOC and conventional-generation information from EAC. Local middleware acquires plant information through Modbus TCP. HTTPS-based APIs support the exchange with the cloud-based data-management platform, where historical and current operational records are stored.

Dedicated middleware links the cloud services and real-time simulator. Simulator-side exchange uses Modbus TCP, while HTTPS APIs connect the middleware to the platform. Operating data enter the model, and simulation outputs and performance indicators return to storage and visualisation services.

Real-time execution uses RT-LAB, eMEGASIM and ARTEMIS, with model partitioning and allocation across processing cores. The EMT model runs with a microsecond-scale fixed-step discrete solver.

The MATLAB App Designer monitoring/control interface displays system frequency, voltage, active and reactive power for all units (i.e., generator, load, converter of RES, FSP and HVDC) of each interconnected system. It also monitors the HVDC exchanges and gives access to controller settings. It supports interaction with the real-time simulation and the initiation of predefined events. The Grafana web interface provides access to historical and current platform data at lower sampling frequencies than the real-time monitoring interface and supports configuration of the coordination unit.

The communication framework supports use-case-specific interfaces for external controllers and Control-Hardware-in-the-Loop interaction.

3.4.5 Current Status and Implementation Highlights

The country-equivalent models, multi-terminal HVDC representation, adaptive support logic, middleware and operator interfaces have been integrated in the real-time platform. The demonstration includes normal-operation monitoring, controlled disturbance initiation and the configuration of FCR/FSM support through the interfaces. The performance assessment comprises eleven distinct scenarios across three operating-condition groups, as summarised in Table 22.

Table 22. Operating-condition groups and evaluated control variants

Disturbed system	Committed synchronous capacity	Disturbance	Control variants
Cyprus, normal inertia	1,000 MVA	149 MW	Baseline; shared FCR with fixed FSM; shared FCR with adaptive FSM.
Cyprus, low inertia	450 MVA	69.35 MW	Baseline; shared FCR with fixed FSM; shared FCR with adaptive FSM.
Mainland Greece, normal inertia	8,100 MVA	514 MW	Baseline; controlled HVDC with fixed/adaptive FSM; unconstrained HVDC with fixed/adaptive FSM.

Disturbances are applied between 20 s and 30 s. The Greece baseline is shared by the controlled and unconstrained comparisons. Cyprus disturbance magnitudes are 149 MW under normal inertia and 69.35 MW under low inertia.

In the baseline, frequency support from the HVDC and FSP converters is disabled, but conventional-generator FCR remains active. The total FCR requirement is 36 MW in the Cyprus cases and 52 MW in the mainland-Greece cases. With sharing enabled, the Cyprus allocation is 18 MW to conventional generation, 12 MW to HVDC and 6 MW to the FSP; the mainland allocation is 24 MW, 18 MW and 10 MW, respectively. For fixed FSM scenarios, the HVDC and FSP controllers provide a minimum level of FSM support using a droop coefficient fixed at the lower limit of the TSO-defined range. In the scenarios with adaptive FSM provision by HVDC and FSP controllers, the droop coefficient is dynamically adjusted according to the real-time inertia conditions of each system. The evaluated scenarios show higher frequency nadirs and improved settling frequencies with coordinated converter support in the disturbed systems. The combination of fast localized frequency support by the FSPs with rapid bulk power transfer by HVDC provides an effective support, improving both the transient response and the post-disturbance settling point, reducing the dependence on conventional generators. They also show that a better nadir need not coincide with a smaller maximum filtered RoCoF in every comparison. Removing the HVDC transfer restriction improves support to mainland Greece but produces larger deviations in the supporting Cyprus system.

The results support controller tuning and regional support-limit selection for the examined model conditions. Section 5.3 presents the frequency and power indicators.

3.5 Slovenia – Fast Frequency Response Enabled by Predictive Stability Assessment

3.5.1 Pilot Overview

The Slovenian contribution uses a digital-twin stability-assessment environment to support prospective FFR development. Task 7.7 addresses the methodology, technical requirements, product definition and simple market rules of the service. Testing uses the shared Slovenian network-modelling and assessment environment.

The implemented supporting infrastructure is a Dynamic Security Assessment framework built around the ELES network models and operational SCADA/EMS data, with contributions from the University of Ljubljana and EIMV. It combines a detailed national transmission-system dynamic model, an external observability-area model and improved equivalent representations of distribution-connected generation and loads [4].

The Slovenian results cover the network model, operational-data integration and dynamic-security assessment used to support prospective FFR service development.

3.5.2 Pilot Scope and Use Case Logic

The assessment environment addresses the difficulty of studying a relatively small, strongly interconnected national power system without representing the neighbouring networks. A disturbance response depends on both domestic equipment and external dynamic behaviour. The model therefore extends beyond the national borders while retaining the most detailed representation inside Slovenia.

The distribution equivalents combine inverter-based, asynchronous and synchronous generation with voltage- and frequency-dependent loads. Parameters reflect the available measurements and modelling assumptions.

Three use cases establish the assessment capabilities. SLO-BUC-1 concerns dynamic RMS analysis with improved distribution equivalents. SLO-BUC-2 covers the extended transmission model, including external generator and controller information. SLO-SUC-1 connects SCADA/EMS export to import in the numerical simulation tool.

The FFR service concept has a design response timescale of up to two seconds, complementing synchronous inertia and FCR. The assessment environment supports studies of generation, demand, inertia and reserves relevant to that design. The response timescale is a service-design objective, not a measured activation result.

3.5.3 Forecasting Functionality

The predictive function evaluates disturbance response from a reconstructed operating state. SCADA/EMS exports a snapshot every 15 minutes, and the framework constructs the corresponding twin for contingency assessment.

A pre-trained AI model estimates selected stability indices and guides the search for stability boundaries. In the transient-stability dashboard, predicted CCT values below 400 ms undergo time-domain verification. Higher predicted values can be displayed as AI estimates.

Transient stability is assessed through critical clearing times. Small-signal analysis evaluates local and regional electromechanical modes and damping within the observability area. Frequency assessment focuses on initial RoCoF following generation outages.

Measurement-based load-model identification supports the quality of the predictive model. Voltage events associated with OLTC operation are detected, filtered and fitted to estimate the static voltage dependence of active power. The event quality and fit are assessed using the reported statistical criteria. Reactive-power sensitivity is less reliably identified because the observed response is small and the fitted parameters can vary markedly in sign and magnitude.

The load-model study combines measurement-supported static voltage sensitivity with configured static/dynamic load fractions, frequency dependence and time constants. A 0.2 s delay is adopted as a modelling assumption.

3.5.4 Optimisation Capabilities

Decision support combines dynamic simulation, stability-index estimation and sensitivity analysis. It identifies critical conditions, examines generator and network behaviour, and evaluates candidate remedial changes.

Transient-stability calculations vary fault duration to identify the boundary between stable and unstable rotor-angle behaviour. AI-assisted search and 64 parallel processes reduce calculation effort. Cases terminate early when the rotor-angle instability criterion is reached.

Small-signal assessment uses eigenvalue analysis around the operating point. The interface shows damping, oscillation frequency, participating units, mode shapes and participation factors. This complements contingency-based transient and initial-frequency assessments by identifying weakly damped electromechanical behaviour in the modelled state.

The time-series study relates low CCT values to high active-power output and substantial reactive-power absorption by an anonymised generator. Simulated reductions in reactive-power absorption improve CCT, with local voltage-support requirements considered alongside the stability benefit.

3.5.5 DT Architecture and Integration Flow

The model-creation workflow starts from operationally maintained network representations. A detailed Slovenian dynamic model is combined with the observability-area model, which supplies the surrounding network's steady-state representation. Automated Python routines perform topological merging, identify boundary relationships and prepare a consistent extended model. Figure 9 shows this periodic construction process.

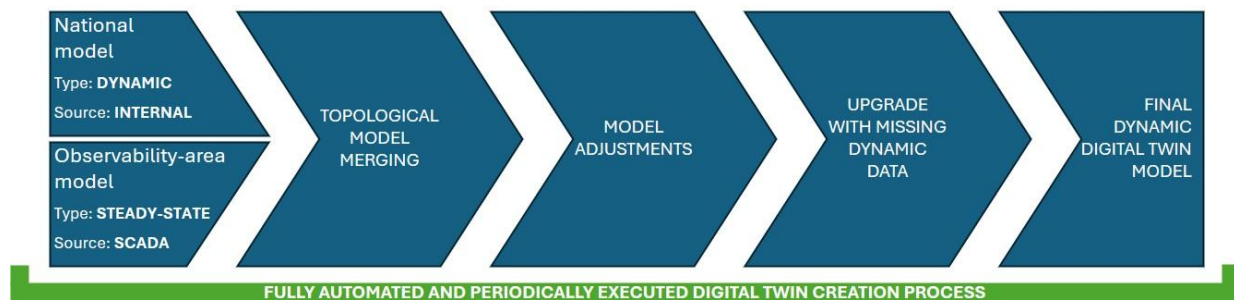


Figure 9. Periodic construction of the Slovenian dynamic twin from national and observability-area models.

External generating facilities are supplemented with dynamic characteristics. Public information supports estimates of technology, capacity and unit composition, while generic dynamic characteristics complement detailed operator parameters.

A correction procedure screens the merged model for physically implausible operating conditions, including excessive reactive-power assignments to equivalent machines. Corrections seek to preserve the original power-flow operating point while restoring suitable dynamic initialisation conditions. The resulting model is then initialised using actual topology and injection data.

The principal implementation inputs include the national PowerFactory model, the observability-area model in PSS/E format and SCADA/EMS operating information in DGS format. Additional state-estimator voltage and power-flow information provides the reference for static validation. CGMES/CIM representation supports the distribution-equivalent integration pathway and the exchange of model information, while native simulation files remain part of the implemented workflow.

Distribution-equivalent exchange separates static equipment information from dynamic model data. In the CGMES/PowerFactory implementation, inverter-based PV dynamics are configured within the simulation environment.

Static validation compares modelled voltages and active/reactive flows with the state-estimator operating point. Normalised deviations are weighted by network significance. Accepted states undergo a no-disturbance dynamic run to check initialisation stability before contingency assessment.

After preparation and validation, the twin is used for dynamic analysis and the results are presented in operator displays. Validation against PMU recordings of actual events is performed with expert supervision.

3.5.6 Current Status and Implementation Highlights

The documented Task 7.7 development context covers the FFR service's technical requirements, product definition, use cases, algorithm and simulation testing environment. The quantitative results

presented here concern the supporting DSA and model-integration workflow. They do not establish an FFR activation time, delivered service volume or service-specific frequency improvement.

The supporting digital-twin and DSA workflow has processed more than 26,000 operating states from the reported observation periods. It demonstrates periodic model construction, initialisation, validation, stability analysis and visualisation using operational data. Dynamic generator and controller information from MAVIR was incorporated into the observability-area model, demonstrating exchange with one neighbouring TSO.

In a comparison of 96 operating states, AI assistance reduces mean total DSA execution time by approximately 37% relative to the simulation-only approach on the evaluated computing configuration.

The individual study cases reconstruct materially different operating states and reveal different security conditions. The lightly loaded case has favourable transient-stability margins despite relatively low online inertia. The higher-load case has lower CCT values and includes two poorly damped local modes. The time-series example demonstrates how recurring conditions with low transient-stability margins can be identified and investigated.

The displays present transient, frequency and small-signal results separately. CCT reference levels of 150 ms and 600 ms support transient-stability presentation; the 400 ms threshold selects AI estimates for time-domain verification. Modal damping classes identify small-signal conditions.

Four Boolean KPIs record achieved distribution-equivalent RMS analysis, interconnected-system stability assessment, operational-snapshot integration and close-to-real-time assessment. Section 5.3 presents their evaluation dates and data references.

4 Digital Twin Functional Architecture and Integration Patterns

The pilot implementations illustrate reusable integration patterns for market scheduling, network planning, real-time controller testing and periodically updated stability assessment. Their common functional structure comprises operating-data preparation, prediction or decision calculation, physical or market validation, and result presentation.

This chapter examines three architectural dimensions: internal digital twin functions, data and synchronisation paths, and interfaces with users and external systems.

4.1 Forecasting and Optimisation Functional Architecture

4.1.1 Forecasting and Optimisation Modules

Greek operator forecasts describe demand and renewable availability, while scenario alteration functions construct future market configurations. Hungarian thermal-rating calculations translate measured or forecast conditions into admissible loading and RAM changes. Bulgarian neural models estimate production, ampacity and selected substation demand. Cyprus evaluates prescribed disturbances, and Slovenia estimates stability margins for operational snapshots.

Table 23. Functional building blocks and their implemented forms

Functional block	Implemented examples	Output interpretation
Input and state preparation	Market orderbooks and scenario alterations; quarter-hourly PSS/E cases; SCADA/EMS snapshot reconstruction.	A defined market instance or physical operating point.
Prediction or conditional assessment	Load/RES models; thermal-rating calculations; ANNs/LSTMs; AI-assisted stability screening.	Forecast, admissible limit or state-conditioned stability estimate.
Decision calculation	MILP market clearing and balancing scheduling; connection-point genetic algorithm; FCR/FSM coordination.	Accepted quantities, selected locations or controller settings within the represented constraints.
Physical and numerical validation	Transmission/distribution power flow; exhaustive connection search; static and no-disturbance dynamic checks; EMT disturbance tests.	Validation for a defined model, operating state and criterion.
Result presentation and exchange	Structured files, simulation diagrams, dashboards and permissioned forecast services.	Results identified by unit, time base, scenario and verification status.

Greek and Hungarian optimisation determines market and service allocations. The Bulgarian genetic algorithm selects connection points under a network-loading criterion. Cypriot coordination configures frequency-support controls, and Slovenian DSA identifies stability conditions and evaluates remedial options.

Table 23 maps the functional blocks and their outputs. The blocks are linked through executable workflows, structured files or operator-defined study sequences.

4.1.2 Applications and Use Case Relevance

The role of a module depends on the application it supports. For market scheduling, forecast profiles and network limits (for balancing-market dispatching) are inputs to an allocation problem. For network planning, forecasts define operating cases in which candidate actions or locations are assessed. For frequency-support control, operating-state information determines gains and transfer limits. For stability assessment, the reconstructed state is the starting point for contingencies and modal analysis.

The pilots therefore validate complementary links in the decision chain. Greece explicitly connects a day-ahead position to balancing schedules and external grid checks. Hungary connects flow-based capacity information to co-optimised auctions and sequential market mechanisms. Bulgaria connects prediction services to network states and selected planning/operational studies. Cyprus connects reserve allocations and inertia-related settings to real-time frequency response. Slovenia connects operational snapshots to model validation and security indices.

Transfer of these methods requires application-specific inputs: candidate locations and a network model for connection planning, dynamic models and controller settings for frequency studies, and comparable orderbooks and capacity assumptions for market analysis.

4.1.3 Functional Objectives and Decision Logic

The Greek DAM maximises market welfare and supplies the reference schedule for BM cost minimisation. The balancing stage jointly allocates energy adjustments, reserves and additional services within shared resource capabilities.

Hungarian clearing maximises welfare from energy and balancing capacity within each auction. Sequential extensions modify the residual bids or network capacity available to later stages. Comparisons identify the starting configuration and auction stage.

The Bulgarian connection objective is average percentage line loading under charging and discharging battery modes. Other network use cases evaluate corrective actions through power-flow and contingency studies. Cyprus applies adaptive frequency-support coordination, while Slovenia selects and verifies stability calculations.

Shared-headroom constraints prevent duplicate reserve allocation. Network calculations assess locational effects, converter and transfer limits govern frequency support, and model-validation gates precede dynamic assessment.

4.1.4 Interactions Across Grid Domains

The Greek market–TSO–DSO workflow combines aggregate scheduling requirements with separate physical validation. Connection-level eligibility and local checks establish the role of each accepted service contribution.

Bulgarian transmission and distribution models assess flexibility connected at different voltage levels, with one Use Case covering the flexibility exchange potential among the operators. Cross-border exchange results enter the network-study inputs, and each proposed action is evaluated through its resulting network state.

Cypriot coordination balances frequency support to the disturbed system against its effects on supporting systems across the simulated HVDC interconnection. Slovenian cross-border model exchange improves the dynamic representation used for security assessment.

The pilots demonstrate joint service allocation, coupled network studies, constrained frequency-support transfer and dynamic-model exchange. Each arrangement follows its own operator responsibilities and data permissions.

4.2 Data Flows, Models, and Synchronisation Architecture

4.2.1 Forecast and Telemetry Data Integration

Historical, forecast and operational data have different roles within the implemented workflows. Historical market records establish the Greek and Hungarian scenario references. Historical production and weather datasets support Bulgarian model training and hourly case preparation. Cypriot field and historical information feeds the simulated operating environment. Slovenian SCADA/EMS snapshots initialise the periodically updated assessment model.

Pre-processing must preserve the connection between an input and its intended physical or market meaning. Greek market volumes are mapped to assets and delivery intervals. Hungarian order aggregation and temporal harmonisation produce a common solver representation. Bulgarian scripts transform prediction and exchange outputs into hourly network cases. Slovenian topology merging and corrections prepare the external model for dynamic initialisation.

Data quality is checked at more than one stage. A syntactically readable file may still use the wrong delivery interval, network element or reference scenario. Similarly, a converged load flow may initialise a dynamically unsuitable model. The implemented workflows therefore combine file and mapping checks with market-balance, network and dynamic-validation checks where those are relevant.

4.2.2 Data Models and Formats

These representations address both syntax and semantics. A file format determines how information is stored, but the receiving tool also needs the correct asset mapping, sign convention, reference point and temporal interpretation. In the Greek workflow, upward action is defined as increased net injection; in the Bulgarian FSP examples, production and consumption use opposite signs. These conventions must be preserved when quantities are transferred or compared.

Model exchange uses CIM/CGMES where applicable. Real-time interfaces, market orderbooks and dynamic network models retain the data structures required by their respective applications.

Table 24. Data representations and interface status across the pilots

Pilot	Principal formats and environments	Implementation
Greece	SQL Server and Oracle for DAM data; structured workbooks/files; CSV and JSON-compatible structures; native PSS/E and PowerFactory models.	File-based, manual or semi-automated data exchange; CSV-based DSO feedback.
Hungary	HUPX/MAVIR market inputs; JAO CSV/XML/API data; PTDF/RAM structures; AMPL/FICO Xpress workflow.	Historical datasets and harmonised inputs for selected standalone and sequential auctions.
Bulgaria	PSS/E models; ANTARES data; Python/R scripts; spreadsheet/CSV exchanges; three CSV forecast-service payloads.	Scripted PSS/E case generation following operator-run ANTARES simulation; permissioned forecast-service exchange.
Cyprus	MATLAB/Simulink and RT-LAB; Modbus TCP; HTTPS APIs; cloud database; MATLAB and Grafana interfaces.	Real-time pre-deployment HVDC simulation and platform data exchange.
Slovenia	PowerFactory PFD, PSS/E RAW, DGS operational snapshots and model-related CIM/CGMES representations.	Automated snapshot-based assessment with simulator-configured converter dynamics.

4.2.3 Forecast–Optimisation Coupling Logic

Four distinct coupling patterns are visible. First, scenario-driven market scheduling passes prepared profiles and requirements through the Greek market sequence and its external grid checks. Second, auction-related capacity preparation supplies the Hungarian solver with the applicable flow-based domain. Third, forecast-informed study generation creates the Bulgarian hourly network cases used in subsequent analyses. Fourth, dynamic applications use operating information for controller configuration or snapshot-based stability assessment.

The workflows identify forecast horizon, historical look-back window, market time unit, snapshot cadence and numerical simulation step separately.

For example, the Bulgarian LSTM look-back windows of 24 and 48 hours support next-hour predictions. The Greek balancing day contains 96 quarter-hourly decisions. The Hungarian forecast-DLR coverage is limited by the available 24-hour weather horizon, while the reported market batch uses its harmonised time base. Cyprus uses microsecond-scale numerical execution for dynamic response, and Slovenia reconstructs operating states on a 15-minute cadence.

Feedback follows the application: Greek grid checks support schedule revision; Bulgarian studies compare alternative actions; Cypriot measurements drive simulated controller response; and Slovenian validation flags unsuitable model states.

4.3 Interfacing, Simulation, and Operator Interaction

4.3.1 Visualisation and Simulation Environments

Visualisation exposes different parts of the decision process. Greek result tables and power-flow diagrams connect market schedules to technical feasibility. Hungarian displays and KPI outputs compare auction configurations, balancing-capacity prices and RAM. Bulgarian single-line diagrams show the network changes associated with contingencies, maintenance or FSP actions.

Cyprus provides a dedicated real-time monitoring and control interface, supported by a web-based management view for historical and current platform information. Slovenia provides separate transient, frequency and small-signal displays, with drill-down into generating units, contingencies and modal characteristics. Figure 10 illustrates the Cypriot monitoring interface as an example of an implemented operator-facing layer.

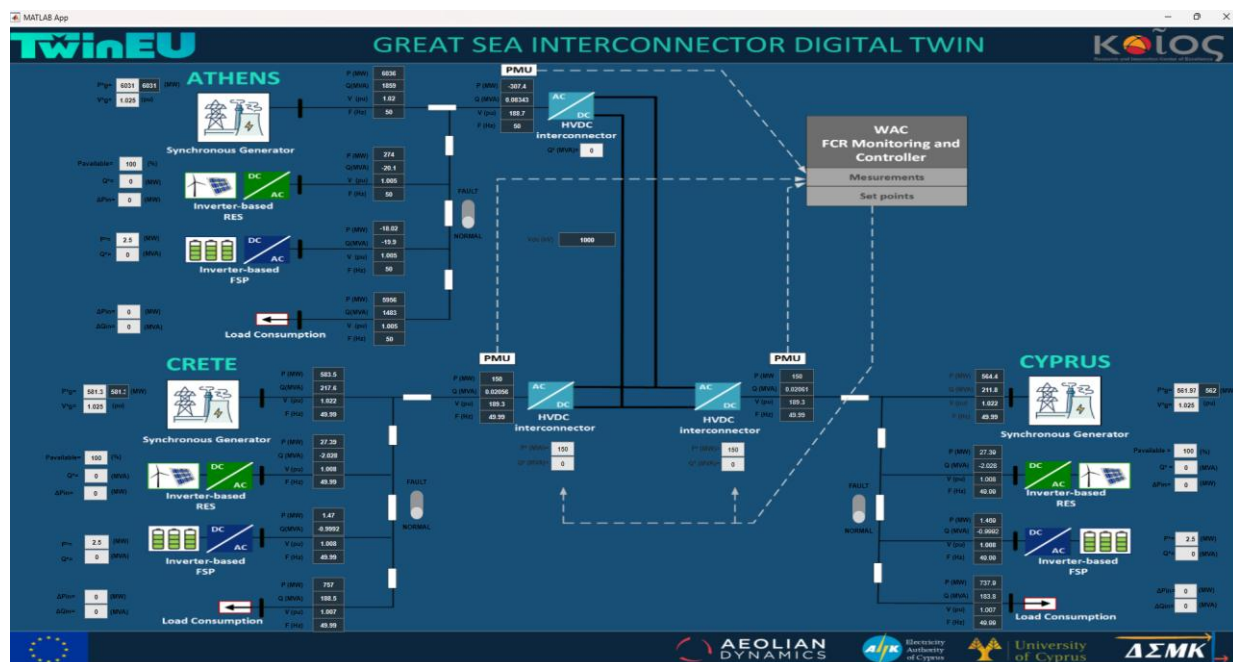


Figure 10. Real-time monitoring interface showing the three equivalent systems and their generator, FSP and HVDC operating quantities.

The displays present results with their study settings, operating states and assessment criteria. Slovenian transient-stability displays identify AI estimates and simulation-verified values. Bulgarian operator feedback covers two organisations.

4.3.2 Operator Control and Human-in-the-Loop Elements

Operators configure and supervise the workflows. Greek users select delivery days and scenario functions and initiate post-clearing extraction. Hungarian users configure auctions and inspect results. Bulgarian operators select network states and assess corrective measures. Cypriot users configure support settings and initiate disturbances.

The Slovenian interface supports model selection, analysis settings and inspection of stability results. Routine snapshot processing is automated, with expert supervision for validation against actual-event measurements and assessment of remedial alternatives.

Operator assessment is particularly important where actions affect connectivity, reserve deliverability or disturbance propagation. The interfaces support investigation of topology changes, constrained connections and the effects of cross-border frequency support.

4.3.3 External System Interfacing and Data Exchange

The external interfaces fall into three main groups: operator or market data supplied to a simulation workflow, measurement and controller exchanges with the real-time platform, and model or forecast services shared between represented organisations. Their access, timing and validation requirements differ.

The Bulgarian Connector workflow comprises service creation, payload publication, consumer subscription request, provider approval and subsequent consumption.

Slovenian model exchange incorporates MAVIR dynamic information, supplemented by public-data-based generic models for other external resources. Greek and Hungarian exchanges follow operator and market confidentiality requirements. Cypriot middleware links the simulator, operational-data providers and user applications.

5 Use Cases, Performance Indicators, and Implementation Challenges

Performance assessment covers forecast and model accuracy, economic outcomes, network and stability effects, computational performance and interface functionality.

Results are presented by dataset, operating condition and scenario comparison. Each indicator retains its reference, unit and calculation basis.

5.1 Overview of Use Cases Across Pilots

Table 25. Consolidated scope of the forecasting and decision-support use cases

Pilot / task	Primary application	Decision horizon and system layer	Demonstrated DT role
Greece / T7.2	Day-ahead simulation; balancing-energy and reserve co-optimisation; TSO–DSO coordination.	Projected 2030 scenarios; one-day quarter-hourly balancing schedules; market, transmission and selected distribution networks.	Generate schedules, allocate eligible services and assess physical feasibility through separate TSO and DSO grid tools.
Hungary / T7.3	HU02: DLR-enhanced capacity; HU03: energy/balancing-capacity co-optimisation and sequential markets.	Day-ahead and available intraday/sequential stages; cross-zonal market and network-capacity representation.	Evaluate prepared market and capacity scenarios over available valid days from the 2024 campaign, including standalone auctions and sequential configurations.
Bulgaria / T7.4–T7.5	Ten BUCs and four SUCs: predictions, network assessments, flexibility and connection locations.	72-hour study preparation and selected operating snapshots; transmission and partial distribution models.	Prepare hourly states, test network actions and optimise virtual facility connections.
Cyprus / T7.6	EM-CY-02 regional frequency support through HVDC and local FSP resources.	Real-time simulation of defined disturbances in three equivalent AC systems.	Configure and test fixed/adaptive support and cross-border transfer coordination.
Slovenia / T7.7 context	Prospective FFR service development supported by the existing Slovenian assessment environment.	Snapshot-conditioned stability assessment at transmission level with distribution equivalents.	DSA integration and performance assessment supporting prospective FFR development.

The Greek and Bulgarian distribution studies use selected network models. Cyprus represents the interconnected systems through aggregated equivalents. Slovenia combines a detailed national model with a lower-detail external observability area.

5.2 KPI Framework for Performance Evaluation

The KPI framework groups the evidence by its contribution to the decision process. Forecast and model accuracy establish how well the relevant variable or operating state is represented. Operational indicators assess network or frequency behaviour. Economic indicators compare market outcomes. Computational indicators assess execution effort. Interface evidence establishes whether users and applications can obtain and interpret the required information.

Table 26 summarises the measurement basis and results. Pilot records retain their local KPI identifiers and catalogue mappings.

Table 26. Performance categories, measurement basis and available evidence

Category	Metric and unit	Measurement basis	Available assessment
Forecast / model accuracy	MAPE (%); MAE/RMSE in the variable's unit; normalised model deviations (%).	Prediction versus the specified measured or calculated reference; modelled state versus operating-state reference.	Bulgarian prediction errors; historical Greek DAM clearing-price reproduction; Slovenian static validation.
Operational impact	Network loading (%), voltage (p.u.), reserve-capacity time integral, CCT (ms), damping (%), frequency (Hz), RoCoF (Hz/s).	Scenario outputs evaluated against the defined operating criterion or comparison.	Network and service results in Greece/Bulgaria; frequency results in Cyprus; DSA indices in Slovenia.
Economic benefit	Welfare change (% or EUR); product-price indicators; cleared energy (MWh).	Target versus an explicitly identified baseline with input differences disclosed.	Greek DAM comparisons and Hungarian controlled/qualified scenario comparisons.
Latency and responsiveness	Runtime or runtime change; snapshot cadence; controller-response trajectories.	The relevant calculation or event window, measured separately from data and market timing.	Hungarian auction-completion rates and complete-day runtime distributions; Slovenian 96-state runtime comparison; real-time Cypriot response; reported Bulgarian calculation durations.
Usability and interpretability	Interface functions; operator feedback and replication scores (0–4); exchange coverage (%).	Demonstrated interaction and access; reported organisational assessments with their sample size and scoring rule.	Dashboards, Connector exchange, two-organisation Bulgarian feedback and self-assessed transferability.

KPI records, evidence scores and reporting scope

Two supplementary registers provide 38 KPI records: 26 for Bulgaria, 8 for Greece and 4 for Slovenia. They complement the technical demonstration deliverables with submitted targets, completion status, evidence scores and additional measurements. Table 27 summarises their reporting scope and metadata. The earlier D7.1 mid-term description supplies the Task 7.7 service-development context; the Slovenian quantitative assessment is based on the supporting DSA work.

The qualitative evidence score q uses the submitted scale: 0 = not demonstrated; 1 = isolated demonstration; 2 = limited validation; 3 = robust validation; 4 = transferable/replicable. These are submitted assessments rather than new independent validation scores, and a recorded Complete status does not resolve an outstanding calculation issue. Four Greek records contain reporting-window text instead of a numerical q ; no replacement score is assigned.

Table 27. Reporting scope and metadata of the additional KPI records

Record group	Coverage label / evaluated sample	Evaluation date	Status / mode
Bulgaria: 19 BUC/SUC KPIs	Until M23; individual studies use their stated hourly horizon or selected network state.	31 Oct 2025	Complete; batch.
Bulgaria: 7 common validation KPIs	Until M33; model errors, a forecasting run, historical-data checks, three exchanges and organisational scores have different samples.	28 Aug 2026	Complete; batch.
Greece: GR01_KPI1–4	KPI1: one July day selected from four studies. KPI2: assessed feeder schedules. KPI3–4: four historical/projected market-day pairs.	31 Aug 2026	Complete; batch.
Greece: GR01_KPI5–6; GR02_KPI1–2	Four study days: 384 quarter-hours for procurement/reservation; 163 active directional periods for utilisation; 384 paired quarter-hours for FFR cashflow.	16 Sep 2026	Completed; simulation outputs.
Slovenia: 4 Boolean KPIs	M3–M33 is stated for three records; the equivalent-model entry refers to the RMS validation studies.	24 Jun 2026	Complete; batch equivalent-model studies and operational-data-based near-real-time assessment.

Table 27 retains the recorded evaluation dates separately from project-coverage labels and measurement samples. Some coverage labels extend beyond the corresponding recorded evaluation date; they are not evidence that every later period had already been evaluated.

Units and aggregation

Energy schedules are integrated over delivery intervals to obtain MWh or GWh. Reserve-capacity schedules are expressed as capacity–time integrals representing scheduled availability. The Greek BM uses a 0.25 h interval.

The Hungarian additional-RAM indicator measures the difference in mean RAM over matched CNECs within each date and MTU. Welfare changes are calculated over common valid days, while beneficial-hour ratios measure the frequency of higher hourly welfare. Price effects are reported as

absolute differences between monthly mean prices for the same bidding zone, auction stage and product. These indicators retain their separate units and evaluation populations.

Bulgarian forecast-error improvements are expressed in percentage points. Cypriot RoCoF uses a one-second moving-average filter. Slovenian power-flow deviations are normalised to rated transmission-line power.

Comparison basis

Greek DAM comparisons cover the complete historical and projected market configurations. The 17 May BM pair holds common-product requirements fixed. Hungarian comparisons identify the auction stage, reference scenario and valid paired sample. Differences between independently aggregated totals do not isolate individual mechanisms when their date populations or initial inputs differ.

5.3 Pilot-Specific KPI Application and Early Results

5.3.1 Greece: market outcomes, reserve allocation and grid feasibility

Historical market reproduction and projected 2030 outcomes

Four representative operating days cover low/high load and low/high RES conditions. Their historical delivery dates are 1 November 2025, 21 January 2026, 17 May 2026 and 6 July 2026. The projected cases represent the corresponding seasonal operating conditions under the 2030 configuration. Table 28 reports the reproduction of historical market-clearing prices before the future scenario alterations are assessed [1].

Table 28. Historical Greek DAM market-clearing-price validation

Historical delivery date	Mean error	MAE	RMSE	Maximum absolute error
01/11/2025	0.071	0.404	0.678	2.150
21/01/2026	-0.096	0.286	0.628	2.710
17/05/2026	-0.003	0.013	0.071	0.590
06/07/2026	0.011	0.361	0.781	3.400

Historical market-reproduction errors; all values in EUR/MWh.

RMSE ranges from 0.071 to 0.781 EUR/MWh, and maximum absolute error from 0.59 to 3.40 EUR/MWh across the selected historical days.

Table 29 presents cleared DER energy and social welfare for the historical and complete 2030 market configurations.

Table 29. Greek DAM cleared DER energy and social-welfare comparison

Historical reference day	DER baseline (MWh)	DER 2030 (MWh)	Welfare baseline (EUR)	Welfare 2030 (EUR)	Welfare change (%)
01/11/2025	48,246.228	97,491.036	143,781,720.34	177,424,382.65	23.40
21/01/2026	75,327.997	139,538.246	229,675,319.01	280,460,029.80	22.11
17/05/2026	97,628.448	162,975.974	146,538,969.85	186,639,590.64	27.37
06/07/2026	114,055.803	191,021.599	212,781,689.45	269,038,356.87	26.44

The historical reference date identifies the input day; the target values correspond to the projected 2030 market configuration. Welfare is the reported sum of consumer and producer surplus.

Cleared DER transactions rise in all four cases. The additional daily volume ranges from approximately 49 GWh in the autumn case to approximately 77 GWh in the summer case. Relative increases range from approximately 66.9% to 102.1%. Total social welfare increases by 22.11%–27.37% across the four comparisons.

GR01_KPI3 is the mean daily cleared DER energy across the four cases: 83,814.62 MWh in the historical configuration and 147,756.71 MWh in the projected configuration. GR01_KPI4 is the unweighted mean of the four daily welfare changes, equal to 24.83%.

Average market prices fall in all four cases. Standard deviation falls in November and increases in January, May and July, as shown in Table 30.

Table 30. Daily Greek DAM price level and dispersion

Historical reference day	Mean baseline	Mean 2030	Mean reduction (%)	Std. baseline	Std. 2030
01/11/2025	85.61	74.70	12.7	41.90	40.49
21/01/2026	146.33	125.44	14.3	23.24	32.85
17/05/2026	75.21	33.21	55.8	65.93	71.43
06/07/2026	110.13	77.88	29.3	48.58	66.34

Means and standard deviations are in EUR/MWh; reductions are reported at one decimal place.

Balancing comparisons and the controlled flexibility result

The full-flexibility configuration includes additional TSO/DSO congestion-management and FFR requirements. Table 31 identifies the common-product requirements and BESS/DR participation in each reduced/full pair.

Table 31. Comparability of the Greek reduced/full balancing pairs

Operating day	Difference in common requirements	BESS/DR common-product provision already in reduced case	Interpretation
17 May	0.00%	No	Controlled common-product comparison.
1 November	5.57%	Yes	Comparison of complete configurations.
6 July	8.14%	Yes	Configuration comparison with changed common requirements.
21 January	20.71%	Yes	Configuration comparison with changed common requirements.

For 17 May, unchanged BE, FCR, aFRR and mFRR requirements provide a common reference for comparing their allocation, while BESS/DR participation and the additional CM/FFR requirements differ between the paired configurations. The other days also change common-product requirements or resource participation, as indicated above.

Common products are balancing energy, FCR, aFRR and mFRR. Additional CM/FFR requirements are part of the full configuration.

Controlled reserve substitution on 17 May

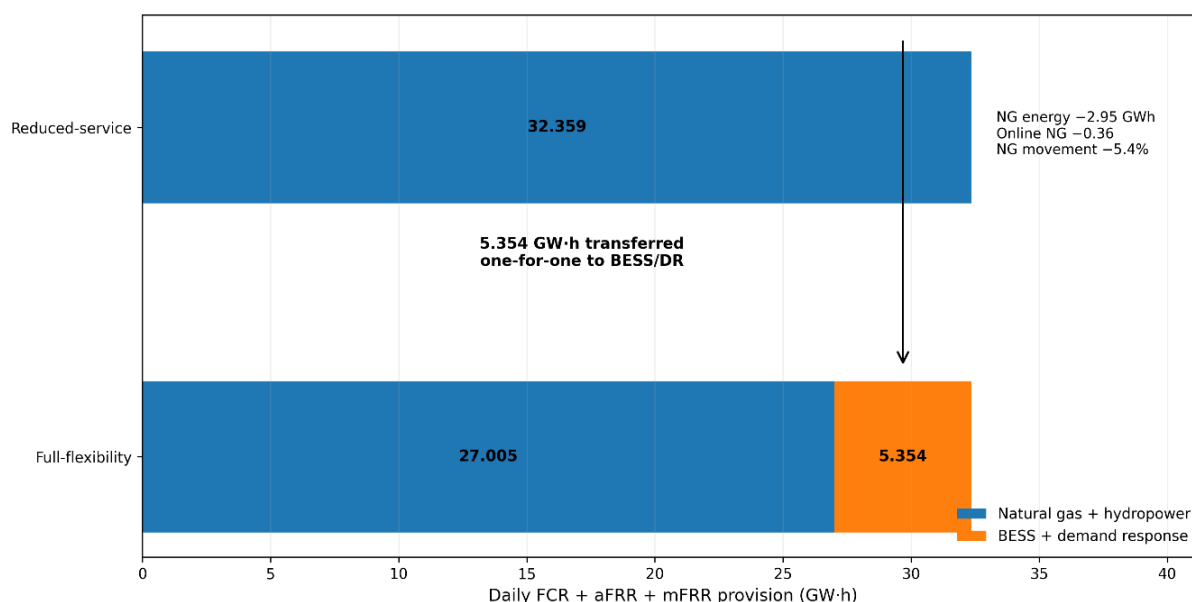


Figure 11. Controlled 17 May reserve reallocation and associated changes in conventional operation. The 5.354 GWh quantity is a reserve-capacity time integral, with BESS/DR participation through mFRR.

In the controlled 17 May comparison, conventional FCR/aFRR/mFRR provision falls from approximately 32.36 to 27.01 GWh of capacity–time integral. BESS and demand response contribute 5.354 GWh through mFRR.

The same pair shows 2.95 GWh less natural-gas generation, 0.56 GWh less hydro generation, 0.36 fewer gas units online on average and a 5.4% reduction in gas-unit ramping. Figure 11 illustrates the reported reserve reallocation and associated operational differences. Reserve-capacity integrals in the figure remain distinct from generated energy.

Table 32. Full-flexibility minus reduced-service balancing results

Day	NG energy (GWh)	Hydro energy (GWh)	BESS throughput (GWh)	Average online NG units	NG ramping change
17 May	–2.95	–0.56	+13.57	–0.36	–5.4%
6 July	–5.36	Approximately 0	+0.13	–0.35	+23.3%
1 November	Approximately 0	+0.04	–1.73	+0.02	+12.6%
21 January	+7.63	Approximately 0	+0.09	+1.05	+8.8%

The 17 May pair has identical common-product requirements. Battery throughput is charging plus discharging energy.

In July, lower natural-gas energy coincides with greater unit-level ramping. In November, additional services are accommodated with almost unchanged conventional energy and lower battery throughput. In January, upward balancing-energy requirements increase from approximately 6.76 to 16.24 GWh and are a major driver of the generation difference.

Battery throughput in the full configurations is approximately 16.44 GWh in November, 14.12 GWh in May, 0.14 GWh in January and 0.17 GWh in July. In the low-throughput cases, batteries mainly provide service headroom and power availability.

In a separate 96-period coordination comparison, upward CM capacity–time falls from 1,704.854 to 1,551.259 MW h and downward CM from 2,079.830 to 1,754.289 MW h. The corresponding reductions are 9.01% and 15.65%. The coordinated formulation removes overlapping compatible requirements while retaining the larger individual need and local feasibility conditions.

Provider concentration remains relevant despite daily technology diversity. Individual mFRR-up provider shares reach approximately 88.8% in July, 81.3% in November, 68.4% in May and 42.9% in January. For mFRR down, some intervals on three of the four days are supplied by one provider for the optimised requirement. Daily shares, interval provider counts and fixed pumping contributions therefore require separate interpretation.

Transmission and distribution validation

In the increased-flexibility case, under the first BM solution on 6 July 2030 at 15:45, the 117.8 MW transfer from Agia Varvara towards Linoperamata reaches 90% of the relevant line capacity and is classified as infeasible under the adopted loading criterion. This infeasibility triggers a new run of the BM solver, which results in a second dispatch of the batteries placed near the congested line.

The new dispatch reshapes the power flows under the same load and renewable-generation conditions. The reported overhead-line congestion is removed without further redispatch. Figures 12 and 13 show the operating points of the first and the subsequent BM solutions, respectively.

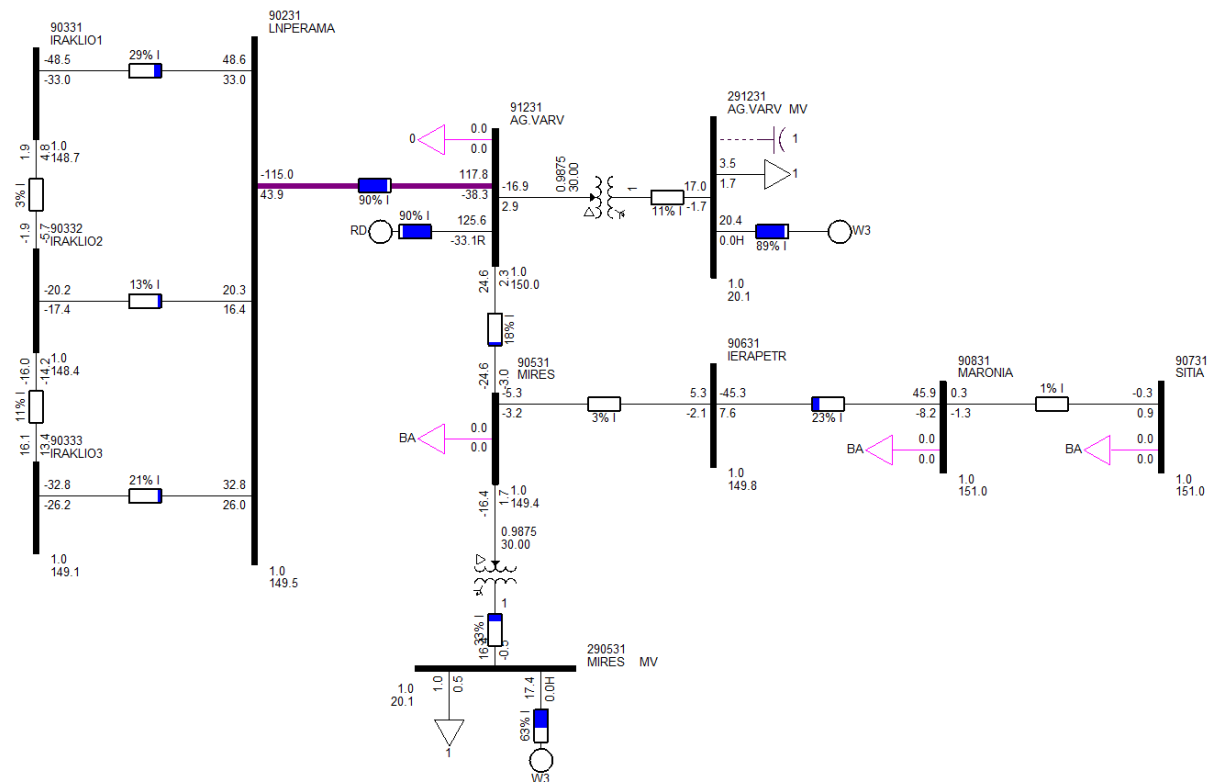


Figure 12. Selected Crete power-flow result at the first dispatch, 6 July 2030 at 15:45, including the transfer classified as infeasible under the adopted loading criterion.

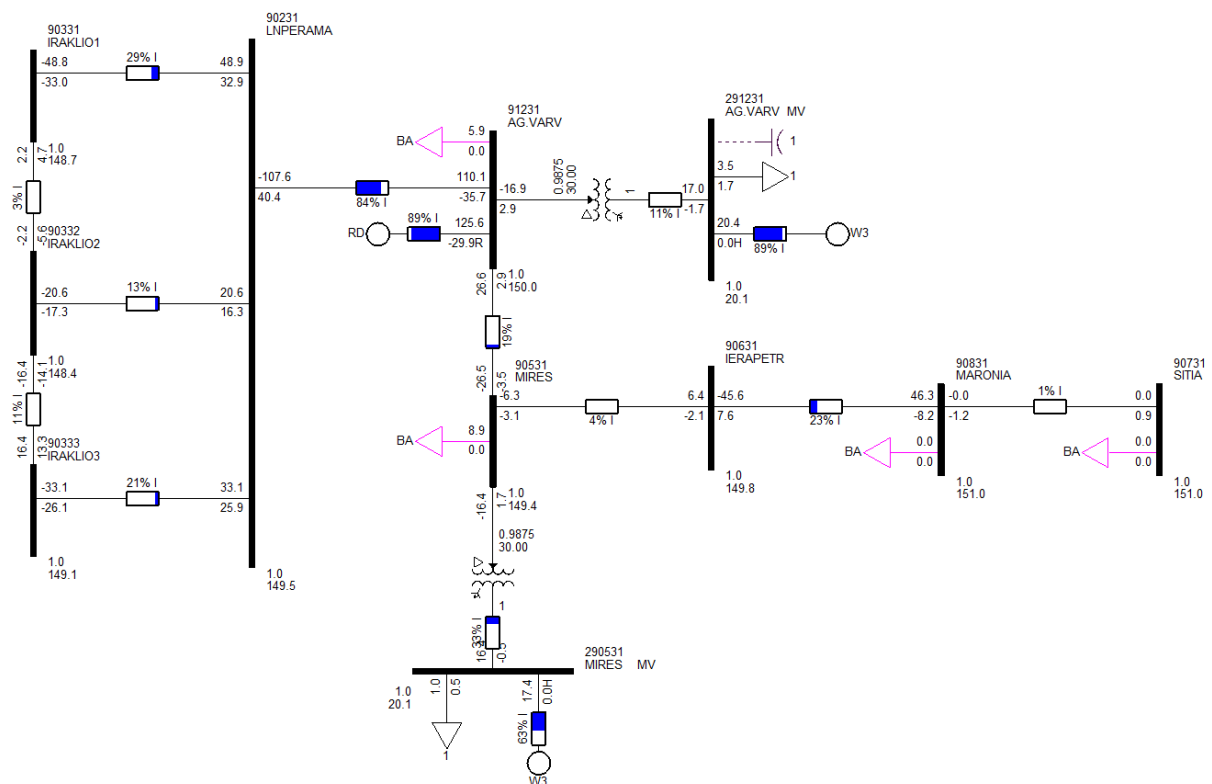


Figure 13. Selected Crete power-flow result after the second dispatch, 6 July 2030 at 15:45.

Distribution validation covers three battery schedules on a representative MV feeder. In the increased-flexibility case, the most heavily used battery operates between 90% and 10% SoC. Feeder

voltages remain approximately within 0.96–1.00 p.u., and line and transformer loadings remain below 95%. All assessed battery activations are accepted within the adopted 0.90–1.10 p.u. voltage band.

The transmission and distribution studies establish physical feasibility for the evaluated locations, operating conditions and schedules.

Greek KPI results

GR01 covers TSO–DSO congestion and DAM participation; GR02 covers FFR-related cashflow and capacity reservation. GR01_KPI1 maps to VAL_KPI3, while GR01_KPI3–4 map to VAL_KPI7; the other records retain their local identifiers.

Table 33. Greek network and day-ahead-market KPI records

KPI / measure	Baseline / result; target; q	Calculation and interpretation
GR01_KPI1 Thermal Limit Violation (TSO+DSO) Catalogue link: VAL_KPI3	8% → 0%; target 0%; q = 1.	Congested MTUs / 96 for the affected transmission line on 6 July 2030.
GR01_KPI2 Transformers overloading (DSO)	Result 0%; target 0%; q = 1.	MTUs with any assessed MV transformer above 95% loading / 96.
GR01_KPI3 Facilitating DERs Transactions in DAM Catalogue link: VAL_KPI7	83,814.62 → 147,756.71 MWh per representative day; target above baseline; q = 3.	Mean daily cleared DER energy across four historical/projected 2030 market pairs.
GR01_KPI4 Social Welfare Increase from DERs in DAM Catalogue link: VAL_KPI7	0% change reference → 24.83%; target positive change; q = 3.	Unweighted mean of four daily relative welfare changes for the complete market configurations.

GR01_KPI1 records an 8% to 0% reduction in congested intervals for the selected transmission line.
GR01_KPI2 records 0% transformer-overload incidence in the assessed feeder schedules.

Table 34. Greek congestion-management procurement and utilisation records

KPI / measure	Result / reference	Calculation basis
GR01_KPI5 Redispatch Volumes	Mean CM capacity: 210.759 MW. Capacity–time total: 20,232.881 MW h. Baseline CM award: 0.	Four days / 384 quarter-hours. Average of total accepted UP and DOWN CM capacity.
GR01_KPI6 Utilization Rate of Flexibility Resources	Reported utilisation: 19.2%; detailed value: 19.231129%. BESS-only rate: 19.387880%. Reference flexible CM awards: 0.	Four days / 163 active directional periods. Availability is net of battery operation and other service awards; the earlier DR profile must be aligned with the evaluated runs.

Mean CM procurement is 20,232.881 MW h / 96 h = 210.759 MW. The four-day reference has CM and FFR disabled and records zero CM awards. This zero-CM reference measures introduced procurement, not the savings in the separate coordination comparison; relative growth from zero is undefined.

GR01_KPI6 reports 19.2% utilisation across 163 active directional periods; the BESS-only rate is 19.387880%. The denominator subtracts directional battery operation and other service commitments and uses an earlier assumed DR availability profile. The DR profile must match the evaluated runs before the combined ratio can be treated as reconciled. The aligned interval-level availability and awards are not supplied for independent recomputation. Active directional periods need not be distinct clock intervals, and the ratio alone does not certify state of charge, service-sustaining duration or local network deliverability.

Table 35. Greek FFR cashflow and capacity-reservation records

KPI / measure	Result	Calculation basis
GR02_KPI1 FFR Opportunity cost Index Signed BE cashflow proxy	1.39% reduction in signed balancing-energy cashflow; a partial proxy, not full arbitrage opportunity cost.	Paired FFR-ON/OFF cases with integrated CM. EUR 57,736.00 / EUR 4,152,442.51 × 100.
GR02_KPI2 FFR Capacity Reservation Rate	1.20% capacity reservation; detailed value 1.195133%. Baseline: 0.	Sum of groupwise UP/DOWN maxima across 384 quarter-hours / (384 × 1,730 MW). UP: 1.138098%; DOWN: 0.189683%.

The balancing-energy cashflow is $C = 0.25 \times \sum (UP \times price_UP - DOWN \times price_DOWN)$, with awards in MW and prices in EUR/MWh. Across 384 paired quarter-hours, FFR reduces this cashflow by EUR 57,736.00 relative to EUR 4,152,442.51 in the FFR-OFF case, giving 1.39%. Both cases retain integrated CM and use the same historical valuation profiles. This is a signed balancing-energy cashflow proxy only. Full day-ahead arbitrage profit and its normalisation, operating costs and a validated provider counterfactual are not supplied; the result therefore does not establish the complete arbitrage profit forgone when capacity is committed to FFR.

FFR capacity reservation is $100 \times \sum_t \sum_g \max(R_UP,g,t, R_DOWN,g,t) / (384 \times 1,730)$, where g denotes the TSO and DSO battery groups. The resulting rate is 1.20%, compared with zero in the FFR-OFF reference. Directional reservation rates are 1.138098% upward and 0.189683% downward. The displayed 1.20% is the ordinary two-decimal rounding of the detailed 1.195133%; the register's 1.19% summary is not that rounding. This is a groupwise reserved-capacity indicator, not activated energy or an FFR activation-time result.

5.3.2 Hungary: market co-optimisation, DLR and sequential auctions

The Hungarian evaluation covers available valid observations from the 2024 simulation campaign. Each economic comparison identifies the target configuration, reference configuration, auction stage and paired sample. Missing observations are excluded rather than assigned zero effect. Intraday execution performance is assessed from 13 June 2024 inclusive.

Table 36 summarises the principal welfare comparisons against the separated-market references. Relative welfare gains use baseline welfare over the same valid days. The share of higher-welfare hours is a separate indicator of how frequently the evaluated configuration improves the hourly outcome.

Table 36. Hungarian scenario comparisons and welfare indicators

Target / baseline	Comparison	Welfare change (%)	Beneficial observations	Basis
C0a / A0	DAM	261	63.77	0.0217
D0a / B0	IDA2	193	2.89	0.0386
G0a / A0	DAM	161	6,450.80	3.5914
G0a / B0	IDA2	188	1.22	0.0167
H0c / A0	DAM	161	6,450.79	3.5914
H0c / B0	IDA2	193	1,030.18	13.7594
I0c / A0	DAM	162	6,451.01	3.5696
I0c / B0	IDA2	189	832.58	11.3737
I2c / A0	DAM	161	6,404.90	3.5659
I2c / B0	IDA2	188	1,040.81	14.3413

Beneficial MTUs/hours are defined by welfare improvement. Beneficial CNECs measure changes in the network-capacity domain.

Standalone co-optimisation produces modest positive relative welfare gains in both DAM and IDA2. The sequential configurations containing bid forwarding show substantially larger IDA2 gains, with higher welfare in more than 98% of comparable hours. Comparisons against B0 measure the complete configurations and do not establish the marginal contribution of forwarding or cascading separately.

The sequential DAM results describe differences between the initial clearing configurations. Forwarding and cascading operate between auctions and cannot explain an effect already present in DAM. Attribution therefore requires confirmation of common initial bids, network inputs and evaluation dates.

DAM and IDA2 contributions should also be assessed jointly. The sum of the reported welfare gains is EUR 7,283.59 million for I0c and EUR 7,445.72 million for I2c. I2c's larger IDA2 gain therefore more than offsets its lower reported DAM gain. These sums cover different date populations; a definitive combined comparison requires aggregation over common valid dates.

DLR increases mean RAM by 470.71 MW in standalone DAM, 468.20 MW in standalone IDA2 and 472.13 MW in the combined sequence. These values average additional margins across matched network constraints and must not be interpreted as equivalent increases in a single cross-border transfer capacity. Table 37 reports the corresponding incremental welfare comparisons.

Table 37. Mean relative price differences for standalone Hungarian co-optimisation

Target / reference	Market	Paired days	Welfare gain [EUR]	Welfare gain [%]
C2a / C0a	DAM	261	2,558,455	0.0009
D2a / D0a	IDA2	193	4,313	0.0001
I2c / I0c	DAM	186	5,147,351	0.0024
I2c / I0c	IDA2	187	208,272,905	2.5837

The price indicator is the unweighted mean of relative zone–MTU changes, excluding observations with zero reference prices.

The incremental value of DLR is much larger in the combined IDA2 sequence than in standalone IDA2. This is consistent with additional capacity enabling trading opportunities created by residual orders and capacity carried forward between auctions. The comparison supports evaluating network capability together with market design, while not separately quantifying each interaction.

Price effects are assessed through absolute monthly zonal differences, expressed in EUR/MWh for energy and EUR/(MW h) for balancing capacity. Standalone co-optimisation produces relatively small energy-price changes, while reserve-price effects are more pronounced. In the bid-forwarding configurations, lower monthly energy prices can coexist with higher upward-reserve prices. Aggregate welfare improvement therefore does not imply that every product price decreases.

Standalone DAM execution success rates are approximately 71–72%, while standalone IDA2 rates are approximately 93–94% after applying the IDA launch-date cutoff. H0c completes 561 of 618 scheduled stages and provides 177 complete three-stage days. G0a completes 719 of 820 stages with 159 complete four-stage days; I0c completes 621 of 820 with 60 complete days, and I2c completes 605 of 820 with 48 complete days. Stage-level success and complete-day execution therefore describe different aspects of workflow performance.

Median complete-day runtime is 46.22 minutes for G0a, 26.56 minutes for H0c, 35.14 minutes for I0c and 28.23 minutes for I2c. Sequential runtime sums the required auction-stage durations and includes only complete days. Different stage counts and samples prevent these medians from establishing a causal runtime advantage for any individual mechanism. Missing outputs as well as infeasibility contribute to unsuccessful execution, so completion rates do not identify solver performance as the sole cause.

The yearly evaluation demonstrates repeated operation of the principal configurations and positive economic outcomes on the evaluated samples. Further development should prioritise consistent initial inputs, reliable completion of sequential stages and assessment against stage-specific operational deadlines. Detailed KPI definitions, product-price results and scenario evaluations are provided in D7.2, Sections 3.5.5 and 3.7.

5.3.3 Bulgaria: prediction accuracy, connection points and network studies

Prediction and thermal-rating results

Table 38 presents production-prediction errors, thermal-rating approximation errors and next-hour demand-forecasting results with their respective reference datasets [2].

Table 38. Bulgarian neural-model results and their measurement basis

Target	Model	Reported MAPE (%)	Reference and interpretation
WPP Sveti Nikola production	ANN [64, 32]	5.09	Production-data comparison; KPI reference error 9%, giving a 3.91 percentage-point difference.
SPP Karadzholovo production	ANN [64, 32, 24]	3.08	Production-data comparison; KPI reference error 5%, giving a 1.92 percentage-point difference.
Plovdiv–Aleko internal-line ampacity	ANN [24, 12, 24]	0.05	Calculated thermal-rating reference.
Thessaloniki–Blagoevgrad ampacity	ANN [32, 24, 16, 12, 6]	0.76	Calculated thermal-rating reference for the selected line.
Alen Mak active demand	LSTM; 24-hour look-back	2.1437	Next-hour active-demand prediction.
Belene active demand	LSTM; 48-hour look-back	2.1126	Next-hour active-demand prediction.

ANN structures are specified by layer size. LSTM windows indicate the historical look-back used for next-hour prediction.

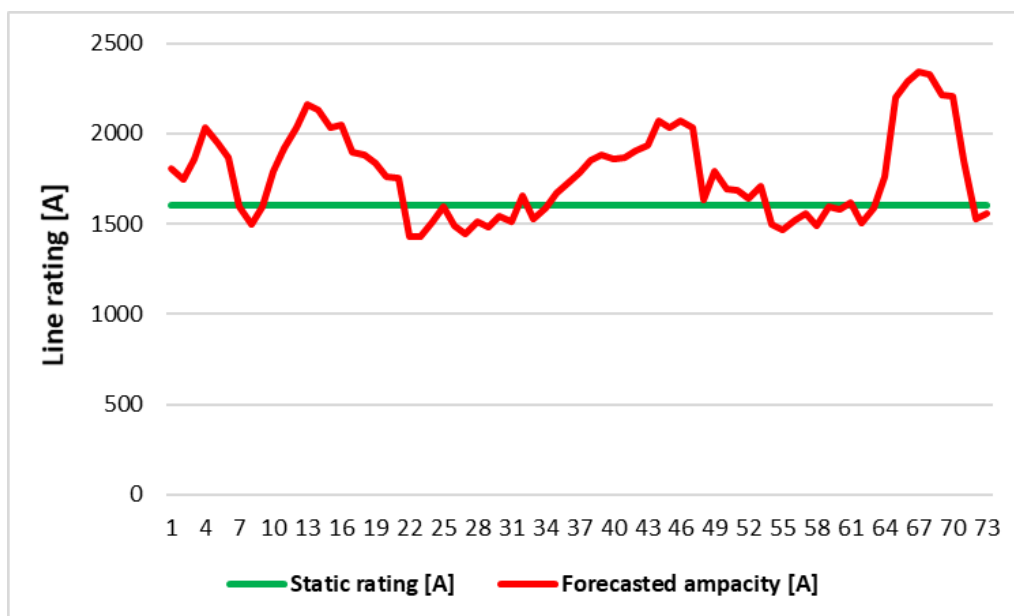


Figure 14. Forecast ampacity and static rating for the selected interconnector over the evaluated period, including intervals below the static rating.

Wind and solar MAPE values improve on the adopted literature references by 3.91 and 1.92 percentage points, respectively, exceeding the use-case target of 1 percentage point.

Over the selected 72-hour interval, the internal-line ampacity is approximately 42% above the static rating on average, while the interconnector result is approximately 10.7% above its static rating on average. The latter includes intervals below the static rating. Figure 14 illustrates this time-dependent interconnector comparison.

Percentage loading expresses current relative to the applicable rating. The rating and loading indicators refer to the selected lines and study period.

Connection-point optimisation

Table 39 presents the selected connections. Exhaustive evaluation of all 625 assignments confirms the genetic-algorithm solution, with an average line-loading objective of 13.42% across the charging and discharging cases.

Table 39. Selected connection points for the four virtual facilities

Facility	Represented capacity	Selected node
WPP 1	40 MW	1026
WPP 2	40 MW	1029
WPP 3	50 MW	1026
BESS	30 MW charging / 30 MW discharging	1025

Table 40. Line loadings in the selected connection configuration

Line / circuit	Battery charging (%)	Battery discharging (%)
1025–1028 (1)	13.3	16.3
1025–1029 (1)	22.8	27.0
1025–1031 (1)	16.0	19.0
1025–1031 (2)	16.0	19.0
1026–1028 (1)	7.4	9.9
1026–1029 (1)	8.0	12.1
1027–1028 (1)	6.6	6.5
1027–1029 (1)	7.4	7.4

Mean loading across the sixteen displayed values is 13.42%. Circuit identifiers distinguish parallel lines.

Repeated runs return the same assignment. Four facilities are connected at three selected nodes, meeting the use-case target of more than zero optimised connections. Figure 15 shows the charging case.



The Connector demonstration completes publication, subscription approval and consumption of the three forecast CSV services. Internal scripts incorporate these forecasts into the network-study inputs.

Use-case KPI register: identity, target and evaluated scope

The 19 use-case KPI records cover ten BUCs and four SUCs. All have recorded status Complete, coverage label “until M23” and evaluation date 31 October 2025 (M22). The tables retain their local identifiers, targets and evidence scores.

Table 41. Bulgarian data-exchange, forecasting and line-rating use-case KPIs

KPI / measure	Reported result; target; q	Measurement basis and interpretation
BG-BUC01.01 Percentage of verified DTs	100%; target 100%; q = 2.	Four DTs verified: three by the TSO and one by the DSO.
BG-BUC01.02 DT interoperability success rate	100%; target 100%; q = 2.	Correctly exchanged information / checked information exchanged between the DTs.
BG-BUC02.01 Improvement of WPP forecast accuracy	3.91 percentage points; target >1 percentage point; q = 4.	Literature reference MAPE 9.00% minus WPP MAPE 5.09%.
BG-BUC03.01 Improvement of SPP forecast accuracy	1.92 percentage points; target >1 percentage point; q = 4.	Literature reference MAPE 5.00% minus SPP MAPE 3.08%.
BG-BUC04.01 Internal line rating increase	Average 42%; target >0%; q = 4.	ANN-based ampacity compared with the internal line's static rating over the selected 72-hour study.
BG-BUC04.02 Reduction in internal line loading	Average 30.5%; target >0%; q = 4.	Submitted mean loading reduction under forecast versus static ratings. The interval currents, weighting and relative/percentage-point convention require confirmation.
BG-BUC05.01 Interconnector rating increase	Average 10.7%; target >0%; q = 4.	Forecast ampacity compared with the interconnector's static rating. The evaluated forecast includes intervals below the static rating.
BG-BUC05.02 Reduction in interconnector loading	Average 9.03%; target >0%; q = 4.	Submitted mean loading reduction under forecast versus static ratings. Its precise averaging basis is not independently reconciled from interval data.

The use-case register reports mean loading reductions of 30.5% for the internal line and 9.03% for the interconnector, alongside mean rating increases of 42% and 10.7%. These are retained as submitted values. Their common calculation basis is not fully specified: confirmation is needed of the interval currents, rating series, averaging weights and whether loading reduction means a relative change or a percentage-point difference. Increasing the rating can lower percentage loading without reducing physical current or increasing cross-zonal transfer capacity.

A conditional arithmetic check in this consolidation illustrates why that clarification matters. If current is unchanged in each compared interval, the same intervals and non-negative averaging weights are used, and the reported loading reduction is the weighted mean of relative reductions, each interval satisfies $r = u/(1 + u)$, where u is the fractional rating increase and r the fractional loading reduction. The concavity of this relationship gives a mean-reduction upper bound of 0.42/1.42, or approximately 29.577%, for a mean rating increase of 42%. Thus 30.5% is not compatible with those

assumptions. Different currents, weights or aggregation definitions require a different check. The 10.7%/9.03% pair does not violate its analogous 9.666% bound, but that alone does not verify it. These derived bounds are consistency diagnostics, not replacement simulation results.

Table 42. Bulgarian connection, security and flexibility use-case KPIs

KPI / measure	Result; target; q	Measurement basis and interpretation
BG-BUC06.01 Number of optimized connections	4 virtual facilities; target >0; q = 3.	Four facility-to-node assignments, occupying three distinct selected buses. The 625-case enumeration validates the selected assignment for the finite test problem.
BG-BUC07.01 Number of detected critical outages	3; target >0; q = 3.	Three critical N–1 outages producing four overloads in the selected snapshot.
BG-BUC07.02 Percentage of considered congestions	100%; target 100%; q = 3.	Corrective measures identified for all four N–1 overloads.
BG-BUC08.01 Number of detected critical outages (N-2)	4; target >0; q = 3.	Four critical additional outages while transformer 1035–1026 is under maintenance, producing five overloads.
BG-BUC08.02 Percentage of considered congestions (N-2)	100%; target 100%; q = 3.	All five maintenance-conditioned overloads are considered and corrective actions identified for the evaluated topology.
BG-BUC09.01 DSO-to-DSO mitigated congestions	100%; target 100%; q = 2.	Mitigated / identified congestions in the simulated DSO cases using DSO-connected FSPs.
BG-BUC10.01 DSO-to-TSO mitigated congestions	100%; target 100%; q = 2.	Mitigated / identified TSO congestions in the simulated cases using DSO-connected FSPs.

Table 43. Bulgarian system-use-case KPI records

KPI / measure	Result; target; q	Measurement basis and interpretation
BG-SUC01.01 Successfully conducted load flow analyses	72; target >0; q = 4.	72 hourly load-flow studies using forecast-populated network models.
BG-SUC02.01 Successfully estimated energy exchanges	72; target >0; q = 2.	TSO–DSO boundary exchange calculations for 72 hourly operating regimes.
BG-SUC03.01 Percentage of assessed differences in ratings	100%; target 100%; q = 3.	Assessed / identified differences between forecast and static OHL ratings.
BG-SUC04.01 All-to-TSO mitigated congestions	100%; target 100%; q = 2.	Mitigated / identified TSO congestions for the tested selection of FSPs connected at either TSO or DSO level.

The studies run in batch mode and combine historical production and meteorological records with simulated operating conditions. Literature error values provide the references for the forecast-improvement KPIs.

Common validation KPIs: model accuracy, runtime and data quality

The seven common validation records have status Complete, coverage label “until M33” and evaluation date 28 August 2026 (M32). The tables present their results, targets and evidence scores.

Table 44. Bulgarian common validation KPIs for accuracy, computation and data

KPI / measure	Result; target; q	Calculation basis
VAL_KPI1 DT model output accuracy	4.085%. Target MAPE <5%; q = 4.	Unweighted mean of WPP and SPP MAPE: (5.09 + 3.08)/2.
VAL_KPI2 DT computational performance and latency	<5 s. Target <15 min; q = 2.	Duration of one forecasting-algorithm run in batch mode.
VAL_KPI6 Operational decision lead time gained by DT Forecast-horizon measure	72 h = 4,320 min. Target >30 min; q = 3.	Forecast coverage of 72 hours.
VAL_KPI8 Data quality index for DT input data	100/100. Target >90%; q = 2.	Mean completeness and plausibility scores for the requested historical 2018–2024 production dataset.

The mean of the wind and solar MAPEs is 4.085%. A forecasting run takes less than five seconds. The historical production dataset receives a data-quality score of 100/100 based on completeness and plausibility checks.

Common validation KPIs: interoperability, replication and operator feedback

Table 45. Bulgarian common validation KPIs for exchange, replication and usability

KPI / measure	Result; target; q	Calculation basis
VAL_KPI9 Data federation and interoperability coverage	100% = 3/3 exchanges. Target >80%; q = 1.	Three forecast-file exchanges completed between two represented Bulgarian-pilot roles.
VAL_KPI10 Transferability and replication potential score	4/4; unrounded mean 3.5/4. Target >3; q = 2.	Self-assessment scores 3, 4, 4, 3 for documentation, independence, configuration and regulatory portability. Upward rounding follows the register rule.
VAL_KPI12 Stakeholder usability and acceptance	3.7/4. Target >3; q = 2. Two organisations.	Mean of usefulness 4, ease of use 4, trust 3.5, fit 4 and intention to use 3, using TSO and DSO organisational responses.

Transferability is self-assessed across documentation, independence, configuration and regulatory portability, scored 3, 4, 4 and 3. The mean is 3.5/4, reported as 4/4 under the register's upward-rounding rule.

Usability scores average 3.7/4 across two organisations. Criterion means are usefulness 4, ease of use 4, trust 3.5, fit 4 and intention to use 3. The DSO and TSO organisational means are 3.6 and 3.8, respectively.

5.3.4 Cyprus: frequency response and regional support trade-offs

The eleven distinct scenarios are identified below by operating group and control variant. CN denotes a Cyprus disturbance under normal inertia; CL denotes a Cyprus disturbance under low inertia; and G denotes a mainland-Greece disturbance. The suffix B indicates the baseline, F fixed FSM and A adaptive FSM. GC and GU distinguish controlled and unconstrained HVDC support in the Greece cases. All shared-support cases also include the applicable FCR allocation.

The Greece baseline is common to both HVDC-transfer comparisons and is listed only once. Table 46 gives the complete Cyprus and mainland-Greece frequency indicators at the reported precision. The corresponding converter power components are separated in Table 47 [3].

Table 46. Frequency indicators for the eleven distinct HVDC support scenarios

Scenario	Cyprus nadir (Hz)	Cyprus settling (Hz)	Cyprus RoCoF (Hz/s)	Greece nadir (Hz)	Greece settling (Hz)	Greece RoCoF (Hz/s)
CN-B: baseline	48.88	48.93	0.432	50	50	0.147
CN-F: fixed FSM	49.43	49.49	0.392	49.98	49.99	0.101
CN-A: adaptive FSM	49.56	49.62	0.353	49.97	49.99	0.153
CL-B: baseline	49.05	49.19	0.502	50	50	0.101
CL-F: fixed FSM	49.51	49.65	0.579	49.96	49.96	0.095
CL-A: adaptive FSM	49.53	49.75	0.416	49.958	49.958	0.037
G-B: baseline	50	50	—	49.44	49.44	0.190
GC-F: controlled, fixed	49.87	49.87	0.037	49.53	49.53	0.175
GC-A: controlled, adaptive	49.75	49.75	0.088	49.71	49.74	0.178
GU-F: unconstrained, fixed	49.55	49.55	0.096	49.58	49.60	0.185
GU-A: unconstrained, adaptive	49.25	49.25	0.256	49.74	49.76	0.192

RoCoF is the maximum absolute value of the frequency-sample derivative after a one-second moving-average filter. Settling values refer to the post-transient portion of the ten-second disturbance; the low-inertia baseline is still settling at the end of this window. Disturbance magnitudes are 149 MW (CN), 69.35 MW (CL) and 514 MW (G).

Table 47. Reported HVDC and FSP frequency-support power components

Scenario	HVDC FCR (MW)	HVDC FSM (MW)	FSP FCR (MW)	FSP FSM (MW)
CN-B	0	0	0	0
CN-F	12	53	6	28
CN-A	10.67	61.33	5.33	33.67
CL-B	0	0	0	0
CL-F	11.73	21.27	5.87	11.13
CL-A	9.87	30.13	4.93	14.57
G-B	0	0	0	0
GC-F	18	8	10	110
GC-A	18	35	10	242.5
GU-F	18	84	10	82.5
GU-A	18	157	10	153.5

Values are the converter power contributions during the evaluated responses. Conventional-generator FCR remains active in the baseline.

For the normal-inertia Cyprus disturbance, the nadir improves from 48.88 Hz in the baseline to 49.43 Hz with fixed FSM and 49.56 Hz with adaptive FSM. The corresponding settling values are 48.93, 49.49 and 49.62 Hz. Adaptive support increases the HVDC and local-FSP contribution while retaining the distinction between the FCR and FSM components.

For low-inertia Cyprus, the nadir increases from 49.05 Hz to 49.51 Hz with fixed support and 49.53 Hz with adaptive support. Settling frequency increases from 49.19 Hz to 49.65 Hz and 49.75 Hz. Filtered RoCoF is 0.502 Hz/s in the baseline, 0.579 Hz/s with fixed support and 0.416 Hz/s with adaptive support.

In the controlled mainland-Greece cases, adaptive support raises the nadir from 49.53 to 49.71 Hz relative to fixed support. Filtered RoCoF changes from 0.175 to 0.178 Hz/s.

The regional trade-off is clearest in the adaptive Greece comparison. Removing the HVDC support constraint raises the mainland nadir by 0.03 Hz, from 49.71 to 49.74 Hz, but lowers the supporting Cyprus nadir by 0.50 Hz, from 49.75 to 49.25 Hz. The HVDC FSM contribution rises from 35 to 157 MW, while its FCR contribution remains 18 MW. The larger transfer improves the disturbed-system response at the expense of the supporting system's frequency performance.

Figure 16 shows the simulated frequency and power responses for the controlled adaptive mainland-Greece case.

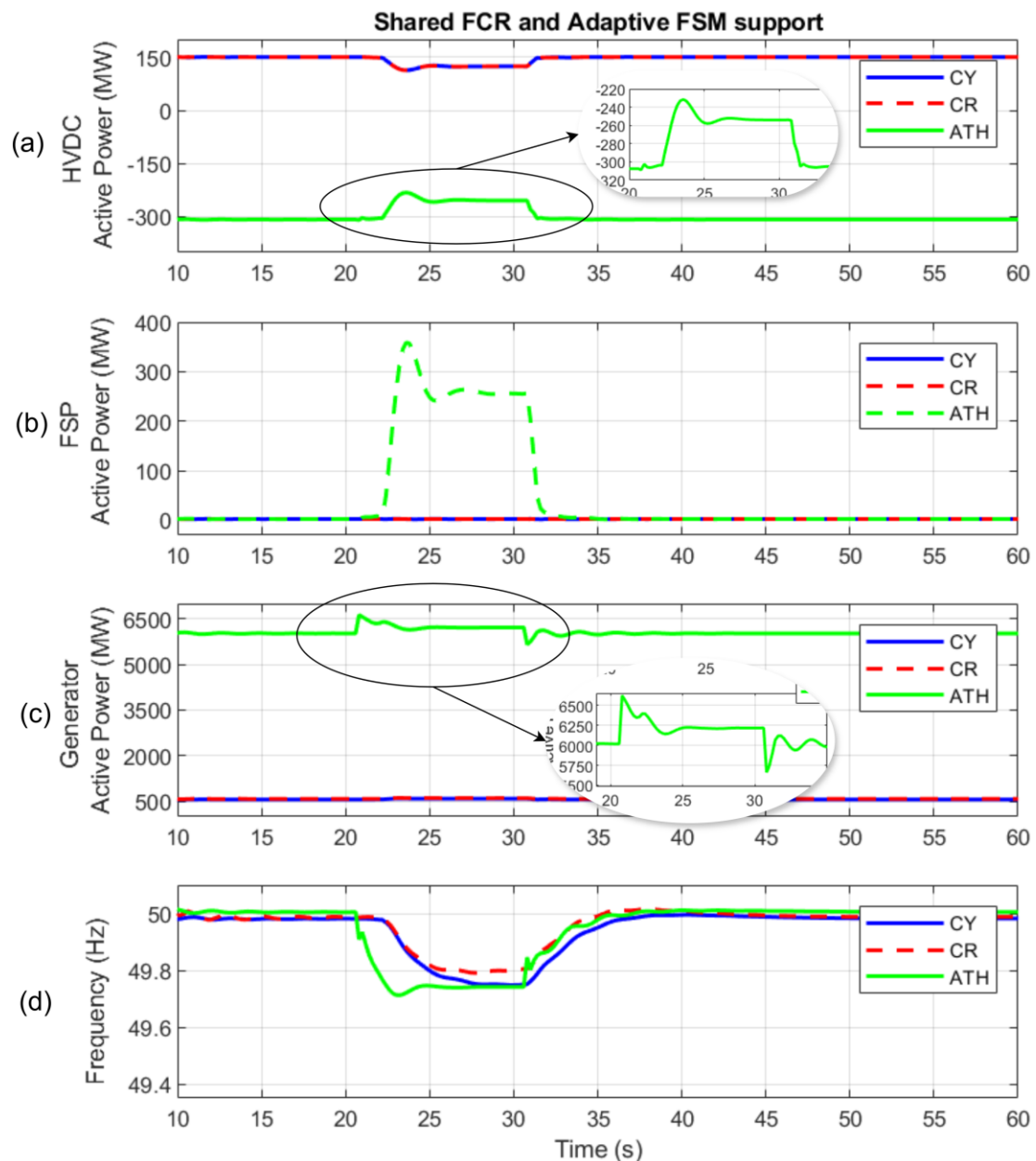


Figure 16. Controlled HVDC transfer with shared FCR and adaptive FSM during the mainland-Greece disturbance: HVDC, FSP and generator power, and system frequency.

The results support coordinated tuning of local and cross-border support. Assessment considers allocated FCR, additional FSM, and frequency performance in both disturbed and supporting systems.

5.3.5 Slovenia: model integration and DSA performance

The Slovenian indicators evaluate model integration and the DSA workflow. Table 48 summarises the implementation results, and Table 49 compares two operating-state studies [4].

Table 48. Slovenian assessment implementation and performance evidence

Item	Reported outcome	Assessment basis
SLO-BUC-1	Distribution-equivalent integration and RMS dynamic analysis achieved.	Measurement-supported static voltage sensitivity with configured dynamic and frequency-dependent parameters.
SLO-BUC-2	Extended dynamic model and DSA workflow achieved; more than 26,000 operating states processed.	National model and external observability area with available dynamic data.
Dynamic model exchange	MAVIR generator and controller information incorporated.	Dynamic-data exchange with one neighbouring TSO.
SLO-SUC-1	Operational snapshot export, shared storage, retrieval and simulation-tool import achieved.	Operational-data path for model initialisation and assessment.
AI-assisted acceleration	Approximately 37% mean runtime reduction in a comparison of 96 operating states.	Comparison across 96 states on the evaluated computing configuration.
Transient-stability verification	Predicted CCT below 400 ms is verified through detailed simulation.	Predictions below 400 ms undergo simulation verification; higher predictions may be displayed as AI estimates.
Task 7.7 FFR service	Service requirements, product definition, algorithm and simulation-testing development.	Prospective service-development context. The DSA results do not quantify FFR activation or delivered-service performance.

Figure 17 compares DSA runtime with and without AI assistance across 96 operating states. Mean total execution time is reduced by approximately 37%.

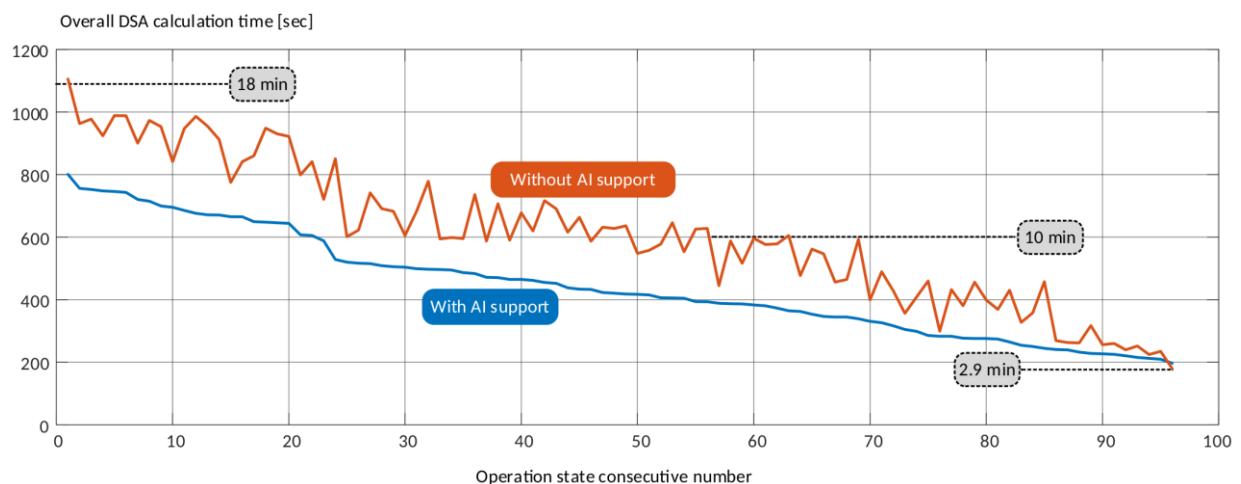


Figure 17. Comparison of DSA execution times with and without AI assistance for 96 operating states, ordered by calculation time.

Table 49. Individual Slovenian operating-state validation and stability findings

Indicator	Lightly loaded night-time case	Higher-load case
Operating state	25 April 2026, 03:00	2 April 2026, 19:00
Mean active-flow deviation	1.35% of rated transmission-line power	2.09% of rated transmission-line power
Mean reactive-flow deviation	1.24% of rated transmission-line power	1.79% of rated transmission-line power
Transient stability	Mean CCT approximately 500 ms; reported values above 150 ms.	Mean CCT slightly above 350 ms; none of the evaluated values below 150 ms.
Online rotational kinetic energy	Approximately 26% of the maximum represented resources.	Nearly 60% of the maximum represented resources.
Small-signal stability	Reported identified modes have damping above 5%.	Two local modes have damping of approximately 2.1% and 2.6%, below the 3% critical-display threshold.

Power-flow deviations are normalised to rated transmission-line power. The two cases represent different generation, loading and topology conditions.

The higher-load case has evaluated CCT values above 150 ms and two poorly damped local electromechanical modes. Transient and small-signal results therefore identify different aspects of its security performance.

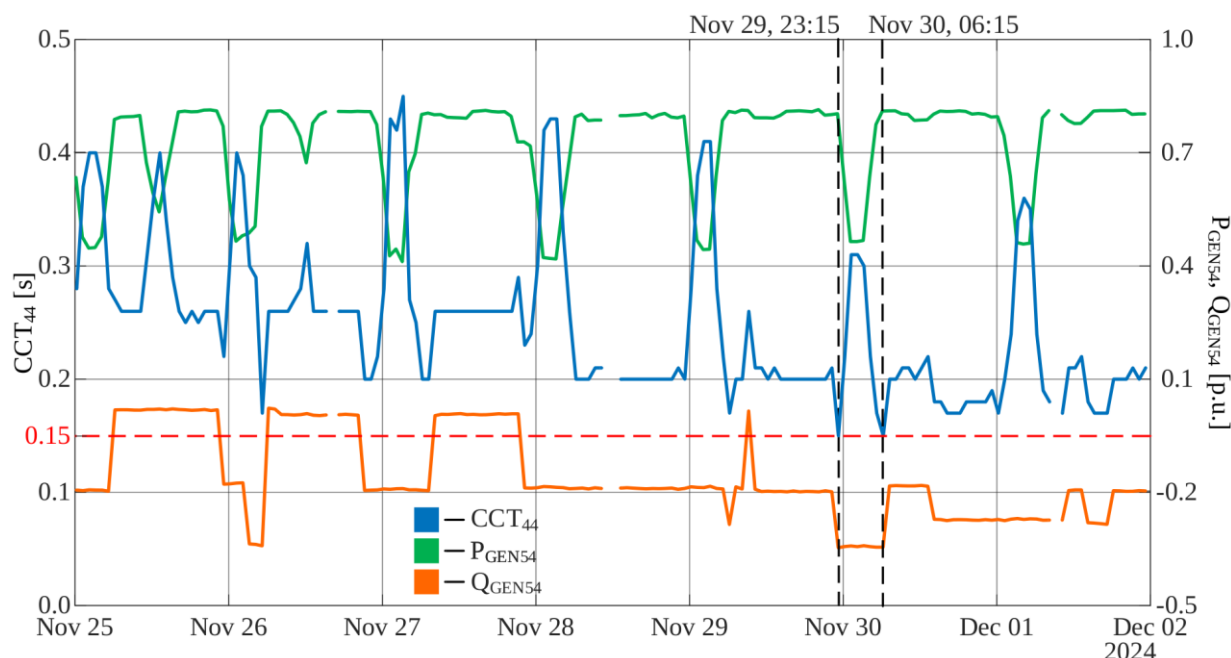


Figure 18. Time evolution of the critical clearing time for the anonymised line-44 contingency and the active/reactive operating point of GEN54.

The time-series study covers operating states between 25 November and 2 December 2024, sampled hourly at fifteen minutes past the hour. For the anonymised GEN54 and a fault on line 44, CCT falls to approximately 150 ms at the identified states on 29 November at 23:15 and 30 November

at 06:15. These low margins coincide with high active output and reactive-power absorption, as illustrated in Figure 18.

The sensitivity study improves transient-stability margins by reducing the magnitude of the generator's reactive-power absorption. Local voltage-support requirements are considered alongside the revised operating point.

Additional Boolean assessment KPIs

All four Slovenian records have target Pass, result Achieved, status Complete, evidence score $q = 3$ and evaluation date 24 June 2026. Table 50 presents the local identifiers, catalogue mappings and recorded coverage labels.

Table 50. Slovenian Boolean KPI records and catalogue correspondence

Local KPI / catalogue mapping	Assessment basis	Declared data / mode / coverage	Interpretation
SLO-BUC-2_VAL_KPI2 Close-to-real-time computational performance	National PowerFactory RMS model and operating-state snapshots. Successful close-to-real-time assessment is the pass criterion.	Real operational data; field-measurement reference; near-real-time mode. Coverage label M3–M33.	Boolean Pass achieved across the assessment functions of SLO-BUC-1, SLO-BUC-2 and SLO-SUC-1.
SLO-BUC-1_VAL_KPI1 Use of the equivalent model in RMS studies Catalogue link: SLO_UC1_KPI2.	PowerFactory RMS studies of the Gorenjska model, including 110/20 kV substations and representative disturbances.	Synthetic disturbance simulations; conventional static-load reference; batch mode. Coverage: stated RMS validation studies.	Successful RMS execution and interpretable active/reactive responses with the upgraded equivalent.
SLO-BUC-2_VAL_KPI1 Interconnected-network stability assessment Catalogue links: SLO_BUC2_KPI1–KPI4.	National model and observability area with available external dynamic data; assessment validated against past-event PMU records.	Real operational data; field-measurement reference. Mode declared near-real-time and real time; coverage M3–M33.	Periodic dynamic assessment with operational data and model information from one neighbouring TSO.
SLO-SUC-1_VAL_KPI1 SCADA/EMS snapshot integration Catalogue link: SLO_SUC1_KPI1.	15-minute state-estimator snapshots initialise the model; calculated flows and bus voltages are checked against field values.	Real operational data; field-measurement reference; near-real-time mode. Coverage label M3–M33.	Successful operating-state reconstruction and data integration.

The assessment workflow uses SCADA/EMS state-estimator snapshots for model initialisation and comparison with calculated flows and voltages.

5.4 Challenges and Lessons Learned

Table 51 summarises the implementation challenges and the approaches used across the demonstrations.

Table 51. Cross-pilot implementation challenges and response status

Challenge area	Concrete examples	Implemented approach
Data availability and confidentiality	Confidential market and network data; thermal-rating references; external dynamic-model parameters.	Anonymised identifiers, virtual connection facilities, calculated thermal references and generic external models.
Temporal alignment	Quarter-hourly schedules, hourly study models, 24-hour weather coverage, next-hour LSTM outputs and 15-minute snapshots.	Workflow-specific preprocessing and compatible time bases.
Forecast–decision integration	Forecasts, market scenarios and operating snapshots have different roles; some inter-tool exchanges remain file-based.	Pilot-specific coupling through structured files, scripted transfers and real-time interfaces.
Computational effort	Mixed-integer clearing, repeated network studies and numerous dynamic simulations.	Input aggregation, scripted case generation, parallel simulation and AI-assisted screening reduce effort within their respective applications.
Physical model fidelity	Aggregated storage, selective MV coverage, equivalent AC systems and simplified external-network dynamics.	Separate grid validation and model-quality gates within the represented network scope.
Scenario comparability	Different Greek requirements, Hungarian initial-stage input comparability and unequal valid-day samples, and Cyprus disturbance magnitudes.	Explicit reference configurations and auction stages; Hungarian mechanism attribution requires common initial inputs and valid dates; differences between independently aggregated totals do not isolate individual effects.
Operator usability and trust	Complex stability indices, competing network effects and AI estimates of differing verification status.	Dedicated interfaces and organisational feedback; Bulgarian usability score 3.7/4 from two organisations.
KPI definition and reporting	Different denominators and averaging methods; DR availability alignment, partial FFR cashflow and unconfirmed rating/loading aggregation.	State the reference, unit, sample and evaluation date. Retain submitted values with specific qualifications instead of assuming missing inputs are reconciled.

The results show that the economic value of additional network capacity depends on binding constraints and the trading opportunities available to market clearing. In Hungary, standalone DLR welfare gains are small, whereas the combined sequence produces a substantially larger IDA2 benefit. Flexibility and cross-border support can improve one indicator while worsening another. Data exchange, predictive accuracy, physical feasibility and complete workflow execution require distinct checks.

Table 52 summarises practices for applying these methods in other networks and operating environments.

Table 52. Implementation lessons and conditions for reuse

Area	Practice supported by the demonstrations	Condition for reuse
Forecast deployment	Identify the prediction target, reference dataset, horizon, historical look-back and update process separately.	Retain the same definitions when comparing accuracy or integrating the output into another model.
Optimisation logic	Represent shared physical capability and keep the relevant baseline fixed in a mechanism comparison.	Explicit product eligibility, local deliverability and reference inputs.
DT architecture	Separate data preparation, model execution, validation and presentation while retaining scenario and asset identity.	A reusable module still requires compatible inputs and an identified owner of validation and access rights.
User engagement	Provide the context behind a result: disturbance, location, reference, constraint and verification status.	Operator oversight for consequential decisions and application-specific user feedback.
Service development	Use validated dynamic models to test proposed support logic before operational deployment.	Service-specific activation tests and frequency-response assessment within the validated model.

Further development priorities include detailed resource modelling, wider operator-data access, additional operating conditions and improved automated interfaces.

6 Conclusions

Taken together, the demonstrations establish that effective digital-twin decision support depends on the consistency between what is anticipated, what is selected and what the represented system can sustain. Forecast accuracy, economic efficiency and dynamic performance are therefore complementary dimensions of evaluation, not substitutes for one another. The contribution of Task 7.1 is to bring these dimensions into a common methodological perspective, so that the relevance and limits of each analytical result remain visible when moving from a conceptual use case to a tested application.

The complementarity of the pilots is clearest at the boundaries between decision problems. The Greek and Hungarian market studies expose how resource allocation and network capability interact; the Bulgarian studies show why those capabilities also depend on the operating conditions and connection locations represented in the network. The Cypriot controller investigations and Slovenian dynamic-security assessments add the disturbance-response perspective needed alongside scheduling and steady-state feasibility. Together, these contributions connect planning, market coordination and security assessment at the conceptual level. They do not constitute a single coupled implementation, but they demonstrate the importance of considering these perspectives together when evaluating proposed grid and market actions.

A common lesson is that the benefit of flexibility cannot be judged solely by the volume offered, allocated or exchanged. Its usefulness depends on location, timing, competing service obligations and the constraints of the systems providing and receiving support. Likewise, additional network capability does not guarantee an economic improvement, and a better response in one system can impose a greater burden on another. The digital-twin approach allows these trade-offs to be examined before proposed arrangements are introduced into physical operation or live market processes.

Interoperability consequently requires more than a working data connection. The documented workflows indicate that reusable services need consistent asset identities, compatible temporal definitions, explicit model boundaries and a clear allocation of data-access and validation responsibilities. Modularity allows these requirements to be addressed without imposing a single software environment or removing local operational expertise. Operator interfaces and review remain integral to this architecture because the interpretation and acceptance of consequential actions cannot be inferred from successful computation alone.

The transition from demonstration to wider use should build on the evidence already established while retaining its scope. Scenario results, model-validation outcomes and successful information exchanges support different claims; none alone certifies an operational service. Unresolved data and calculation issues require confirmation at their source, while further development should prioritise broader operating-condition coverage, appropriate resource and network detail, improved interfaces and service-specific validation. These are complementary steps towards deployment, rather than grounds for treating all applications as equally mature.

The resulting perspective supports the TwinEU ambition of a federated digital-twin ecosystem through complementary expertise rather than uniform implementations. Progress towards that ambition depends on preserving the link between data, model assumptions, decisions and validated consequences as applications are extended and shared. The collective contribution is a method for developing and assessing coordinated grid and market services while retaining the local knowledge and accountability on which reliable use depends.

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